FILED MAY 20, 2014
DOCUMENT NO. 02380-14
FPSC - COMMISSION CLERK



May 20, 2014

Carlotta Stauffer
Director, Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

RE: Docket No. 130199-EI Florida Power & Light Company
Docket No. 130200-EI Duke Energy Florida, Inc.
Docket No. 130201-EI Tampa Electric Company
Docket No. 130202-EI Gulf Power Company
Docket No. 130203-EM JEA
Docket No. 130204-EM Orlando Utilities Commission
Docket No. 130205-EI Florida Public Utilities Company

Dear Ms. Stauffer:

Enclosed for filing in the above-stated dockets please find the Sierra Club's Direct Testimony of Tim Woolf and Exhibits TW-1 through TW-13. Sierra Club confirmed that the Parties received the Testimony and Exhibits yesterday; however, Sierra Club understands that the Clerk's Office was unable to access the Exhibits due to a technical issue. Further, Sierra Club corrected a technical issue with the way that certain characters appear in the Prefiled Testimony. Should you have any questions regarding this filing, please call me at (413) 768-7313.

Sincerely,

/s/ Diana A. Csank

Diana A. Csank
50 F St NW, 8th Floor
Washington DC 20001
(202) 548-4595 (direct)
(413) 768-7313 (mobile)
Diana.Csank@sierraclub.org
Qualified Representative for Sierra Club

Enclosures

CERTIFICATE OF SERVICE
DOCKET NOS. 130199-130205

I HEREBY CERTIFY that a true and correct copy of the foregoing was served by electronic delivery this 20th day of May, 2014 to the following:

Florida Public Service Commission Charles Murphy, Theresa Tan, Kelley Corbari, Shalonda Hopkins 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 cmurphy@psc.state.fl.us ltan@psc.state.fl.us kcorbari@psc.state.fl.us	**Duke Energy Florida** Mr. Paul Lewis, Jr., Dianne Triplett, John Burnett, Matthew Bernier 106 East College Avenue, Suite 800 Tallahassee, FL 32301-7740 paul.lewisjr@duke-energy.com john.burnett@duke-energy.com dianne.triplett@duke-energy.com matthew.bernier@duke-energy.com
Florida Power & Light Company (Juno) John Butler/Jessica Cano 700 Universe Blvd Juno Beach, FL 33408 John.Butler@FPL.com Jessica.Cano@fpl.com	**Florida Industrial Power Users Group** Jon C. Moyle, Jr./Karen Putnal c/o Moyle Law Firm 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com
Florida Power & Light Company (Miami) Kevin Donaldson 4200 West Flagler Street Miami, FL 33134 kevin.donaldson@fpl.com	**Tampa Electric Company** Ms. Paula K. Brown P. O. Box 111 Tampa, FL 33601-0111 Regdept@tecoenergy.com
Florida Power & Light Company Mr. Ken Hoffman 215 South Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com	**Hopping Law Firm** Gary V. Perko P.O. Box 6526 Tallahassee, FL 32314 Gperko@hgslaw.com
Florida Public Utilities Company Ms. Cheryl M. Martin 1641 Worthington Road, Suite 220 West Palm Beach, FL 33409-6703 cyoung@fpuc.com	**Beggs & Lane** J. Stone/R. Badders/S. Griffin P.O. Box 12950 Pensacola, FL 32591-2950 srg@beggslane.com
Orlando Utilities Commission Mr. W. Christopher Browder P. O. Box 3193 Orlando, FL 32802-3193 cbrowder@ouc.com	**Gulf Power Company** Mr. Robert L. McGee, Jr. One Energy Place Pensacola, FL 32520-0780 rlmcgee@southernco.com

Southern Alliance for Clean Energy George Cavros 120 E. Oakland Park Blvd., Suite 105 Fort Lauderdale, FL 33334 George@cavros-law.com	**Florida Department of Agriculture and Consumer Services** Steven L. Hall, Senior Attorney Office of General Counsel 407 South Calhoun Street, Suite 520 Tallahassee, FL 32399 Steven.Hall@FreshFromFlorida.com
Earthjustice Alisa Coe/David G. Guest 111 S. Martin Luther King Jr. Blvd. Tallahassee, FL 32301 acoe@earthjustice.org Attorneys for SACE	**Environmental Defense Fund** John Finnigan 128 Winding Brook Lane Cincinnati, Ohio 45174 jfinnigan@edf.org
JEA Mr. P. G. Para 21 West Church Street, Tower 16 Jacksonville, FL 32202-3158 parapg@jea.com	**Office of Public Counsel** c/o The Florida Legislature 111 W. Madison Street, Room 812 Tallahassee, FL 32399-1400 sayler.erik@leg.state.fl.us
Wal-Mart Stores East, LP & Sam's East, Inc. Kenneth E. Baker Energy Department 2001 SE 10th St. Bentonville, AR 72716-0550 ken.baker@wal-mart.com	**Florida Solar Energy Industries Ass'n** Colleen McCann Kettles, JD ckettles@fsec.ucf.edu
Keyes, Fox and Wiedman LLP Kevin Fox/Justin Barnes/Rusty Haynes 436 14th St., Ste. 1305 Oakland, CA 94612 kfox@kfwlaw.com	**Southeast Energy Efficiency Alliance** Abby Schwimmer aschwimmer@seealliance.org
Opower Alex Lopez alex.lopez@opower.com	**The Alliance for Solar Choice** Anne Smart 595 Market St. 29th Floor San Francisco, CA 94105 anne@allianceforsolarchoice.com

DATED this 20th day of May, 2014.

/s/ Diana A. Csank

Diana A. Csank
Diana.Csank@sierraclub.org
Qualified Representative for Sierra Club

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric conservation goals (Florida Power & Light Company).	DOCKET NO. 130199-EI
In re: Commission review of numeric conservation goals (Duke Energy Florida, Inc.).	DOCKET NO. 130200-EI
In re: Commission review of numeric conservation goals (Tampa Electric Company).	DOCKET NO. 130201-EI
In re: Commission review of numeric conservation goals (Gulf Power Company).	DOCKET NO. 130202-EI
In re: Commission review of numeric conservation goals (JEA).	DOCKET NO. 130203-EM
In re: Commission review of numeric conservation goals (Orlando Utilities Commission).	DOCKET NO. 130204-EM
In re: Commission review of numeric conservation goals (Florida Public Utilities Company).	DOCKET NO. 130205-EI Filed: May 19, 2014

Direct Testimony of Tim Woolf

On Behalf of the Sierra Club

On the Topic of Setting Goals for Increasing the Efficiency of Energy Consumption and Increasing the Development of Demand-Side Renewable Energy Systems

May 19, 2014

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Exhibit TW-4	Ceres, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know*, prepared by Ron Binz, Rich Sedano, Denise Furey, Dan Mullen, April 2012.
Exhibit TW-5	Synapse Energy Economics, *2013 Carbon Dioxide Price Forecast*, November 2013.
Exhibit TW-6	Synapse Energy Economics, Inc., *Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for Other Program Impacts and Environmental Compliance Costs*, prepared for Regulatory Assistance Project, November 2012.
Exhibit TW-7	Synapse Energy Economics, *Best Practices in Energy Efficiency Program Screening: How to Ensure that the Value of Energy Efficiency is Properly Accounted For*, prepared for the National Home Performance Council, July 2012.
Exhibit TW-8	Florida Solar Energy Center (FSEC). ZEH: Lakeland, Florida. 1998.
Exhibit TW-9	Kristen Funk, Small Business Energy Efficiency: Roadmap to Program Design, Proceedings of the 2012 ACEEE Summer Study on Energy Efficiency in Buildings, August 2012.
Exhibit TW-10	Synapse Energy Economics. Big Risks, Better Alternatives - An Examination of Two Nuclear Energy Projects in the U.S. October 6, 2011.
Exhibit TW-11	NREL. Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities, February 2012
Exhibit TW-12	US DOE. SunShot Vision Study, February 2012
Exhibit TW-13	Interstate Renewable Energy Council. U.S. Solar Market Trends 2012, July 2013

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and employer.

A. My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning and analysis. Our work covers a range of issues, including economic and technical assessments of energy resources; electricity market modeling and assessment; integrated resource planning; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the US Environmental Protection Agency, the US Department of Energy, the US Department of Justice, the Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has over twenty-five professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU). In that capacity, I was responsible for overseeing a considerable expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of DPU's energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; the review of smart grid pilot programs; and the review and approval of long-term contracts for renewable power. I also oversaw a variety of other DPU dockets, including several electric and gas rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director of the Association for the Conservation of Energy; a Staff Economist at the

Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Master's Degree in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a Bachelor of Science Degree in Mechanical Engineering and a Bachelor of Arts Degree in English from Tufts University.

Q. Please describe your professional experience as it relates to energy efficiency policies and programs.

A. Energy efficiency policies and programs have been at the core of my professional career. While at the Massachusetts DPU, I played a leading role in updating the Department's energy efficiency guidelines, in reviewing and approving the 2010-2012 three-year energy efficiency plans, in reviewing and approving energy efficiency annual reports, in leading a working group on rate and bill impacts, and advocating for the New England wholesale electricity market to include energy efficiency. I also co-chaired the Working Group on Utility Motivation as part of the State Energy Efficiency Action Network sponsored by the US Department of Energy and the US Environmental Protection Agency.

As a consultant, my work has encompassed all aspects of energy efficiency program design and implementation, including cost-benefit analyses, avoided costs, program budgeting, program assessment, utility financial incentives and other relevant regulatory policies. I am currently the lead technical consultant for the National Efficiency Screening Project. In addition, I recently completed three national studies on demand resource cost-effectiveness, including one for the US Department of Energy and the Federal Regulatory Commission. I have reviewed and critiqued utility energy efficiency policies and programs throughout the US, and I have testified on these issues in British Columbia, Colorado, Delaware, Kentucky, Massachusetts, Minnesota, Nevada, Nova Scotia, Québec, and Rhode Island. I have also represented clients on several energy efficiency collaboratives, where policies and programs were discussed and negotiated among a variety of stakeholders. I work for a variety of clients on energy efficiency

issues, including consumer advocates, environmental advocates, regulatory commissions and the US Department of Energy.

Q. On whose behalf are you testifying in this case?

A. I am testifying on Sierra Club's behalf.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the goals of the electric utilities that are subject to the Florida Energy Efficiency and Conservation Act (the Utilities). I focus on Florida Power & Light Company (FPL) and Duke Energy Florida, Inc. (DEF), because they serve such a large portion of Florida's electricity demand. However, many of my findings and recommendations can and should be applied to all of the Utilities.

Also, much of my testimony addresses the Utilities' energy efficiency and load management programs. I also address demand-side renewable resources, primarily in Section 7. Throughout my testimony, I refer to the energy efficiency and load management programs as demand-side management (DSM), and I refer to the customer-sited renewable resources as demand-side renewables. I do not address supply-side efficiency goals.

Q. Have you previously testified before this Commission?

A. No.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

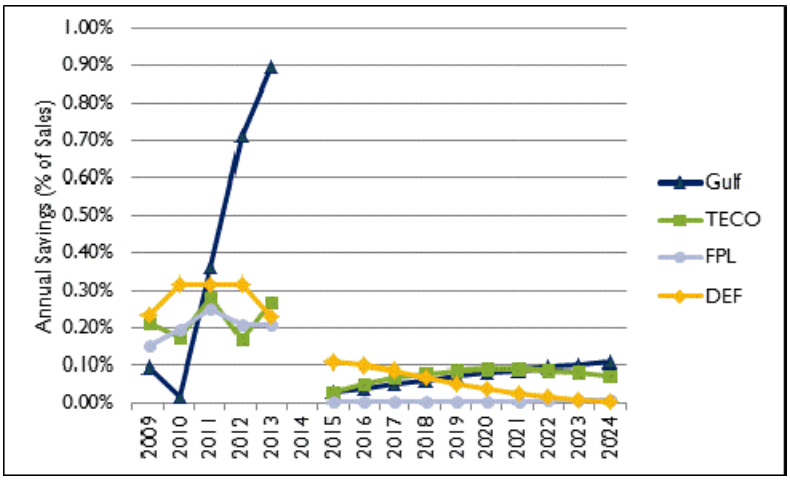
Q. Please summarize your primary conclusions.

A. My primary conclusions are summarized below. Additional details and citations are provided in the main body of my testimony.

<u>The Utilities DSM Goals Are Extremely Low</u>

By any measure the Utilities' proposed DSM goals are extremely low. Figure 2.1 compares the DSM goals proposed by FPL, DEF, Tampa Electric Company (TECO) and Gulf Power Company (Gulf) to these utilities' DSM savings in recent years.

Figure 2.1 Historic Savings and Proposed Energy Goals



As Figure 2.1 shows, the proposed goals depart dramatically from past DSM savings levels. For example, FPL achieved 214 GWh savings in 2013, but proposes to save 2.4 GWh in 2015. In other words, *FPL's proposed goals are one hundred times less than what FPL achieved in 2013*—a drop that my analysis below shows is entirely unwarranted.

The Utilities' historic DSM savings are well below industry practices in most other states. In 2011 over half of the states in the US saved at least 0.5 percent of retail sales though DSM programs, several states saved over 1.0 percent of retail sales. If the Commission were to accept FPL's proposed DSM goals, then FPL's energy savings in 2015 would be less than the 2011energy savings achieved by every other state in the country.

Figure 2.1 also shows that these four utilities propose very different DSM goals over the relevant ten-year period, from 2015 to 2024: DEF's goals, like FPL's, decline to almost nothing, while Gulf and TECO's goals increase modestly. This raises the question of why DEF would have such a dramatic decline in its goals, while other utilities are able to increase their goals over the same period.

These proposed DSM goals are not low because the DSM opportunities are not available or are not cost-effective—as the Utilities claims. The proposed goals are also not low because the Utilities have already achieved most of the DSM potential that is available,

or that new building codes and appliance standards are going to eliminate DSM opportunities—as the Utilities claim.

These goals are extremely low because the Utilities have skewed the analysis by applying overly narrow definitions of cost-effectiveness, thereby significantly understating the value of DSM programs—the lowest-cost, lowest-risk resource. In addition, the Utilities' resource planning processes[1] contain fundamental flaws, leading to results that are not credible, that understate the value of DSM, and ultimately do not provide the Commission with the information necessary to set goals pursuant to FEECA.

The Utilities' DSM Screening Practices Understate the Value of DSM

The Utilities try to define cost-effectiveness in ways that understate the value of DSM. As a result, the Utilities' DSM screening practices are incorrect, misleading, and should not be used for the purpose of setting DSM goals. In particular:

- The Utilities' definition of cost-effectiveness does not take into consideration "the costs and benefits to the general body of ratepayers as a whole," as required by Section 366.82(3), Florida Statutes (F.S.).
- The Utilities ultimately only apply one DSM screening test—the Rate Impact Measure (RIM) test. Despite references to other tests, the Utilities use the RIM test as the sole criterion for proposing DSM goals. The RIM test should not be used to determine DSM cost-effectiveness. It has been rejected by essentially every state except Florida. There are better ways to address the important issue of DSM rate impacts.
- The Utilities use incorrect methodologies and assumptions for estimating the lost revenues from DSM programs. Consequently, the Utilities significantly overstate their estimates of lost revenues—the key additional cost included in the RIM test.

[1] I use the terms resource planning processes and resource planning practices interchangeably to mean the Utilities' analytic methodology for resource planning.

- The Utilities do not properly account for the cost of complying with greenhouse gas (GHG) regulations, as required by Section 366.82(3)(d). The Utilities also do not account for non-energy benefits of DSM. Consequently, their analyses significantly understate the benefits of DSM, both to participants and non-participants.

The Utilities' Resource Planning Practices are Fundamentally Flawed

In my 30 years of experience in reviewing and regulating DSM plans and integrated resource plans, I have never seen such opaque, convoluted, and misguided resource screening practices. In particular, the Utilities' attempt to incorporate DSM into their resource planning suffers from the following flaws:

- The Utilities' technical potential estimates significantly understate the full technical potential for DSM in Florida by ignoring several efficiency technologies, and by applying an overly-stringent free-rider screen.

- FPL and DEF undervalue DSM by conducting two economic screens. The problem with this approach is that the first screen can eliminate a lot of potential DSM measures, before they even get a chance to be integrated and "optimized" with supply-side resources.

- FPL's resource planning understates DSM capacity (i.e., MW) benefits by freezing in place several new generation options, including new combustion turbines and the Turkey Point Units 6 and 7. Thus, FPL ignores the potential for DSM measures to postpone, reduce or avoid these expensive new capacity requirements, and fails to account for key benefits of DSM.

- FPL's resource planning understates DSM energy (i.e., MWh) benefits by assuming that DSM measures can only be installed for meeting reliability needs. This simplistic assumption dramatically understates another key benefit of DSM.

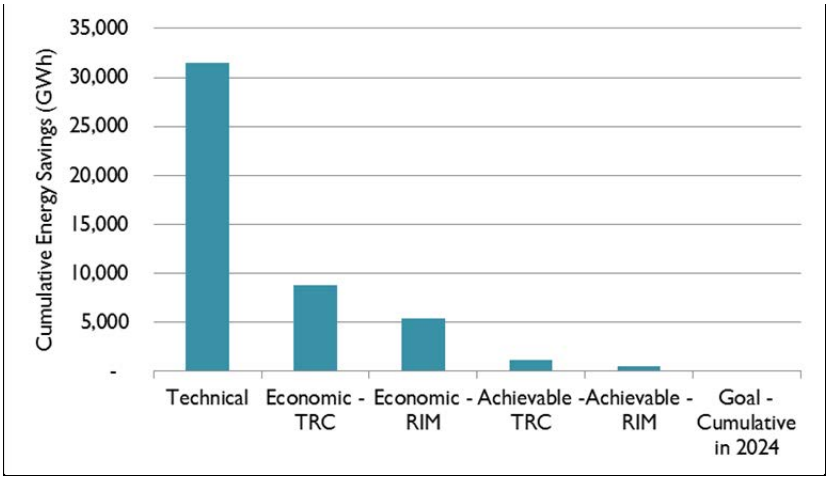
- The Utilities' resource planning is unnecessarily complex and opaque. FPL claims that its complicated process is necessary to understand the economic impacts of DSM, but in fact FPL's process obscures and understates DSM benefits.

Consequently, the output of the process provides no meaningful information regarding the real value and implications of DSM.

The practices listed above conflict with the standard industry resource planning practices.[2] So much so that the results of the Utilities' aberrant practices are not credible and the Commission should not use them to set goals here.

Figure 2.2 shows the results of FPL's technical, economic and achievable estimates, demonstrating how a dramatic reduction in DSM potential occurs at each step. At the final step, due to FPL's incorrect practice of considering DSM only when it is needed to meet reliability needs (in MW), FPL eliminates nearly all potential DSM from its proposed goals—this is not a credible result.

Figure 2.2 FPL Efficiency Savings at Various Screening Levels (GWh)



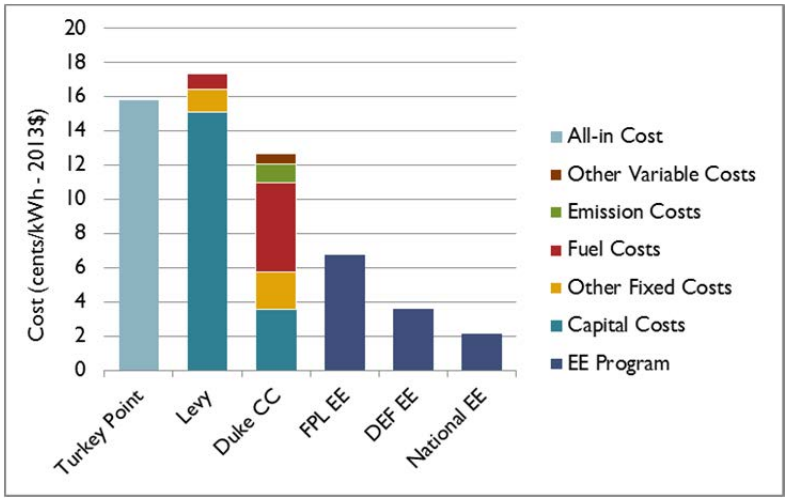
DSM costs significantly less than supply-side alternatives. Therefore, DSM can significantly reduce utility system costs and customer bills, a key fact that risks being obscured by the Utilities' incorrect analysis.

Figure 2.3 compares the levelized cost of saved energy from DSM to the levelized costs of the proposed Turkey Point and Levy nuclear facilities, and the estimated costs of the

[2] See, e.g., Synapse Energy Economics, *Best Practices in Electric Utility Integrate Resource Planning*, prepared for the Regulatory Assistance Project, 2013.

combined-cycle gas facility used by DEF in its resource planning process.[3] DSM is the clear winner, costing significantly less than alternative resources, contrary to what the Utilities try to argue by citing their flawed resource planning processes. Moreover, DSM helps mitigate the significant risks associated with these, more expensive supply-side resources.[4]

Figure 2.3 Cost of Generation Technologies versus the Cost of Saved Energy



Higher DSM Goals Would Lead to a Better Balancing of Costs and Rates

One of the key objectives in setting DSM goals is to strike the proper balance between reduced costs and the potential for increased rates. Striking this balance requires a much better assessment of rate impacts than the RIM test provides (even when correctly applied). It requires a reasonable assessment of (a) the potential rate impacts of the DSM proposed goals; (b) the potential for reducing customer costs and customer bills; and (c) the customer participation rates in the DSM programs. My analysis shows that:

- The rate impacts of the Utilities' proposed DSM goals will be so low as to be unnoticeable, and higher DSM goals would lead to very small rate impacts, if any.

[3] Levelized costs are the constant unit cost (in $/MWh) that, if incurred over a pre-determined period would have the same net present value as the stream of annual costs incurred over the same period.

[4] Ceres, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know*, prepared by Ron Binz, Rich Sedano, Denise Furey, Dan Mullen, April 2012.

- Higher DSM goals would result in reduced costs, and therefore reduced bills.
- Higher DSM goals would result in greater DSM program participation, further offsetting any increase in rates that might occur as a result of DSM programs.

The Utilities Understate the Potential Value of Demand-Side Renewables

The Utilities significantly understate the potential value of demand-side renewable resources by not accounting for recent and anticipated cost trends in the PV industry; overstating customers' ability and interest in installing PV systems without utility support; and by omitting the avoided cost of GHG emissions.

Q. Please summarize your primary recommendations.

A. My primary recommendations are summarized below. Additional details are provided in the main body of my testimony.

DSM Goals. The Commission should set DSM goals[5] for the Utilities as follows:

- Energy (GWh) Savings. Each Utility should be required to achieve annual efficiency savings equal to one percent of retail sales by 2019.
- Capacity (MW) savings. Each utility should be required to achieve capacity savings such that the ratio of capacity-to-energy savings is consistent with the ratios that were achieved by the Companies in recent years. This will maintain the current balance between energy and capacity savings of the DSM programs.[6]

Demand-Side Renewables. The Commission should require the Utilities to continue to provide PV programs to their customers, with some modifications to the current programs as outlined below. The Commission should open a separate docket to investigate appropriate goals for customer-sited renewables, and to address some related issues, e.g., the effectiveness of solar rebate programs and the role of utility-owned solar photovoltaic (PV) systems.

[5] These goals do not include savings from demand-side renewable resources.
[6] This recommendation is not meant to suggest that the current balance between capacity and energy savings is ideal. It is merely meant to prevent the balance from becoming any worse.

Regulatory Support. The Commission should open a generic docket to investigate opportunities to establish a revenue decoupling mechanism to help remove the Utilities' financial disincentive to advance DSM. That docket should also investigate opportunities to establish shareholder performance incentives to help provide positive financial incentives for the Utilities to implement successful DSM programs.

Future DSM Screening. For future DSM planning and goal-setting purposes, the Commission should: (a) clarify that the RIM test should not be used for screening DSM programs; (b) clarify that a proper application of the TRC test should include the customer incentive provided by a utility, and participant non-energy benefits; (c) require reasonable estimates of GHG compliance costs be used in the base case analysis; and (d) present the results of the Utility Cost test for consideration by the Commission.

Future Resource Planning. For future DSM planning and goal-setting purposes, the Commission should require the Utilities to conduct resource planning processes that provide meaningful information for the purpose of setting DSM goals. In particular, the resource planning process should: (a) comport with standard industry resource planning practices; (b) be transparent with regard to decision-making processes, the results and interpretation of the results; (c) use the present value of revenue requirements as the primary criterion for selecting among different resource plans; (d) analyze numerous plans to optimize the combination of demand-side and supply-side resources; and (e) use reasonable estimates of free-rider impacts from measurement and verification studies, and not the overly simplistic payback criterion.

3. DEMAND-SIDE MANAGEMENT COST-EFFECTIVENESS TESTS

Q. Why is cost-effectiveness so important in setting goals DSM goals?

A. DSM is by far the lowest-cost resource available to meet customer needs. Efficiency resources reduce electric system costs and thereby reduce average customer bills. These cost- and bill-impacts are precisely what an economic regulator like the Commission oversees with the help of cost-effectiveness tests. When applied correctly, the tests can substantiate whether a particular resource or portfolio of resources is cost-effective.

DSM goal-setting is no exception. Notably, at least once every five years, FEECA requires the Commission to avail itself of the best available information regarding the cost-effectiveness of potential DSM, demand response, and demand-side renewable energy resources to set DSM goals. *See* Sections 366.81, 366.82(3)(a)-(d), (5)(b), F.S. Moreover, each year, the Utilities are required to provide the Commission with evidence of "lowest cost possible" planned energy, including the resources covered by DSM goals. *See* Rule 25-22.072, F.A.C. (incorporating by reference Form PSC/RAD 43-E (11/97)).

In setting DSM goals, the Commission must not lose sight of the fact that DSM can significantly reduce utility and customer costs. If DSM cost-effectiveness analyses are not properly defined or conducted, then the Utilities may implement an inappropriate amount of DSM, and their customers will pay more—potentially a lot more—than necessary for electricity services.

Q. Have the Utilities properly evaluated the cost-effectiveness of DSM in setting their DSM goals?

A. No. The Utilities' proposed DSM goals are way too low because the Utilities' cost-effectiveness screening is fundamentally flawed in ways that significantly understate the cost-effectiveness of DSM programs.

Q. Please describe how the remainder of this section is organized.

A. Since the DSM cost-effectiveness tests are so important to setting DSM goals, I dedicate a large portion of my testimony to them. First, I describe a national effort that provides useful guidance on the very issues of cost-effectiveness in these dockets. Second, I describe how cost-effectiveness is defined in Florida based on FEECA and the Commission's implementing regulations and orders. Third, I discuss my concerns with the way that the Utilities have defined and used cost-effectiveness tests for setting their DSM goals. Finally, I discuss several important benefits that the Utilities have omitted from their screening tests, particularly greenhouse gas (GHG) regulatory compliance costs and non-energy benefits associated with DSM programs.

The National Efficiency Screening Project

Q. What is the National Efficiency Screening Project?

A. The National Efficiency Screening Project (NESP) was recently formed to provide guidance on ways to improve efficiency screening practices. The NESP Team published a set of principles and recommendations for how states should reconsider and potentially modify their efficiency screening practices.[7] One of NESP's key recommendations is that each state should apply a framework—the Resource Value Framework (RVF)—to identify the most appropriate costs and benefits to consider when screening DSM programs. I will describe RVF and its relevance to the Utilities' DSM goals below.

Q. What is the NESP Team?

A. The NESP Team is led by a steering committee who oversees the entire initiative. I am a member of this steering committee, as the lead technical consultant. The NESP Team also includes project advisors, who assist in developing and refining NESP's key principles and recommendations. The project advisors are nationally-recognized energy efficiency experts who help capture perspectives from across the country. Finally, NESP project members, representing many organizations that support the NESP principles and recommendations, advance national and state campaigns to improve energy efficiency screening. The individuals and organizations that comprise the NESP Team are listed in the NESP Recommendations document cited above.

Q. What are the key elements of the Resource Value Framework?

A. The RVF includes several principles that each state should apply when designing its energy efficiency screening test:

- The Public Interest. The ultimate objective of efficiency screening is to determine whether a particular energy efficiency program, or portfolio of programs, is in the public interest.

[7] National Efficiency Screening Project, *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening* (March 2014), available at http://www.nhpci.org/projects/costbenefittesting.html.

- Energy Policy Goals. Efficiency screening practices should account for the energy policy goals of each state, as articulated in legislation, commission orders, regulations, guidelines and other policy directives. These policy goals provide guidance as to which efficiency programs are in the public interest.

- Symmetry. Efficiency screening practices should ensure that tests are applied symmetrically, where both relevant costs and relevant benefits are included in the screening analysis. For example, a state that chooses to include participant costs in its screening test should also include participant benefits, including non-energy benefits, otherwise the test will be skewed against energy efficiency resources.

- Hard-to-Quantify Benefits. Efficiency screening practices should not exclude relevant benefits on the grounds that they are difficult to quantify and monetize. Several methods are available to approximate the magnitude of relevant benefits, as described below.

- Transparency. Efficiency program administrators should use a standard template to explicitly identify their state's energy policy goals and to document their assumptions and methodologies.

- Applicability to all resources. In general, these principles should be applied to all types of electric and gas utility resources; both demand-side and supply-side resources.

Q. Does the NESP Recommendations document provide any guidance on how the standard screening tests should be defined?

A. Yes. While all states use one or more of the standard "tests" described in the California Standard Practice Manual as the foundation for their own efficiency screening practices, states differ in their definitions of these tests. Figure 3.1 presents the definitions of the standard screening tests, based on the most recent literature on this topic and the NESP recommendations. I will return to Figure 3.1 when I discuss the Utilities' definitions of cost-effectiveness below.

Figure 3.1. Components of the Standard Cost-Effectiveness Tests

	Participant Test	RIM Test	Utility Test	TRC Test	Societal Test
Energy Efficiency Program Benefits:					
Customer Bill Savings	Yes	---	---	---	---
Avoided Energy Costs	---	Yes	Yes	Yes	Yes
Avoided Capacity Costs	---	Yes	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	---	Yes	Yes	Yes	Yes
Wholesale Market Price Suppression Effects	---	Yes	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (utility perspective)	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (participant perspective)	Yes	---	---	Yes	Yes
Non-Energy Benefits (societal perspective)	---	---	---	---	Yes
Energy Efficiency Program Costs:					
Program Administrator Costs	---	Yes	Yes	Yes	Yes
EE Measure Cost: Program Financial Incentive	---	Yes	Yes	Yes	Yes
EE Measure Cost: Participant Contribution	Yes	---	---	Yes	Yes
Lost Revenues Associated with Fixed Costs	---	Yes	---	---	---

Q. Is the Resource Value Framework a new screening test for states to consider?

A. No. It is a framework—a set of principles and recommendations—that provides guidance for each state in designing and implementing its energy efficiency screening process. The Resource Value Framework is designed to provide each state with flexibility to ensure that its screening practices meet its own needs and interests.

One of the key concepts in the RVF is that states do not need to be confined to the strict definition of the standard screening tests described in the California Standard Practice Manual. The RVF includes the key principles that each state should incorporate into its efficiency screening practices to ensure consistency between its energy efficiency programs and energy policy goals. In other words, each state's screening test should be based on its own legislation, regulations and commission orders. While this may seem like an obvious recommendation, some states apply efficiency screening tests that are not consistent with their own regulatory standards and energy policy goals. In fact, this is one

of the fundamental problems with the Utilities' DSM screening practices—they conflict with FEECA standards and policy goals.

Q. Does the NESP Recommendations document provide any guidance on efficiency screening tests that should not be used?

A. Yes, the NESP Recommendations document clearly recommends against the RIM test's use for screening energy efficiency programs, for reasons that I will describe below. Instead, states should use other analyses, and apply other considerations to address concerns about rate impacts from energy efficiency programs. Florida is no exception.

Q. Based on your work with the National Efficiency Screening Project, what lessons does it offer to Florida?

A. Contrary to perhaps the most fundamental NESP recommendation, the Utilities try to define cost-effectiveness and conduct resource screening in ways that conflict with FEECA and the related Commission regulations and decision-making precedents.

Another key NESP recommendation is that the RIM test should not be used for screening DSM measures. Contrary to this recommendation, the Utilities rely almost entirely on the RIM test in their definitions of cost-effectiveness, and in their resource planning process.

Another key NESP recommendation is that a utility's DSM screening assumptions, methodologies and practices should be transparent, so that regulators and other stakeholders can draw meaningful conclusions from them. The Utilities resource planning process is anything but transparent; it is convoluted, overly-complex, not well explained, and lacking in the information that the Commission ultimately needs to set DSM goals. To make matters worse, the Utilities present the results of their resource planning analyses in ways that are unnecessarily confusing and even misleading.

In sum, the Utilities' DSM screening practices are out of synch with standard industry practices, and do not even come close to meeting evolving industry "best practices." I elaborate on all of these points below.

The Definition of Cost-Effectiveness in Florida

Q. How is DSM cost-effectiveness defined in FEECA?

A. The Florida Energy Efficiency and Conservation Act focuses on cost-effectiveness, starting with the very first sentence in the Act, which states: "[t]he Legislature finds and declares that it is critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. This language is especially important in this goal-setting docket, not only because it requires that demand-side conservation systems (i.e., DSM programs) be cost-effective, but also because it places the concept of cost-effectiveness in the context of protecting the health, prosperity and general welfare of the state and its citizens.

FEECA provides further guidance on how to assess cost-effectiveness. Section 366.82(3), F.S., states that in developing DSM goals the Commission shall take into consideration:

a) The costs and benefits to customers participating in the measure.

b) The costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions.

c) The need for incentives to promote both customer-owned and utility-owned DSM and demand-side renewable energy systems.

d) The costs imposed by state and federal regulations on the emissions of greenhouse gases.

Q. How is DSM cost-effectiveness defined in the Commission's regulations?

A. Rule 25-17.008, F.A.C., sets out in detail the methodologies and tests for estimating efficiency program cost-effectiveness. In particular, the Rule identifies the minimum filing requirements for utilities reporting cost-effectiveness data, and the Rule refers to the Commission's Cost-Effectiveness Manual.[8] That Manual requires that cost-effectiveness analyses be conducted using three tests: the Participants test, the RIM test, and the Total Resource Cost (TRC) test.

[8] Florida Public Service Commission, *Cost-Effectiveness Manual For Demand-Side Management Programs and Self-Service Wheeling Proposals,* July 17, 1991.

In its FEECA Annual Report, the Commission provides the following definitions of these DSM cost-effectiveness tests:

- Participants test. The Participants test analyzes costs and benefits from a program participant's point of view and ignores the impact on the utility and other ratepayers not participating in the program. The costs customers pay for equipment and maintenance are considered under the Participants test. Benefits considered in the test include incentives that are paid by the utility to the customers and a reduction in customer bills.

- RIM test. The RIM test includes the costs associated with incentive payments to participants and decreased revenues to the utility which typically must be recovered from the general body of ratepayers at the time of a rate case. In particular, the RIM test is designed to ensure that all ratepayers, not just the program's participants, will benefit from a proposed DSM program. A DSM program that passes the RIM test ensures that all customer rates are lower than they otherwise would have been without the DSM program.

- TRC test. The TRC test measures the overall economic efficiency of a DSM program from a social perspective. This test measures the net costs of a DSM program based on its total costs, including both the participant's and the utility's costs. Unlike the RIM test, customer incentives and decreased revenues are not included as costs in the TRC test; instead, these factors are treated as transfer payments among ratepayers. Moreover, certain external costs and benefits such as environmental impacts are appropriate for inclusion under the TRC test.

FPSC, *Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act*, (Feb. 2014), at 15, *available at* http://www.psc.state.fl.us/publications/pdf/electricgas/FEECA2014.pdf ("2014 FEECA Report").

Q. How did the Commission address DSM cost-effectiveness in the last DSM goal-setting case?

A. The Commission found that the TRC test (or, the e-TRC test) should be used to set DSM goals, and that consideration should be given to the impacts—especially the rate impacts—of efficiency programs on non-participants. In particular, the Commission found that:

> . . . consideration of both the RIM and TRC tests is necessary to fulfill the requirements of Section 366.82(3)(b), F.S. Both RIM and TRC tests address costs and benefits beyond those associated solely with the program participant. By having RIM and TRC results, we can evaluate the most cost-effective way to balance the goals of deferring capacity and capturing energy savings while minimizing rate impacts to all customers.

Order No. PSC-09-0855-FOF-EG, at 15. The utilities proposed DSM goals that were based on the E-RIM test, which is an enhanced version of the RIM test including avoided carbon compliance costs. The Commission rejected this approach and approved DSM goals based upon the unconstrained E-TRC test, which is an enhanced version of the TRC test including avoided carbon compliance costs. *Id*.

With regard to rate impact considerations, the Commission found that:

> Those who do not or cannot participate in an incentive program will not see their monthly utility bill go down unless they directly decrease their consumption of electricity. If that is not possible, non-participants could actually see an increase in the monthly utility bill. Since participation in DSM programs is voluntary and this Commission is unable to control the amount of electricity each household consumes, we should ensure the lowest possible overall rates to meet the needs of all customers.

Id. at 26.

Q. How has the Commission addressed DSM cost-effectiveness issues in more recent orders?

A. After the Commission set the 2009 DSM goals, the Utilities' filed DSM Plans that described their proposals to meet those goals. The Commission approved the proposed DSM Plans of TECO, JEA, Orlando Utilities Commission (OUC) and Florida Public

Utilities Company (FPUC) in 2010, and the proposed DSM Plan of Gulf in 2011. *See* 2014 FEECA Report, at 17-18 (citing relevant orders).

However, the Commission modified the proposed DSM Plans proposed by FPL and DEF. The Commission found that their proposed DSM Plans would result in an increase to the average residential customer's monthly bill that would "constitute an undue rate impact on customers." Order No. PSC-11-0346-PAA-EG, at p. 4 (FPL); Order No. PSC-11-0347-PAA-EG, at 5, 6 (DEF, then Progress Energy Florida, Inc.). Consequently, the Commission directed FPL and DEF to modify their DSM plans to continue their existing programs, finding that the rate impacts of those programs were "relatively minor." Order No. PSC-11-0346-PAA-EG, at 5; Order No. PSC-11-0347-PAA-EG, at 7.

The Utilities' Definition of Cost-Effectiveness

Q. How have the Utilities defined cost-effectiveness?

A. FPL uses four tests in its preliminary screening of DSM: the Participants test; the preliminary RIM test, the preliminary TRC test; and the "years-to-payback test, using a two-year criterion. Direct Testimony of Witness Sim, Document No. 01476-14, at 23. DEF uses the Participant, TRC, and the RIM tests in its preliminary screening of DSM. Direct Testimony of Witness Guthrie, Document No. 01497-14, at 27.

However, both FPL and DEF ultimately use the RIM test in determining their DSM goals.

Q. Please summarize your concerns with the Utilities' definitions of cost-effectiveness.

A. I summarize several concerns here, and address each of them in more detail in the following subsections.

First and foremost, the Utilities' definitions are not in compliance with either the overall intent of FEECA or the specific requirements of FEECA. FEECA states that "it is critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. The Utilities' cost-effectiveness analyses do not meet this overall goal. FEECA also requires that in establishing the DSM goals, the

Commission should take into consideration "the costs and benefits to customers participating in the measure" and "the costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions." Section 366.82(3), F.S. Again, the Utilities definition of cost-effectiveness does not comply with this requirement.

Second, the Utilities ultimately only rely on one test to propose goals: the RIM test. Despite the appearance of modeling and analyzing several different tests, they use the RIM test as the sole criterion for making the final decision in setting DSM goals. The RIM Test should never be used to determine DSM cost-effectiveness; there are better ways to address the important issue of DSM rate impacts.

Third, the Utilities use incorrect methodologies and assumptions for estimating the lost revenues from DSM programs. Consequently, their estimates of lost revenues —the key additional cost included in the RIM test—are significantly overstated. Furthermore, the Utilities present the results of the RIM Test in misleading ways, dramatically overstating the extent to which customers will experience higher rates.

Fourth, the Utilities misrepresent (or misunderstand) the proper definition of the TRC test, by asserting that this test does not account for the incentive payments that the utility provides to the participating customer. Accordingly, they have incorrectly dismissed the TRC test as not in compliance with FEECA, when in fact it is the one test that is most in compliance with FEECA.

Fifth, the Utilities ignore one of the most useful screening tests available: the Utility Cost test. This test is especially helpful for determining the economic impact on all customers as a whole, and for providing useful information regarding rate and bill impacts.

Sixth, the Utilities do not properly account for the cost of complying with greenhouse gas (GHG) regulations, as required by FEECA in Section 366.82(3)(d), F.S. They also do not account for non-energy benefits of DSM. Consequently, their analyses significantly understate the benefits of DSM, both to participants and non-participants.

Finally, the Utilities apply fundamentally flawed resource planning practices to further analyze the potential role of DSM programs in meeting resource planning needs. This exacerbates and adds to the problems outlined above. I address these problems in more detail in Section 4.

In sum, the Utilities' misuse of DSM cost-effectiveness tests, combined with their flawed efficiency screening process, lead to results that are so defective as to make them meaningless. The Utilities' analyses ultimately obscure the basic fundamental fact that DSM programs offer tremendous benefits to customers because they cost significantly less than supply-side alternatives. I offer some alternative economic analysis in Section 5 to expand upon and clarify this critical point.

The Rate Impact Measure Test Can Lead to Perverse Outcomes

Q. Why do you recommend that the RIM test not be used to evaluate DSM cost-effectiveness?

A. The RIM test should never be used for evaluating DSM cost-effectiveness both on theoretical grounds and for practical reasons. In sum, the logic underlying the RIM test is flawed; it will not result in lowest costs to the utility system or to the utility customer; it can lead to perverse outcomes where significant cost reductions are foregone in order to avoid negligible rate impacts; it is inconsistent with the regulatory treatment of supply-side resources; and (worst of all) it provides no meaningful information for the Utilities or the Commission to use in addressing the key issue of rate and bill impacts.

Q. Why do you say that the underlying logic of the RIM test is flawed?

A. The only difference between the RIM test and the Utility Cost test is the "lost revenues," (i.e., the reduction in the revenues as a result of reduced consumption). If the utility is to be made financially neutral to the impacts of the DSM programs, then the utility should collect that portion of the lost revenues necessary to recover its fixed costs (because fixed costs are not reduced as a result of DSM). If the utility were to recover these lost revenues in rates, then they would result in rate increases.

To understand this issue it is critical to recognize that these lost revenues are the primary reason that long-term rates increase as a result of DSM programs. If it were not for these

lost revenues, then DSM programs would generally cause long-term rates to be *lower than they would be otherwise*, because the benefits of cost-effectiveness DSM outweigh the costs.

It is also critical to recognize that lost revenues are not a "new" cost created by the DSM programs. Lost revenues are simply a result of the need to recover *existing costs spread out over fewer sales*. The existing costs that might be recovered through rate increases as a result of lost revenues are (a) not caused by the efficiency program themselves, and (b) are not a new, incremental cost. In economic terms, these existing costs are called "sunk" costs. Sunk costs should not be used to assess future resource investments because they are incurred regardless of whether the future project is undertaken. Application of the RIM test is a violation of this important micro-economic principle.

Q. Why do you say that the RIM test will not result in the lowest cost to the utility system or customers?

A. Applying the RIM test to screen efficiency programs will not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal, and if the test is applied properly). However, achieving the lowest rates is not the primary or sole goal of utility planning and regulation; there are many goals that utilities and regulators must balance in planning the electricity system. Maintaining low utility system costs, and therefore low customer bills on average, should be given priority over minimizing rates. For customers, the size of the electricity bills that they must pay is more important than the rates underlying those bills.

Q. Why do you say that strict application of the RIM test can lead to perverse outcomes?

A. A strict application of the RIM test can result in the rejection of *significant* reductions in utility system costs to avoid what may be *insignificant* impacts on customers' rates. In fact, this is the outcome of the DEF and FPL reliance on the RIM test to propose DSM goals. As I demonstrate in Section 4, the magnitude of rate impacts that are likely to result from the Utilities' DSM goals are so small as to be unnoticeable, and yet the Utilities use the concept of rate impacts to reject large amounts of DSM measures that

could save customers millions, perhaps billions of dollars. Such a result is clearly not in the best interests of customers overall.

Q. Why do you say that applying the RIM test is inconsistent with the regulatory treatment of supply-side resources?

A. The main goal of the RIM test is to avoid cross-subsidies between customers. In theory, DSM program non-participants may subsidize participants, because the participants may experience reduced bills as a result of reduced electricity consumption, while non-participants may experience increased bills as a result of increased rates. The Utilities claim many times over that they should use their resource planning process to minimize rate impacts, because this will then avoid cross-subsidization. *See*, *e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 26-28; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 7, 15.

While it is important to avoid cross-subsidies where possible, it is also important to recognize that cross-subsidies are endemic to regulated electric utilities. For example:

- When a utility installs a new power plant to meet increasing electricity demands, customers whose electricity demands have not increased in recent years subsidize those customers whose demands have increased.

- When a utility installs a new transmission line to maintain or improve reliability in one part of its service territory, all customers are required to pay for the new transmission line, even though many customers do not experience its benefits.

- When a utility installs distribution systems to serve a newly-developed residential neighborhood or a new industrial park, all customers are required to pay for the new distribution systems, even though many customers do not experience the benefits of them.

- Customers within a rate class that have a high load factor (i.e., high energy consumption relative to peak demand), will subsidize customers in that same rate class with a low load factor, because the cost of power is so much greater during times of peak demand.

Accordingly, DSM should not be held to a standard that cross-subsidization will not be allowed, when that same standard is not applied to supply-side resources. This is especially true given that doing so can lead to perverse outcomes, as described immediately above.

Q. Why do you say that the RIM test provides no meaningful information for addressing the issue of rate and bill impacts?

The RIM test does not provide any information about what actually happens to rates as a result of program implementation. A RIM test benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact, in terms of the percent (or ¢/kWh) increase in rates or the percent (or dollar) increase in bills. In other words, the RIM test results do not provide any context for utilities and regulators to consider the magnitude and implications of the rate impacts. What are the implications of DSM plan with a RIM Test benefit-cost ratio of 0.98? How about a benefit-cost ratio of 0.87? How much are customers harmed by these results relative to a positive RIM benefit-cost ratio of 1.2? The RIM Test cannot answer such important questions.

Even worse, the RIM test results can be very misleading. When the RIM test results are put in terms of negative net benefits (the net benefits will be negative for DSM programs that fail the RIM test), it appears as though the DSM programs will be *increasing* costs to customers. However, as described above, the costs that drive the rate impacts under the RIM test are not new, incremental costs associated with the DSM programs. They are *existing costs*, existing fixed costs to be more precise. These are the existing costs that are already in electricity rates. Any rate increase from lost revenues would be a result of recovering those existing fixed costs over fewer sales; not as a result of incurring new costs. In fact, the Utilities present their RIM test results in this misleading way. For example, FPL states that it would have to incur "an additional cost of approximately $296,000,000 in 2015, or of approximately $630,000,000 in 2014" to raise rates enough to cover the TRC 337 MW plan relative to the RIM 337 MW plan. Direct Testimony of Witness SIM, Document No. 01476-14, at 58. This simply is not true. The recovery of

lost revenues does not result in "additional" costs to the utility or to customers. Lost revenues are recovered to help the utility pay for existing fixed costs.

Finally, the RIM test does not provide the specific information that utilities and regulators need to assess the actual rate and bill impacts of DSM programs. Such information includes the impacts of DSM on long-term average rates, the impacts on average customer bills, and the extent to which customers participate in efficiency programs and thereby experience lower bills.

Q. Are these concerns about the RIM test recognized by other states and other regulatory commissions?

Yes, essentially every state in the country has rejected the use of the RIM test as the primary test to use for determining DSM cost-effectiveness. The Commission should not set efficiency goals based on the outcome of the Utilities' analyses, which are directly in conflict with standard industry practice throughout the US.

Q. So far, you have shown why the RIM test generally should not be used in any state for screening DSM programs. Do you have any particular concerns with the way that the RIM test is calculated and applied by the Utilities in Florida?

A. Yes. The Utilities's methodology significantly overstates the magnitude of the lost revenues, and as a consequence significantly overstates the rate impacts of their DSM proposals. This occurs in two ways.

First, the Utilities use an incorrect methodology for estimating the magnitude of the lost revenues that will impact rates. The Utilities estimate lost revenues on the basis of a projection of total electricity prices. *See*, *e.g.*, Direct Testimony of Witness Guthrie, Document No. 01497-14, at 38. This is not the correct methodology for estimating lost revenues that will impact rates. The correct methodology is to use a projection of the *fixed components of rates*, not the fixed plus variable components of rates. It is necessary to separate out the portion of rates that represent variable costs, because utilities will be able to reduce variable costs through DSM and therefore will not need to recover any lost revenues associated with those variable costs. The Utilities' assumption that lost revenues should be based on the total electricity rates (fixed and variable components) implies that they will somehow be allowed to increase customer rates for *variable costs that they do*

not incur. That is clearly not how rates are set in Florida, or any state, and should not be the assumption underlying estimates of DSM rate impacts.

Second, the Utilities' methodology for estimating rate impacts is inconsistent with the way that rates are set in Florida. Base rates are only increased at the time of a rate case. Between rate cases, *DSM will not increase rates* because the Utilities' rates will not be adjusted to collect lost revenues of any kind. Eventually with the next rate case, rates will be adjusted based on the most recent sales levels, including savings from DSM up to that point in time. However, the lost revenues that may occur between rate cases are not recovered by the utility, even at the next rate case. For this reason alone, the RIM test results provided by the Utilities are simply wrong—they significantly overstate the extent to which the Florida DSM programs might increase rates.

Each of the two reasons that I just described renders the Utilities' estimates of rate impacts fatally flawed and essentially useless for setting DSM goals. Therefore, I recommend that the Commission completely reject the Utilities' rate impact estimates when setting DSM goals.

Q. Do the Utilities claim that application of the RIM test is consistent with FEECA?

A. Yes. FPL and DEF claim that the Participants test and the RIM test should be used for screening DSM. *See*, *e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 28; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 15 ("these two tests capture all of the relevant costs and benefits that should be evaluated when considering an efficiency or load reduction program."). However, the RIM test is much more stringent than the Participants test, and therefore if the two tests are applied together, then the RIM test will be the deciding factor on cost-effectiveness.

Further, FPL proffers that the TRC test "omits the incentive payments made to program participants." *Id*. at 26-27. Based on FPL's misunderstanding that the TRC test omits these incentive payments, FPL essentially rejects the use of the TRC test for screening purposes. Finally, FPL ignores other cost-effectiveness tests that could meet FEECA standards and policy goals.

Q. Do you agree with the Utilities' characterization of these tests?

A. No. The Utilities misinterpret FEECA requirements, and screening test-definitions and implications. Consequently, the Utilities' methodology conflicts with FEECA.

First, the RIM test does not indicate the "cost" impacts on the utility and its customers. As discussed above, it indicates the potential rate impacts on the utility customers (although a not a very useful indication). The distinctive component of the RIM test is the lost revenues, which are not costs associated with DSM. Lost revenues can potentially lead to rate impacts, but they are not cost impacts.

It is important to note that FEECA does not in any way require the minimization of rates as a criterion for setting DSM goals. FEECA is clear about the intent to reduce costs, but does not mention minimization of rates at all.

Second, the Utilities have misinterpreted the definition of the TRC test. FPL and DEF try to argue that the TRC test does not include the incentive payments made to program participants. *See*, *e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 27; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 15-16. In fact, the TRC test does, or should, include these customer incentive payments. The purpose of the TRC test is to include all costs associated with a DSM measure, regardless of who pays them. That is why it is called the "Total Resource Cost" test. Note in Figure 3.1 above, that the customer incentive payment should be included in the TRC test. This is standard industry practice.[9]

In sum, the Utilities rely on a misunderstanding of the definition of the TRC test to reject this test for the purpose of screening DSM measures. However, the TRC test is in fact the best test to indicate the "costs and benefits to the general body of ratepayers as a whole,

[9] It appears as though the Commission is inconsistent on the definition of the TRC test. The 2014 FEECA Report states that the TRC test measures a "DSM program based on its total costs, including both the participant's and the utility's costs." In the next sentence, however, Report states that customer incentives are not included in the TRC test, instead they are treated as "transfer payments" among ratepayers. 2014 FEECA Report, at 15. These two sentences are inconsistent. The first point, about including both the participant's and the utility's costs is the correct definition of the TRC test.

including utility incentives and customer contributions," as required by FEECA. Section 366.82 (3)(b), F.S.

Q. Has the Commission the authority to consider the rate impacts of DSM goals?

A. Yes. Commissions generally have wide discretion to consider many aspects of rates, in many contexts. In previous DSM goal-setting docket, the Commission noted that:

> As specified in Section 366.01, F.S., the regulation of public utilities is declared to be in the public interest. Chapter 366 is to be liberally construed for the protection of the public welfare. Several sections within the Chapter, specifically, Sections 366.03, 366.04, and 366.05, F.S., refer to the powers of the Commission and setting rates that are fair, just and reasonable. The 2008 legislative changes to FEECA did not change our responsibility to set such rates.

Order No. PSC-09-0855-FOF-EG at 25.The concept of setting rates that are "fair, just and reasonable" is widely used in the regulation of the electricity industry. Notably, this standard makes no reference to rate minimization. Rates should be fair, just and reasonable. This requires consideration of, and often a balancing among, several factors beyond rates alone.

Q. Should the Commission consider rate and bill impacts when setting DSM goals?

A. If the rate impacts of DSM goals are of concern, then, yes the Commission should consider implications of rate and bill impacts. However, the RIM test should not be used for this purpose, for the reasons provided above. Instead, rate and bill impacts should be considered using comprehensive, meaningful analyses that provide the utilities and Commissioners with the information necessary to strike the appropriate balance between reduced bills and increased rates. I offer some recommendations on this point in the following subsection.

Rate and Bill Impacts Should be Assessed in Other Ways

Q. How should the Utilities address rate and bill impacts from DSM programs?

A. It is important to recognize that the primary challenge facing the Commission in setting DSM goals is in striking the proper balance between reduced costs and the potential for increased rates. FEECA is clear that the Commission should seek to establish DSM goals

that will reduce costs to the "general body of ratepayers as a whole." Section 366.82(3)(b), F.S. This suggests an emphasis on reduced costs, because ratepayers on average will be better off with reduced costs and reduced bills. In addition, FEECA provides the Commission with the authority to "modify or deny plans that would have an undue impact on the costs passed on to customers." Section 366.82(7), F.S. This language also emphasizes costs over rates.

Nonetheless, the Commission always has the responsibility to consider rate impacts in resource decision-making, and to prevent "undue" rate impacts on customers. Taken together, these considerations indicate that the Commission should not set DSM goals based on rate impacts alone, but should instead strike the proper balance between reduced costs and the potential for increased rates.

Q. What kind of considerations help strike a balance between reduced costs and the potential to increase rates?

A. Three considerations are the most helpful: rate impacts, bill impacts, and DSM program participation rates. Rate impacts, properly estimated, provide an indication of the extent to which rates might increase due to DSM. Bill impacts, properly estimated, provide an indication of the extent to which average customer bills might be reduced due to DSM. Participation rates, properly estimated, provide an indication of the extent to which customers will experience bill reductions or bill increases. Taken together, these three measures indicate the extent to which customers as a whole will benefit from DSM.

Q. How should rate impacts be estimated?

A. Rate impact estimates should account for all factors that impact rates, either positively or negatively. This would include all avoided costs that might exert downward pressure on rates (e.g., generation, transmission, and distribution), including the avoided costs of complying with environmental regulations. Any estimates of the impact of lost revenue recovery on rates should (a) only reflect collection of lost revenues necessary to recover fixed costs, and (b) only reflect the actual impact on rates according the Florida ratemaking practices. Rate impacts should be estimated over the long-term, to capture the full period of time over which the efficiency savings will occur. Rate impacts should also

be put into terms that place them in a meaningful context; e.g., in terms of ¢/kWh or percent of total rates.

Q. How should bill impacts be estimated?

A. The bill impacts should build upon the estimates of rate impacts described above. The rate impacts apply to every customer (within the rate class analyzed). Bill impacts, on the other hand, will vary between customers depending upon whether they participate in the DSM programs, and depending upon which DSM program they participate in. Therefore, bill impacts should be estimated separately for each of the types of DSM programs. As with rate impacts, they should be estimated over the long-term, and they should be put into terms that place them in a meaningful context; e.g., in terms of dollars per month, or percent of total bills.

Q. How should program participation rates be estimated?

A. Program participation rates should be estimated by dividing the program participants by the total population of eligible customers, to get a rate in percentage terms. This should be done for each year, and for each program. Participation rates should be compiled across several years to indicate the extent to which customers are participating in the programs over time. To the extent possible, participation in multiple programs and across multiple years should be captured. The long-term program participation rates can be compared with the long-term bill impacts and the long-term rate impacts to get a sense of the extent to which customers are benefiting from the DSM programs.

Q. You recommended that the level of program participation should be considered when deciding whether specific rate impacts are acceptable. Please elaborate on why the level of program participation should be considered when assessing rate impacts of DSM programs.

A. Rate impacts primarily raise the issue of customer equity. Therefore, to assess whether rate impacts—and more importantly, bill impacts—are acceptable and yield equitable outcomes, customer participation rates must be considered. Specifically, program participation rates can reveal the extent to which customers experience bill increases or decreases. If a large portion of customers participate in DSM programs, then the Commission and other stakeholders should be willing to accept relatively higher rate

impacts because many customers will experience net bill reductions and few customers will experience bill increases.

Furthermore, this type of participation information can be very important in reviewing and assessing the Utilities' DSM programs in general. It provides an indication of how successfully each program is pursuing customers, as well as an indication of which types of customers could benefit from future efficiency programs.

Q. Are there actions that the Commission and Utilities can take to increase customer participation in the DSM programs, and thereby mitigate customer equity concerns?

A. Yes. First, the DSM program goals and budgets can be set in a way to increase customer participation. Energy efficiency program goals and budgets could be increased to grow the number of customers that experience bill reductions. This is the exact opposite of approach proffered by the Utilities, which is to reduce DSM program goals and budgets to minimize rate impacts. *In my view, customers overall are better served by a broader application of well-designed, cost-effective DSM programs, because such programs reduce energy system costs and reduce customer bills.*

Q. Is there another approach that the Commission and Utilities can take to maximize customer participation in the DSM programs?

A. Yes. The DSM programs can be designed in a way that encourages as much participation as possible, across as broad a variety of customer types as possible. In particular, DSM programs can be designed to:

- promote all types of efficiency measures that offer cost-effective savings;
- provide all customer types with an opportunity to participate, including hard-to-reach customers such as low-income customers;
- offer efficiency measures that are specifically tailored to many different customer types;
- provide financial and other incentives to overcome the market barriers that prevent customers from participating; and

- identify, target and actively pursue non-participants.

Programs that incorporate these design principles will be more likely to reach a large number of customers, and eventually increase program participation.

Q. Do non-participants experience any benefits of DSM programs?

A. All customers experience the benefits—regardless of whether they participate in the programs. Energy efficiency provides benefits to the entire electricity system, and these benefits are shared by all customers. In particular, DSM can improve system reliability, reduce the need for new generation capacity, reduce planning risk, reduce transmission and distribution costs, reduce the costs of complying with environmental mandates, and reduce reliance upon fossil fuels. Efficiency also results in societal benefits such as local job growth and economic development, reduced environmental impacts and increased economic development. FEECA recognizes this when stating that the Act's intent is to "protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S.

My main point is that concerns about rate impacts are rooted in customer equity issues between participants and non-participants because participants experience direct benefits from DSM (i.e., reduced bills from reduced consumption) that non-participants do not experience. Therefore, when addressing rate impact issues, it is important to fully understand and address this customer equity issue.

The Utilities Do Not Account for the Cost of GHG Regulations

Q. Does FEECA require the Commission to consider the costs of compliance with greenhouse gas regulations?

A. Yes. FEECA requires the Commission to consider, among other things, the "cost imposed by state and federal regulations on the emission of greenhouse gases." Section 366.82(3)(d), F.S.

Q. How should the various efficiency screening tests account for GHG regulatory compliance costs?

A. The cost of complying with current and expected GHG regulations should be included in the TRC test, the Utility Cost test, the Societal Cost test, and in any analyses of rate and

bill impacts. The cost of compliance with any environmental requirements is a cost that will be incurred by utilities and passed on to electricity customers through electricity rates. This compliance cost is therefore an electric system cost, and reducing that cost through DSM is an electricity system benefit. All electricity system costs and benefits should be included in the Utility Cost test, the TRC test, the Societal Cost test, and any analyses of rate and bill impacts.

Note that the cost of complying with environmental regulations are not the same as environmental damage costs (e.g., reduced air quality, damages to lakes and forests, public health impacts). The cost of complying with environmental regulations are an electricity system cost that will be passed on to customers. Environmental damage costs are born by society at large, but do not affect electricity costs or electricity rates.

Q. Why is it so important to account for the cost of compliance with environmental regulations when screening DSM programs?

A. Energy efficiency resources are the most widely available and the lowest-cost option to reduce greenhouse gas pollution and other air pollution. It is important that these low-cost resources be fully utilized to comply with current and future environmental regulations. Otherwise, the costs of complying with such regulations will be greater, and electricity customers will end up paying higher costs than necessary.

Furthermore, DSM offers a set of policy options for reducing GHG pollution that result in *lower bills* for customers, by reducing customer electricity consumption levels. Other GHG pollution reduction options typically result in higher bills for customers.

In sum, it is important to properly account for environmental compliance costs when screening DSM programs because this will minimize future costs to electricity customers.

Q. How should the Utilities account for GHG regulatory compliance costs?

A. The Utilities should apply the best estimate available of the likely costs of complying with state and federal requirements for controlling greenhouse gas pollution during the entire DSM cost-effectiveness study period. Doing so is common practice in the electricity industry. At least 28 utilities have recently used a forecast of CO_2 costs in their planning practices, including utilities in: Arkansas, Arizona, California, Connecticut,

Hawaii, Louisiana, Maine, Massachusetts, Mississippi, South Carolina, New Hampshire, New Mexico, Nevada, North Carolina, Tennessee, Idaho, Indiana, Oklahoma, Oregon, Utah, Vermont, Washington.[10]

Q. How do DEF and FPL account for the cost of complying with GHG regulations when screening efficiency and setting goals?

A. As a part of their resource planning, DEF and FPL have conducted sensitivity analyses where they include CO_2 cost estimates. Both DEF and FPL proffer that adding the CO_2 costs hardly changes the amount of economic or achievable DSM potential, and thus hardly impacts efficiency opportunities or their DSM goals. *See*, *e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 45-46; Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibit HG-14.

Q. Do you agree with FPL's and DEF's conclusion that the cost of complying with GHG regulations will have little impact on their efficiency opportunities?

A. No. This conclusion is counter-intuitive, and highlights just how constraining FPL's and DEF's screening process is. As described in Section 4, FPL's and DEF's resource screening practice suffers from so many flaws and limitations that the results cannot be trusted. Furthermore, FPL's and DEF's resource screening eliminated the majority of DSM measures before CO_2 costs were even considered in the sensitivity analyses. Therefore, I recommend that the Commission give no weight to the results of FPL's and DEF's CO2 sensitivity analyses.

Q. How would the proper accounting of GHG regulatory compliance costs impact the Utilities' cost-effectiveness analyses?

A. The impact would be significant for several reasons. First, properly accounting for GHG regulatory compliance costs would increase the number of DSM measures included in the economic potential and the achievable potential. For example, the consideration of carbon costs was "the primary driver behind why Tampa Electric's energy [GWh] goals

[10] Synapse Energy Economics, *2013 Carbon Dioxide Price Forecast*, November 2013, p. 17.

increased over 70 percent" in the last round of goal-setting. *See*, Witness Bryant Deposition Transcript, Hearing Exhibit 4, Item 7, Docket Nos. 080407–080413, at 89.

Second, properly accounting for the value of avoiding GHG compliance costs would decrease the estimated rate impacts of DSM. As described above, complying with an environmental regulation is a cost to the utility system. For any given level of efficiency savings, proper treatment of the value of avoiding GHG compliance costs would indicate lower utility system costs, which would in turn indicate lower rate impacts. In other words, by failing to correctly account for avoided GHG compliance costs in their resource planning, the Utilities omit one of the benefits of DSM that should be included in the RIM test, and thus overstate the rate impacts.

The Utilities Ignore Non-Energy Benefits of Energy Efficiency

Q. What are non-energy benefits of DSM programs?

A. Non-energy benefits are those costs and benefits that are not part of the costs, or the avoided costs, of the energy provided by the utility that funds the efficiency program.[11] There is a wide range of non-energy benefits associated with DSM programs. Non-energy benefits are categorized by the perspective of the party that experiences the impact: the utility, the participant, or society at large.

- Utility non-energy benefits are indirect savings to the utility; savings that will reduce revenue requirements and thus benefit all ratepayers. These include, for example, reduced arrears, reduced bad debt, reduced costs associated with customer disconnection and reconnection.

- Participant non-energy benefits are benefits to DSM program participants. These include, for example, reduced O&M costs, increased safety, improved health, improved productivity in schools and businesses, improved aesthetics and comfort, and water savings. Participants can also experience benefits in terms of "other fuel

[11] Synapse Energy Economics, Inc., "Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for Other Program Impacts and Environmental Compliance Costs," prepared for Regulatory Assistance Project, November 2012, at 3.

savings;" i.e., when gas, oil or other fuels are saved as a result of an electric efficiency program. Participant non-energy benefits can be experienced by all types of customers, but certain non-energy benefits are more significant for low-income programs.

- Societal non-energy benefits are benefits that accrue to society at large, beyond those realized by utilities or program participants. These include, for example, impacts on the environment, economic development, job growth, reduced healthcare costs, and national security benefits.

Q. Are these non-energy benefits relevant to the efficiency screening tests used in Florida?

A. Yes, for three reasons. First, as noted above FEECA requires that utilities implement DSM programs "to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. Thus, DSM goals should reflect DSM benefits beyond just those that accrue to the utility system. To do so, non-energy benefits should be included in DSM screening.

Second, as noted above, FEECA requires that in establishing the DSM goals the Commission shall consider "the costs and benefits to customers participating in the measure." Section 366.82(3)(a), F.S. To comply with this directive, participant non-energy benefits should be included in DSM screening.

Third, as indicated in Figure 3.1, participant non-energy benefits are one of the key parts of the TRC test. If these benefits are omitted from the TRC test, then the test will be internally inconsistent and inherently skewed against DSM.

Q. Why would the TRC test be internally inconsistent and skewed against efficiency if participant non-energy benefits are omitted from the TRC test?

A. One of the distinguishing features of the TRC test is that it includes the costs to program participants. When including all participant costs, it is necessary to also include all participant benefits, including both energy benefits and non-energy benefits. Otherwise, the TRC test will include certain costs without considering comparable benefits. This

results in a test that is internally inconsistent, and will provide results that are skewed against DSM programs.

Q. Do other states account for participant non-energy benefits in applying the TRC Test?

A. Yes. States that include participant non-energy benefits in their TRC screening use various methodologies and assumptions to estimate the value of participant non-energy benefits. Some states conduct detailed studies to identify these benefits, and to estimate their monetary value so that the estimates can be included in DSM screening. Other states use "a proxy adder" to increase the utility system benefits by a certain percentage amount, as a rough approximation of non-energy benefits. Still other states conduct sensitivity analyses to indicate the extent to which non-energy benefits might influence DSM cost-effectiveness. In recent years, efficiency industry stakeholders have increasingly strived to properly account for participant non-energy benefits.[12]

Q. What about the uncertainty associated with participant non-energy benefits? Are these benefits certain enough to use when screening DSM programs?

A. While there is some uncertainty regarding the magnitude of some participant non-energy benefits, there is no question that they can be quite large, and that they will have a significant impact on DSM cost-effectiveness under the TRC test. There are several ways to address the uncertainties associated with participant non-energy benefits, and it is better to use an informed estimate of non-energy benefits values than to simply assume that they are equal to zero; a number that we know is wrong. Furthermore, it is important to recognize that there is considerable uncertainty regarding many of the assumptions for the future costs and benefits of demand-side and supply-side resources. There is no reason to hold participant non-energy benefits to a higher standard of certainty than these other costs and benefits.

[12] National Efficiency Screening Project, *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening*, March 2014.

Q. What should the Commission do in this docket to account for participant non-energy benefits?

A. I recommend that the Commission require the Utilities to apply a proxy adder to the efficiency program benefits in the TRC test as an estimate of the participant non-energy benefits. While proxy adders are inherently inexact, it is better to use an informed estimation than to simply assume that the value is zero. Here, I recommend that the Commission require the Utilities to apply the following participant NEB proxy adders: 50 percent for low-income customer programs; 25 percent for residential non-low-income customer programs; and 10 percent for commercial and industrial customer programs. These recommended values are based on my extensive review of non-energy benefits in other states, and are conservative relative to some of the quantified values of non-energy benefits that I am aware of.[13]

If the Commission does not require the Utilities to apply a proxy adder for participant non-energy benefits, the Commission should give less weight to the results of the TRC test and instead give more weight to the results of the Utility Cost test. In the absence of reasonable estimates of participant non-energy benefits, the results of the TRC Test are inherently skewed against DSM, while the Utility Cost Test is not.

At a minimum, the Commission should recognize that TRC results that do not include participant non-energy benefits significantly undervalue the full benefits of the DSM programs. This should at least be a qualitative factor that the Commission considers when setting DSM goals.

[13] Synapse Energy Economics, Inc., *Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for Other Program Impacts and Environmental Compliance Costs*, prepared for Regulatory Assistance Project, November 2012. Synapse Energy Economics, *Best Practices in Energy Efficiency Program Screening: How to Ensure that the Value of Energy Efficiency is Properly Accounted For*, prepared for the National Home Performance Council, July 2012.

4. THE UTILITIES' RESOURCE PLANNING PROCESS

Q. Please provide a summary of the FPL's screening process.

A. FPL provides a relatively detailed description of its screening process, so I will focus on FPL in this Section for this reason. FPL uses a six-step resource planning process to screen DSM and propose DSM goals. Direct Testimony of Witness Sim, Document No. 01476-14, at 15-17, Exhibit SRS-1. To summarize:

- Step 1 develops the DSM Technical Potential. This includes the theoretical full potential for DSM regardless of economic constraints, FPL's resource needs, or customer adoption of efficiency measures. *Id*. at 15.

- Step 2 determines resource needs over the 10-year DSM goal-setting time period. At this point, FPL studies how much capacity (in MW) is needed to meet peak demand requirements, both for a Supply-Only scenario and a With-DSM scenario. *Id*. at 18-22. The results are used in Step 5.

- Step 3 identifies a preliminary DSM Economic Potential via preliminary economic screening that compares DSM options to a single supply-side resource; i.e., without any sort of resource planning analysis. *Id.*at 16. This preliminary economic screening applies the Participants test, the RIM test, the TRC test, and a "years-to-payback" test. *Id.* at 16. At this point, FPL creates two screening "paths." The RIM path analyzes the DSM measures using the RIM test, the Participants Test, and the years-to-payback test. The TRC path analyzes the DSM measures using the TRC test, the Participant test, and the years-to-payback test. *Id*. at 29-30. FPL also conducts several sensitivity analyses, including analyses regarding CO_2 costs, fuel prices, and different levels of years-to-payback. *Id.* at 32-33.

- Step 4 identifies the DSM Achievable Potential. FPL applies an assumption of the "maximum customer incentive level" that it can pay for the DSM measures that passed the economic potential screening above. FPL then estimates the "maximum annual signups" that it could expect from customers based on those customer

incentives. The number of customer signups indicates the extent to which FPL deems DSM savings achievable. *Id*. at 16, 38-39.

- Step 5 develops resource plans (Supply-Only and With-DSM). FPL identifies how many of the DSM measures that passed the Achievable Potential screening above could be used to meet its resource planning needs. The latter only reflect FPL's capacity needs, especially with regard to meeting FPL's 20 percent total reserve margin criterion. *Id.* at 41-42.

- Step 6 analyzes resource plans from both economic and "non-economic" perspectives to select the best resource plan and the accompanying amount of DSM to include in FPL's proposed DSM goals. The economic perspective calculates the levelized system average electric rate for each resource plan. FPL uses this electric rate metric to conduct the economic evaluation of the resource plans and associated amounts of DSM. This metric is also proffered to ensure that there is no cross-subsidization across different groups of customers. *Id*. at 54. The "non-economic" analysis includes two additional "perspectives," including (a) emissions of SO_2, NO_X, and CO_2, and (b) system oil and natural gas usage. *Id*. at 66-67.

Note that the analysis described above is performed for each efficiency measure in isolation. There is no consideration of DSM programs, or the associated technical support, education, marketing, and delivery practices that can be used to implement DSM measures.

Q. Please provide a summary of DEF's resource planning process.

A. DEF performs a resource planning process that is similar to FPL's process. It includes the following key elements:

- DEF conducts a technical potential analysis to identify the amount of DSM and demand-side renewable measures that are theoretically available. Direct Testimony of Witness Guthrie, Document No. 01497-14, at 24.

- DEF conducts a resource planning process, using the Strategist model, to analyze the impacts of DSM from a system resource perspective. DEF develops a Base Case (Supply-Only) plan, and begins economic analysis of DSM measures using the RIM, TRC and Participant tests. *Id*. at 24-27.

- DEF then determines the DSM economic potential, by applying a two-year payback limit for free-ridership, and by performing cost-effectiveness analyses using the RIM and TRC tests. *Id*. at 29-30.

- DEF then sets the DSM achievable potential by applying administrative costs and participant incentives to the economic potential measures. Next, DEF uses a set of "payback acceptance curves" to determine "maximum expected participation rates," and applies a set of "diffusion" curves to determine 10-year participation limits. *Id*. at 31-32.)

- DEF then sets the economic and achievable potentials based on (a) the RIM and Participants tests, and (b) the TRC test. *Id*. at 32-34.

- Finally, DEF conducts sensitivity for fuel prices and free-ridership exclusion periods. *Id*. at 36-37.

Q. Do you have any concerns about the resource planning processes that the FPL and DEF used to set DSM goals?

A. Yes. FPL's and DEF's screening processes suffer from many fundamental flaws. I summarize these flaws below, and elaborate on them in the following subsections.

- The Technical Potential estimates significantly understate the full DSM technical potential in Florida. They exclude many important efficiency measures that are proven to be available, and they continue the Utilities' misguided use of a two-year payback to screen out supposed free-riders.

- FPL and DEF perform two separate economic screening analyses in this process—first, a preliminary screen to determine the economically viable DSM measures, and second, a screen based on resource planning models that supposedly optimize both demand-side and supply-side resources. This results in "double-screening,"

which eliminates a large portion of the DSM measures before they are compared to supply-side resources with the resource planning models.

- FPL and DEF use rate impacts as the primary criterion for resource planning and choosing among resource options. This perpetuates all of the problems with the RIM test that I described above, including the fact that the Utilities' estimates of rate impacts are simply wrong and grossly overstated. Furthermore, FPL's and DEF's own analyses indicate that the rate impacts from the DSM plans that they analyze are likely to be so small as to be unnoticeable.

- FPL incorrectly assumes that DSM can only be implemented if it provides capacity (in terms of MW) that can be used to meet reliability requirements. This ignores DSM's ability to reduce energy costs, and dramatically biases the resource planning process against DSM.

- The FPL's and DEF's resource planning processes do not allow DSM measures the full opportunity to defer new supply-side resources, to reduce the size of new supply-side resources, or to assist with retiring existing, uneconomic supply-side resources. This conflicts with FEECA and gives undue preference to supply-side resources that are "hard-wired" into the system regardless of the amount of DSM savings, including the very expensive and very risky Turkey Point nuclear plant in the case of FPL.

In sum, FPL's and DEF's resource planning processes does not provide the critical information that the Commission needs to set DSM goals pursuant to FEECA. These processes do not provide reasonable estimates of Technical, Economic, or Achievable potential; they do not provide evidence of the extent to which DSM can reduce electricity system costs and therefore reduce customer bills; and they do not provide meaningful information on the extent to which DSM affects the general body of ratepayers as a whole. Ironically, FPL and DEF (erroneously) claim that rate impacts should be the primary criterion for selecting cost-effective DSM, but their own analyses provide almost no useful information that the Commission can use to consider the implications of rate impacts.

1

The Technical Potential Estimates Understate DSM Potential

Q: What kind of technical potential evaluation does FEECA require?

A: Section 366.82(3), F.S., requires the Commission to "evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures." FEECA also requires such evaluation of demand-side renewable energy systems, as discussed in Section 7.

Q: Do you think such an effort is warranted at least every five years?

A: Absolutely. Section 366.82(6), F.S., requires this "full technical potential" evaluation to occur at least every five years, for good reason: Conservation and DSM (together, DSM) are integral parts of a balanced and cost-effective energy system. DSM is particularly valuable in the face of many current challenges for utilities in Florida and many other states, including an over-reliance on generation tied to natural gas (a fuel with notoriously volatile pricing), the need to replace an aging generation fleet, the rising costs and risks of conventional new generation, and the need for transmission and distribution infrastructure upgrades to maintain and expand capacity.

Moreover, rapid changes in the energy sector effectively re-define the regulated energy landscape in intervals even shorter than five years. To meet FEECA's intent to utilize the most efficient and cost-effective DSM programs, the Utilities and the Commission must stay informed of the ongoing research and development regarding these resources, and the potential to include them in Florida's energy system.

Q: Does the evaluation of the full technical potential required by Section 366.82(3), F.S., identify the complete picture of the DSM potential in Florida?

A: No. Technical potential studies by definition do not assess all the implications of DSM. Most importantly, they do not consider the cost-effectiveness of DSM measures; they only measure whether a measure is technically feasible. In addition, they do not consider the likely behavior of customers in response to market changes, pricing signals, and outreach and marketing of efficient products and services. Therefore, to fully capture the potential for DSM in Florida and to best understand the likely costs and benefits to the Utilities' customers, the Commission must also look at the economic and achievable

DSM potential. In fact, the goals proposed by the Utilities are determined by the achievable potential.

Q: Does that mean that the technical potential estimates are irrelevant?

A: No. Each successive estimate of potential is based on the previous one. In other words, the achievable potential is developed based on the results of the economic and technical potential estimates. Therefore, the Commission must verify the completeness and accuracy of every part of the Utilities analysis, from technical potential to achievable potential to the ultimate goal-setting.

Q. Did you review the materials provided by the Utilities regarding their updates of technical DSM potential?

A. Yes, I reviewed the filings by DEF and FPL (Dockets 130199-EI and 130-200-EI, filed on April 2, 2014), as well as their responses to discovery requests by Sierra Club and the Southern Alliance for Clean Energy (SACE). I also reviewed worksheets provided by DEF, FPL, TECO, and Gulf Power that summarize the results of their technical potential updates. These were submitted in advance of the filings as "preliminary drafts" subject to change. I also reviewed a short narrative description of the methodology for updating the 2009 technical potential estimates.

Q. Did you review any other material related to the technical potential estimates?

A. Yes. Because the new estimates are updates of previous estimates from 2009, I also reviewed the potential estimates from the 2009 Technical Potential Study by Itron, Inc. on behalf of the Collaborative comprised of the Utilities (DEF, FPL, TECO, Gulf Power, OUC, and JEA), and the related materials in Dockets No. 080407–080413. In particular, I reviewed critiques of the 2009 Technical Potential Study in Witness Mosenthal's Direct Testimony on behalf of NRDC and SACE, and in Witness Spellman's Direct Testimony on behalf of Staff. Also from those dockets, I reviewed testimony filed by SACE's Witness Wilson and rebuttal testimony filed by Witness Rufo on behalf of the Utilities.

Q. Please summarize the findings of your review of the technical potential.

A. Table 4.1 presents the technical potential by sector as a percentage of sales for that sector, for each of the four utilities named above. These data are drawn from responses provided

by the Utilities on December 6, 2013, to SACE's informal data requests dated November 6, 2013.

Table 4.1 Summary of Technical Potential Estimates

	Technical Potential as % of sales			
Utility	Residential	Commercial	Industrial	Total
DEF	44%	24%	15%	33%
FPL	35%	25%	34%	31%
TECO	36%	33%	14%	32%
Gulf	36%	33%	10%	31%

The Utilities' estimates represent a limited estimate of technical potential, in part because they have omitted relevant measures and relevant energy-consuming sectors and end uses from the analysis. These same problems existed in the 2009 Technical Potential Study, as demonstrated by Witness Mosenthal and Witness Spellman in that docket.

Q. What types of measures have been omitted in these estimates of technical potential?

A. The Utilities overlook various measures and market segments. Here I highlight the key omissions, those that are most likely to represent a substantial amount of potential that is omitted from subsequent analysis of the economic and achievable potential. These including building commissioning and retro-commissioning, new types of LED lighting fixtures, various efficiency measures in data centers, efficiency measures for water and wastewater treatment plants and the agricultural sector, and ultra-low energy buildings such as net zero energy buildings and "Passive Houses." I will explain in detail each of these omissions. Also, because the Utilities' discovery responses list dozens of measures in each of the three sectors, and these measure lists appear to be consistent across the Utilities, my observations and recommendations apply to all of the Utilities.

First, the Utilities omit building commissioning and retro-commissioning in the commercial and industrial sectors. These omitted measures involve targeted efforts by building operation experts to identify operational changes and repairs/adjustments to equipment to realize optimum performance. Typically, these savings opportunities are widespread, inexpensive, and result in substantial savings. Witness Mosenthal noted the

omission of these measures in his 2009 testimony. *See* Document No. 06794-09, at 11. In rebuttal testimony, Witness Rufo claimed that several of the measures included in the technical potential "represent" the potential associated with retro-commissioning. Document No. 07822-09, at 14 . Yet none of the measures described by Witness Rufo address the operational improvements (rather than equipment-based measures) that are a primary result of retro-commissioning activities. While it may be true that the measures offered by Witness Rufo have some overlap with commissioning and retro-commissioning, his testimony does not substantiate that the full technical potential from these activities are included in the Utilities' estimates and updates.

Second, the Utilities appear to omit new types of efficient lighting fixtures for commercial and industrial applications. For instance, from among the most common type of recessed linear fluorescent lighting, the Utilities only include "LED linear tubes." These products were some of the first of their kind on the commercial marketplace, but they have been rapidly eclipsed in performance by newer fixtures that take advantage of LEDs' particular technical characteristics, rather than being limited to the old form-factor and housings of tubular fluorescents. The potential for emerging LED lighting technologies was noted by witnesses, including Witness Spellman in the 2009 goal-setting. *See*. *e.g.*, Witness Spellman Direct Testimony, Document No. 07271-09, at 59. This is another major omission to a technical potential estimate, as there are likely to be LED solutions for virtually every lighting application in commercial and industrial spaces.

Third, the Utilities identify only one data center-related measure, server virtualization. Data centers present openings for significant energy savings because they represent a growing percentage of electricity consumption in many jurisdictions. Therefore, the Utilities should consider other efficiency strategies and technologies ranging from the efficiency of the computing equipment to the power supply and HVAC systems. These represent yet another area where the technical potential likely falls short of the actual opportunity.

Fourth, in 2009, Witness Mosenthal noted the apparent omission of measures specific to water and wastewater treatment plants and to the agricultural sector. The updates do not seem to remedy this omission.

Fifth, in 2009, Witness Wilson, noted that efficient outdoor and street lighting measures were entirely omitted. Yet these measures represent substantial energy consumption, and they are clearly technically feasible. Nonetheless, they are still missing from the Utilities updates.

Last, the updates fail to account for ultra-low energy or net-zero energy buildings. Constructing such new buildings or retrofitting existing buildings to those standards is technically feasible, and thus should be included in the technical potential analysis. For example, an experimental super-energy-efficient residence in Lakeland, Florida demonstrated a 70% to 84% reduction in cooling loads. When the PV electric generation is included during the peak period, the home net demand was only 199 Watts, a 93% reduction in electricity requirements.[14]

Q: Are the Utilities' proposed DSM goals based on their technical potential estimates?

A. Yes, although not directly. The technical potential forms the basis for assessing the economic potential, which in turn forms the basis for the achievable potential. As discussed above in Section 4, the economic and achievable potential estimates are also flawed.

Q: What flaws have you identified in the Utilities' economic potential estimates?

A: The worst flaw is the Utilities' use of the RIM test to determine economic potential, as discussed above in in Section 4. Also problematic are the Utilities': (1) use of a two-year payback to screen efficiency measures for supposed free riders; (2) omission of non-energy benefits; and (3) omission of openings for DSM to replace aging, uneconomic generation. I elaborate on each of these flaws below.

[14] Florida Solar Energy Center (FSEC). "ZEH: Lakeland, Florida."

Q: What is the problem with two-year payback screening?

A: The Utilities screen out any measure from their economic potential estimates if participant payback for that measure is less than two years without incentives. This is a blunt and overly-constrictive way to screen for free riders who would participate in programs without any incentives. As with several other flaws discussed in this testimony, the two-year payback screen was critiqued in the 2009 goal-setting docket. There, Witness Mosenthal described how the use of a two-year simple payback threshold is a critically flawed method to estimate economic potential for several reasons, including (1) inconsistencies between the Utilities' load forecast and the two-year payback method; and (2) the inaccurate assumption that all customers implement efficiency measures with a short payback whether or not the customers know the payback is short. To these, I add that the Utilities' two-year payback screening relies on the incorrect assumption that all customers have ready access to capital sufficient to take advantage of even highly cost-effective efficiency resources.

Q. Please explain these issues in detail.

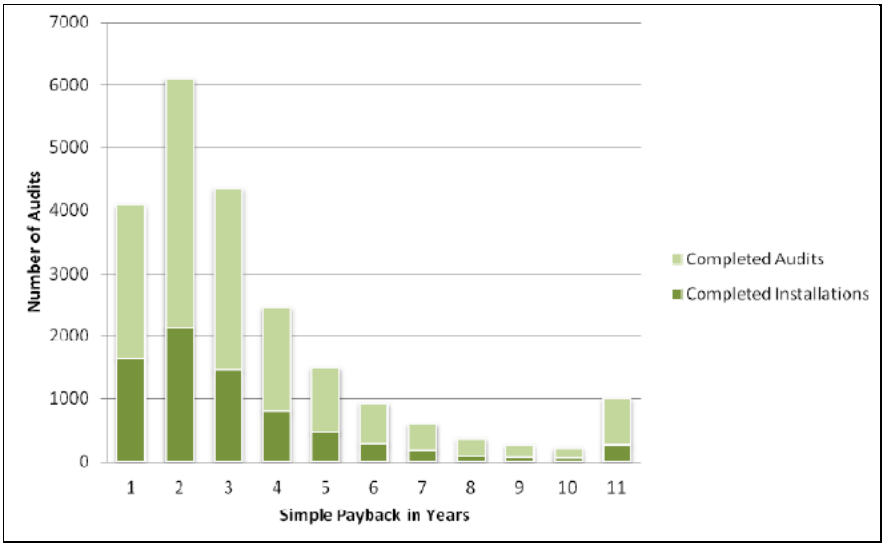
A: First, the Utilities' base load forecast should already include naturally occurring DSM, which is essentially the impact from supposed free riders in an efficiency program. Accordingly, the baseline penetration of such measures that are naturally adopted without incentives should be 100%, and the Utilities' baseline forecast should reflect this. However, the technical and economic potential estimates actually assume some non-zero penetration of these measures, and therefore estimates some non-zero potential which is then removed from the potential estimate. This implies that they are in fact *not* currently installed and *not* reflected in the base load forecast.

Essentially, the Utilities try to "have it both ways" by claiming all these measures would be adopted naturally without incentives, but then the Utilities proceed to estimate DSM potential as though these measures are not adopted without incentives. If the Utilities have not included the impact of naturally occurring efficiency in their load forecast, then it is inappropriate to also omit it from the assessment of potential. That is, it should appear in one of these locations. If it does not, then the utility's need for future capacity

and energy supply is overstated and the ability of efficiency to reduce that need is understated.

Second, the Utilities continue to assume that all customers know and understand the simple payback when buying efficient appliances or equipment. *See*, *e.g.*, Direct Testimony of Witness Deason, Document No. 01474-14, at 27. There are many customers who do not have time or sufficient understanding to think about whether they can reduce their energy bills and whether or not an initial investment will be recouped. Even when customers do understand that efficiency investments provide a good return on investment, they may not follow through with those investments for myriad reasons. For example, Xcel Minnesota's innovative small business program, One-Stop Efficiency Shop[SM], identified many small business customers who did not adopt DSM even with simple paybacks in the range of 1 to 2 years, as shown in Figure 4.1. More than half of the customers with completed audits did not install DSM measures despite highly favorable returns.

Figure 4.1 Xcel Minnesota One-Stop Shop Audits vs. Installations in 2000 – 2011[15]



Last, even when customers understand the return on their efficiency investment and want to proceed to make that investment, they may not have access to the necessary capital

[15] Kristen Funk, *Small Business Energy Efficiency: Roadmap to Program Design*, Proceedings of the 2012 ACEEE Summer Study on Energy Efficiency in Buildings, August 2012.

monies. This is particularly true of low-income and fixed-income customers and new home-owners who are fully extended with credit obligations. Utility-sponsored DSM programs can assist with such consumers by offering low or zero interest loans.

In summary, it is clear that assuming that all measures with a two-year simple payback are automatically captured by the marketplace without any intervention is a gross over-simplification that dramatically reduces the achievable potential that utility efficiency programs should be addressing.

Q: Do the Utilities' present any information that supports your contention that not all customers will automatically take advantage of opportunities with a simple payback of less than two years?

A. Yes, the two-year payback threshold conflicts with Itron's 2009 Technical Potential Study, which clearly indicates that far less than 100% of customers will adopt measures with even a better return on investment. For example, DEF applies a payback-acceptance curve to determine maximum expected participation rates by measure. *See* Direct Testimony of Witness Guthrie, Document No. 01497-14, at 32. The maximum participation rates are presented in several Excel worksheets that DEF provided in response to Sierra Club's First Set of Interrogatories, No. 1-18. According to those worksheets, the maximum adoption rate for a residential measure with a two-year payback is approximately 42%; for a commercial measure it is just over 30%. Yet the Utilities' screening methodology would assume 100% penetration at two years, without intervention by their efficiency programs. Even at a one-year simple payback, the maximum adoption rates are just 51% for residential customers and 60% for commercial customers, still far below universal acceptance. The Utilities' assumption of maximum adoption rate and free-ridership are therefore internally inconsistent.

Q: Has the Commission expressed any concern with the two-year payback screen?

A: Yes. In the last round of goal-setting, the Commission noted that screen eliminates a substantial amount of potential savings. *See* Order No. PSC-09-0855-FOF-EG, at 9. As a result, the Commission increased the proposal goals for several utilities to account for the potential savings from several residential measures that the Utilities would have eliminated using the two-year payback screen.

Q: Did the Utilities' revise their approach in response to the Commission's Order?

A: No. For example, DEF's filing states that "the first step in the determination of economic potential was to evaluate and account for free-ridership by screening out any measure that had a participant payback of less than two years without a utility incentive." Direct Testimony of Witness Guthrie, Document No. 01497-14, at 29-30.

Q: What is the effect of this approach to assessing free riders?

A: It is significant. For instance, FPL eliminated nearly a quarter of the DSM potential using this screen. *See* Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-5 (showing that FPL eschewed 210 measures out of the total of 850 measures based on the two-year payback year screen under the TRC Test).

The Resource Planning Process is Driven Entirely by Rate Impacts

Q. What is the primary criterion that the Utilities use to set their DSM goals?

A. FPL and DEF both set their DSM goals by including only those DSM measures that will not increase electricity rates. FPL calculates a levelized system average electric rate for each resource plan, and then the "rate metric is used as the primary economic basis by which the resource plans, and the amount of DSM in each resource plan, are evaluated." Direct Testimony of Witness Sim, Document No. 01476-14, at 54.

DEF has not identified its primary criterion for selecting DSM. However, DEF's proposed DSM goal is essentially the same as its estimate of achievable potential under the RIM test, indicating that DEF used rate impacts to set its DSM goals. *See* Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibits HG-1 & HG-12.

Q. What is wrong with using rate impacts as the primary criterion to set DSM goals?

A. In Section 3 I describe several fundamental flaws of screening DSM programs with the RIM test; i.e., rate impacts. All of those points are relevant to the Utilities' resource planning process. To summarize:

- Using rate impacts as the primary criterion to select DSM programs conflicts with FEECA's requirements and policy goals.

- Lost revenues are not a "new" cost created by DSM programs; they are instead driven by costs already included in rates. In other words, they are "sunk" costs, and should not be used to determine cost-effectiveness.

- Using rate impacts as the primary criterion to select DSM programs can lead to perverse outcomes; where the opportunity to significantly reduce utility system costs and customer bills may be forgone to avoid a very small increase in rates.

- Using rate impacts as the primary criterion to select DSM programs is inconsistent with the treatment of supply-side resources, which can also lead to cross-subsidization between customers.

- The Utilities calculate rate impacts incorrectly, by estimating lost revenues on the basis of the full electricity rate, as opposed to just the fixed portion of electricity rates. This results in lost revenue estimates that could be more than double what the correct number would be.

- The Utilities calculate rate impacts incorrectly for another reason, by assuming that base rates will increase every year, when in fact base rates only increase at the time of a rate case. Consequently, the Utilities' estimates of rate impacts are grossly overstated.

Furthermore, FPL and DEF's resource planning process is inconsistent with standard industry practice for integrated resource planning. All states that I am aware of that use integrated resource planning practices use the minimization of the present value of revenue requirements as the primary criterion for selecting the preferred resource plan.

Q. Do the Utilities' resource planning processes highlight any additional reasons why rate impacts should not be used as the primary criterion for setting DSM goals?

A. Yes. FPL's own results indicate that the rate impacts of DSM are likely to be very small. Table 4.2 presents the results of FPL's resource planning process, in terms of the levelized system avenge electric rate (cents/kWh). Table 4.2 also presents the difference in levelized average system rates between the Supply Only case and the other cases, as well

as the difference between the RIM 337 MW case and the other cases. Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-11.

Table 4.2 Results of FPL's Resource Planning Process

Resource Plan	Levelized System Average Rate	Difference From Supply Only	Difference from RIM 337 MW
Supply Only	11.7419	0.000%	0.006%
RIM 337MW	11.7412	-0.006%	0.000%
TRC 337 MW	11.7579	0.136%	0.142%
RIM 526 MW	11.7431	0.010%	0.016%
TRC 576 MW	11.7636	0.185%	0.191%

As indicated, there are very small differences in levelized rates between the plans. The levelized rates for the TRC 337 MW plan and the TRC 576 MW plan are only 0.136 percent and 0.185 percent higher than the rate for the Supply Only plan. Note that these rate impacts are based on lost revenue estimates that are grossly overstated, as described in Section 3. A proper estimate of rate impacts would indicate even lower impacts than the impacts presented in Table 5.1.

Q. Does DEF provide any information on the potential rate impacts of its DSM programs?

A. Only a little. DEF estimates a typical residential customer's rates under the RIM test and the TRC test. The results are summarized in Table 4.3. *See* Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibits HG-2 & HG-3. I estimate the rate impacts by calculating the percent difference between rates under the RIM the TRC scenarios.

Table 4.3 Residential Customer Rate Estimates

Year	RIM ($/month)	TRC ($/month)	Difference (percent)
2015	1,820	1,829	0.5%
2016	1,802	1,811	0.5%
2017	1,911	1,919	0.4%
2018	1,972	1,980	0.4%
2019	2,103	2,111	0.4%
2020	2,129	2,136	0.3%
2021	2,190	2,195	0.2%
2022	2,235	2,238	0.1%
2023	2,252	2,254	0.1%
2024	2,246	2,247	0.0%

The rate impacts presented in Table 4.3 are relatively small, ranging from 0.5 percent to 0.1 percent. Note that these rate impacts are based on lost revenue estimates that are grossly overstated, as described above in Section 3. A proper estimate of rate impacts would indicate even lower impacts than those presented in Table 4.3. Further, the DEF rate impacts presented above do not account for the years after 2014, when the DSM installed in this period will continue to result in savings, and will therefore help to lower rates. From a long-term perspective (i.e., over the lives of the efficiency measures), the rate impacts would be significantly lower than those presented in Table 4.3.

Q. What conclusions do you draw from FPL's and DEF's rate impact results?

A. The rate impacts of FPL's and DEF's DSM plans are likely to be very small, so small as to be essentially unnoticeable by most customers. FPL's estimates in particular indicate that the actual rate impacts are likely to be "in the noise." By this I mean that the estimates are likely to be so small that they are within the rounding and uncertainty errors of the resource planning analysis. Therefore, the Commission should give the Utilities' rate impact estimates no weight in setting DSM goals. While the other Utilities provide even less information on rate impacts in their resource planning processes, I expect that the rate impacts from their DSM plans will also be very small, because those plans are of a comparable scale to FPL's and DEF's.

Also, it is helpful to keep these rate impact estimates in perspective. The rate impacts estimated by FPL and DEF, even if they were not overstated, are small relative to the other factors that cause rates to change over time. Rates typically increase by much, much higher amounts after a rate case. It is safe to assume that if FPL completes the construction of Turkey Point Units 6 and 7, rates will need to be increased by much more than the DSM rate impacts estimated by FPL and DEF. However, FPL's resource planning does not capture the potential benefits of postponing Turkey Point Units 6 and 7, as described below, and therefore ignores the potential for DSM programs to help postpone, mitigate or avoid the rate impacts associated with this expensive generation.

FPL and DEF Undervalue DSM by Conducting Two Economic Screens

Q. Please explain what you mean by conducting two economic screens.

A. Both FPL and DEF conduct a screen to determine economic potential, then they conduct a second screen using their resource planning models. FPL describes the first screen as Step 3 of its analysis, where FPL conducts a "preliminary" screening analysis against a single supply-side option, utilizing the Participant test, the RIM test, the TRC test and the "years-to-payback" test. Direct Testimony of Witness Sim, Document No. 01476-14, at16. The second screen occurs during FPL's Step 6, where the resource plans are analyzed from both economic and non-economic perspectives, and where the DSM measures are selected based upon the minimization of levelized rates. Direct Testimony of Witness Sim, Document No. 01476-14, at 54.

DEF explains that its first screen is conducted when each DSM measure is compared to the Base Optimal Supply-Side Plan, to determine sets of cost-effective DSM measures based on the RIM test, the TRC test, and the Participants test. The second screen is conducted when the cost-effective supply-side and demand-side portfolios are "optimized together to formulate integrated resource plans." Direct Testimony of Witness Guthrie, Document No. 01497-14, at 26-27.

Q. Is there any problem with conducting two economic screens in this way?

A. Yes. The problem with this approach is that the first screen can eliminate a lot of potential DSM measures, before they even get a chance to be integrated and supposedly "optimized" with supply-side resources.[16] This approach is especially problematic if the first screen is unduly constrained, either by using incorrect free-rider assumptions, by using incorrect definitions of the screening tests, or by ignoring some key benefits such as avoided GHG emissions—all of these flaws appear in DEF and FPL's methods. Consequently, when DEF and FPL insert their narrowly-defined set of "cost-effective"

[16] As described in the following subsection, FPL does not actually optimize the combination of supply-side and demand-side options. This, however, does not mitigate the flaws identified in this subsection.

DSM measures into their resource planning process, there are too few DSM measures to meet resource planning needs, and DSM's value is significantly understated.

This practice essentially results in "double-screening" of DSM measures. I am aware of many states that screen DSM using a simple economic screen without resource modeling, and I am aware of many states that screen DSM using a resource planning process, but I am not aware of any states that use both combined. For good reason: doing so severely confines the resource planning process; needlessly complicates DSM screening; and obscures the critical fact that DSM is the lowest-cost, lowest-risk resource.

FPL Significantly Understates Avoided Capacity Benefits

Q. Please summarize how FPL compares DSM measures to supply-side resources.

A. FPL prepares a Supply-Only resource plan, which does not include any new DSM measures after 2014. This plan includes five approved and/or planned change to FPL's generating system, including: (a) retirement of existing Putnam units; (b) the completion of Port Everglades modernization; (c) the removal of existing gas turbines and the addition of 5 new combustion turbines in Broward County; the addition of the firm capacity portion of the EcoGen power purchase agreement; and the addition of Turkey Point Units 6 and 7. Direct Testimony of Witness Sim, Document No. 01476-14, at 21.

In the resource plans that include DSM, FPL includes a 1,269 MW combined cycle unit, as well as various amounts of purchase power agreements. *Id.*, Exhibit SRS-10. These are the resources that are potentially avoidable by DSM measures.

Q. Is this an appropriate way to compare demand-side resources to supply-side resources?

A. No. This methodology significantly understates the potential for DSM to help reduce capacity costs, by fixing the amount of capacity in the system that can be deferred, reduced or avoided by DSM.

First, this methodology freezes in place the five potential changes to FPL's generating system listed above. This means that DSM measures cannot defer, reduce the size of, or avoid several future supply-side resources, such as Turkey Point Unites 6 and 7, or new

combustion turbines. As shown in Sections 2 and 5, DSM costs significantly less than new supply-side resources, and could play a role in deferring, reducing or avoiding new supply-side capacity. The proposed Turkey Point units, in particular, are expected to be very expensive, and involve considerable risks for the FPL's customers. Any opportunity to further delay these units could offer significant benefits to customers. These benefits are not captured in FPL's resource planning process.

Second, the combined cycle unit that FPL used as the potentially avoidable unit was modeled with the fixed size of 1,269 MW. One of the advantages of combined cycle units is that they can be constructed within a wide range of sizes to best match system needs. DSM programs could potentially reduce the size of this unit, thereby saving significant capacity costs. FPL's methodology did not allow for this potential savings opportunity to even be investigated in its resource planning process.

Third, FPL does not even attempt to optimize supply-side capacity options relative to demand-side capacity options. FPL uses a "reserve margin analysis" to estimate supply-side and demand-side capacity needs. *See* Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-8. FPL does not use its optimization model to identify the best mix of supply-side and demand-side capacity resources. *See* FPL Responses to Sierra Club's Second Set of Interrogatories, Nos. SC-1-31 and SC-1-54. As a result, FPL has not investigated a variety of DSM plans that could potentially reduce utility system costs. This lack of modeling, combined with the first two points above, where FPL considers only a very limited amount of capacity options that can be avoided, demonstrates that FPL has significantly understated the potential for DSM measures to defer, reduce or avoid new capacity resources, thereby understating avoided capacity costs.

FPL's Planning Criteria Ignores Avoided Energy Benefits

Q. How does FPL determine the amount of DSM that should be included in its resource plans and DSM goals?

A. FPL uses a "reserve margin analysis" to estimate supply-side and demand-side capacity needs, as demonstrated in Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-8. FPL identifies the amount of capacity needed to meet its 20 percent

reserve margin, either using supply-side or demand-side resources. In the DSM resource plan, FPL assumes the installation of enough DSM to meet any deficiency in the reserve margin, and no more. *Id*. at 41-43. This presumes that DSM measures can only be installed when they are needed for capacity or reliability purposes.

Q. Can DSM measures only be installed when there is a capacity need?

A. No, not at all. FPL ignores the fact that DSM can reduce energy costs, by reducing fuel consumption, even if there is no need for new capacity. FPL thus ignores one of the key benefits of DSM.

Further, FPL's DSM screening practices conflict with standard industry practice, and in fact conflicts with FPL's screening practices for supply-side resources. That is, if energy impacts were ignored on the supply-side, then peaking combustion turbines would be the lowest-cost way to meet future peak demand. Also, there would be no need to build baseload units, such as combined cycle facilities, conventional steam facilities, or nuclear facilities.

Clearly, this is not an appropriate way to plan a utility system. In fact, FPL describes the importance of considering both capacity and energy benefits when developing future resource plans, and states that it is necessary to "capture and accurately compare all of the impacts that competing resource options with different capacity amounts, terms-of-service, heat rates, types of fuel, MW and GWh reduction impacts, and costs will have on FPL's system." Direct Testimony of Witness Sim, Document No. 01476-14, at 43. FPL has failed to do so in its DSM planning, has essentially ignored DMS' energy benefits, and has thus dramatically understated the economic and achievable DSM potential.

<u>The Utilities' Fundamentally-Flawed Resource Planning Eliminates Most DSM</u>

Q. What are the ultimate implications of these flaws in the Utilities' resource planning process, in terms of setting DSM goals?

A. The Utilities' screening process rejects nearly all DSM programs leading to extremely low proposed DSM goals. Figures 4.1 through 4.4 present the bottom-line screening results for FPL and DEF, showing the amount of the technical potential, the economic potential under the RIM and the TRC tests, and the proposed DSM goals. For each

company the first figure is for the energy savings (in terms of GWh), and the second figure is for capacity savings (in terms of MW). As indicated in the figures, the proposed DSM goals are a small fraction of the technical, economic and achievable potential.

Figure 4.1 FPL Efficiency Savings at Various Screening Levels (GWh)[17]

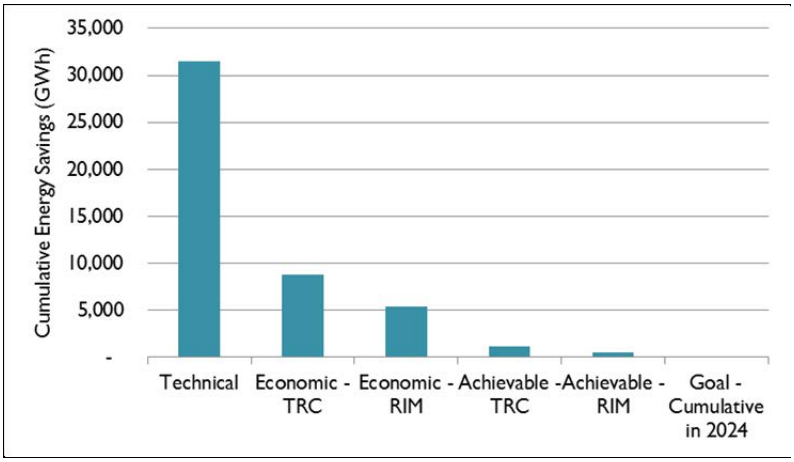
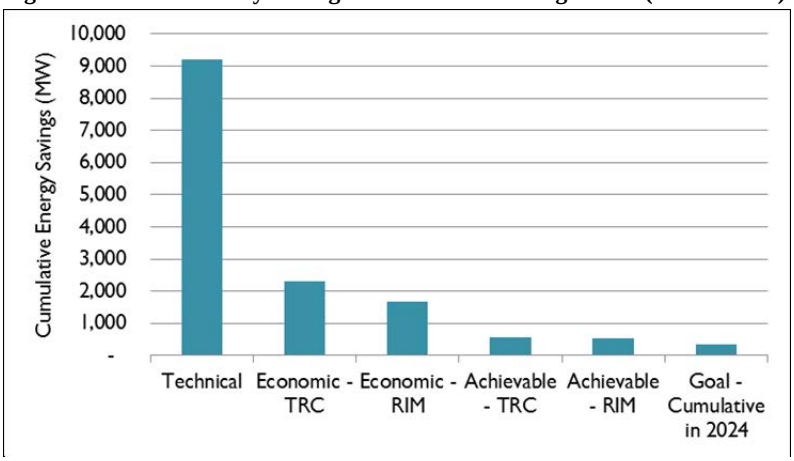


Figure 4.2 FPL Efficiency Savings at Various Screening Levels (Winter MW)[18]



[17] Based on Direct Testimony of Thomas Koch, Document No. 01475-14, Exhibits TRK-4, TRK-5, TRK-6, and TRK-7.
[18] *Id*.

Figure 4.3 DEF Efficiency Savings at Various Screening Levels (GWh)[19]

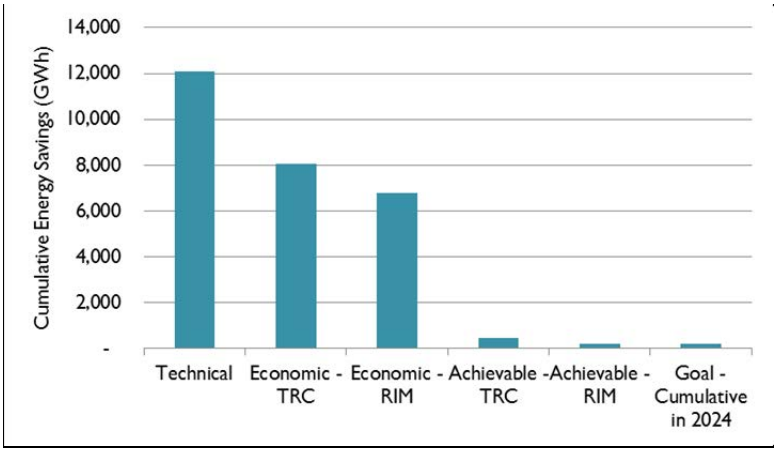
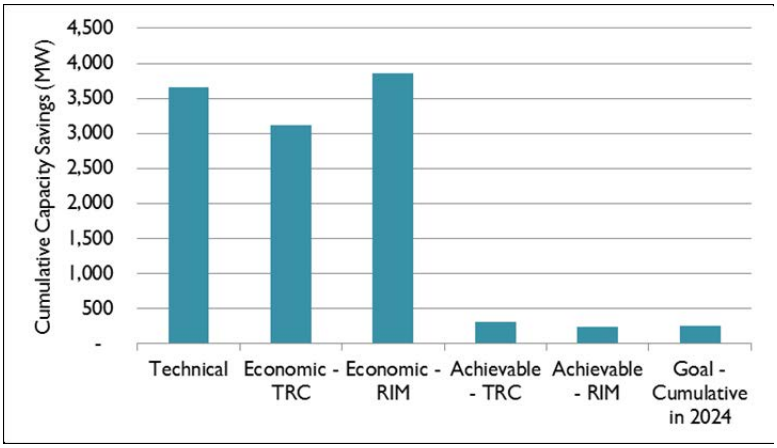


Figure 4.4 DEF Efficiency Savings at Various Screening Levels (Winter MW)[20]



Q. What do these results say about the Utilities' planning analysis?

A. First, recall that the Utilities' technical potential estimates are understated, for the reasons described above. Therefore, the DSM technical potential estimates should be higher than those presented above.

Second, the differences between the technical potential and the economic potential estimates are driven by applying the TRC, RIM and years-to-payback screens. These differences have a dramatic impact on the amount of economic potential, especially for

[19] Based on Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibits HG-1, HG-5, HG-7, HG-8, HG-12, and HG-13.
[20] *Id*.

FPL. Given the flaws in the Utilities' attempts to use the RIM and TRC tests, as described in Section 3, and that a two-year-payback screen should not be applied at all, the economic potential estimates are clearly too low.

Third, the differences between economic and achievable potential estimates are driven primarily by the Utilities' assumptions regarding maximum incentive amounts and maximum customer signup rates. As described above, these assumptions are overly simplistic and do not account for the many opportunities for the Utilities to promote customer participation through program marketing and delivery options.

Fourth, the differences between FPL's achievable potential estimates and DSM goals are due entirely to FPL's erroneous assumption that DSM can only be implemented for the purposes of meeting reliability requirements. The extent of this limitation is not apparent in the figures above, due to the scale of the vertical axis. FPL's cumulative achievable potential is estimated to be 526 GWh, but FPL has set its DSM goal at only 59 GWh. In other words, FPL has reduced its DSM goals by roughly nine times, because of FPL's incorrect assumption that DSM can only be implemented for the purposes of meeting reliability requirements.

Q. Are there other conclusions that can be drawn from the Utilities' resource planning processes?

A. The Utilities' resource planning process prioritize load management programs (i.e., those that curtail peak demand only), and place little, if any, priority on DSM programs (i.e., those that curtail both energy consumption and peak demand). Specifically, the Utilities' misguided view that DSM can only be implemented to meet reliability requirements strongly favors load management over energy efficiency.

Table 4.3 below provides weighted average summer peak reduction factors for the DSM measures being selected for different potential estimates and scenarios for FPL and DEF. While there are some differences between the Utilities, the Utilities selected resources that offer significantly more peak reduction per MWh energy savings in their achievable potential estimates and proposed goals. For example, FPL's technical potential on average

reduces about 0.3 kW summer peak per MWh energy savings, but FPL's goal is expected to reduce about 5.7 kW summer peak per MWh energy savings.

Table 4.3 Peak Reduction Factor by Scenario for FPL and DEF (kW peak per MWh)

Scenario	FPL	DEF
Technical	0.29	0.30
Economic TRC	0.26	0.39
Economic RIM	0.31	0.57
Achievable TRC	0.53	0.67
Achievable RIM	1.00	1.33
Goal	5.68	1.33

Q. Is there anything wrong with placing a high priority on load management programs?

A. No, not necessarily. Load management programs offer a very low-cost opportunity for the Utilities to reduce demand in the most expensive hours of the year. I encourage the Utilities to maintain, or expand, these programs. My concern is that the Utilities place too much emphasis on load management programs, and not enough emphasis on energy efficiency programs. In doing so, the Utilities are missing the opportunity to significantly reduce electricity costs and to help "protect the health, prosperity and general welfare of the state and its citizens," pursuant to Section 366.81, F.S.

5. THE CENTRAL ISSUE: BALANCING RATE AND BILL IMPACTS

Q. Why is it so important that the Utilities and the Commission strike an appropriate balance between rate impacts and bill impacts?

A. As noted above, this is the primary challenge facing the Commission in setting DSM goals. DSM offers many advantages, with the primary advantage being that DSM reduces utility system costs and thereby reduces customer bills. The one (and only) countervailing consideration is that DSM can potentially increase electricity rates. To understand the implications of rate impacts, it is necessary to consider three important factors: rate impacts, bill impacts, and efficiency program participation rates. Taken together, these three factors indicate the extent to which customers as a whole will benefit from DSM.

Q. Do the Utilities' provide any meaningful information on these three factors in their filings in this docket?

A. No. As described above, the Utilities' analyses of rate impacts are so misguided and replete with flaws that they provide no information that would be useful to the Commission. In fact, the rate impact information that the Utilities provide is very misleading and should be ignored in its entirety. The Utilities' TRC analyses are also flawed, particularly because they ignore several key benefits such as avoided GHG regulatory compliance costs and participant non-energy benefits. Finally, the Utilities do not even provide results for the Utility Costs test, which is the one test that could provide the most information about the impacts on utility revenue requirements and thus the impacts on customer bills.

Q. How, then, do you recommend that the Commission consider the important issues regarding rate impacts and bill impacts?

A. I provide below some high-level information regarding the issues of rate, bills and participants. This information is helpful in illustrating the key tradeoffs that should be considered in setting DSM goals.

DSM Rate Impacts Will be Very Small

Q. How do you recommend that the Commission consider rate impacts associated with the DSM goals?

A. There is very little evidence presented in this case on what the actual rate impacts of the Utilities' DSM goals are likely to be. The Utilities estimates of lost revenues and rate impacts are clearly overstated and therefore unreliable. Even with this caveat, FPL's and DEF's own results suggest that the rate impacts of the DSM plans they have analyzed are likely to be very small, so small as to be unnoticeable by most customers. For these reasons, I recommend that the Commission give very little weight to concerns about the DSM goals discussed in this docket imposing an undue burden on customers as a result of rate impacts.

Q. Has the Commission recently issued an order indicating what an undue rate impact might be?

A. Yes. In Docket No. 1001155-EG, the Commission considered the potential rate impacts of FPL's DSM Plan proposed in that docket. The Commission determined that rate impacts of FPL's proposed DSM plan would cause an undue rate impact on customers. Order No. PSC-11-0346-PAA-EG, at 4. The Commission, therefore, rejected FPL's proposed DSM plan, and required FPL to maintain its existing DSM Plan because its rate impacts were determined to be relatively minor. Order No. PSC-11-0346-PAA-EG, at 5.

Q. How does that precedent impact your assessment of rate impacts here?

A. The Commission's Proposed Agency Action Order in Docket No. 1001155-EG included an estimate of the potential rate impacts of the proposed DSM Plan on a typical residential customer. Those rate impacts were estimated by determining the Energy Conservation Cost Recovery (ECCR) charge needed to support FPL's proposed DSM Plan, and adding those costs to the estimated residential bill. The results indicated that typical residential customer bills could increase in the range of 1.9 – 3.4 percent. Order No. PSC-11-0346-PAA-EG, Table 1.

The methodology used to estimate these rate impacts is very simplistic and does not account for the fact the DSM programs also exert downward pressure on rates. DSM programs reduce generation, transmission, distribution and other costs, which reduces a utility's revenue requirements, which in turn reduces customer rates. These avoided costs are significant and will outweigh the increase in revenue requirements associated with the DSM costs. This downward pressure on rate impacts is not accounted for in the rate impact estimates presented in Order No. PSC-11-0346-PAA-EG.

The downward pressure on rates is especially important in light of the magnitude of rate impacts that result from the installation of baseload power plants. When FPL has a rate case to recover the costs associated with a new power plant, such as Turkey Point Units 6 and 7, there will likely be much higher rate impacts than any impacts associated with DSM programs. DSM can help offset, reduce, defer or even totally avoid some of the rate impacts of large new power plants, but the rate impact estimates presented in Order No.

PSC-11-0346-PAA-EG do not account for any of these benefits. Consequently, they significantly overstate the potential rate impacts from DSM programs, and should not be used in setting DSM goals.

Higher DSM Goals Would Result in Lower Costs and Lower Bills

Q. How do you recommend that the Commission consider bill impacts associated with the DSM goals?

A. As noted above, the Utilities' resource planning process provides little information regarding the extent to which DSM can reduce customer bills. Even worse, the Utilities' overly-complex and overly-constrained screening process actually obscures the undisputable fact that DSM costs significantly less than alternative supply-side resources.

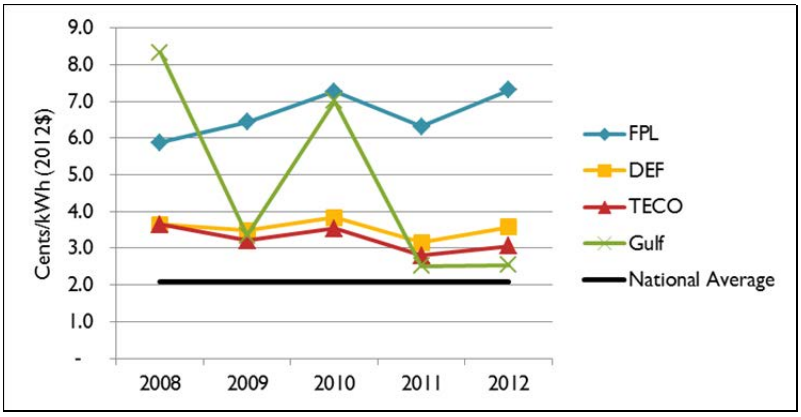
I provide some information below to illustrate this key point. I compare the "cost of saved energy" from DSM programs to the cost of generating energy from alternative sources, in terms of levelized costs.

Q. What is the cost of saved energy from DSM programs?

A. The cost of saved energy (in cents/kWh) is simply a ratio of the cost of implementing DSM programs (in dollars) divided by the energy savings (in GWh). The cost of saved energy can be presented in terms of either annual energy savings, lifetime energy savings, or in terms of levelized lifetime energy savings. I prefer to use levelized lifetime energy savings, because these can then be compared directly to levelized costs of supply-side alternatives.

Figure 5.1 presents the levelized cost of saved energy for the four largest electric utilities in Florida, for 2008 through 2012. It also presents the national average levelized cost of saved energy for 2012, for comparison purposes. As indicated, DEF and TECO have been achieving efficiency savings for roughly 3 to 4 cents/kWh; FPL has been achieving efficiency savings for roughly 6 to 7 cents/kWh; and Gulf's costs have varied considerably over this period.

Figure 5.1. Levelized Cost of Saved Energy: Florida Utilities versus National Average.[21]



Q. What conclusions do you draw from Figure 5.1?

A. First, the DSM programs offered in Florida are considerably more expensive than the national average. I expect this is due more to program design and implementation than it is due to anything unique about Florida.

Second, DEF and TECO have demonstrated that it is possible to implement DSM programs in Florida for roughly 3 to 4 cents/kWh. There is no reason why FPL and the other utilities cannot implement efficiency programs at this level of costs as well.

Third, no matter which utility you look at, DSM is significantly less expensive than supply-side alternatives.

Q. How do you know that DSM is significantly less expensive than supply-side alternatives?

A. Figure 5.2 compares the cost of several generation technologies to the cost of saved energy. The levelized cost of FPL's proposed Turkey Point nuclear unit is estimated by the Company to be roughly 16 cents/kWh.[22] The levelized cost of DEF's proposed Levy nuclear unit is estimated by Synapse Energy Economics to be roughly 17 cents/kWh as a

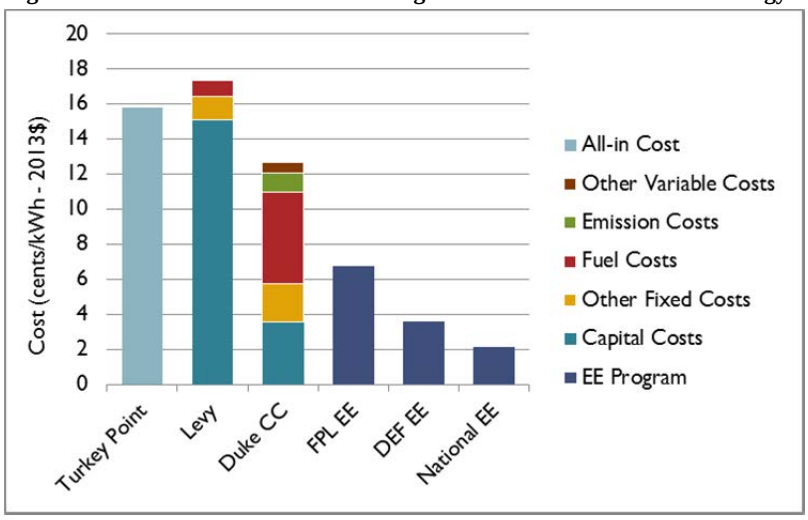
[21] Note that these costs and savings are for the energy efficiency programs offered by the Florida utilities. They do not include the costs or savings for the load management programs, because this metric is much less relevant for programs that have few energy savings.

[22] FPSC, "Hearing Proceedings of Docket No. 130009-EI, Nuclear Cost Recovery Clause" (August 14, 2013), Volume 4, at 821.

mid-point estimate.[23] The DEF CC unit is the cost of a combined cycle unit that DEF used in this docket in its resource planning process.[24] The cost of saved energy values for DEF, FPL and the national average are taken from Figure 5.1.

As indicated in Figure 5.2, the costs of DSM programs are well below those of the supply-side alternatives that those programs could potentially displace. Note that the avoided costs of transmission and distribution associated with the supply-side generation technologies are not included in Figure 5.2, making those resources look less expensive than they really are.[25] Also, note that the DSM programs can help reduce the reserve margin requirements (in MW), and reduce line losses, unlike the supply-side options.

Figure 5.2. Cost of Generation Technologies versus the Cost of Saved Energy



[23] Synapse Energy Economics. "Big Risks, Better Alternatives - An Examination of Two Nuclear Energy Projects in the U.S." October 6, 2011.

[24] The cost estimate is based on the underlying cost assumptions for the "CC2X1 P1 - COMBINED CYCLE" unit provided in Excel file, "Sierra Club ROG 1-13 - Avoided Costs.xlsx" as part of Duke's response to Sierra Club Interrogatory No. 1-13.

[25] According to FPL's response to Sierra Club Interrogatory No. 1-13, the avoided cost of transmission and distribution systems are approximately $150/kW-year and $27/kW-year respectively.

Q. Figure 5.1 presents supply-side and demand-side resource costs in a relatively simple format. Is it not necessary to account for more details of how the two types of resources would affect the utility system, by using resource planning processes?

A. A more detailed resource planning process would provide a better, more comprehensive picture of the costs and benefits of DSM programs in Florida. However, there are two very important conclusions that can be drawn from Figure 5.1, despite its simplicity.

First, DSM programs cost significantly less than supply-side resources. They can cost as little as 2, maybe 4, maybe 6 cents per kWh, while supply-side options cost as much as 12, 16, or even 17 cents/kWh (even before avoided transmission and distribution costs are factored in, or accounting for reserve margin benefits or line loss benefits).

Second, reduced costs from DSM programs will result in reduced customer bills. All of the costs that are shown in Figure 5.1 would eventually be included in a utility's revenue requirements, and passed on to customers. Therefore, the savings resulting from DSM programs would be passed on to customers in the form of lower average customer bills. In fact, the data in Figure 5.1 is the only data presented so far in this docket that provides any indication of how DSM might help reduce customer bills. None of the Utilities' analyses presents information on the impact on customer bills, and yet this is one of the key factors that the Commission should consider in setting DSM goals. I recommend that the Commission consider the information in Figure 5.1 when considering the bill impacts of the proposed DSM goals.

Program Participation Will Mitigate Rate Impacts

Q. Why is it so important to consider program participants, when analyzing rate and bill impacts?

A. Generally speaking, program participants are essentially shielded from the rate impacts of DSM programs; they experience reduced bills as a result of reduced consumption, regardless of any rate increases. Therefore, to the extent that rate impacts appear to be a problem, it is essential to consider the offsetting impact of program participation, in order to understand the extent of the problem.

Q. Do you have any information to offer regarding DSM participation rates?

A. Yes. Figures 5.3 and 5.4 present historic and forecast participation rates for FPL's DSM programs. These are taken from the Company's most recent Annual DSM Report.[26] The participation rates in these figures are based on the number of historic and forecast participants divided by the eligible population of participants. Note that the forecast of participants are based on placeholder goals that FPL was forecasting at the time it prepared the Annual DSM Report. If the Commission were to approve the lower DSM goals proposed by FPL in this docket, then the future participation rates would be much lower than those presented in Figures 6.3 and 6.4.

Figure 5.3. FPL Cumulative Participation Rates – Residential Programs

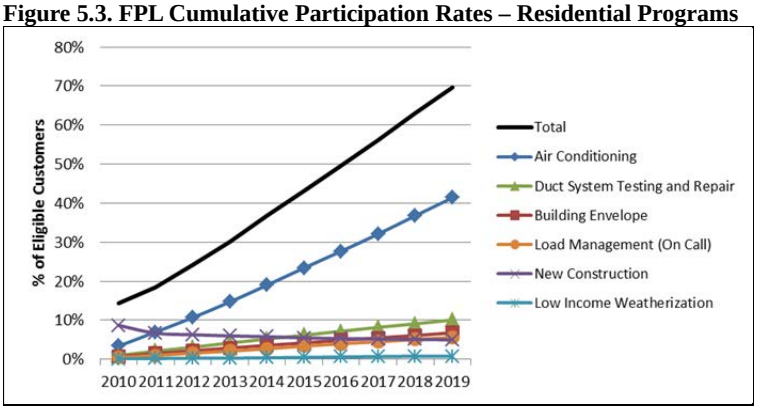
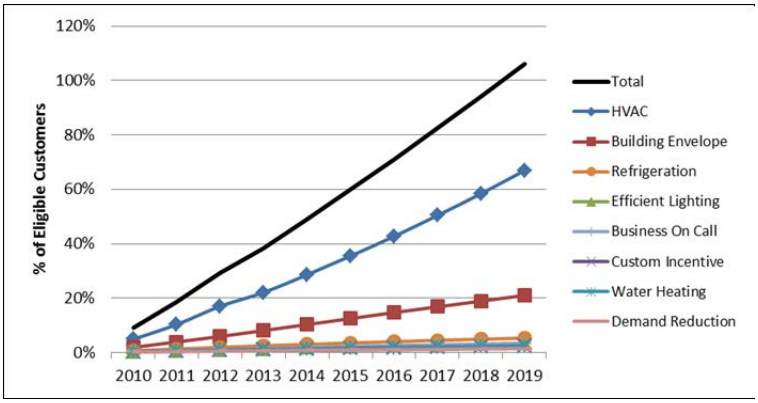


Figure 5.4. FPL Cumulative Participation Rates – Commercial & Industrial Programs



[26] FPL. "2013 Demand Side Management (DSM) Annual Report." February 28, 2014.

Q. What conclusions do you draw from the participation rates presented in Figures 5.3 and 5.4?

A. This information suggests that FPL would be able to serve a significant portion of its residential, commercial and industrial (C&I) customers with DSM programs—if FPL were to continue with the goals it had at the time of the Annual DSM report published in February this year. Roughly 40 percent of residential and 60 percent of C&I customers could be served with air conditioning or HVAC services. Roughly 10 percent of residential and 20 percent of C&I customers could be served with building envelope measures. The total amount of participation could reach up to 70 percent for residential customers, and 100 percent for C&I customers.

In addition, the participation information presented above does not include any of the customer participation that occurred prior to 2010. If this were included in the information presented above, then the cumulative participation rates would be significantly higher.

It is important to note that there are probably instances of multiple participation embedded in the participation rates presented in Figures 6.4 and 6.5. Multiple participation occurs when a single customer participates in more than one program in a single year, or in more than one program across years. Multiple participation is common in DSM programs, and is not discouraged; in fact it is encouraged. I mention this phenomenon to note that in some cases the participation information presented in Figure 5.4 and 6.5 may be somewhat over stated.

In sum, it is safe to conclude that a large portion of FPL's customers has been, or could be, served by the DSM programs. To the extent that there are any significant rate impacts as a result of these programs, they will be offset by efficiency savings for a large portion of customers. This should be a central consideration when setting DSM goals.

A Better Balance Between Reduced Costs Against Increased Rates

Q. Please summarize the conclusions that you draw from the information above regarding rates, bills and participation.

A. There is no question that the Utilities could achieve significantly higher DSM goals, without causing a significant increase in electricity rates. The Utilities' own analysis shows that the rate impacts from higher DSM goals would be so small as to be in "the noise" of the analysis, and this result is from a resource planning process that *overstates* the rate impacts of DSM programs in many ways.

It is also clear that if the Utilities were to adopt significantly higher DSM goals, then customer bills would be reduced significantly. This is the basic conclusion from a straightforward comparison of the costs of supply-side and demand-side resources; unencumbered by opaque, unduly complex and constraining resource planning practices.

Furthermore, the Utilities could provide DSM services to a large portion of their customer base, thereby offsetting any rate impacts that do occur. This could be achieved by maintaining the DSM goals that were previously approved by the Commission in the 2009 goal-setting dockets. Participation could be expanded even further with higher DSM goals.

In sum, this high-level consideration of rate impacts, bill impacts and participation rates indicates that increased DSM goals would lead to greater benefits to "the general body of ratepayers as a whole," consistent with Section 366.82(3)(b), F.S. This is a much better indication of the issues at stake in these dockets than resource planning results presented by the Utilities.

6. ENERGY EFFICIENCY SAVINGS AND GOALS

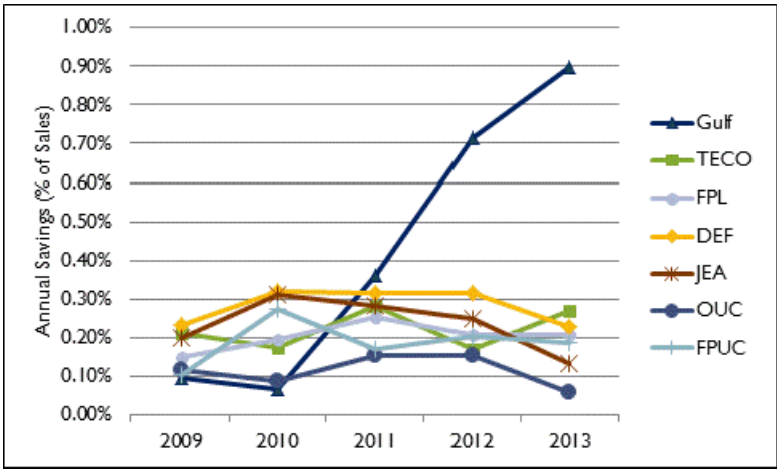
Efficiency Savings in Recent Years

Q. Please summarize the efficiency savings that have been achieved in recent years.

A. Figure 6.1 provides an overview of the energy savings achieved by the FEECA utilities in recent years. The energy savings are presented in terms of annual energy saved as a percent of annual retail sales. This allows for an easy comparison of savings across

utilities of different sizes. It also allows for easy comparison of savings across utilities in different states and regions of the country. As indicated, the Utilities saved roughly 0.1 percent to 0.3 percent of sales in this period, with Gulf achieving higher savings in the later years.

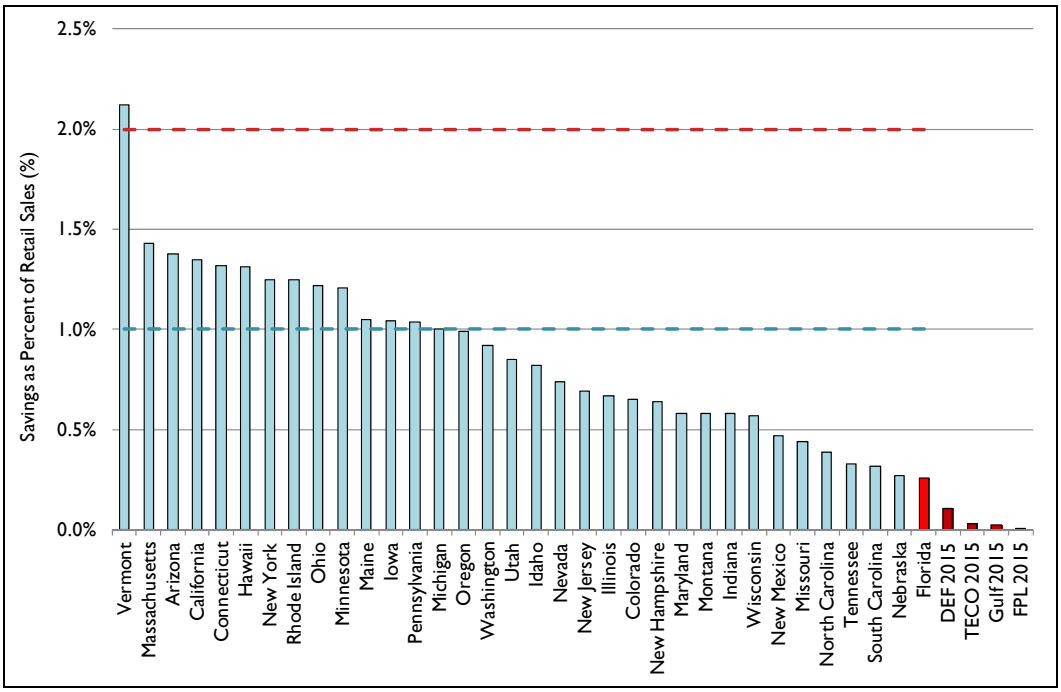
Figure 6.1 Efficiency Savings of Florida Utilities 2008 – 2013



Q. **How do the Utilities' DSM savings in recent years compare with savings by utilities in other states?**

A. Figure 6.2 presents the efficiency savings in 2011 from several states, including Florida, again in terms of percent of retail sales. The savings from all 50 states have been presented in order from the greatest to the lowest savings. To fit the graph onto the page, I have not presented the states that had less energy savings than Florida. As indicated, Florida's 2011 efficiency savings are less than those of 33 other states. Roughly 15 states achieved savings of 1 percent or more, and roughly half of all states achieved savings of 0.5 percent or more. In contrast, Florida saved just about 0.25 percent in 2011. Furthermore, these numbers are a little out of date; I am aware of many states that achieved higher levels of savings in 2012 than in 2011.

Figure 6.2 Efficiency Savings in 2011: Top US States and Florida



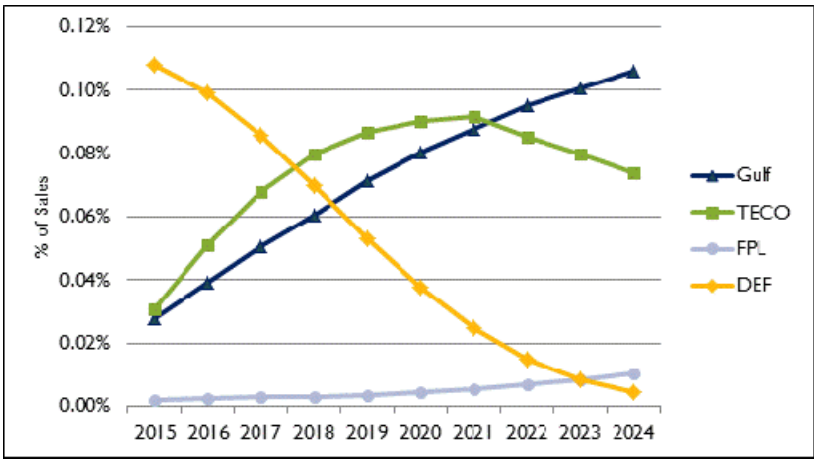
In sum, the Florida utilities are not one of the leading states in terms of delivering DSM savings. Figure 6.2 also presents the proposed 2015 DSM savings goals for the four largest Florida utilities. As indicated, the 2015 DSM goals are well below Florida's 2011 savings, and are well below the historic savings of many other states. I return to this point in the next subsection.

The Utilities' Proposed Efficiency Goals

Q. Please summarize the efficiency goals proposed by the Utilities.

A. Figure 6.3 presents the DSM savings goals proposed by the four largest FEECA utilities. As indicated, DEF's proposed goals start out higher than the others, d then decline significantly during this period. FPL's proposed goals start out much lower than the others and rise slightly during this period. TECO's proposed goals increase significantly at first, then decline in the second half of this period. Finally, Gulf's proposed goals increase significantly throughout this period.

Figure 6.3. Proposed Goals (2015-2024)



Q. How do these proposed goals compare with the amounts of savings achieved by the Utilities in recent years?

A. Figure 6.4 combines the historical savings from Figure 6.1, with the proposed goals presented in Figure 6.3. As indicated, the proposed DSM goals are dramatically lower than the amount of savings achieved in recent years.

Figure 6.4 Historic Savings and Proposed Energy Goals

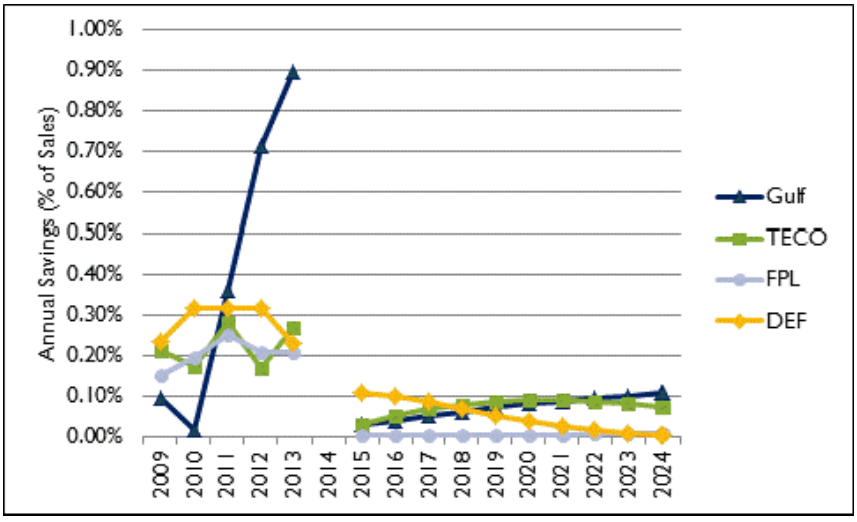


Table 6.1 Historic and Proposed Savings Goals (GWh)

	FPL	DEF	TECO	Gulf
2009	155	88	40	10
2010	204	124	34	8
2011	261	119	52	40
2012	211	115	32	76
2013	214	84	50	95
2014	---	---	---	---
2015	2	40	6	3
2016	3	37	10	4
2017	3	33	13	6
2018	4	27	15	7
2019	4	21	17	8
2020	5	15	18	9
2021	7	10	18	10
2022	8	6	17	11
2023	10	4	16	12
2024	13	2	15	13

Q. Are there any high-level conclusions that can be drawn from the historical and proposed savings levels presented in Figure 6.4?

A. Yes. First, the DSM goals proposed by these four utilities are well below the levels of efficiency savings that they themselves have achieved in recent years. FPL's proposed 2015 goal is less than the company's 2013 savings by a factor of 100. This is a dramatic reduction in DSM goals. DEF's 2015 goal is roughly half of its 2013 savings level. It is also remarkable that FPL is proposing to reduce its DSM goals by so much more than the reductions proposed by the other companies. There is no reason why there should be such striking differences between the goal reductions across the four utilities.

Second, these four utilities (FPL, DEF, TECO, and Gulf) are all proposing inconsistent trends for savings over the DSM goals period. Some propose a dramatic increase over the period, some propose a dramatic decrease over the period, and Gulf proposes both. There

is no logical explanation for such differences in the trends over this period. These Utilities have roughly similar customer bases, and will be exposed to similar efficiency standards and building codes over this period. The differences between the savings trends across the utilities can only be explained by inappropriate assumptions and methodologies, poor planning practices, or some combination of both.

Third, the proposed 2015 goals are dramatically less than the savings achieved by other states, as indicated in Figure 6.2, above. In 2011, over half of the states in the US saved at least 0.5 percent of retail sales though DSM programs, and 15 states saved roughly 1.0 percent of retail sales or more. If the Commission were to accept FPL's proposed DSM goals, then *FPL's energy savings in 2015 would be less than the 2011energy savings achieved by every other state in the country*.

Q. The Utilities have argued that their DSM goals should be lower than in the past, because they have already implemented much of the efficiency savings available in Florida. Do you agree?

A. No. Relative to many other states the Utilities' DSM programs have not achieved large amounts of energy savings in the past. Figure 6.2 illustrates how small the Florida efficiency savings were in 2011 relative to other states. Data from earlier years demonstrate the same point. Relative to the achievements of many other states, the Utilities have left a large portion of the efficiency savings potential in Florida untapped.

In addition, the Utilities' argument is based on a very simplistic understanding of DSM programs, markets and opportunities. The potential for DSM savings is not a stagnant figure, that a utility can pursue for several years and then claim that it has finished the job. Instead, efficiency products are constantly being introduced into the marketplace, creating new opportunities for efficiency savings every year. The recent introduction of LED lighting products is but one example of how new products can create new opportunities for efficiency savings. Furthermore, and more importantly, utility DSM programs should constantly evolve to account for new developments in the market. Utility efficiency programs should constantly be seeking new efficiency measures to promote, considering new marketing and delivery opportunities, and looking for new ways to overcome customer barriers to DSM measures. This is how efficiency programs

are designed in the leading states, and why those states have been able to achieve significantly higher savings than Florida in the past, and plan to achieve higher savings than Florida in the future. I address this point in more detail in the following subsection.

Q. The Utilities try to argue that their DSM goals should be lower than in the past, because avoided costs are lower than they have been in the past. Do you agree?

A. No. First, the Utilities have understated avoided costs by not properly accounting for GHG compliance costs and by ignoring participant non-energy benefits. If these costs were properly included in their analysis, then the economic potential for DSM would be higher than indicated by the Utilities.

Second, the Utilities' efficiency programs cost much less than supply-side alternatives, as indicated in Figure 5.1—even under the Utilities' current assumptions of avoided costs. This means there is still lots of room for the efficiency program benefits to exceed the costs, even though avoided costs are less than they were in the past.

Third, this argument would only make sense if the Utilities were implementing the total economic potential for DSM (i.e., all cost-effective energy efficiency), both in the past and proposing to do so going forward. If avoided costs decline for some reason, then the total economic potential for DSM would decline as well. However, the Utilities have not implemented the total economic potential in the past, and they do not propose to implement the total economic potential in the future. Their past savings and future goals are based on implementing the achievable efficiency potential, and only a portion of the achievable efficiency potential at that. This means that there is likely to be a significant amount of efficiency potential that is still available, despite the lower avoided costs.

Q. The Utilities try to argue that their DSM goals should be lower than in the past, because new building codes and efficiency standards will diminish the amount of efficiency available. Do you agree?

A. No, not entirely. It is true that increasing building codes and standards will make it more difficult to achieve DSM savings over time. However, this does not mean that the potential for efficiency savings will be reduced by anywhere near the amount indicated by the Utilities' proposed goals.

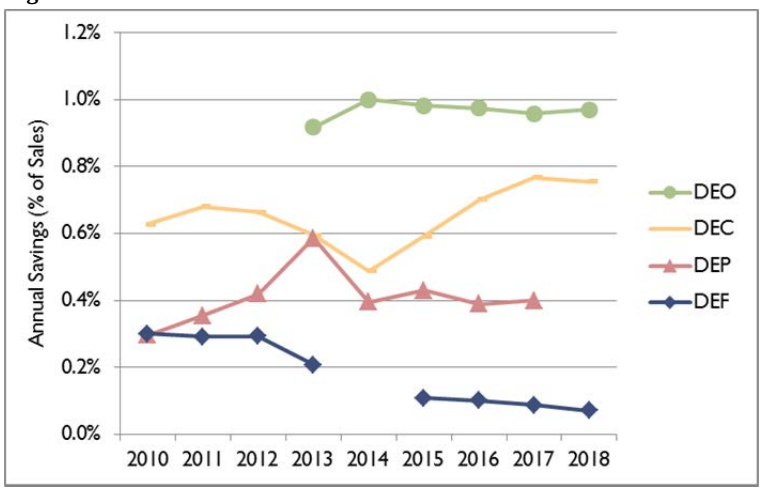
Figure 6.4 shows that some utilities propose future DSM goals that are a small fraction of their recent savings. DEF's proposed DSM goal for 2020 is roughly 15 GWh, which is six times lower than the savings that DEF achieved in 2013. Increasing efficiency standards and building codes will not have such a dramatic effect on the potential efficiency savings available in DEF's service territory. Furthermore, as new efficiency standards begin to take effect, the Utilities should modify their DSM programs to offer additional efficiency measures that are more efficient than the standards. Promoting the purchase of LED lighting products in response to the new federal lighting standards is one example of how utilities in general should respond to the new federal standards. In addition, as efficiency standards are applied to some end-uses (e.g., lighting), utilities should generally place greater emphasis on other types of end-uses where efficiency opportunities still remain.

Efficiency Goals in Florida Relative to Other States

Q. How do DEF's DSM savings goals compare with the efficiency savings of other Duke utilities?

A. Figure 6.5 presents DEF's efficiency savings in recent years, as well as proposed DSM goals, alongside those of Duke Energy Carolinas (DEC), Duke Energy Progress (DEP) and Duke Energy Ohio (DEO). As indicated, the other Duke companies have already achieved significantly higher levels of efficiency savings than DEF, and have set significantly higher goals for future efficiency savings.

Figure 6.5 Duke Florida Goals Relative to Duke Goals in Other States



Q. What conclusions do you draw from this comparison of efficiency goals across Duke's companies?

A. First, DEF should be able to achieve roughly the same goals as other Duke companies. There is no reason why DEF cannot implement the same types of efficiency programs, offer the same types of efficiency measures, and achieve roughly the same amount of customer participation as other Duke companies. As I describe in more detail below, the differences between these companies is more due to the regulatory environment in each state than the achievable efficiency potential. In addition, DEO, DEC and DEP have all achieved greater savings than DEF in recent years; thus, the goals for these other Duke companies contradict DEF's argument that it has already achieved much of the achievable efficiency potential available in Florida. If that argument were true, then DEO, DEC and DEP could not have saved more energy than DEF in the past and still have higher goals the future.

Furthermore, DEO, DEC and DEP will all be subject to the same federal efficiency standards as DEF; thus the goals of the other Duke companies contradicts DEF's arguments that the achievable potential in Florida is shrinking dramatically due to federal efficiency standards. Finally, even if one were to agree with DEF's arguments that there is less achievable efficiency potential in Florida relative to other states, which I do not, there is no way to justify the magnitude of the difference between DEF's proposed goals, and those of other Duke companies. DEF's proposed efficiency goals are roughly one-tenth the size of DEO's. This means that DEF is proposing to forgo 90 percent of the efficiency savings that DEO is able to achieve. There is no justification for depriving customers of such a large opportunity to reduce system costs and reduce customer bills.

Q. Are you aware of other states in the Southeast that are proposing significantly higher future efficiency savings than what the Utilities are proposing for their DSM goals?

A. I am aware of one state in the Southeast that has recently established significantly higher efficiency goals than those proposed by the Utilities. The Arkansas Public Service Commission recently issued a set of orders that outline several regulatory policies affecting the planning and implementation of DSM programs there. The orders require

several significant changes to these regulatory policies, including the introduction of decoupling, the introduction of shareholder incentives, the requirement to incorporate non-energy benefits into the TRC test, and more. One of the key elements of the recent orders is a set of efficiency goals for the next several years. The Arkansas Commission has required that the electric utilities ramp up their efficiency programs over the next few years, so that they achieve savings equal to 1.0, 1.25 and 1.5 percent by 2014, 2015, and 2016, respectively. I have seen no evidence in this docket indicating that the Florida Commission cannot set comparable goals for the Florida utilities.

Q. Are you aware of other states in the US that are proposing significantly higher future efficiency savings than what the Utilities are proposing for their DSM goals?

A. Yes. I have been involved in three states that have achieved, and plan to continue to achieve, significantly more than what the Utilities are currently achieving or what the Utilities are proposing for their DSM goals.

Massachusetts: In 2012 the Massachusetts program administrators achieved electric efficiency savings equal to 2.1 percent of sales. The energy savings goals that the efficiency program administrators set for the years 2013 to 2015 are 2.50, 2.55 and 2.56 percent of sales each year, respectively. These goals have been approved by the Massachusetts Department of Public Utilities.

Rhode Island: In 2012, the Rhode Island program administrator achieved electric efficiency savings of 1.5 percent of sales. The energy savings goals for 2013 and 2014 are 2.05 and 2.44 percent of sales per year, respectively. These goals were approved by the Rhode Island Public Utilities Commission. The program administrator and other stakeholders are currently proposing energy savings goals for 2015-2016 equal to 2.50, 2.55 and 2.60 percent of sales each year, respectively. These goals have been approved by the Rhode Island Public Utility Commission.

Vermont: As noted above, Vermont has achieved significant energy savings of roughly 2 percent per year on average for the past five years, cumulatively achieving 10 percent savings over those years. The state currently has efficiency savings goals of roughly 2 percent per year for 2012 – 2014. The state is currently in the middle of a planning docket

to set future efficiency savings goals, where the base case proposal is for annual savings goals to of roughly 1.7 percent of retail sales through 2019, 1.4 percent of retail sales through 2026, and 1.3 percent of retail sales through 2033.

Note that all three of these states have been implementing some of the most aggressive and successful efficiency programs in the country for many years. Also, note that the energy savings goals above account for federal efficiency standards, as well as state and local standards and building codes. Even so, *these states are setting DSM goals that are more than 100 hundred times greater than the goals being proposed by the Company in this docket.* There is no justification for such a wide disparity energy efficiency opportunities across these states.

Sierra Club Proposed Efficiency Goals

Q. Does the Sierra Club recommend that the Commission set different DSM goals than the goals proposed by the Utilities?

A. Yes. The Utilities' DSM goals are way too low, for all the reasons outlined above. I recommend that the Commission set significantly higher goals, in order to reduce costs to Florida electricity customers.

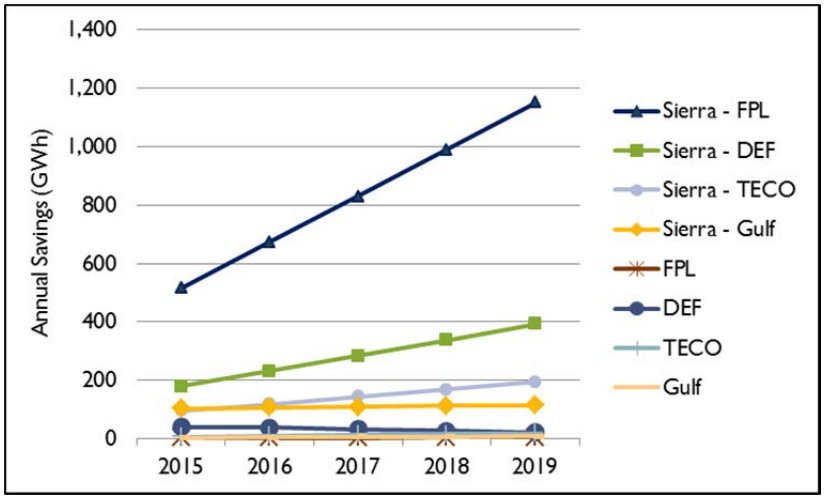
Q. What DSM goals do you recommend for the Florida utilities?

A. I recommend that the Commission set DSM goals such that each of the FEECA utilities will achieve annual efficiency savings equal to one percent of annual retail sales by 2019. These goals are presented in Table 6.2 and Figure 6.6

Table 6.2 Sierra Club DSM Goals (2015-2019) - GWh.

	FPL	DEF	TECO	Gulf
2015	516	180	95	103
2016	673	231	118	106
2017	830	283	143	109
2018	990	337	168	112
2019	1152	394	193	114

Figure 6.6 Sierra Club Goals Relative to Utilities' Goals (2015-2019) – Percent of Sales



Q. Do you recommend that the Commission set goals for capacity savings as well?

A. Yes. It is important that the Commission set goals for both energy (GWh) and capacity (MW) savings. Up until now I have focused on energy savings, as I believe that energy savings are an important indication of the magnitude of a utility's DSM efforts. However, the Commission should set capacity savings as well, as this is different indicator of the magnitude of a utility's DSM efforts.

In fact, it is important for the Commission to consider the ratio of energy savings per capacity savings (MW/GWh), because this provides an indication of the type of programs the Utilities offer—in particular the emphasis that the Utilities are placing on energy efficiency programs relative to load management programs.

Q. Please explain why it is important for the Commission to consider the emphasis that the Utilities are placing on energy efficiency programs versus load management programs when setting DSM goals.

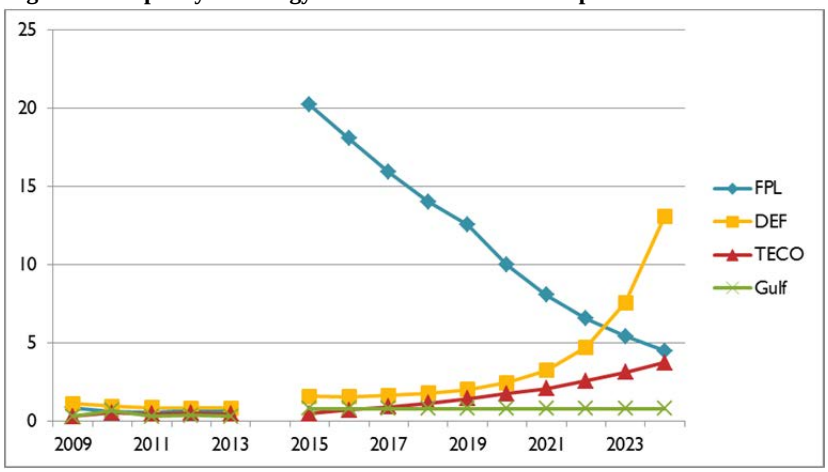
A. Energy efficiency and load management programs both offer benefits to the Utilities and their customers, and the Utilities should offer a proper balance of both types of programs. Load management programs offer some customers the opportunity to reduce their costs in some portions of the year. Energy efficiency programs offer a wider range of opportunities to a wider range of customers, relative to load management programs. Energy efficiency programs also offer customers the potential for reducing their energy consumption by a much greater amount that load management programs. Therefore, if

too much priority is given to load management programs, at the expense of energy efficiency programs, then many customers will be deprived of opportunities to reduce their costs and bills.

Q. Do the Utilities' proposed DSM goals provide a good balance of load management and energy efficiency programs?

A. No. The Utilities have historically placed a much higher emphasis on load management programs and capacity savings than the utilities that I typically work with. More importantly, the Utilities' proposed goals make a dramatic shift toward increased capacity savings and load management, relative to historic programs. This is demonstrated clearly in Figure 6.7, which present capacity-to-energy ratios for the four Utilities, for historic and proposed DSM goals. Note that a higher capacity-to-energy ratio indicates a greater emphasis on load management, relative to energy efficiency.

Figure 6.7 Capacity to Energy Ratios – Historic and Proposed Goals



For some reason that the Company has not explained, FPL's capacity-to-energy ratio is much, much higher than it has been in past years, and is far higher than the other Utilities presented here. FPL's ratio then declines precipitously over the course of the next ten years. The other four utilities start their proposed DSM goals with higher than historic ratios, and then increase them over the course of the period, with DEF's ratios increasing dramatically more than the others.

Q. What conclusions do you draw from the capacity-to-energy ratios presented in Figure 6.7?

A. These capacity-to-energy ratios raise several concerns for the Commission to be aware of. First, these Utilities are clearly planning to make a dramatic shift away from energy efficiency programs toward load management programs. This suggests that they will not be placing much, if any, emphasis on energy efficiency savings, and may therefore deprive customers of large opportunities to reduce costs and bills.

Second, the FPL capacity-to-energy ratios do not make any sense. There is no reason why a utility would make such a major shift toward load management programs in the two years between 2013 and 2015, and then make a shift back away from load management programs. This result suggests that FPL's planning process is flawed, or that the Company is not paying sufficient attention to these important results of its own planning process, or both.

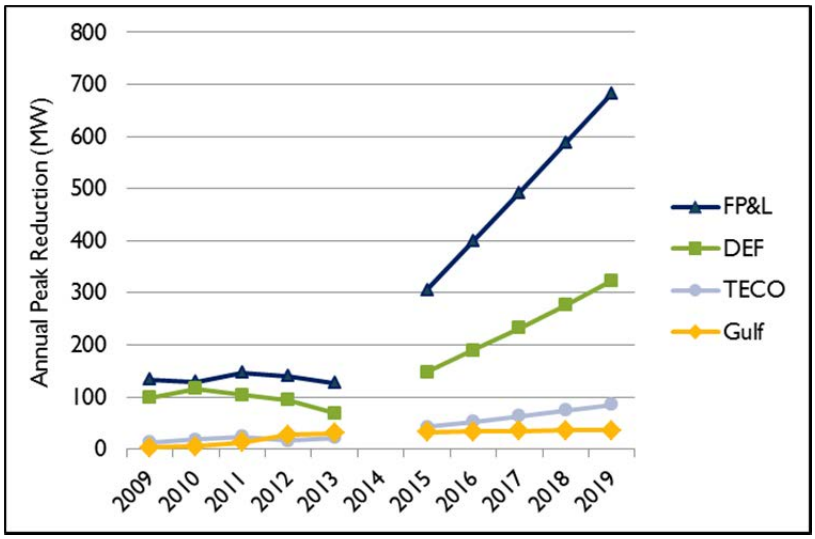
Third, there is a big difference in the ratios across the four Utilities presented in Figure 6.7. There is no good reason for such differences across utilities within the same state. These differences suggest that customers in some of the utilities will not be as well served by the DSM programs as other customers.

Fourth, the Company's do not mention this shift away from energy efficiency programs in their filings. Such an important change in their DSM profiles certainly warrants bringing to the Commission's attention, so that the Commission can make an informed decision on an important shift in DSM priorities and services to customers.

Q. How then have you set capacity DSM goals?

A. I start with the simplistic assumption that the ratio of capacity to energy savings achieved in 2013 is a reasonable balance of energy and capacity savings. I then hold this ratio fixed for the purpose of setting the Sierra Club DSM capacity goals, for each company. I then apply this ratio to the GWh savings of the Sierra Club DSM goals, to back out a capacity goal for each year. The results are provided in Figure 6.8 below.

Figure 6.8 Annual Peak Reduction from DSM – historic and Sierra Club Goals.



Q. Did you rely upon the Utilities' economic analyses or resource planning results in developing the Sierra Club DSM goals?

A. Yes, but only in a limited way. After reviewing the Utilities' economic analyses and resource planning results, I have determined that they suffer from so many fundamental flaws that they are of very limited value for the purpose of setting DSM goals. Even worse, they are misleading in several ways. My reasons for reaching this conclusion are described in detail in Sections 3 and 4 of my testimony.

Q. How then did you develop the Sierra Club DSM goals?

A. These goals are based upon the limited information of value that the Utilities did provide in their analyses in this docket, combined with my extensive knowledge of DSM opportunities, achievements and plans in other states.

As indicated in Section 5 of my testimony, and illustrated in Figure 5.2, there is no question that DSM programs in Florida cost significantly less than supply-side alternatives in Florida, and that increased efficiency savings will result in significantly lower costs to electricity customers.

In addition, I have considered the likely rate impacts of the Utilities' proposed DSM goals, as well as the potential rate impacts of the proposed Sierra Club goals, and it is clear that the average, long-term rate impacts of both sets of goals are likely to be very

low. In the case of the Utilities' proposal, they are likely to be so low as to be "in the noise" of the analysis. The rate impacts of the Sierra Club goals will not be much higher than those of the Utilities' goals.

Furthermore, I have considered the likely customer participation rates that could result from the Utilities' goals, as well as the Sierra Club goals. Under both sets of goals, the Utilities should be able to serve a large portion of customers with efficiency programs, thereby offsetting any increases in rates that might occur. And the Sierra Club's higher goals should result in significantly greater participation levels than the Company's proposed goals, thereby mitigating customer equity and cross-subsidization concerns, and resulting in greater benefits for the "general body of ratepayers as a whole."

As described above, one of the key challenges in setting DSM goals is striking the appropriate balance between reduced costs and increased rates, which requires consideration of rates, bills and customer participation. On these points, the evidence that I present above indicates that the Sierra Club DSM goals strike a good balance and will be in customers' best interest.

Q. How do you know that the Utilities will be able to achieve the Sierra Club's DSM goals ?

A. I am confident that all Florida electric companies have the technical, economic and achievable potential of at least one percent of retail sales, for several reasons. Gulf achieved nearly this level of savings in 2013. If Gulf can achieve this level of savings, there is no reason that the other Utilities cannot. In addition, Duke Energy Ohio has achieved nearly this level of savings, and has goals to achieve one percent savings. If Duke Energy Ohio can achieve savings of one percent by 2014, then surely Duke Energy Florida can achieve similar savings levels by 2019.

Furthermore, I have seen the amounts of efficiency savings that are available in other states, that have been achieved in other states, and that are planned to be achieved in other states. I know the types of efficiency programs, marketing, delivery, customer incentives, and other factors that can be utilized to achieve savings of at least one percent of retail sales. There is no reason that the Utilities cannot achieve savings of at least one

percent of retail sales by 2019, given the levels of savings that have been achieved in other states.

Q. But Florida is a different state from the other states. How can you be sure that the experience in other states is relevant to Florida?

A. First of all, I have worked on the topics of DSM planning and integrated resource planning for most of my 30-year career, and I have addressed these issues in states all across the US, as well as several Canadian provinces. I have prepared many national studies on DSM screening and analysis, including the studies for the National Efficiency Screening Project. I have prepared several regional studies where I estimated the potential for DSM and renewable resources over the long-term horizon; including a study of the Southeast, a study of the Midwest, and a study of the West. I have reviewed state-specific DSM plans and integrated resource plans in many states. In my experience, I have found that most, if not all, states face the same issues, the same barriers, and the roughly same potential for DSM savings. My findings and recommendations are based on my experiences in all of these states and provinces.

Second, the biggest difference between states and provinces affecting the development of DSM programs is the regulatory environment; it is not the customers, or the end-uses, or the climate of the state or province. The regulatory environment is created by legislation, by regulations, and by Commission orders. The legislation in Florida provides as much support for DSM as legislation in many states; this does not pose a barrier to DSM in any way. The Commission's regulations similarly are fairly supportive of DSM relative to other states; they do not pose a barrier to DSM either. The biggest difference between the regulatory environment in Florida and other states is the signals that the Commission sends regarding DSM screening. And the Commission has complete control over the signals that are sent from this point forward. In fact, I believe that given the right regulatory environment, and sufficient time, the Utilities should be able to achieve annual DSM savings of as much as two percent of retail sales. I recommend a DSM goal of one percent of sales by 2019 in this docket to allow time for the Utilities and the relevant trade allies to ramp up to this higher level of DSM savings.

Third, one of the biggest differences between Florida's regulatory environment and those of other states is that many of regulators and other stakeholders, especially those in the leading states, recognize that *well-designed, cost-effective DSM is good for customers*. By this I mean that the advantages that DSM offers customers (i.e., reduced bills, reduced generation costs, reduced transmission and distribution costs, increased reliability, reduced risk, environmental benefits, and more) far outweigh any disadvantages to customers (i.e., very small, if any, increases to long-term average rates). It is ironic, misguided, and very misleading for the Utilities to try to argue that they should limit their DSM goals to protect customers from alleged rate increases or potential cross-subsidization of customers. This implies that cost-effective DSM is somehow bad for customers, when in fact the opposite is true.

Note that while I am representing Sierra Club in this docket, roughly half of all of my clients are either consumer advocates or regulatory commissions. I make similar recommendations for those clients; all on the same concept that well-designed, cost-effective DSM is good for customers.

7. DEMAND-SIDE RENEWABLES

Solar PV Potential

Q. Please briefly describe the results of the technical potential estimates for solar PV by Duke and FPL.

A. As part of this docket, five of the seven utilities subject to FEECA have updated their original technical potential for solar photovoltaic (PV) along with other DSM measures that were estimated by Itron in 2009. The updates for solar PV have been made just to take into account the historical PV projects installed to date since the original study was conducted and the growth of the rooftop areas for additional PV capacity. The results are that Florida utilities still have plenty of PV technical potential. For example, FPL identified about 14 GW summer peak capacity (66% of summer peak) and 38,000 GWh annual generation potential (37% of sales) from PV. DEF identified about 14 GW summer peak capacity (66% of summer peak) and 38,000 GWh annual generation potential (37% of sales) from PV. See Tables 7.1 and 7.2, below.

Table 7.1 Comparison of Solar PV Technical Potential Estimates for FPL and Duke[27]

	Summer Peak Capacity MW			Annual Generation GWh		
	2014 Estimate	2009 Estimate	Installation since 2009	2014 Estimate	2009 Estimate	Installation since 2009
FPL	14,055	13,815	9	38,136	37,488	27
Duke	5,054	5,000	1	13,737	13,593	6

Table 7.2 Comparison of Solar PV Technical Potential Estimates for FPL and Duke[28]

	Summer Peak Capacity (% of 2012 Peak Demand)			Annual Generation (% of 2012 Sales)		
	2014 Estimate	2009 Estimate	Installation since 2009	2014 Estimate	2009 Estimate	Installation since 2009
FPL	66%	64%	0.04%	37%	37%	0.03%
Duke	56%	55%	0.01%	38%	37%	0.02%

Tables 7.1 and 7.2 also show that there have been very little solar PV installations in the Utilities service territories (i.e., cumulative increase of only 0.01% to 0.04% of peak load for the past 4 to 5 years), and the increase in PV capacity due to increased rooftop areas outpaced the capacity additions. This resulted in a slight increase in the total PV capacity potential for 2014 for the two utilities (about 2% increases for FPL and 1% for DEF) when compared with the original estimates made in 2009.

Q. How do the conclusions and methods of the Itron potential study compare with other technical potential estimates you are aware of?

A. Given that not all FEECA utilities have updated their PV potential estimates and new estimates are likely to be very similar to the original estimates based on our review of FPL and DEF's updates, I am comparing the 2009 Itron study results with the results from a recent national solar PV potential study by the National Renewable Energy Laboratory (NREL). For methodologies, Itron made no changes to the original methods

[27] Based on Thomas R. Koch's Exhibit TRK-4 for FPL, Document No. 01475-14, and Helena Guthrie's Exhibit HG-5 for DEF, Document No. 01497-14.

[28] 2012 sales and peak load data for FPL and DEF are from US EIA.

except subtracting the recent solar development and adding new roof space for additional solar.

NREL estimated technical potential of solar PV resources for each state across the United States in 2012 using the geographic information system (GIS). NREL analyzed the technical potential for solar capacity additions across multiple technologies. While Itron only studied the technical potential of rooftop PV installations in the state, NREL examined utility scale PV in both urban and rural settings, in addition to concentrated solar power potential., I will focus on the rooftop PV potential estimates in these two studies.

The conclusions of the NREL study are similar to those of the Itron study: although NREL predicts a higher potential capacity for rooftop solar in Florida, the two studies forecast a similar potential for energy generated through rooftop PV installations in the state. See Table 7.3 below.

Table 7.3 Comparison of Solar PV Potential Results for Florida

	NREL 2012	Itron 2009
GW of potential	49	30
GWh of potential	63,987	69,449
Given state energy consumption	231,210	159,795
Potential as % of Itron consumption assumption	40%	43%
Potential as % of NREL consumption assumption	28%	30%

Similar to the Itron study, the NREL study bases the rooftop PV technical potential calculation on three main variables: available rooftop area; size of the PV module; and the capacity factor for the given region.

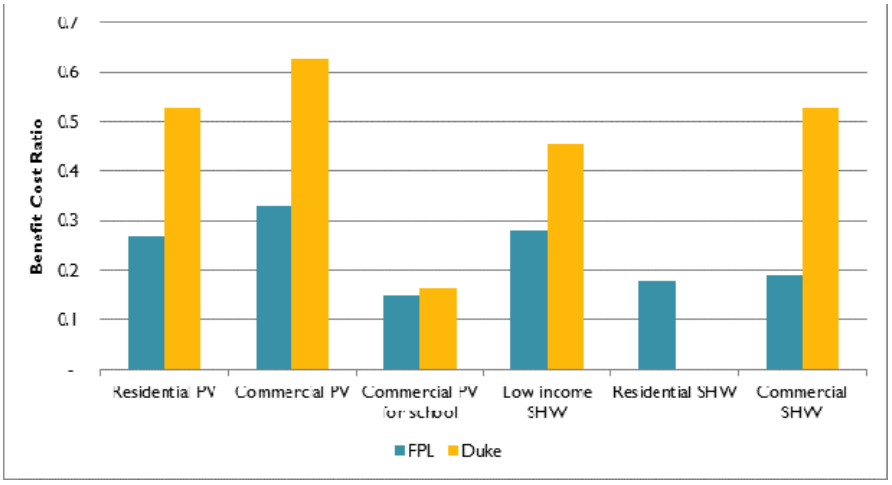
Q. Please briefly describe the results of the achievable potential estimates for solar PV and solar hot water (SHW) by FPL and DEF.

A. DEF and FPL do not provide achievable potential or economic potential for solar resources because their analysis found solar resources are not cost-effective in their jurisdictions.

Q. Please present cost-effectiveness for FPL and DEF's solar pilot programs.

Figure 7.1 presents benefit cost ratios estimated by both companies for their solar PV and solar hot water pilot programs. FPL and DEF proffer that these pilots have benefit cost ratios below 1 under the TRC test.

Figure 7.1 TRC Test Results (Benefit Cost Ratios) of Solar PV Pilot Programs



However, it is highly likely that solar PV and solar hot water could be more cost-effective than the Utilities suggest, as the Utilities do not fully take into account full benefits of demand-side resources and do not assume declining costs of solar PV systems in the future. Secondly, from the utility's perspective using the Utility Cost test, solar PV could be already cost-effective without fully including missed benefits, especially for DEF.

Lastly, note that it is odd that FPL's benefit cost estimates are about half of DEF's estimates for the residential and commercial solar PV pilots. There is a high likelihood that either FPL or DEF are underestimating or overestimating avoided benefits of solar PV systems given that system costs should not differ much between their service territories.

Q. Please explain why the Utilities are not fully taking into account the benefits of solar systems.

A. In a recent meta-analysis of solar PV benefit cost studies, the Rocky Mountain Institute examined 15 studies in detail, and identified that there are numerous benefits of solar PV. This finding indicates that the benefits from solar PV could exceed the costs when

benefits are fully considered. For example, four out of the 15 studies found the benefits of solar PV exceeds 20 cents/kWh, and the two of the studies found benefits exceeding about 30 cents/kWh.

The types of benefits identified in the study are (a) avoided energy, (b) avoided generation, transmission and distribution capacity, (c) avoided grid support services (e.g., reactive supply and voltage control), (d) financial risk hedge (e.g., fuel price hedge and market price response), (e) security risk reduction, (f) environmental benefits (e.g., reduction in CO2 and criteria pollutants and water), and (g) economic development (e.g., jobs and tax revenues). FPL and DEF only include benefits from (a) and (b). While they do include some carbon costs in their sensitivity analysis of DSM measures, as discussed above in Section 3, they underestimate carbon costs for complying with future environmental regulations. Further, the Utilities incorrectly assume zero carbon costs in their base case.

Q. Are the costs assumed by the Utilities reflective of forecasts of future PV costs?

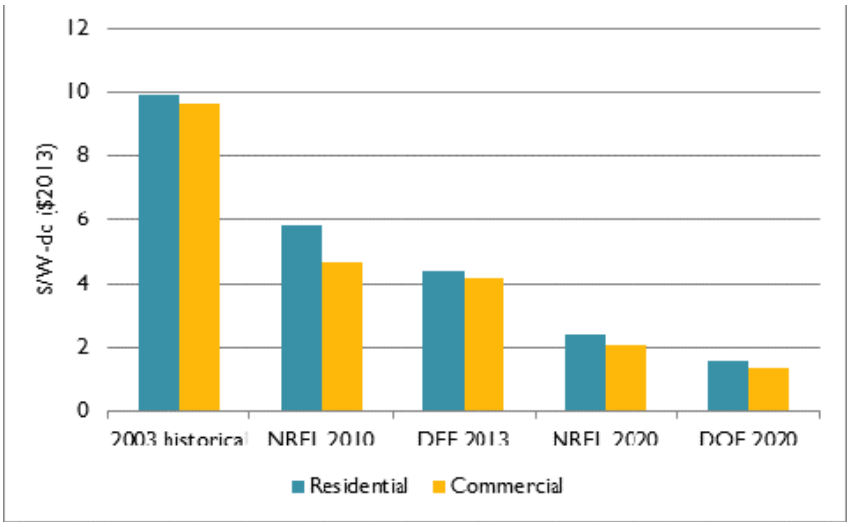
A. No. The Utilities cost-effectiveness results for solar PV are only based on the costs of the current pilot program. *See*, *e.g*., Direct Testimony of Witness Koch, Document No. 01475-14, at 28–29; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 49 –51. If this is also the case for the formal economic screening, the Utilities are significantly undervaluing the benefits of solar PV for the next decade because price forecasts for PV such those by NREL and US DOE show declining costs.

Q. Please provide solar PV price forecasts by NREL and US DOE and compare them with the current and historical prices.

A. NREL and US DOE have recently developed solar PV price forecasts for the residential and commercial systems. Figure 7.3 provides their price forecasts along with historical prices in 2003, 2010, and 2013. The "DEF 2013" in this figure represents today's solar PV prices in Florida based on DEF's data. Direct Testimony of Witness Guthrie, Document No. 01497-14, at 51. Solar PV installed prices have declined by more than half relative to the prices in 2003 as shown in Figure 7.3. Going forward, NREL and

DOE are predicting that solar PV prices will be reduced further by more than half from today's level of $4 per Watt-DC to $2 to $1.5 per Watt-dc levels by 2020.[29]

Figure 7.3 History and Forecast of Installed Costs of Solar PV Systems[30]



US DOE's price forecast represents aggressive price reduction targets under its SunShot Initiative where solar PV prices are reduced by 75% by 2020 from the 2010 levels.[31] In contrast, NREL's price forecast is based on its detailed simulations of silicon module manufacture costs and represents an evolutionary—or business-as-usual—development trajectory for PV prices. NREL indicates that the difference between the evolutionary projections and SunShot targets highlights the need for innovative system designs and installation methods to complement module-level cost reductions.[32]

These low projected installed costs of distributed solar PV systems will result in significantly low levelized costs of solar PV systems by 2020 at levels that are lower than

[29] NREL. "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities," February 2012; US DOE. "SunShot Vision Study." February 2012.

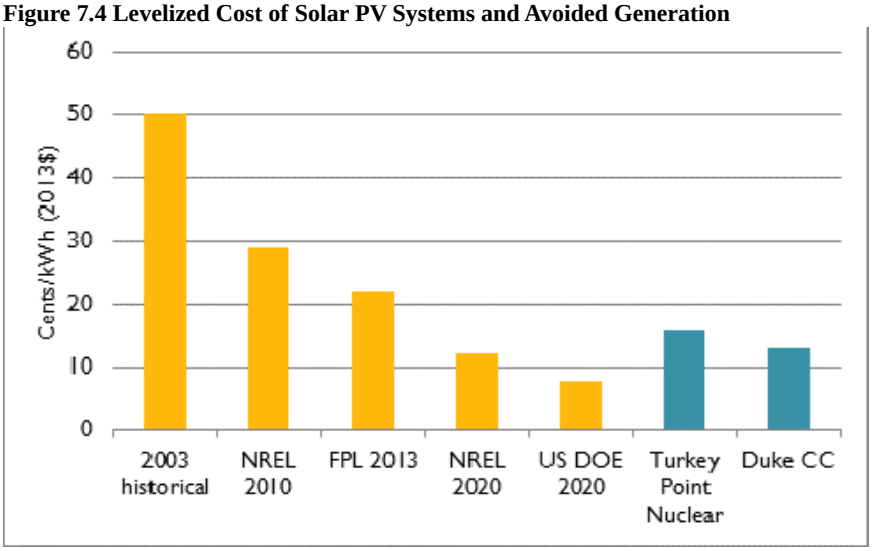
[30] The 2003 historical prices are based on LBNL. "Tracking the Sun VI An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012," July 2013. The "NREL 2010" prices are based on NREL (2012) and represents NREL's simulated historical PV prices used as benchmarking prices to be compared with the NREL's 2020 price forecasts.

[31] US DOE. "SunShot Vision Study." February 2012.

[32] NREL. "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities," February 2012.

the levelized costs of new nuclear and natural gas combined cycle power plants as presented in Figure 7.4 below.[33] This means that within the Florida Utilities' 10-year planning horizon solar PV is likely to be cheaper and more cost-effective than the traditional supply-side resource options, even excluding the avoided costs of transmission and distribution systems.

Figure 7.4 Levelized Cost of Solar PV Systems and Avoided Generation



Solar PV Goals

Q. Please describe the solar PV resource goals proposed by Duke and FPL.

A. Both Duke and FPL did not present any goals for solar PV and proposed to discontinue their demand-side solar pilot programs mainly because they found solar pilot programs are not cost-effective, as shown in Figure 7.1**Error! Reference source not found.** above. In addition, DEF's Witness Guthrie and FPL's Witness Koch question whether the programs' rebates are influencing the market to reduce costs or increasing the availability of solar technologies for customers. *See* Document No. 01497-14, at 51; Document No. 01475, at 30. Further, Witness Guthrie tries to cite the competitiveness of the solar market in Florida as another reason for discontinuing solar rebates and the solar pilot programs

[33] The levelized cost of the residential solar systems are estimated based on (a) the installed costs as presented in Figure 7.3, (b) a 20 year economic life, (c) a 19% capacity factor, and (d) a 5% discount rate. The capacity factor was obtained from NREL's PVWatts for Florida. The levelized costs of Turkey Point nuclear power plants and a combined cycle power plant were taken from Figure 6.2 above in my testimony.

Document No. 01497-14, at 50. More specifically, Witness Guthrie states that Florida's solar market has matured significantly over the last five years, and that Florida is "among the most cost competitive states in the U.S." for solar technologies based on a recent report from Green Tech Media and Solar Electric Industries Association. Document No. 01497-14, at 50

Q. Do you agree with FPL and DEF's proposal to discontinue the solar pilot programs?

A. No. I believe it is premature to discontinue the solar pilot programs, and evidence presented by FPL and DEF to support their position is not compelling for the following reasons:

1. FPL and DEF did not provide compelling evidence for their position nor any study to support their positions. Decisions such as those proposed by the Utilities to discontinue the solar pilot should be based on the results of an independent evaluation similar to the evaluation typically conducted for energy efficiency programs.

2. As discussed in Section 3, the Utilities do not properly account for the benefits of reducing GHG emissions, thereby understating the economic value of the solar pilot programs.

3. Promoting customer-side renewable energy meets FEECA requirements and objectives. FEECA's overall goals are to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. Further, FEECA is specifically designed "to meet the complex problems of reducing and controlling the growth rates of electric consumption and reducing the growth rates of weather-sensitive peak demand; increasing the overall efficiency and cost-effectiveness of electricity and natural gas production and use; encouraging further development of demand-side renewable energy systems; and conserving expensive resources, particularly petroleum fuels." *Id*.

4. Florida has some of the lowest levels of solar PV installations in the country, despite DEF's claim that Florida is among the most-competitive state for solar.

This indicates that there remains considerable opportunity for more solar installations in Florida.

5. Several other states have aggressive solar PV goals in place that are in effect over the next 5 to 10 years.

6. The cost of solar PV is expected to decline further, and to improve cost-effectiveness of solar PV systems.

7. FPL and DEF haven't provided compelling evidence that solar rebates are not influencing the market, and there is possibility that they could enhance or redesign the solar pilots to increase the program's influence on the market.

Q. How much PV capacity Florida has installed to date, and how does it compare with capacity installed in other states?

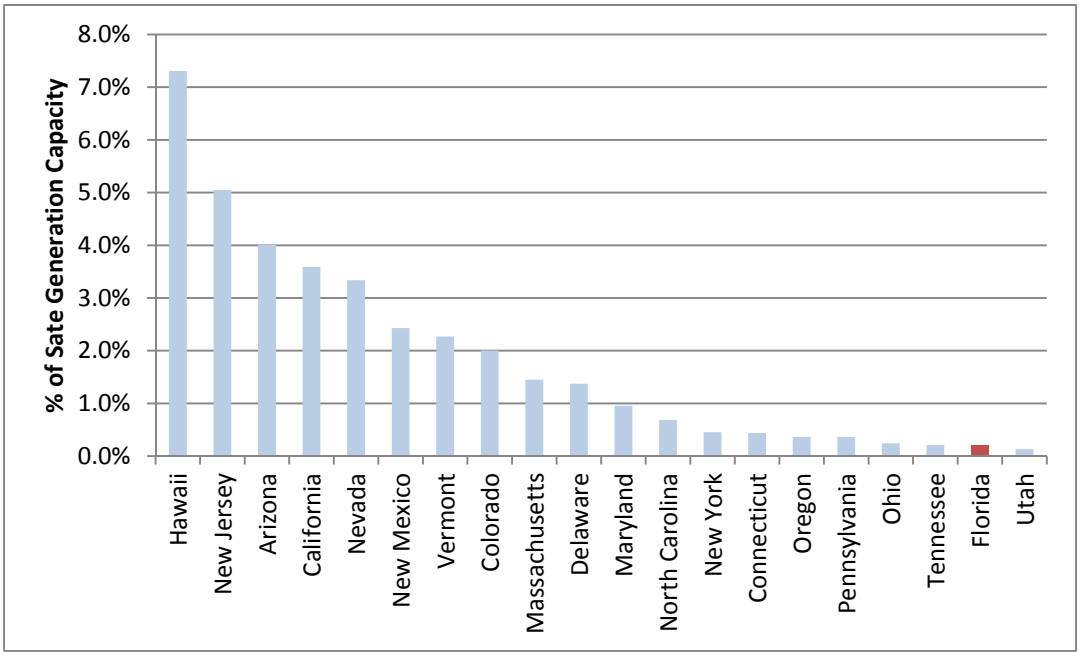
A. Despite the significant amount of solar resource potential in the state and despite DEF's claim that Florida is among the most-competitive state for solar, Florida has installed just about 120 MW of grid connected solar PV as of the end of 2012 according to the Interstate Renewable Energy Council.[34] This ranks Florida 13th in terms of capacity installed in the nation, but ranks 19th in terms of solar PV capacity as a percentage of state total generation. See Table 7.5. As a percentage of state generation capacity, the majority of the top 20 states have installed two to thirty times more solar PV capacity than Florida has installed to date. Note also that more than half of the states with the highest proportion of grid-connected solar photovoltaic capacity to date have less solar resources than Florida. These data imply that Florida's solar market is not competitive, and has not yet matured. Further, the Utilities could and should offer continued, and even more effective support for installations of solar PV.

[34] Interstate Renewable Energy Council, "U.S. Solar Market Trends 2012," July 2013.

Table 7.5 Top 20 States with the Highest Grid-Tied Solar Photovoltaic Capacity

Rank	State	Capacity Added in 2012	Cumulative Capacity at the end of 2012	Cumulative Capacity (% of State Generation Capacity)
1	Hawaii	114	200	7.3%
2	New Jersey	391	956	5.1%
3	Arizona	709	1106	4.0%
4	California	983	2559	3.6%
5	Nevada	226	350	3.3%
6	New Mexico	38	203	2.4%
7	Vermont	16	28	2.3%
8	Colorado	103	300	2.0%
9	Massachusetts	123	207	1.5%
10	Delaware	20	46	1.4%
11	Maryland	80	117	1.0%
12	North Carolina	122	208	0.7%
13	New York	56	179	0.5%
14	Connecticut	8	40	0.4%
15	Oregon	21	56	0.4%
16	Pennsylvania	31	164	0.4%
17	Ohio	48	80	0.2%
18	Tennessee	23	45	0.2%
19	Florida	22	117	0.2%
20	Utah	6	10	0.1%

Figure 7.5 Top 20 States with the Highest Grid-Tied Solar Photovoltaic Capacity[35]



[35] Interstate Renewable Energy Council, "U.S. Solar Market Trends 2012," July 2013;US Energy Information Administration, "Electricity Power Monthly," Table 6.2A, January 2014,

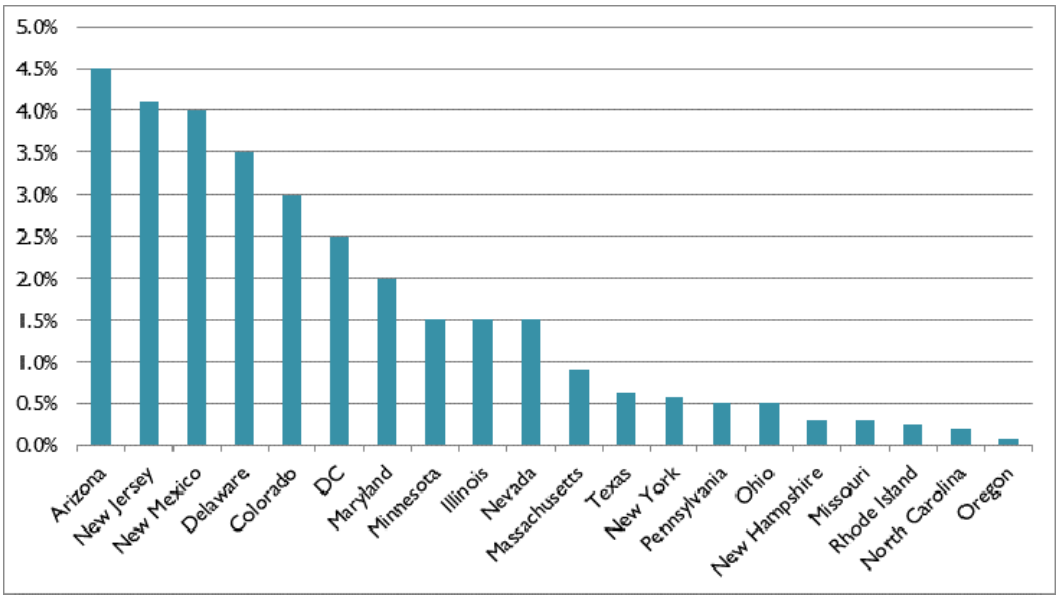
Q. Please describe PV goals established by other states.

A. Across the nation, there are approximately 20 states that require utilities to support the development of solar PV and renewable energy distributed generation systems as part of their renewable energy portfolio standards (RPSs). These states established targets specifically set for promoting either solar system in general (including solar PV and solar hot water), solar PV systems, or distributed generation. **Error! Reference source not found.** 8.6, below, presents a summary of such solar/DG policies along with a normalized target as a percentage increase per year. Figure 7.6 provides just cumulative PV/DG targets. State targets range from 0.1% of sales to 4% of sales in five to fifteen year periods. More than half of the states promote solar/DG at a level exceeding 0.10% per year on average, and 7 states promote solar/DG at more than 0.2% per year on average. In contrast, PV systems installed on FPL and DEF's systems over the past 5 years are very small. Those systems generate about 6 GWh for DEFand 27 GWh for FPL, which are about 0.02% to 0.03% of their 2012 sales or 0.003% to 0.005% per year over a 5 year period or 0.005% to 0.009% per year over a 3 year period (which corresponds to the period of the solar pilot programs).

Table 7.6 Summary of Solar/Distributed Generation Targets under State RPS Policies[36]

State	Technology goal (as % of sales)	Technology	Target Year	% Target per Year of Policy
Arizona	4.50%	DG	2025	0.24%
New Jersey	4.10%	Solar	2027-2028	0.27%
New Mexico	4.00%	Solar	2020	0.31%
Delaware	3.50%	PV	2025-2026	0.23%
Colorado	3.00%	DG	2020	0.30%
DC	2.50%	Solar	2023	0.21%
Maryland	2.00%	Solar	2020	0.15%
Minnesota	1.50%	Solar	2020	0.13%
Illinois	1.50%	PV	2025-2026	0.11%
Nevada	1.50%	Solar	2025	0.09%
Massachusetts	0.90%	Solar	2020	0.13%
New York	0.60%	DG	2015	0.12%
Texas	0.60%	Non-Wind	2020	0.04%
Pennsylvania	0.50%	PV	2020-2021	0.04%
Ohio	0.50%	Solar	2024	0.03%
New Hampshire	0.30%	Solar	2014	0.04%
Rhode Island	0.30%	Solar	2020	0.02%
Missouri	0.30%	Solar	2021	0.02%
North Carolina	0.20%	Solar	2018	0.02%
Oregon	0.10%	PV	2025	0.01%

Figure 7.6. Summary of Solar/Distributed Generation Targets under State RPS Policies (% of Sales)



[36] Developed based on information from the DSIRE website, available at http://www.dsireusa.org.

Q. Do you think utility programs could influence Florida's solar PV market? If so, please explain how.

A. Yes. As explained in DEF and FPL's testimony, the number of payback years influence consumer decisions for adopting energy efficiency measures, and customer payback should influence customers' decisions whether to purchase solar PV and Solar Hot Water (SHW) systems. Thus, if the Utilities were to provide some kind of financial support such as rebates or low-interest loans to their customers, such support should increase the number of customers adopting solar systems.

Utility programs could even reduce purchase price of solar systems instantly if the programs could purchase systems in bulk by teaming up with a handful of solar PV installation or marketing companies. Overtime, more installation will develop the solar system installation market in the state, spur competition, and reduce costs.

Q. Should the Utilities continue to offer their solar rebate programs?

A. Yes. These programs are consistent with FEECA's policy goals and provide benefits to participants, as well as system-wide benefits to all customers. FEECA states that "it is critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. Further, it is the intent of "to meet the complex problems of reducing and controlling the growth rates of electric consumption and reducing the growth rates of weather-sensitive peak demand; increasing the overall efficiency and cost-effectiveness of electricity and natural gas production and use; encouraging further development of demand-side renewable energy systems; and conserving expensive resources, particularly petroleum fuels." *Id.* Solar PV systems clearly meet most of these objectives and benefits, and are likely to be cost-effective today if benefits are fully accounted for, and are highly likely to be very cost-effective by 2020 as discussed above in my testimony.

Q. Should Florida utilities modify their rebate program designs?

A. Yes. Florida utilities including Duke and FPL should investigate further whether the current level of incentives is sufficient or excessive to spur solar system development in

the state. If they find rebates are excessive, they could consider to what extent rebates should be reduced.

In addition, the utilities should consider offering low-interest loans for solar systems along with reduced level of rebates. In some cases, loans are more helpful than rebates for customers to install solar systems because there are always customers who do not have capital or access to loans.

Lastly, as mentioned above, the utilities should consider coordinating solar system installations by their customers so as to take advantage of bulk purchase practices.

Q. What do you recommend that the Commission do with regard to demand-side renewable goals in this docket?

A. I recommend that the Commission require the Utilities to continue to provide PV programs to their customers, with the modifications to the current programs outlined above. In addition, the Commission should open a separate docket to investigate appropriate additional goals for demand-side renewables, and to address some related issues, e.g., the effectiveness of solar rebate programs and the role of utility-owned solar PV systems.

8. REGULATORY SUPPORT

Treatment of Lost Revenues

Q. Do you think the Utilities should be allowed to recover lost revenues from efficiency programs somehow?

A. Yes. The Utilities should not be penalized financially as a result of successful implementation of efficiency programs. Without recovery of these lost revenues, the Utilities cannot be expected to implement comprehensive, meaningful efficiency programs, their customers will be deprived of the lowest-cost resource, and total electricity costs will be significantly higher.

Q. How should the Utilities recover the lost revenues from DSM programs?

A. I recommend that the Commission require the Utilities to implement a revenue decoupling mechanism to recover the lost revenues from DSM programs. Decoupling is a

modification to traditional ratemaking that allows a company to recover a target level of revenues, regardless of the level of sales that occur between rate cases.

Revenue decoupling does not suffer from the fundamental flaws listed above regarding direct recovery of lost revenues. Revenue decoupling provides much more comprehensive and much better financial incentives with regard to all the Utilities' actions that might affect customer sales. I have been involved in several states that use direct recovery of lost revenues as well as several states that use revenue decoupling, and the difference is striking. Utilities that are allowed revenue decoupling are significantly more supportive of DSM and other demand resources, and the entire regulatory context around efficiency and demand resource planning is significantly less contentious and adversarial. Further, there are ways to design revenue decoupling mechanisms that not only protect consumers but ensure that customers are better off than under traditional ratemaking.

If the Commission does not somehow address the recovery of lost revenues, then it is very likely that the Utilities will continue to understate the value of DSM, propose sub-optimal DSM goals, and deprive customers of the opportunity to significantly reduce their electricity bills.

Q. Has the issue of decoupling been addressed before by the Commission?

A. Yes. In December 2008 the Commission prepared a report to the Legislature on utility revenue decoupling. FPSC, *Report to the Legislature on Utility Revenue Decoupling* (Dec. 2008), *available at* http://www.psc.state.fl.us/publications/pdf/electricgas/ Decoupling Report_To_ Legislature.pdf. At that time, the Commission decided not to implement revenue decoupling, because "Florida is already paving a path toward the objectives of decoupling without incurring the cost and difficulties associated with design, implementation and maintenance of a specific decoupling mechanism." *Id*. at 5.

Q. Is there evidence in the current dockets that the Utilities are paving a path toward more comprehensive implementation of cost-effective DSM programs?

No. In fact, the evidence presented in these dockets suggests the opposite. As described in Section 6, the Utilities' DSM programs are already much smaller than those of most

other states, and the DSM goals proposed in these dockets would essentially take the Utilities on a path of less and less DSM. In addition, the Utilities' analyses in these dockets are so clearly heavily biased against DSM programs, that one can only conclude that the Utilities really do not want to implement DSM programs and achieve DSM savings for their customers. This is quite likely due to the financial disincentive associated with DSM programs. A revenue decoupling mechanism would eliminate this disincentive, and create a much more positive regulatory environment for setting future DSM goals.

Q. How should the Commission proceed on this issue of decoupling?

A. I recommend that the Commission open a separate docket to investigate whether revenue decoupling should be implemented to align the Utilities' financial incentives with the state's efficiency policies and goals. There are many important implications of revenue decoupling, and the issues are best addressed in a docket dedicated to investigating them.

Shareholder Incentives

Q. Why is it necessary to provide utilities with shareholder incentives for implementing DSM programs?

A. While decoupling is necessary to eliminate the financial disincentive that utilities experience with efficiency, it does not provide utilities with positive financial incentives. When given the choice between investments in supply-side resources, which can be included in rate base and contribute toward utility profits, and investments in DSM that are simply passed through to customers, utilities will prefer the former.

Q. Does the Commission have authority to provide the Utilities with shareholder incentives for implementing successful DSM programs?

A. Yes. The recent amendments to FEECA allow the Commission to "authorize financial rewards for those utilities over which it has ratesetting authority that exceed their goals and may authorize financial penalties for those utilities that fail to meet their goals." Section 366.82(8), F.S. Further, FEECA is to be liberally construed. *See* Section 366.81.

Q. Is it necessary that DSM programs be included in rate base in the same way that supply-side resource are?

A. No. The two investments have different financial and ratemaking implications, and thus do not need to be treated identically for shareholder incentive purposes. What is important is that the DSM shareholder incentives be: (a) large enough to provide the utility management with the incentive to pursue DSM programs; and, (b) designed in a way that encourages the implementation of cost-effective, successful DSM programs that are in the customers' best interests. It is also important to keep the shareholder incentives reasonably low, so that customers are not required to pay more than necessary for a utility to implement successful DSM programs.

Q. What type of shareholder incentive mechanism would you recommend to achieve these objectives?

A. Here I summarize an DSM shareholder incentive mechanism that the Commission should establish:

- A utility will have the opportunity to earn a maximum of eight percent of its total annual DSM budget as a shareholder performance incentive. The amount of this total incentive that each utility earns will depend on what portion of its efficiency savings target it achieves, as prescribed below.
- A utility will not be allowed to earn any shareholder incentive until it achieves at least 80 percent of its annual efficiency savings goal.
- If a utility achieves 80 percent of its annual efficiency savings goal, it will be entitled to keep four percent of the annual efficiency budget as a shareholder incentive
- If a utility achieves 100 percent of its annual efficiency savings goal, it will be entitled to keep six percent of the annual efficiency budget as a shareholder incentive.
- If a utility achieves 120 percent of its annual efficiency savings goal, it will be entitled to keep eight percent of the annual DSM budget as a shareholder incentive.

- If a utility achieves efficiency savings that are between 80 percent and 120 percent of its annual efficiency savings goal, it will be entitled to keep an portion of the annual DSM budget determined by linear interpolation between four and eight percent.

- Shareholder incentives will only be allowed for DSM program savings that are measured and verified and presented to the Commission in annual reports.

Q. How should the Commission proceed on this issue of shareholder incentives?

A. I recommend that the Commission consider the issue of shareholder incentives in the same generic docket that it uses for investigating revenue decoupling. Like decoupling, shareholder incentives require consideration of some important details, and most of the issues should be relevant to all Florida utilities. A single generic docket would allow the Commission to address both revenue decoupling and shareholder incentives in a comprehensive way.

Q. Does this conclude your pre-filed testimony?

A. Yes, it does.

Tim Woolf

Vice President
Synapse Energy Economics, Inc.
485 Massachusetts Avenue, Suite 2, Cambridge, MA 02139
(617) 453-7031 • fax: (617)-661-0599
twoolf@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Vice President, 2011 to present. Provides expert consulting on the economic, regulatory, consumer, environmental, and public policy implications of the electricity and gas industries. The primary focus of work includes technical and economic analyses, electric power system planning, climate change strategies, energy efficiency programs and policies, renewable resources and related policies, power plant performance and economics, air quality, and many related aspects of consumer and environmental protection.

Massachusetts Department of Public Utilities, Boston, MA. Commissioner, 2007- 2011. Oversaw a significant expansion of clean energy policies as a consequence of the Massachusetts Green Communities Act, including an aggressive expansion of ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power. Oversaw six rate case proceedings for Massachusetts electric and gas companies. Played an influential role in the development of price responsive demand proposals for the New England wholesale energy market. Served as President of the New England Conference of Public Utility Commissioners from 2009-2010. Served as board member on the Energy Facilities Siting Board from 2007-2010. Served as co-chair of the Steering Committee for the Northeast Energy Efficiency Partnership's Regional Evaluation, Measurement and Verification Forum.

Synapse Energy Economics Inc., Cambridge, MA. Vice President, 1997-2007.

Tellus Institute, Boston, MA. Senior Scientist, Manager of Electricity Program, 1992-1997.

Association for the Conservation of Energy, London, England. Research Director, 1991-1992.

Massachusetts Department of Public Utilities, Boston, MA. Staff Economist, 1989-1990.

Massachusetts Office of Energy Resources, Boston, MA. Policy Analyst, 1987-1989.

Energy Systems Research Group, Boston, MA. Research Associate, 1983-1987.

Union of Concerned Scientists, Cambridge, MA. Energy Analyst, 1982-1983.

EDUCATION

Masters, Business Administration. Boston University, Boston, MA, 1993.
Diploma, Economics. London School of Economics, London, England, 1991.
B.S., Mechanical Engineering. Tufts University, Medford, MA, 1982.
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Dated April 2014.

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Best Practices in Electric Utility Integrated Resource Planning

Examples of State Regulations and Recent Utility Plans

Authors
Rachel Wilson
Bruce Biewald



Synapse Energy Economics, Inc.

June 2013

Prepared by Synapse Energy Economics
for the Regulatory Assistance Project.
Funding provided by the Southern Alliance for Clean Energy.

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Executive Summary

An integrated resource plan is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. For utilities, integrated resource planning is often quite time- and resource-intensive. Its benefits are so great, however, particularly to consumers, that utilities are frequently required by state legislation or regulation to undertake planning efforts that are then reviewed by state public utilities commissions (PUCs). (In this document, the acronym IRP is used, depending on the context, to denote either an integrated resource plan or the process of integrated resource planning.)

IRP rules governing utilities have been created in a number of ways. Bills that mandate integrated resource planning have been passed into law by state legislatures; rules have been codified under state administrative code; and state utility commissions have adopted IRP regulations as part of their administrative rules, or have ordered it to be done as a result of docketed proceedings. Although some state IRP rules have remained unchanged since they were first implemented, other states have amended, repealed, and in some cases reinstated their IRP rules. Examples can be found in the rules of Arizona, Colorado, and Oregon. Rules that have been amended recently often reflect current concerns in the electric industry—e.g., fuel costs and volatility, the effects of power generation on air and water, issues of national security, electricity market conditions, and climate change, as well as individual state concerns.

There are, however, certain subject-matter areas that are essential to resource planning on which state regulations are silent. Utilities must use their discretion in determining how best to address these areas in their resource plans. This paper provides utilities, commissions, and legislatures with guidance on these subject-matter areas. Section III summarizes three recent utility IRPs from the states mentioned above, in an effort to determine both best practices in integrated resource planning and ways in which utilities can improve their planning processes and outcomes. Section IV then presents a series of recommendations, developed from these examples, for integrated resource planning and its resulting plans.

For an IRP process to be deemed successful, it should include both a meaningful stakeholder process and oversight from an engaged public utilities commission. A successful utility's resource plan should include consideration in detail of the following elements: a load forecast, reserves and reliability, demand-side management, supply options, fuel prices, environmental costs and constraints, evaluation of existing resources, integrated analysis, time frame, uncertainty, valuing and selecting plans, action plan, and documentation. Section IV describes in detail the elements of both the process and the plan.

Introduction

As energy demand across the United States rises and falls and the generation fleet ages, utilities must plan to add and retire resources in the most cost-effective manner while meeting regional reliability standards. Integrated resource planning began in the late 1980s, as states looked for a way to respond to the oil embargos and nuclear cost overruns of the previous decade—and ever since, it has been an accepted way in which utilities can create long-term resource plans. State requirements for resource plans vary in terms, among other things, of planning horizon, the frequency with which plans must be updated, the resources required to be considered, stakeholder involvement, and the actions that public utilities commissions should take in reference to the plan (review, acknowledge, and accept or reject the plan).

As the electric industry began to restructure in the mid-1990s, integrated resource planning rules in many states were repealed or ignored. Some states have since made an effort to update IRP rules to make them applicable to current industry conditions, while other states have continued to use rules that are now out of date. This report describes IRP requirements in three states that have recently updated their regulations governing the planning process, and it reviews the most recent resource plan from the largest utility in each of those states. Rules from Arizona, Colorado and Oregon are described in detail, in order to demonstrate ways in which states can require comprehensive planning processes and resource plan outcomes from the utilities under their jurisdictions.

These particular states were chosen not only because their rules have recently been updated, but also because the guidance they provide to electric utilities offers examples of best practices in integrated resource planning. The updated rules have been designed to give thoughtful consideration to specific resources that have traditionally been ignored, and to produce outcomes that are in the best interests of both ratepayers and society as a whole. Utility resource plans from Arizona Public Service, Public Service Company of Colorado, and PacifiCorp utilize progressive methodologies and contain modern elements that contribute to the production of high-quality plans that are useful examples of superior resource planning efforts.

This report is intended to be helpful to policymakers, public utility commissions and their staff, ratepayer advocates, and the general public as they each consider the ways in which utility resource planning can best serve the public interest.

I. The Purpose and Use of Integrated Resource Planning

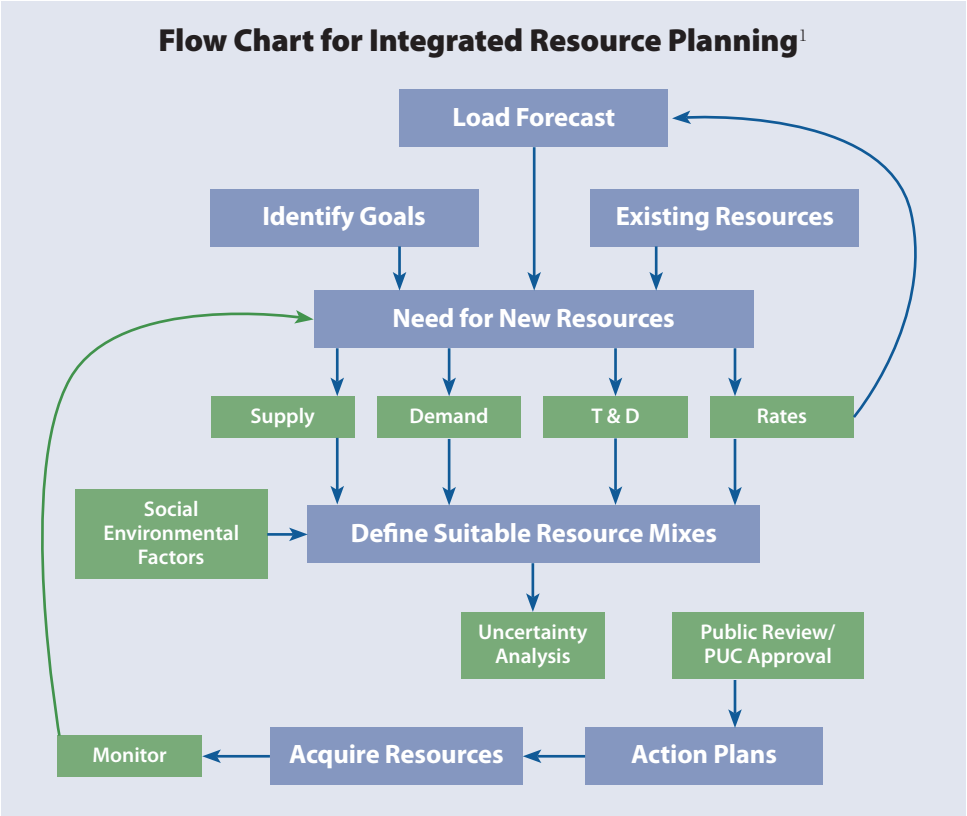
An integrated resource plan, or IRP, is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. Steps taken in the creation of an IRP include:

- forecasting future loads,
- identifying potential resource options to meet those future loads,
- determining the optimal mix of resources based on the goal of minimizing future electric system costs,
- receiving and responding to public participation (where applicable), and
- creating and implementing the resource plan.

Figure 1 shows these steps in a flow chart.

Integrated resource planning has many benefits to consumers, and other positive impacts on the environment. This is a planning process that, if correctly implemented, locates the lowest practical costs at which a utility can deliver reliable energy services to its customers. IRP differs from traditional planning in that it requires utilities to use analytical tools that are capable of fairly evaluating and comparing the costs and benefits of both demand- and supply-side resources.[2] The result is an opportunity to achieve lower overall costs than might result from considering only supply-side options. In particular, the inclusion of demand-side options presents more possibilities for saving fuel and reducing negative environmental impacts than might be possible if only supply-side options were considered.[3]

Figure 1



1 Hirst, E. A Good Integrated Resource Plan: Guidelines for Electric Utilities and Regulators. Oak Ridge National Laboratory. December 1992. Page 5. As it appears in Harrington, C., Moskovitz, D., Austin, T., Weinberg, C., & Holt, E. Integrated Resource Planning for State Utility Regulators. The Regulatory Assistance Project. June 1994.

2 Integrated Resource Planning for State Utility Regulators. Available at: http://www.raponline.org/document/download/id/817

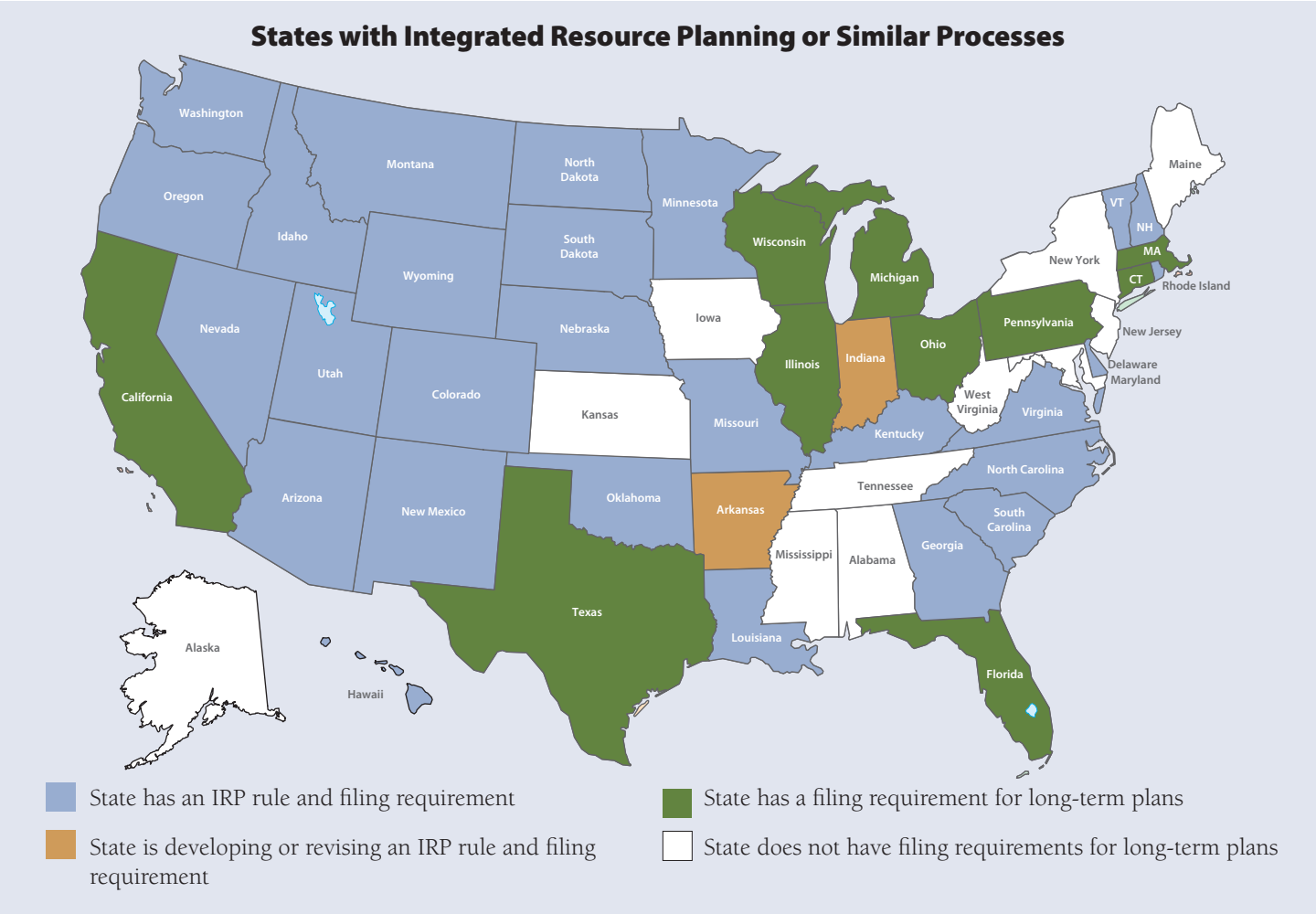
3 Kushler, M. & York, D. Utility Initiatives: Integrated Resource Planning. July 2010. American Council for an Energy-Efficient Economy. Available at: http://aceee.org/policy-brief/utility-initiatives-integrated-resource-planning

In general, IRP focuses on minimizing customers' bills rather than on rates—but an overall reduction in total resource cost achieved through the efficient use of energy will lower average energy bills. As a result, all customers benefit from the lower system costs that IRP achieves.[4]

Alternatives examined by system planners in an IRP setting include adding generating capacity (thermal, renewable, customer-owned, or combined heat and power), adding transmission and distribution lines, and implementing energy efficiency (EE) and demand response programs. Common risks that are addressed by scenario or sensitivity analyses in IRPs include fuel prices (coal, oil, and natural gas), load growth, electricity spot prices, variability of hydro resources, market structure, environmental regulations, and regulations on carbon dioxide (CO_2) and other emissions.[5]

Resource planning requirements exist in many states, but may differ significantly from state to state. Utilities that create more than one resource plan in the same state may have different processes for creating those plans and may arrive at significantly different conclusions, despite being governed by the same regulations. Figure 2 shows the states that have IRP or long-term planning requirements.[6]

Figure 2



4 Id footnote 2.

5 Hopper, C. & Goldman, N. Review of Utility Resource Plans in the West. Lawrence Berkeley National Laboratory. Presentation at the New Mexico PRC IRP Workshop, Santa Fe. June 8, 2006. Slide 17.

6 For a complete list of the rules and regulations associated with integrated resource planning in the states, see Appendix 1.

II. Examples of State Integrated Resource Planning Statutes and Regulations

State IRP rules have been established in a number of ways. In certain states, legislatures have passed bills into law mandating that utilities engage in resource planning; in others, IRP rules have been codified under state administrative code. Some state utility commissions have adopted integrated resource planning regulations as part of their administrative rules, or have ordered it through docketed proceedings. Rules can also be developed through a combination of these processes. Various state IRP rules and their individual requirements are discussed in the sections below.

A. IRP Planning Horizons

Integrated resource plans are long-term in nature, but these planning periods vary according to state regulations. Table 1 lists the length of planning horizons typically found in IRP rules, as well as the states that have implemented these various planning horizons as a part of their rules.

The most common planning horizon spans a 20 year period, with half of the IRP states mandating this planning period.

B. Frequency of Updates

Utility integrated resource plans must be updated periodically to reflect changing conditions with respect to load forecasts, fuel prices, capital costs, conditions in the electricity markets, environmental regulations, and other factors. IRP updates are typically required every two to three years, as shown in Table 2, below.

Montana appears twice in Table 2, as traditional utilities are required to file IRPs every two years, while restructured utilities are required to file updates every three years. There are some exceptions to the typical update requirements of

Table 1

Planning Horizons Found in IRP Rules

Planning Horizon	States with Specified Planning Horizon
10 years	Arkansas, Delaware, Oklahoma, South Dakota, Wyoming
15 years	Arizona, Kentucky, Minnesota, North Carolina, South Carolina, Virginia
20 years	Georgia, Hawaii, Idaho, Indiana, Louisiana, Missouri, Nebraska, Nevada, New Mexico, North Dakota, Oregon, Utah, Vermont, Washington
Multiple periods	Montana
Utility determined	Colorado
Not specified	New Hampshire

Table 2

Frequency of IRP Updates, as Determined by State Rules

Planning Horizon	States with Specified Planning Horizon
Every two years	Arizona, Delaware, Idaho, Indiana, Minnesota, Montana, New Hampshire, North Carolina, North Dakota, Oregon, South Dakota, Utah, Virginia, Washington
Every three years	Arkansas, Georgia, Hawaii, Kentucky, Louisiana, Montana, Missouri, Nevada, New Mexico, Oklahoma, South Carolina, Vermont
Every four years	Colorado
Every five years	Nebraska
Not specified	Wyoming

two to three years. Nebraska, for example, has a five year requirement for updates and is the only state to be made up entirely of public power utilities, many of which are customers of the Western Area Power Administration (WAPA). Pursuant to the Energy Policy Act of 1992, municipally-owned utilities are required to prepare resource plans every five years, but do not have to make those plans publicly available. Most Nebraska utilities must comply with both WAPA IRP requirements as well as state IRP requirements.

C. Resources Evaluated in Integrated Resource Planning

Generally, state rules mandate that utilities consider all feasible supply-side, demand-side, and transmission resources that are expected to be available within the specified planning period. Many state IRP requirements make no specifications for resources that must be evaluated beyond this. Other states have gone into further detail about the resources that should be investigated, including:

- **Delaware** – utilities shall identify and evaluate all resource options, including: generation and transmission service; supply contracts; short and long-term procurement from demand-side management (DSM), demand response (DR) and customer sited generation; resources that utilize new or innovative baseload technologies; resources that provide short or long-term environmental benefits; facilities that have existing fuel and transmission infrastructure; facilities that utilize existing brownfield or industrial sites; resources that promote fuel diversity; resources or facilities that support or improve reliability; and resources that encourage price stability.[7]
- **Indiana** – utilities shall examine: all existing supply and demand-side resources and existing transmission; all potential new utility electric plant options and transmission facilities; all technologies and designs expected to be available within the twenty-year planning period, either on a commercial scale or demonstration scale; and a comprehensive array of demand side measures, including innovative rate design.[8]
- **Kentucky** – utilities shall evaluate improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.[9]

There are state IRP rules that specify not only the resources that must be evaluated, but also the amount of weight given to a particular resource by either the utilities or the Public Service/Utilities Commissions. Colorado is one such state, and is described in more detail in later sections.

In almost all cases, state integrated resource planning rules have specific requirements for the planning horizons that should be covered, the frequency with which utility plans must be updated, and the generating resources that should be considered. Some states require nothing more, while others might also require, for example: 1) a certain number or a certain type of scenario analysis; 2) that certain types of resource cost tests be used to evaluate demand-side management policies; or 3) that externalities be considered by utilities when creating resource plans. Requirements for generating unit retirements and associated decommissioning costs are another example of something that some states might include in integrated resource planning rules, while others might not. The next section describes the discussion of this type of requirement in state IRP regulations.

D. Retirements and Decommissioning

Integrated resource planning is generally understood to be primarily concerned with the addition of resources in order to meet growing demand for electricity, and very few IRP rules mandate that utilities address end-of-life issues for generating units in their resource plans. In a summary document on integrated resource planning, the Regulatory Assistance Project states that "as utilities compare the cost of each supply- and demand-side option, they need to capture the entire life-cycle cost. This life-cycle cost means the fixed and variable costs incurred over the life of the investments: construction, operation, maintenance, and fuel costs."[10] This description does not represent the full

7 HB 6, the Delaware Electric Utility Retail Customer Supply Act of 2006.

8 170 Indiana Administrative Code 4-7-1: Guidelines for Integrated Resource Planning by an Electric Utility.

9 Kentucky Administrative Regulation 807 KAR 5:058: Integrated resource planning by electric utilities.

10 Harrington, et al. Integrated Resource Planning for State Utility Regulators. The Regulatory Assistance Project. June 1994. Page 14.

life of the investment, however, as it does not specifically include the costs associated with the retirement and decommissioning of a resource.

State IRP rules and utility filings reflect this incomplete assessment of life-cycle costs. Twenty-seven states have IRP rules and 20 of them are silent with respect to unit retirements. Utah and Colorado require that utility filings include information about the life expectancies of the generating units in the resource plans. Three states – New Mexico, North Carolina, and South Dakota – are slightly more specific, and mandate that utilities provide expected retirement dates for generating facilities. Specifically, the utilities in each of the states are required to do the following:

- **Utah** – include the life expectancy of generating resources
- **Colorado** – provide the estimated remaining useful lives of existing generation facilities without significant new investment or maintenance expense
- **New Mexico** – give the expected retirement dates for existing generating units
- **North Carolina** – provide a list of units to be retired from service (applies to both existing and planned generating facilities), with the location, capacity and expected date of retirement
- **South Dakota** – include those facilities to be removed from service during the planning period, along with the projected date of removal from service and the reason for removal

There are only two state rules that make any mention of decommissioning costs:

- Arizona rules state that if the discontinuation, decommissioning, or mothballing of any power source or the permanent derating of any generating facility is expected, the utility must provide:
  "i. Identification of each power source or generating unit involved,
  ii. The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating, and
  iii. The reasons for each discontinuation, decommissioning, mothballing, or derating."[11]
- Georgia laws and rules state that "Total cost estimates for proposed projects must include construction and non-construction related costs incurred through commercial operation, including decommissioning/ dismantlement costs."[12]

Rather than being addressed in utility integrated resource plans, generating unit retirements and associated decommissioning costs are largely left to be dealt with in other cases and proceedings that are brought before Public Utilities/Service Commissions.

E. Long-term Procurement Planning Requirements

As the electric industry began to restructure in the mid-1990s, many states that had integrated resource planning requirements either repealed them with restructuring laws, or simply began to ignore them. Some states eventually replaced integrated resource planning laws with rules for resource procurement plans. A document designed to inform California's 2010 Long-Term Procurement Plan (LTPP) requirement surveys the ways in which utilities in other states create their resource plans. The document states that "[w]hile California utilities have not undertaken a full integrated resource planning effort in many years, the 2010 LTPP proceeding is considering the appropriate role of utility resource planning in procuring the resources needed to meet state policy goals."[13]

Requirements for procurement plan filings differ from requirements for integrated resource plans. Planning periods are typically ten years, with some states requiring only a five year planning period. Procurement plans are usually required to be updated every year. Because utilities

11 Arizona Corporation Commission Decision No. 71722, in Docket No. RE-00000A-09-0249. June 3, 2010. Page 13. Amends Arizona Administrative Code Title 14, Chapter 2, Article 7, "Resource Planning." Available at: http://images.edocket.azcc.gov/docketpdf/0000112475.pdf

12 Integrated Resource Planning Act of 1991 (O.C.G.A. § 46-3A-1), Amended. See also: Georgia Public Service Commission, General Rules, Integrated Resource Planning 515-3-4. Available at: http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1

13 Aspen Environmental Group and Energy and Environmental Economics, Inc. Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California - DRAFT. Prepared for the California Public Utilities Commission. September 2008. Page 1.

in these states operate in a deregulated market and do not own generation, procurement plans evaluate purchases for capacity and energy, as well as energy efficiency and other demand-side management programs.

Connecticut is one such state that used to have an integrated resource planning requirement, and now has a requirement for procurement plans. The state had IRP regulations in place by the late 1980s, but this requirement was repealed when the restructuring law (Public Act 98-28) was passed in 1998. A long-term procurement planning law then became effective in 2007 (Public Act 07-242). Plans submitted to the Connecticut Energy Advisory Board in compliance with the 2007 law have much in common with utility IRPs and have even been called "Integrated Resource Plans," though they are technically long-term procurement plans.

The following section describes the ways in which IRP rules have been made in Arizona, Colorado, and Oregon, and presents some of the specifics of each of those rules.

1. Arizona

The Arizona Corporation Commission (ACC) has been given both constitutional and statutory authority to oversee the operations of electric utilities, and to engage in rulemaking that includes the establishment of IRP regulations. Article 15 of the Arizona Constitution created the ACC, which oversees the operations of all public service corporations in the state, including investor-owned electric utilities. The Commission is given exclusive authority to establish rates, enact rules that are reasonably necessary in ratemaking, and determine what sort of regulation is reasonably necessary for effective ratemaking,[14] as established in Article 15, §3:

> *The Corporation Commission shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the State for service rendered therein, and make reasonable rules, regulations, and orders, by which such corporations shall be governed in the transaction of business within the State…and make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of such corporations…*

Utility practices in Arizona are not governed by legislation or by statute, but rather through administrative code created by rulemaking proceedings of the Arizona Corporation Commission. Renewable energy requirements, distributed energy resource requirements, and integrated resource planning reporting requirements have all been established in this way.

The ACC has the authority to require that electric utilities provide reports concerning both past business activities and future plans. Integrated resource plans fall into this category. Article 15, §13 of the Arizona Constitution states that "[a]ll public service corporations… shall make such reports to the Corporation Commission, under oath, and provide such information concerning their acts and operations as may be required by law, or by the Corporation Commission." Arizona Revised Statute §40-204(A) expands on this requirement, stating that:

> *Every public service corporation shall furnish to the Commission, in the form and detail the Commission prescribes, tabulations, computations, annual reports, monthly or periodical reports of earnings and expenses, and all other information required by it to carry into effect the provisions of this title and shall make specific answers to all questions submitted by the Commission.*

Regulating and requesting information regarding the resource portfolios of electric utilities is one way in which the ACC meets its constitutional and statutory obligations to ensure that just and reasonable rates are being charged to consumers of electricity. In this pursuit, the ACC adopted the state's first Resource Planning and Procurement Rules in February 1989, requiring that utilities owning electric generation facilities file historical data every year, and 10-year resource plans every three years. The rules also provide for a Commission hearing to review these filings. In accordance with the rules, the first round of utility IRPs were filed in 1992 and hearings were held. In 1995, however, the Commission suspended the obligation of the electric utilities to file future resource plans until IRP rules could be modified to be consistent with impending electric industry competition and the passage of the retail electric competition rules.[15]

14 Arizona Corporation Comm'n v. Woods, 171 Ariz. 286, 294 ("Woods").

15 The Commission adopted retail electric competition rules in Decision No. 59943, dated December 26, 1996.

In revising the IRP rules, Commission staff were required to hold workshops, open to all stakeholders and to the public, on specific resource planning topics. These workshops:

> *Were to focus on developing needed infrastructure and a flexible, timely, and fair competitive procurement process; and were to consider whether and to what extent competitive procurement should include consideration of a diverse portfolio of purchased power, utility-owned generation, renewables, demand-side management, and distributed generation.*[16]

Following the workshops, a docket was opened for proposed rulemaking regarding resource planning, and on June 3, 2010 in Decision No. 71722, the Commission amended the Arizona Administrative Code Title 14, Chapter 2, Article 7, Resource Planning. In the most significant changes, compared to the original rules, the revised IRP rules:

- Extend the forecasting and planning horizon from 10 years to 15 years;
- Require submissions of utility IRPs every even-numbered year rather than every third year;
- Require load-serving entities to include, in their IRP, data regarding air emissions, water consumption, and tons of coal ash produced;
- Require that environmental impacts related to air emissions, solid waste, and other environmental factors and reduction of water consumption be analyzed and addressed in utility plans;
- Require that plans address costs for compliance with current and projected environmental regulations;
- Require that the resource plans include energy efficiency, to meet Commission-specified percentages;
- Require that the resource plans include renewable resources, to meet the specified percentages in Arizona Administrative Code R14-2-1804;
- Require that the resource plans include distributed energy resources, to meet the specified percentages in Arizona Administrative Code R14-2-1805;
- Require that utilities submit a work plan in every odd year that outlines the upcoming 15-year resource plan, and lays out: 1) the utility's method for assessing potential resources; 2) the sources of its current assumptions; and 3) a general outline of the procedures it will follow for public input, which includes an outline of the timing and extent of public participation and advisory group meetings that will be held before the resource plan is completed and filed.[17] Before they file the resource plan, utilities are required to provide an opportunity for public input. ACC practice also allows for public comment on the completed resource plan after it has been filed by the utility.

In the revised rulemaking proceedings emphasis was placed on diversifying the resource base in utilities' generation portfolios; on lowering costs through decreased reliance on volatile fossil-fuel based generation; and on considering and addressing environmental impacts, such as air emissions, coal ash, and water consumption.[18] Utilities must also submit a set of analyses to identify and assess the errors, risks, and uncertainties in: demand forecasts; the costs of DSM measures and power supply; the availability of sources of power; the costs of compliance with current and future environmental regulations; fuel prices and availability; construction costs, capital costs and operating costs; and any other factors the utility wishes to consider. This assessment should be done using sensitivity analysis and probabilistic modeling analysis.[19] The utility should provide a description of the ways in which these errors, risks, and uncertainties can be managed (e.g., by obtaining additional information, liming risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects), along with a plan to do so.[20]

Following the review of the utility IRP, the Commission is required to file an order that either acknowledges the resource plan (with or without amendment) or states the reasons for not acknowledging it.

The first electric utility IRPs filed under the revised rules were submitted to the ACC in 2012. The filing from Arizona Public Service (APS) is discussed in later sections.

16 Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. June 3, 2010.

17 Id.

18 Id. Page 12.

19 Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. June 3, 2010. Exhibit A: Notice of Proposed Rulemaking. Page 42.

20 Id. Page 43.

2. Colorado

Title 40 of the Colorado Revised Statutes establishes the state Public Utilities Commission and gives it authority to regulate the public utilities located within the state, specifically with regard to "the adequacy, installation, and extension of the power services and the facilities necessary to supply, extend, and connect the same."[21] Title 40 also contains all of the legislative requirements with which Colorado's public utilities must comply, and prescribes the general methods by which the PUC should evaluate compliance.

The evaluation process is described in more detail in 4 Code of Colorado Regulations (CCR) 723-3: Rules Regulating Electric Utilities. This section of the code describes the rules promulgated by the Public Utilities Commission to establish the process for determining the need for additional electric resources by those electric utilities subject to the Commission's jurisdiction, and for developing cost-effective resource portfolios to meet such need reliably.[22] The rules, in their current form, were adopted in 2003 and were referred to as *least-cost planning* rules. Beginning in 2003, utilities were required to file resource plans every four years, and may file an interim plan if changed circumstances justify the filing.

Utilities may choose their own planning period, but that period must be at least 20 and no more than 40 years. Utilities may also specify the resource acquisition period they will follow, which will be between the first six and ten years of the planning period. The planning period is both the time frame for which the resource plan is developed, and the long-term period over which the net present value of revenue requirements is calculated. The resource acquisition period represents the near-term period in which the utility must actually acquire resources to meet system energy and demand requirements. For any resources they propose to acquire, utilities file needs assessments and draft requests for proposals (RFPs). The PUC may approve, deny, or order modifications to utility plans. Following PUC approval, utilities then begin the competitive bidding process to acquire the new resources needed to meet load and reserve requirements.

Over the past decade, the PUC has opened several docketed proceedings and issued emergency rules revising the least-cost planning rules to provide specific guidelines for utilities, and to ensure compliance with new legislation adopted by Colorado state government. In Decision No. C07-0829 of September 19, 2007, the PUC adopted emergency rules modifying LCP rules as required by bills enacted in the 2006 and 2007 sessions of the Colorado Legislature. In general, these bills required the PUC to consider not only the costs of new generation resources as prescribed in least-cost planning rules, but also various benefits, requiring more technical expertise and involvement from the PUC in the resource selection process.[23]

Specifically, the following bills required the associated changes:

- HB07-1037 establishes requirements for energy efficiency and demand-side management resources, and requires the PUC to shift from a least-cost planning standard to a more subjective consideration of multiple criteria "which will require substantially more Commission involvement in the resource selection process."[24] The criteria shift applies to the evaluation of all resources, not only demand-side management (DSM)[25] measures.
- HB07-1281 increases the renewable energy resources that electric utilities must acquire, necessitating greater integration between the resource planning rules and the new Renewable Energy Standards.
- SB07-100 is intended to improve the economic viability of rural renewable resources. The bill provides for the designation of energy resource zones, and for the construction of transmission infrastructure to bring energy from these zones to load centers.
- HB06-1281 requires the Commission "to give the fullest possible consideration to new clean and energy efficient technologies…(and) provides an

21 Colorado Revised Statutes 40-1-103.

22 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3601.

23 Colorado Public Utilities Commission. Decision No. C07-0829. Docket No. 07R-0368E. September 19, 2007.

24 Id. Page 7.

25 Demand-side management , or DSM, measures involve reducing electricity use through activities or programs that promote electric energy efficiency or conservation, or more efficient management of electric energy loads.

example of how the Commission can give such consideration to resources that may be in the public interest when accounting for the benefits of advancing the development of a particular resource, or when accounting for other benefits outside of a strict cost perspective."[26]

The statutory language describes some of those benefits:

The Commission shall give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases. The Commission shall consider utility investments in energy efficiency to be an acceptable use of ratepayer moneys.[27]

As a result of the various bills described above, the PUC chose to strike the term "least-cost" from the rules in all instances, changing their title to Resource Planning Rules. It also introduced the term cost-effective into the rules, defining it as "the reasonableness of costs and rate impacts in consideration of the benefits offered by new clean energy and energy-efficient technologies."[28] These and other emergency rules were adopted on a permanent basis in Decision No. C07-1101 in Docket No. 07R-419E.

Other significant changes to the Resource Planning Rules were adopted by the PUC in 2010 in response to the passage of HB10-1365, known as the Clean Air-Clean Jobs Act (CACJA). The legislative declaration of the Act states that:

The general assembly hereby finds, determines, and declares that the federal "Clean Air Act," 42 U.S.C. sec. 7401 et seq., will likely require reductions in emissions from coal-fired power plants operated by rate-regulated utilities in Colorado. A coordinated plan of emission reductions from these coal-fired power plants will enable Colorado rate-regulated utilities to meet the requirements of the federal act and protect public health and the environment at a lower cost than a piecemeal approach. A coordinated plan of reduction of emissions for Colorado's rate-regulated utilities will also result in reductions in many air pollutants and promote the use of natural gas and other low-emitting resources to meet Colorado's electricity needs, which will in turn promote development of Colorado's economy and industry.[29]

The Act required that all utilities owning or operating coal-fired generating units in Colorado file an emissions reductions plan, which may include the following elements: emission control equipment, retirement of coal-fired units, conversion of coal units to natural gas, long-term fuel agreements, new natural gas pipelines, increased utilization of existing natural gas resources, and new transmission infrastructure. The CO Department of Public Health and the Environment and the PUC were tasked with reviewing the utility filings.

Approval of the plans is contingent on several factors, including whether required emissions reductions would be achieved; whether the plan promotes economic development in the state; whether reliable electric service is preserved; and the degree to which the plan increases the utilization of natural gas or relies on energy efficiency or other low-emitting resources. Plans were to be filed by August 15, 2010, and full implementation is to occur by December 31, 2017.[30]

While required emissions reduction plans were separate from Electric Resource Plans, the PUC opted to revise and clarify Electric Resource Planning (ERP) rules to make them more consistent with the CACJA. The PUC adopted revised rules on July 29, 2010 in Decision No. C10-0958 as part of Docket No. 10R-214E. Significant changes to the rules include:

- Adoption as the policy of the state of Colorado that the PUC give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies.
- Inclusion in the resource plan of the annual water withdrawals and consumption for each new resource, and the water intensity of the generating system as a whole.
- Inclusion of the projected emissions of sulfur dioxide, nitrogen oxides, particulate matter, mercury, and

26 Id. Page 9.

27 Colorado Revised Statutes 40-2-123(1)(a).

28 Colorado Public Utilities Commission. Decision No. C07-0829. Docket No. 07R-0368E. September 19, 2007. Page 20.

29 Colorado Revised Statutes 40-3.2-203(1).

30 General Assembly of the State of Colorado. House Bill 10-1365.

carbon dioxide for new and existing generating resources.

- The Commission must consider the likelihood of new environmental regulations, and the risk of higher future costs associated with greenhouse gases, when it considers utility proposals.
- Descriptions of at least three alternate resources plans that meet the same resource need as the base plan but include proportionally more renewable energy or demand-side resources. For the purpose of risk analysis, a range of possible future scenarios and input sensitivities should be proposed for testing the robustness of the alternative plans.
- Permission for the utilities to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise need to be obtained through a competitive acquisition process.[31]

Colorado's IRP rules do not mandate public participation prior to the filing of the IRP. The rules are, however, unique in requiring that the utility, Commission staff, and the Office of Consumer Counsel agree upon an entity to act as an independent evaluator (paid for by the utility) and advisor to the Commission. The independent evaluator reviews all documents and data used by the utility in developing its resource plan, and submits a report to the Commission that contains its analysis of "whether the utility conducted a fair bid solicitation and bid evaluation process, with any deficiencies specifically reported."[32]

Following the filing of the utility's resource plan, the IRP rules state that parties in the proceeding have 45 days to file comments on the plan and on the independent evaluator's report. The utility has a chance to respond to comments, after which the Commission is required to issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, "which decision shall establish the final cost-effective resource plan."[33] In 2011 the Colorado electric utilities filed the first electric resource plans that were consistent with these revised rules. The plan from Public Service Company of Colorado ("Public Service") is discussed in section III of this report.

3. Oregon

Oregon's IRP rules are the most straightforward of the three states examined here. The state first established resource planning rules in 1989, in Public Utility Commission Order 89-507. The order directs all energy utilities in Oregon to undertake least-cost planning, which the Commission defines in a somewhat unique way, stating that:

> *Least-cost planning differs from traditional planning in three major respects. It requires integration of supply and demand side options. It requires consideration of other than internal costs to the utility in determining what is least-cost. And it involves the Commission, the customers, and the public prior to the making of resource decisions rather than after the fact. …Least-cost planning as mandated by this order will allow the public as well as the Commission to participate in the planning process at its earliest stages.*[34]

The PUC thus identifies one of the key procedural elements of least-cost planning as allowance for significant involvement from the public and other utilities in the preparation of the resource plan, which includes opportunities for the public to contribute information and ideas as well as to receive information. The Commission's order states that "the open and collaborative character of least-cost planning may foster elevated confidence among those affected by the decisions and may make the process more responsive to demonstrated needs."[35] Substantive elements of least-cost planning are similar to those found in other states, with the PUC emphasizing the evaluation of conservation in a manner that is consistent and comparable to that of supply-side resources,[36] and with the analysis of economic, environmental, and social uncertainties.

The order also includes a concurring opinion from Commissioner Myron B. Katz, in which he discusses whether commissions, in the context of least-cost planning, should be interested in costs to utilities and ratepayers alone, or in overall costs to society. Katz suggests that utilities should seek to determine the costs for resources that include any externalities associated with those

31 Colorado Public Utilities Commission. Decision No. C10-0958. Docket No. 10R-214E. July 29, 2010.

32 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3613(b).

33 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3613(e).

34 Public Utility Commission of Oregon. Order No. 89-507. Docket No. UM 180. April 20, 1989.

35 Id. Page 3.

36 Id. Page 7.

resources, stating that "[a] resource should be deemed cost-effective and thus eligible for selection if its costs are lower than the costs of alternative resources assuming a market in which all costs, including environmental costs, are reflected in resource price tags."[37]

Subsequent PUC Orders 07-002, 08-339, and 09-041 (which became O.A.R. 860-027-0400) updated planning guidelines and requirements, and changed least-cost planning terminology to integrated resource planning, in recognition of the fact that there are many risks and uncertainties associated with any portfolio that must be weighed, and that least-cost is not the only criterion for selecting the best resource portfolio. This emphasis on the importance of risk in integrated resource planning is one way in which Oregon differs from some other states. The emphasis is placed in the forefront of the revised rules, with Guideline 1(b) stating that "(r)isk and uncertainty must be considered."[38] *Risk* is defined as a measure of the bad outcomes associated with a resource plan, while *uncertainty* is a measure of the quality of information about an event or outcome. Recognizing risks that are general to the electric industry and those that are specific to Oregon, the rules specify that, at a minimum, the following sources of risk must be considered in utility resource plans: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gases, as well as any additional sources of risk and uncertainty.[39]

In order to quantify these risks, utilities should calculate two different measures of the present value of revenue requirement risk (PVRR). The first should measure the variability of resulting PVRR costs under the different scenarios, and the second should measure the severity of any bad outcomes.[40] The primary goal of Oregon's IRP planning process is thus "the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[41] A portfolio of resources with the lowest expected cost before the inclusion of various risks may in fact have higher costs than other resource portfolios once those risks are considered.

The goal of the Oregon PUC in amending its rules was for utilities to identify the lowest-cost resource plan over the specified planning horizon by balancing both cost and risk. The Commission declines to mandate how the measures of PVRR risk be defined, instead leaving it up to the utilities and to "the interactive process of developing an IRP to make the best assessment of appropriate risk measures."[42] Unlike in Arizona, which requires that utilities create a plan to manage specific risks, Oregon requires that utilities take risks, their probabilities of occurrence, and the likelihood of bad outcomes into their choice of preferred resource plan.

These subsequent orders make few other substantive changes to the rules established in order 89-507, but instead add detail on the information and analysis that the PUC wanted in order to acknowledge utility resource plans. Notable changes include:

- The requirement that each utility ensure that a conservation potential study is done periodically for its entire service territory.
- The requirement that demand response and distributed generation be evaluated similarly to more traditional supply-side resources.
- The requirement that utilities include the expected regulatory compliance costs for various pollutants, that a range of potential CO_2 costs be analyzed,[43] and that sensitivity analyses be performed on a range of costs for nitrogen oxides, sulfur oxides, and mercury, if applicable.[44]

Order 07-002 also details the nature of public involvement in the IRP process, stating that the public and other utilities should be allowed significant involvement in the preparation of an IRP—that they should be allowed to contribute information and ideas, and to make relevant inquiries of the utility formulating the plan. The utility should also make a draft IRP available for public review

37 Id. Page 12.

38 Public Utility Commission of Oregon. Order No. 07-002. Docket No. UM 1056. January 8, 2007. Appendix A. Page 1.

39 Id.

40 Id. Appendix A. Page 2.

41 Id. Appendix A. Pages 1-2.

42 Id. Page 7.

43 From zero to $40 (1990$), as established in Order No. 93-695.

44 Public Utility Commission of Oregon. Order No. 07-002. Docket No. UM 1056. January 8, 2007.

45 Id. Page 8.

and comment before filing a final version with the PUC.[45]

Following submission of the integrated resource plan, intervening parties and Commission staff have six months to complete and file written comments on it. In advance of the deadline for written comments, the utility must also present the results of its resource plan to the Commission at a public meeting. The Commission then acknowledges the plan or returns it to the utility with comments. It may allow the utility to revise its resource plan before issuing an acknowledgement order.[46]

The IRP rules are careful to point out that acknowledgement of the IRP does not guarantee favorable ratemaking treatment later on, but that the acknowledgement simply means the plan seemed reasonable at the time it was reviewed by the Commission.[47] PacifiCorp, operating in Oregon as Pacific Power, is expected to file its 2013 IRP this year, but that plan was not available in time for inclusion in this paper. PacifiCorp's 2011 IRP is discussed in later sections.

46 Id. Page 9.

47 Id. Page 2.

III. Examples of Best Practices in Utility Integrated Resource Plans

A. Arizona Public Service

Arizona Public Service (APS) is the state's largest electric utility, and has been serving retail and wholesale consumers since 1886. In March 2012, APS filed the first formal resource plan in 17 years with the Arizona Corporation Commission. This IRP was also the first to be filed under the ACC's revised rules, as described in section II.A.

From the time when the Corporation Commission issued the final IRP rules to the date that APS filed its resource plan, the utility was "engaging key stakeholders to gain an understanding and appreciate of their areas of concern."[48] A series of workshops held during 2010 and 2011 sought to both inform and gather input from interested stakeholders on future resource decisions. The workshop topics included the resource fleet and transmission system; load forecasts; energy efficiency; smart grid; demand response; utility water consumption; fuel supplies and markets; technology options and costs; externalities; resource procurement; portfolios and sensitivities; and metrics and monetization costs for water, sulfur oxides, particulate matter, and nitrogen oxides. Approximately 35 to 50 stakeholders participated in each meeting, and several stakeholders were also invited to give presentations in some of the topic areas mentioned above.[49]

APS also contracted with the Morrison Institute at Arizona State University to conduct a series of four "Informed Perception Project" surveys on customer preferences and concerns regarding the energy resource options available to APS. Results showed that APS customers "favored an increase in the use of renewable energy resources, such as solar and wind, and were interested in both the environmental impacts and reliability of energy choices."[50]

Over the course of the 15-year planning period, with the assumption that migration to the state and individual electricity consumption will return to historic highs, APS has forecast 3% average annual growth in nominal electricity requirements through 2027. Energy efficiency and distributed generation, in the form of rooftop solar installations, will help offset some of this growth, but APS expects that it will need to add additional conventional supply-side resources, in the form of natural gas-fired generation, in 2019. APS created four resource portfolios to evaluate: a base case, a "four corners contingency," an "enhanced renewable" case, and a "coal retirement" case. Figure 3 shows the details of those plans.

Each of the resource plans created by APS were analyzed using a production simulation model, PROMOD IV, which dispatches the energy resources in each of the portfolios and generates system costs, or the likely future revenue requirements, associated with each. Calculation of system revenue requirements demonstrated that the APS base case portfolio was the most cost-effective of the resource plans evaluated. APS also monitors specific metrics to provide a context for comparing and evaluating the portfolios. In addition to revenue requirements, those metrics include fuel diversity, capital expenditures, natural gas burn, water use, and CO_2 emissions.

APS selected major cost inputs and evaluated several sensitivity scenarios, setting the assumptions for these variables higher and/or lower to test the impacts on the specific metrics being evaluated. These major cost inputs include natural gas prices, CO_2 prices, production and investment tax credits for renewable resources, energy efficiency costs, and monetization of SO_2, NO_x, PM, and water. APS also created low-cost and high-cost scenarios,

48 Arizona Public Service. 2012 Integrated Resource Plan. March 2012. Page 2.

49 Id. Page 25.

50 Id.

Figure 3:

Portfolios Considered in the APS 2012 IRP[51]

	Base Case (2012 Resource Plan)	Four Corners Contingency	Enhanced Renewable	Coal Retirement
Description	*Plan includes APS closing Four Corners units 1-3 and purchasing SCE's share of units 4-5; continues the current trajectory of EE and RE compliance*	*Contingency plan depicting the retirement of the Four Corners coal-fired plant; energy replaced by additional natural gas resources*	*Assumes 30% (after EE/DE) of energy needs met by renewable resources; include the consummation of the Four Corners transaction*	*Assumes APS retires all coal-fired generation; energy replaced with a combination of natural gas and renewable resources*
Resource Contributions *(2027 Peak Capacity Contribution/ % Energy Mix)*				
Nuclear	1,146 MW 18.7%MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh
Coal	1,932 MW 26% MWh	962 MW 12.7% MWh	1,932 MW 26% MWh	0MW 0MWh
Natural Gas and Demand Response	7,424 MW 26.3% MWh	8,394 MW 39.6% MWh	7,138 MW 20.7%MWh	9,188 MW 46.3% MWh
Renewable Energy (RE) & Distributed Energy (DE)	1,141 MW 13.7% MWh	1,141 MW 13.7% MWh	1,427 MW 22.8% MWh	1,308 MW 19.7% MWh
Energy Efficiency (EE)	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh

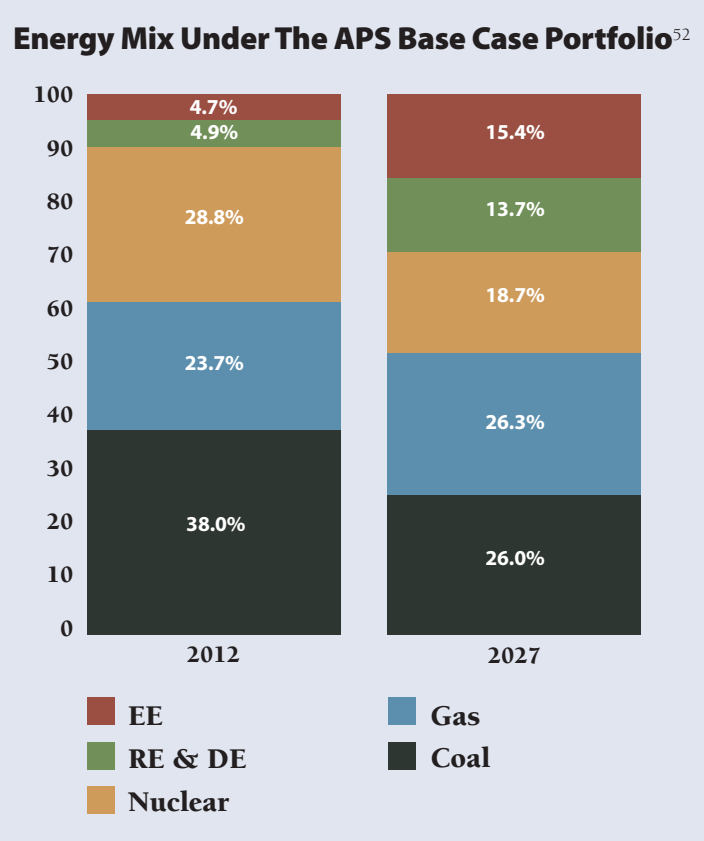
which incorporate the low and high values for all of the variables mentioned above rather than testing them on an individual basis. The results of the sensitivity analysis showed that the four corners contingency and coal retirement portfolios have the most variability in terms of net present value of revenue requirements, which fluctuate 11-12% as compared to 6-7% for the base case and enhanced renewable portfolios. Natural gas price changes caused the largest impact on sensitivity results.

Under the base case plan, APS achieves compliance with energy efficiency requirements and slightly exceeds compliance levels for renewable energy. Consistent with the intent of the revised rules, APS's reliance on coal-fired generating resources drops by 12% between 2012 and 2027. Use of natural gas increases slightly over the course of the planning period under this scenario, but by 2027, no single fuel source makes up more than approximately 26% of the APS resource mix. Figure 4 shows the energy mix in 2027 compared to 2012 under the base case portfolio.

APS had approximately 600 MW of excess capacity in 2012, heading into the summer peak. In the short term—over the next three years—the company planned to continue to pursue energy efficiency and renewable energy resources. During the intermediate term, years four to 15 of the planning period, APS plans to add 3,700 MW of natural gas capacity and 749 MW of renewable capacity. However, "[i]n the event that solar, wind, geothermal, or other renewable resources change in value and become a

51 Id. Page 44. Arizona Public Service Company hired Black and Veatch Corporation to conduct a Solar Photovoltaic (PV) Integration Cost Study report that provides the company with an estimate for the incremental operating reserves necessary to integrate geographically diverse PV development in the APS service territory, and quantifies the anticipated incremental cost to provide the reserve capacity and energy services. "Solar Photovoltaic Integration Cost Study," B&V Project No. 174880 (November 2012).

Figure 4



more viable and cost-effect option than natural gas, future resource plans may reflect a balance more commensurate to the enhanced renewable portfolio."[53]

APS should be commended for several elements of its 2012 IRP. The first of those is the comprehensive stakeholder process, which included workshops covering most, if not all, of the topic areas that are vital to comprehensive integrated resource plans. Not only were stakeholders invited to listen and offer feedback, they were also invited to present their points of view on a subset of these important issues. In the IRP itself, APS provides all non-confidential input and output data for stakeholder review.

Second, APS continues to pursue energy efficiency, renewable energy, and distributed generation resources in each of the resource portfolios it analyzed, meeting or exceeding ACC-specified goals and consistent with the Commission finding that:

> *Continued reliance on fossil generation resources without the addition of renewable generation resources is inadequate and insufficient to promote and safeguard the security, convenience, health, and safety of electric utilities' customers and the Arizona public and is thus unjust, unreasonable, unsafe, and improper.*[54]

APS has also analyzed portfolios that meet the Commission goals of promoting fuel and technology diversity as the utility lowers its reliance on coal-fired generation and increases its use of energy efficiency and renewable energy resources.

Third, APS takes environmental costs into account when evaluating its resource plans. The company uses a CO_2 adder consistent with the assumption that federal regulation of CO_2 will occur within the 15-year planning period. In sensitivity scenarios, APS analyzes alternative prices for CO_2 emissions, and also includes adders for SO_2, NO_x, PM, and water. Emissions cost and water consumption are also two metrics by which APS evaluates its resource portfolios. Water in particular is a resource that has not been given much consideration in utility integrated resource planning in past decades, in this and in other jurisdictions—but it is especially important for Arizona and other states in the arid parts of the country, as it may at times act as a constraining resource on electric power generation.

While APS has indeed done an admirable job in its 2012 Integrated Resource Plan, there are several areas in which the utility can still improve. The first is with respect to its load forecast. APS assumes a return to very high levels of load growth, at 3% per year for a total of 55% growth in energy consumption over the planning period. Load growth is one variable that can be highly uncertain. APS even states that "weather, population growth, economic trends, and energy consumptions behaviors are among the key variables that impact the Company's view of future resource needs. Accurately forecasting any one of these variables over a 15-year period is a challenge. Accurately forecasting them all is impossible."[55]

52 Id. Page 45.

53 Id. Page 64.

54 Arizona Public Service. 2012 Integrated Resource Plan. Page 13.

55 Id. Page 18.

Changes in the forecast can lead to significant changes in the quantity and type of resources needed in a utility's portfolio. For this reason, utilities engaged in resource planning typically analyze sensitivity cases that use at least two (low and high) alternative load forecasts. APS admitted that "a challenge more specific to the APS service territory is load-growth uncertainty,"[56] and yet the company analyzed only a single load forecast—one that the company admits is more than triple the average growth of electricity demand in the United States.[57]

The second improvement that APS could make to its IRP process relates to the creation of the utility's resource portfolios. Often, in integrated resource planning, utilities will use resource optimization models—e.g., EGEAS, Strategist, or System Optimizer—to create resource portfolios. The user inputs data on peak and energy demand, reserve margins, fuel prices, emissions prices, capital and operating cost of both supply and demand resources, etc., and the optimization model will select the number and type of resources to be added over time to make up the least-cost plan. These models will also perform a simplified system dispatch in order to generate system revenue requirements over the planning period. Rather than using an optimization model to select the ideal resource portfolios, APS hand-selected the resource mix for each portfolio. Under this method, it is possible that a lower-cost resource plan exists that APS has not identified.

This is particularly true in the sensitivity analyses that the company conducted. As described above, natural gas prices led to the greatest variance in system revenue requirements in the sensitivity analyses. Had an optimization model been used to evaluate scenarios with high natural gas prices, one might see the model select fewer natural gas-fired resources in favor of increased renewable or energy efficiency. Similarly, in sensitivity scenarios that look at decreased costs for energy efficiency, an optimization model might select additional quantities of energy efficiency to be added to the resource mix. Some of the supply-side resources selected using base EE costs might then not be required, as additional EE would lower both peak and energy demand.

On page 104 of its IRP, APS presents a table of residential and non-residential EE programs that were rejected because program costs were higher than benefits. In sensitivity scenarios where lower EE costs were evaluated, some of these measures that were rejected may have met cost-effectiveness tests and been selected for inclusion in utility resource portfolios.

B. Public Service Company of Colorado

The October 2011 IRP filing from Public Service Company of Colorado ("Public Service") was filed shortly after the company's filing that addressed the Clean Air-Clean Jobs Act. In the CACJA plan ultimately approved by the Colorado PUC, Public Service will retire 600 MW of base-load coal generation, fuel switch from coal to natural gas at another 450 MW of coal generation, and install emission controls at three other coal units by the year 2017. Additionally, as part of two separate filings, the company planned for the installation of 900 MW of additional wind and 30 MW of new solar by the end of 2012. These additions, repowerings, and retirements, along with the current weak growth in Colorado's economy, led Public Service to project a resource need of only 292 MW of additional generation capacity by 2018.

Public Service developed a "least-cost baseline case" resource portfolio, designed to meet resource needs during the Resource Acquisition Period from 2012 to 2018 at the lowest measurement of present value of revenue requirements. The utility also developed eight alternative plans that evaluate increasing amounts of renewable and distributed generation resources. These resource portfolios were evaluated using the Strategist model from the period of 2011-2050, and are shown in Figure 5.

Public Service evaluated the baseline case and the eight alternative cases under several sensitivity scenarios, altering the price of CO_2 emissions, renewable tax incentives, natural gas prices, and level of sales. Figure 6 shows the results of the analysis for the first three variables.

Public Service concludes from its analysis that existing and planned resources would be sufficient to meet the forecasted energy requirements of its system, but that natural gas-fired combustion turbines (CTs) would be required to provide the capacity necessary to maintain reserve margins. The company also concludes that adding

56 Id. Page 20.

57 Id. Page 18.

Figure 5

Least-Cost Baseline Case and Alternative Plans During the Resource Acquisition Period (RAP) From Public Service Company of Colorado's 2011 IRP[58]

		Level A				Level B			
RAP Resource	**1 Baseline**	**A2 Wind**	**A3 PV**	**A4 Battery**	**A5 Solar Thermal**	**B2 Wind**	**B3 PV**	**B4 Battery**	**B5 Solar Thermal**
Thermal Resources	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	1 CT 173 MW	1 CT 173 MW	1 CT 173 MW
Wind		200 MW	200 MW	200 MW	200 MW	800 MW	800 MW	800 MW	800 MW
Solar			25 MW	25 MW	25 MW		100 MW	100 MW	100 MW
Battery				25 MW				100 MW	
Solar Thermal					50 MW				125 MW

Figure 6

Sensitivity Results for Co_2, Tax Incentives, and Gas Prices From Public Service Company of Colorado's 2011 IRP[59]

		Level A				Level B			
		A2 Wind	**A3 PV**	**A4 Battery**	**A5 Solar Thermal**	**B2 Wind**	**B3 PV**	**B4 Battery**	**B5 Solar Thermal**
Alternative Plan 2011-2050 PVRR Deltas from Baseline Case ($Millions)									
	Starting Assumptions	$98	$105	$160	$298	$427	$489	$672	$881
Sensitivities	**CO_2 3-Source Low Esc**	$9	$10	$65	$182	$75	$113	$297	$455
	CO_2 3-Source	$7	$8	$62	$178	$63	$101	$285	$441
	CO_2 Early ($20 in 2017)	($36)	($38)	$17	$124	$117	$92	$98	$223
	Low Gas	$164	$179	$238	$393	$671	$760	$979	$1,204
	High Gas	$21	$19	$72	$183	$151	$176	$369	$503
	PTC Wind	($97)	($90)	($35)	$103	$312	($251)	($67)	$142
	10% ITC Solar PV	$98	$119	$174	$312	$427	$546	$729	$938
	30% ITC Solar Thermal	$98	$105	$160	$235	$427	$489	$672	$741

58 Public Service Company of Colorado. 2011 Electric Resource Plan: Volume 1. October 31, 2011. Pp. 1-38.

59 Id. Pp. 1-41.

renewable generating resources would increase system costs under both baseline and sensitivity assumptions.[60] The results of the sensitivity analysis shown in Figure 6 seem to indicate, however, that if the production tax credit (PTC)[61] for wind were to be extended, there would be some benefit to adding additional wind generation, as shown by the decline in present value of revenue requirements in this scenario relative to the base case.

Given the results of the resource analysis, Public Service proposes to utilize a competitive All-Source Solicitation to acquire the resources needed to meet planning reserve margin targets. The solicitation would seek both short-term and long-term power supply proposals, with a preference for short-term contracts. Public Service lists several uncertainties that it will face over the coming years: future environmental regulations, changing technology costs, tax credits that impact the relative costs of generation alternatives, fuel prices, and economic growth in its service territory.[62] Given these uncertainties and the relatively small resource need, the shorter-term power urchase agreements would allow the utility to wait and see if and how uncertainties can be resolved before adding new generation facilities to its resource mix. The company will also offer enough self-build power supply proposals into the solicitation process to meet the needs over the resource acquisition period.

These proposals would ensure that at least one portfolio could be developed with company-owned facilities, and that generating capacity will be expanded at existing sites. Public Service requests that the PUC allow it to conduct periodic solicitations for additional renewable energy, if and when markets become most favorable to customers; but it reports no plans to add additional renewables over the acquisition period. The company states that, "[t]o the extent the Commission desires to see portfolios from the Phase 2 process that contain increasing levels of renewable or Section 123 Resources the Commission should direct the Company to do so in its Phase 1 order."[63]

Public Service's 2011 IRP is comprehensive, thorough, and a good example of effective resource planning. Resource planning in Colorado is driven by: 1) the state Legislature, as statutes dictate the content of state IRP rules; 2) by interveners, whose comments and suggestions during IRP processes can lead to changes in both rules and content of utility resource plans; and 3) by the PUC, which oversees the process and may require that utilities revise resource plans in specific ways prior to receiving Commission approval. The input and oversight from these three entities, combined with the utilities' expertise, leads to the inclusion of several notable elements in the resource plan that demonstrate additional issues of concern in Colorado.

First, recognizing that acquiring necessary resources does not always go according to plan, the utility creates and describes a series of the more common contingency events—e.g., bidders withdrawing proposals, transmission development delays, higher than anticipated electric demand, etc.—and develops plans to address them if they occur.[64]

Second, Public Service acknowledges that its planned volume of wind installations (2,100 MW by 2012) creates specific challenges and requirements that much lower volumes of renewables would not. Because wind output can be variable and uncertain, there may be additional flexibility requirements on an electric system—i.e., there must be a certain amount of generation that can be brought on-line within a 30-minute period in order to respond to changes in renewable output. Public Service conducts an assessment of the need for flexible resources in its IRP's general assessment of need.

Flexibility studies are not a part of traditional integrated resource planning, but Public Service is responding to unique circumstances in its service territory by incorporating this type of study in its resource planning. Utilities sometimes cite the variability and uncertainty of wind and other renewables as reasons *not* to pursue these types of resources in their portfolios; Public Service shows,

60 Id. Pp. 1-43.

61 The federal renewable energy production tax credit (PTC) provides a per-kilowatt-hour tax credit for electricity generating by various types of renewable energy resources and sold by the taxpayer to an unrelated person during the taxable year. The PTC was originally enacted in 1992 and has been extended several times, most recently in January 2013 as part of the American Taxpayer Relief Act of 2012 (H.R. 6, Sec 407). Currently, the PTC for wind resources for which construction began prior to December 31, 2013 is 2.3 cents/kWh.

62 Id. Pp. 1-5.

63 Id. Pp. 1-49.

64 Id. Pp. 1-59.

however, that these challenges can be planned for in a reasonable way and are not a reason to avoid renewable additions.

Finally, traditional integrated resource planning does not pursue short-term strategies, such as market purchases that may buy time in the hope that some uncertainties will be resolved."[65] The Public Service IRP does just that, however, by making shorter-term resource acquisition decisions and preserving "decisions involving new generation facilities to a point in the future when we see how these uncertainties are resolved."[66]

While Public Service should be applauded for its integration of renewables to date, it is unclear from the company's IRP whether it truly views renewable generating technologies as a system resource as opposed to an obligation established by the state legislature and the PUC. As mentioned above, Public Service has no plans to pursue additional renewable acquisitions during the next seven years, even though sensitivity analyses show that additional wind generation may be beneficial to ratepayers if the production tax credit were to be extended. The company does ask that it be granted permission to conduct solicitations for renewables outside of the resource planning process if it determines that market conditions are "favorable," but it gives no indication as to what favorable market conditions might look like. An evaluation of the market conditions favorable to renewables would be very helpful in the context of resource planning, and could be included in future IRPs or updates from Public Service.

C. PacifiCorp

Of the three utilities examined here, PacifiCorp is unique in that it operates across six states—Oregon, Washington, California, Idaho, Utah, and Wyoming, five of which have IRP or other long-term planning requirements.[67] This gives PacifiCorp the additional challenge of planning on a system-wide basis while meeting each of the resource-acquisition mandates and policies in the states where it operates. The company evaluates a 20-year study period, but focuses on the first ten years (2011-2020) in its assessment of resource need.

In that ten-year planning period, PacifiCorp forecasts that system peak load will grow at 2.1% per year (2.4% for

65 Chupka, M,, Murphy, D. & Newell, S. *Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches.* Brattle Group. 2008. Page 2.

66 Public Service Company of Colorado. *2011 Electric Resource Plan: Volume 1.* October 31, 2011. Pp. 1-5.

67 Wyoming does not have its own IRP obligation, but instead mandates that any utility serving in the state that is required to submit an IRP in another jurisdiction also file that IRP with the Wyoming PSC.

68 Id. Page 8.

Figure 7

Resource Additions in the Preferred Portfolio—PacifiCorp's 2011 IRP[68]

	Capacity (MW)										
Resource	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
CCCT F Class	-	-	-	625	-	597	-	-	-	-	1,222
CCCT H Class	-	-	-	-	-	-	-	-	475	-	475
Coal Plan Turbine Upgrades	12	19	6	-	-	18	-	8	-	-	63
Wind, Wyoming	-	-	-	-	-	-	-	300	300	200	800
CHP-Biomass	5	5	5	5	5	5	5	5	5	5	50
DSM, Class 1	6	70	57	20	97	-	-	-	-	-	250
DSM, Class 2	108	114	110	118	122	124	126	120	122	125	1,189
Oregon Solar Programs	4	4	4	3	3	-	-	-	-	-	18
Micro Solar – Water Heating	-	4	4	4	4	4	4	4	-	-	28
Firm Market Purchases	350	1,240	1,429	1,190	1,149	775	822	967	695	995	N/A

the eastern system peak and 1.4% for the western system peak), and that energy requirements will grow by 1.8% per year. Resource deficits will begin in the first year, with PacifiCorp being short 326 MW in 2011. This deficit grows to 3,852 MW by 2020. In the near-term, shortages will be met with DSM, renewables, and market purchases, but new baseload and intermediate generating units begin to be added to the resource mix in 2014.[69] Figure 7 shows the proposed resource additions.

If PacifiCorp were to proceed with these proposed resource additions, by 2020 its capacity mix would be as shown in Figure 8. In this scenario, traditional thermal resources still make up two-thirds of PacifiCorp's capacity mix; DSM makes up just over 13%, and renewables make up 2.6%.

As Figure 9 shows, PacifiCorp's energy mix looks slightly different under its preferred portfolio. The percentage of total energy generated from coal-fired resources drops by 26% between 2011 and 2020, while the amount of energy from gas-fired resources more than doubles. Even with the significant drop in generation from coal, energy from thermal resources makes up 61% of PacifiCorp's total energy. DSM makes up 11% of the energy mix, with another 11% coming from renewable resources. Hydroelectric power and energy purchases make up the bulk of the remaining energy.

Of the three utilities examined in this report, PacifiCorp's portfolio modeling process is the most comprehensive. It uses a model called System Optimizer, which has the capability to determine capacity expansion plans, to run a production cost simulation of each optimized portfolio, and to perform a risk assessment on these portfolios.

Figure 8

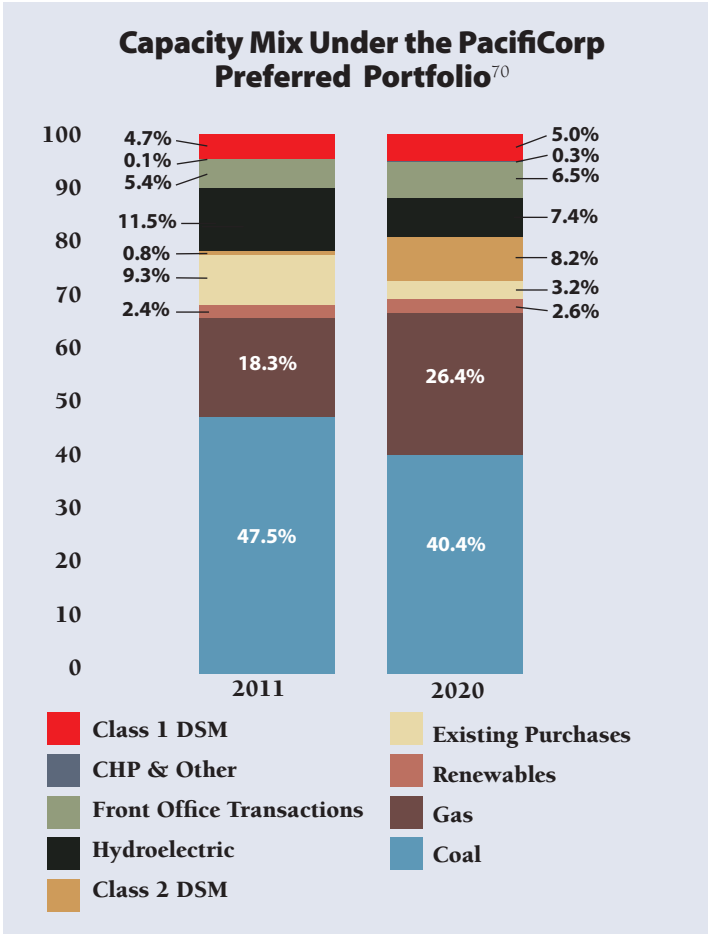
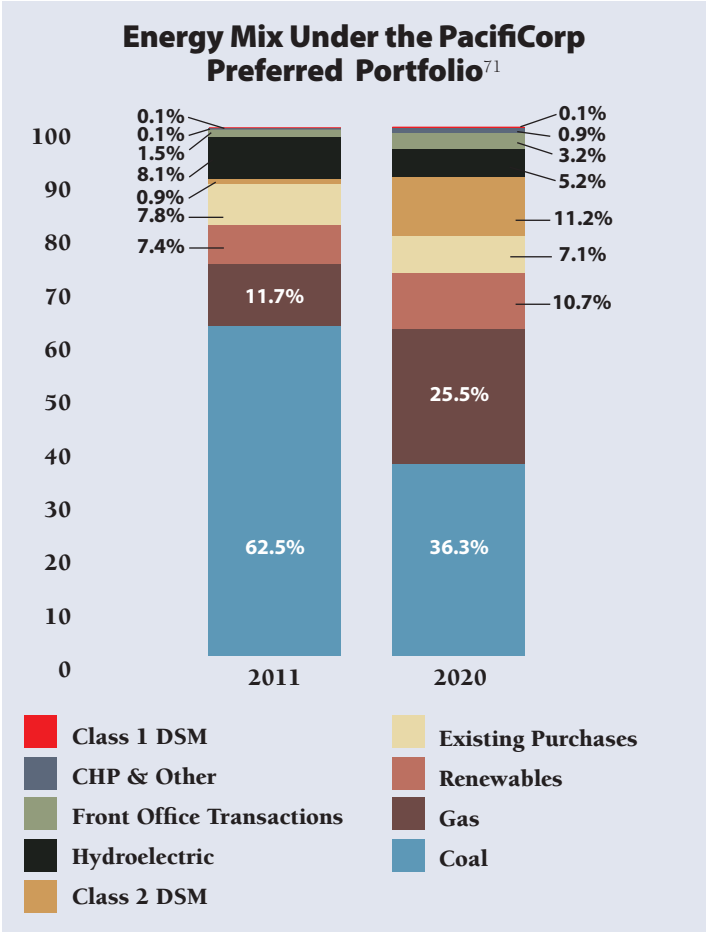


Figure 9



69 PacifiCorp. 2011 *Integrated Resource Plan: Volume 1.* March 31, 2011. Page 83.

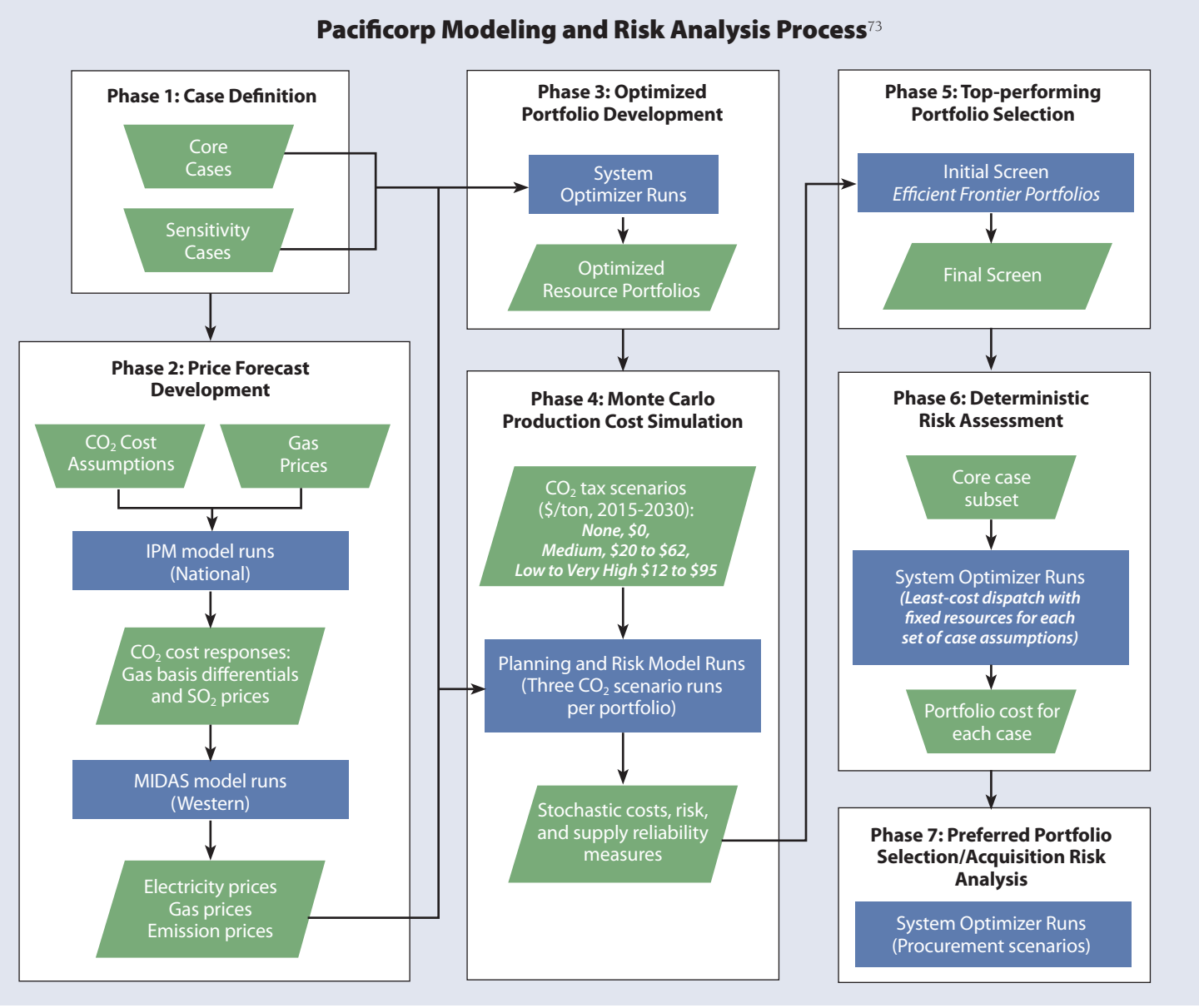
70 Id. Page 10.

71 Id. Page 13.

Altogether, PacifiCorp defined 67 input scenarios for portfolio development. These looked at alternative transmission configurations, CO_2 price levels and regulation types, natural gas prices, and renewable resource policies. Sensitivity cases examined additional incremental costs for coal plants, alternative load forecasts, renewable generation costs and incentives, and DSM resource availability. Top resource portfolios were determined on the basis of the combination of lowest average portfolio cost and worst-case portfolio cost resulting from 100 simulation runs. Final portfolios were selected after considering such criteria as risk-adjusted portfolio cost, 10-year customer rate impact, CO_2 emissions, supply reliability, resource diversity, and uncertainty and risk surrounding greenhouse gas and RPS policies.[72]

Figure 10 shows PacifiCorp's schematic of its modeling process. PacifiCorp is one of the only utilities in the country that models energy efficiency resources as supply-side resources, rather than as load modifiers. The utility provides the model with specific quantities of energy efficiency at given costs, and allows those efficiency resources to compete against the other resources from

Figure 10



72 Id. Page 153.

73 Id. Page 155.

which the model is able to select. PacifiCorp's efficiency resource information in its 2011 IRP is based on a 2010 energy efficiency potential study that provided an estimate of the size, type, timing, location, and cost of the demand-side resources that are technically available in PacifiCorp's service territory. Data for more than 18,000 measures were available after the resources were separated by customer segment, facility type, and unique EE measures.

Energy efficiency measures are called Class 2 DSM, while capacity-based measures are separated into two categories: Class 1 DSM includes dispatchable demand-response programs, and Class 3 DSM includes pricing programs. Focusing on Class 2 DSM measures, PacifiCorp consolidated them into nine cost bundles grouped by levelized cost for inclusion in the modeling, and 1,400 supply curves were modeled for the IRP.[74]

Energy efficiency measures performed well in the modeling, representing the largest resource added through 2030 across all portfolios with cumulative capacity additions exceeding 2,500 MW in the preferred portfolio. The inclusion of such large quantities of energy efficiency creates huge cost savings to ratepayers. If energy efficiency were not included in PacifiCorp's resource portfolio, the utility would have to meet electric load by adding 2,500 MW of supply-side resources at much greater cost.

Although PacifiCorp's portfolio modeling process is comprehensive and well-executed, system resource modeling in general is only as good as the *input assumptions* used to generate the portfolios. The most significant area in need of improvement in the PacifiCorp IRP process relates to the input assumptions and analysis regarding the company's coal fleet—or, rather, the lack of analysis presented on this in the IRP. This lack of analysis began during the stakeholder process. In comments that it submitted, the Sierra Club states that it actively participated in the stakeholder input process, and raised many of the issues discussed in those comments. "The company did not respond to any requests for data related to the topics addressed in these comments, choosing instead to provide only a small amount of materials in the final draft, just days before the company submitted the final IRP."[75]

PacifiCorp's 26 coal-fired boilers make up almost two thirds of its generation. To keep these units running while meeting stricter federal air pollution standards, the company would have to spend $1.57 billion in environmental capital cost from 2011 to 2020, in addition to $1.2 billion that it invested before 2011. Operating costs would raise the total cost to customers to $4.2 billion, or $360 million on an annual basis by 2030.[76] PacifiCorp, however, makes no mention of these current compliance obligations or any future costs in the 2011 IRP or its appendices. The utility failed to disclose the costs that would be faced by its coal fleet in its 2011 IRP, and failed to do a comprehensive analysis of the economics of each of its coal-fired generating units. Absent this analysis, the resource portfolios analyzed by the company cannot be considered to be truly "optimized."

It is highly likely that PacifiCorp could add additional renewable resources to its portfolio. As discussed above, Public Service Company of Colorado had 2,100 MW of wind capacity alone on its system at the end of 2012, and they are a single utility operating in one state. PacifiCorp's territory covers portions of six states, many with large amounts of renewable potential. PacifiCorp's service territory also borders other states with large amounts of renewable potential, and the company could enter into long-term contracts for renewable energy. The company states in the IRP that it commissioned a study on geothermal potential, yet its resource portfolio does not include any anticipated geothermal energy or capacity during the study period.

74 Lamont, D. & Gerhard, J. The Treatment of Energy Efficiency in Integrated Resource Plans: A Review of Six State Practices. Regulatory Assistance Project. January 2013. Pp. 6-8.

75 Sierra Club's Preliminary Comments in the Matter of PacifiCorp 2011 Integrated Resource Plan before the Public Utility Commission of Oregon. LC 52. August 25, 2011.

76 Opening Comments of the Citizens' Utility Board of Oregon in the Matter of PacifiCorp 2011 Integrated Resource Plan before the Public Utility Commission of Oregon. LC 52.

IV. Recommendations for Prudent Integrated Resource Planning

Prudent integrated resource planning involves both the process of creating and sharing the resource plan with stakeholders, and the elements that are analyzed and included in the plan itself. This section provides recommendations, for both the IRP process and the resulting resource plan, that are designed to result in responsible and comprehensive utility integrated resource plans.

A. Integrated Resource Planning Process

Integrated resource planning processes differ from state to state. The ideal process begins with the determination of the IRP guidelines or rules. Integrated resource planning rules were first established in many states in the late 1980s or early 1990s; Oregon's first rules, for example, were established by PUC order in 1989. Significant changes have occurred since then. During the mid- to late 1990s, electric restructuring moved many utilities away from traditional resource planning in favor of market-based provision of electric supply; and today, climate change, national security, and volatility in fuel and commodity markets can make it difficult to determine the best way in which to supply electricity to consumers. Integrated resource planning rules should thus be reexamined periodically, to make sure they reflect the current conditions and challenges associated with providing reliable electric service at reasonable costs.

Arizona began the process of changing its rules after retail competition was instituted in the state by the Corporation Commission—and although the rules took over a decade to be revised and put into effect, the current regulations have been designed to address the issues that are of concern today. When IRP rules are reexamined, state commissions should open proceedings that are open to the public, and stakeholders should be allowed to offer input on the ways in which rules should be revised, as well as to review and comment on any draft documents that are issued. All three of the state IRP rules examined here have gone through this process, and in drafting revised rules, each of the state commissions carefully considered the feedback offered by interveners and adopted recommendations from both public interest groups and utilities.

1. Resource Plan Development

Stakeholder group involvement is equally important when it is time for a utility to develop its integrated resource plan. As was discussed in section III.A., APS detailed its stakeholder process in its 2012 IRP. During the two-year period that preceded the filing of the plan, the utility held various workshops where stakeholders received updates on the inputs to be used, and were able to offer feedback and even give presentations on these various inputs. Stakeholders were also surveyed to determine their preferences with regard to the energy resources selected by APS. Not only does this stakeholder process inform the content of the resource plan that is ultimately filed by the utility; it can also help to inform the review process once the filing has been made.

Other states have also recognized the benefits of stakeholder involvement in IRP and developed model processes. In its *Resource Planning Guidelines for Electric Utilities,* the Arkansas Public Service Commission suggests that utilities establish a Stakeholder Committee to assist in preparing resource plans that "should be broadly representative of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the service area."[77] The members of this committee would review utility objectives, assumptions, and estimated needs early in the planning cycle, and would submit a report along with the utility's resource plan. Committee members may also submit additional comments to the Commission, which may

77 Arkansas Public Service Commission. *Resource Planning Guidelines for Electric Utilities.* June 2007.

require the utility to re-evaluate its plan to address these comments.[78]

In Hawaii, IRP rules were designed to attempt to maximize public participation in the planning process. In each county within its service territory, the utility is required to organize advisory groups made up of representatives of public and private entities whose interests are affected by the utility's resource plan—including state and county agencies and environmental, cultural, business, and community interest groups. The rules specify that "(a)n advisory group should be representative of as broad a spectrum of interests as possible."[79]

Whether required by IRP rules or not, it is good practice for a utility to convene a stakeholder group, or to hold public meetings that are open to all interested parties, before creating and submitting its resource plan. These meetings are useful both to provide information and invite feedback on the input assumptions and the process that the utility is using in its resource planning, and to help ensure that the resulting plan is relevant and reflects the interests of ratepayers and the general public.

2. Resource Plan Review

Many state utility commissions are quasi-judicial boards that rely on the rules of civil procedure and allow for participation and intervention from different organizations and members of the public (provided they have standing in the proceeding, or an ability to assist the commission in making decisions). After a utility has filed its resource plan, the state PUC should open a proceeding that allows stakeholders to review and submit written comments on the filing. This feedback should be taken into account during the review by the PUC and its staff. Commissions should take an active role in assessing the validity of the inputs used by the utilities in their filings, the resulting outcomes, and whether these are consistent with both the IRP rules and the state's energy policies and goals.

In Kentucky, for example, the IRP rules specify that once a utility's IRP has been received, the Commission should develop a procedural schedule allowing for submission of written interrogatories to the utility by commission staff and any interveners, written comments by staff and interveners, and responses to these interrogatories and comments by the utility. The Commission may convene conferences to discuss the filed IRP if it wishes to do so. Following a review of the plan and intervener comments, Commission staff will issue a report summarizing its review and offering recommendations to the utility for subsequent IRP filings.[80]

Of the states examined in this report, the Colorado PUC has taken on a particularly active role in determining whether utility resource choices were in the public interest. The PUC did so, for example, in its review of Public Service Company of Colorado's 2010 DSM Plan, when it rejected the energy efficiency goals proposed by the company and instead asked that the utility adopt goals recommended by an intervener—the Southwest Energy Efficiency Project—that were approximately 130% of the goals in place at the time.[81] These EE goals were then incorporated into the 2011 IRP, in the calculation of resource need as one of the input modeling assumptions.[82]

Many states, though not all, require that utility plans be available to interveners and/or members of the public for review and participation in resource planning dockets. This signals to both stakeholders and utilities that the IRP process should be collaborative, and that stakeholders can and do offer valuable insights and opinions into resource planning that should be taken into account by utilities when developing their plans. Active oversight and participation by the state PUC is critical to ensuring that comments and proposals by interveners are reviewed, considered fully, and incorporated into utility resource plans when reasonable.

78 Id.

79 Public Utilities Commission, State of Hawaii. *A Framework for Integrated Resource Planning.* Revised May 22, 1992.

80 807 KAR 5:058. Integrated Resource Planning by Electric Utilities.

81 Colorado Public Utilities Commission. Decision No. C11-0442. Docket No. 10A-554EG. March 30, 2011.

82 *The Treatment of Energy Efficiency in Integrated Resource Plans.* Page 15.

B. Integrated Resource Plans

A good electric system IRP should include, at a minimum:

Load forecast

A company's load forecast (annual peak and energy) is one of the major determinants of the quantity and type of resources that must be added in a utility's service territory over a given time period, and has always been the starting point for resource planning. Projections of future load should be based on realistic assumptions about local population changes and local economic factors[83] and should be fully documented. Resource needs can rise or fall dramatically over a short period of time, and frequent, up-to-date load forecasts are necessary for utilities to be able to adequately assess the quantity and type of additional resources that might be needed in a specific planning period.

In Colorado, for example, at the time of Public Service's CACJA filing in mid-2010, the company was projecting a resource need of approximately 1,000 MW by 2018. At the time of its IRP filing in October 2011, the projection of resource need had dropped to 292 MW as a result of the economic recession and the success of DSM and solar programs.[84] In order to help plan for any future changes in load, utilities should model a range of possible load forecasts, not just a reference case.

Reserves and reliability

Reliability is typically defined as having capacity equal to the forecasted peak demand, plus a reserve margin during the hours in which that peak demand is expected to occur. Reserve requirements should provide for adequate capacity based on a rigorous analysis of system characteristics and proper treatment of intermittent resources. The system characteristics affecting reliability and reserve requirements include load shape, generating unit forced-outage rates, generating unit maintenance-outage requirements, number and size of the generating units in a region or service territory, transmission interties with neighboring utilities, and availability and effectiveness of intervention procedures.[85]

Demand-Side Management

Many state IRP statutes or regulations include in the definition of integrated resource planning an evaluation of energy conservation and efficiency. Even so, "[w]hile demand-side resources have always been a conceptual part of IRP, in practice they have not always been an important focus."[86, 87] As generation from traditional supply-side resources is growing more costly and energy efficiency measures are becoming less expensive, however, demand-side alternatives have gained a greater number of advocates across the United States.

Not only is energy efficiency often the lowest-cost resource available to system planners, it can also mitigate a variety of risks, such as that of impending carbon legislation and other environmental regulations affecting air and water quality. In addition to offsetting energy consumption, implementing EE measures can lead to a deferral in costly transmission and distribution investments.[88]

In the IRPs of most utilities, demand-side resources are included only up to the point that statutory goals are met, or mandatory levels of investment are included. Resource planners often incorporate the effects of those demand-side policies as adjustments ("decrements") to their forecasts of future load requirements. However,

83 State and Local Energy Efficiency Action Network. *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.* September 2011. Page 5.

84 Public Service Company of Colorado. *2011 Electric Resource Plan: Volume 1.* October 31, 2011. Pp. 1-5.

85 Biewald, B. & Bernow, S. *Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity.* Boston: Energy Systems Research Group. 1988.

86 Chupka, M., Murphy D. & Newell, S. *Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches.* Brattle Group. 2008. Page 3.

87 Demand response, which is another type of demand-side resource, is considered in utility IRPs even less frequently than is efficiency. A full discussion of how demand response is included or excluded in IRPs is beyond the scope of this report.

88 *The Treatment of Energy Efficiency in Integrated Resource Plans.* Page 15.

> "The best IRPs create levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-side resources. … By developing cost curves for demand-side options, planners allow the model to choose an optimum level of investment. So if demand-side resources can meet customer demand for less cost than supply-side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies."[89]

The three integrated resource plans discussed in this report each deal with energy efficiency in different ways. In Arizona, the Corporation Commission has set a demand-side management standard, and each of the portfolios analyzed in the IRP from Arizona Public Service assume full compliance with that standard.[90] Public utilities are required to achieve annual energy savings of at least 22% by 2020, and savings (measured as a percent of retail energy sales) should increase incrementally in each calendar year prior to 2020.[91] In its IRP, APS has calculated the number of MWh of energy savings needed to be compliant with Commission standards, and has imported these targets into the IRP as a load decrement over the planning horizon.

Colorado's Energy Efficiency Resource Standard (EERS) was established by Colorado House Bill 07-1037 and codified under the Code of Colorado Regulations §40-3.2-104. The law requires that the Colorado Commission set savings goals for energy and peak demand for the state's investor-owned utilities, but specifies minimum savings goals of at least 5% of both retail energy sales and peak demand from a 2006 baseline. Utilities are required to submit DSM plans, which are then reviewed and approved by the Commision, or approved with modifications. The plan that is ultimately approved may require levels of DSM that are higher than the minimum savings goals that have previously been established. Similar to APS, in its most recent IRP, Public Service took the most recent utility-specific DSM goals approved by the Commission and imported them into the IRP process as a load decrement, reducing the resource need over the planning period.

PacifiCorp is subject to EERS requirements in Washington and California. In 2006 in Washington, voters passed Initiative 937, which requires that electric utilities serving more than 25,000 customers undertake all cost-effective energy conservation. Beginning in 2010, utilities must do an assessment of all the achievable cost-effective conservation potential in even-numbered years.[92] Alternatively, efficiency targets may be based on a utility's most recent integrated resource plan, provided that plan is consistent with the resource plan for the Northwest Power and Conservation Council.[93]

California Assembly Bill 2021, enacted in 2006, called for a 10% reduction in electricity consumption within 10 years. It also required that the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and other interested parties develop a statewide estimate of all cost-effective electricity savings, develop efficiency and demand reduction targets for the next 10 years, and update the study every three years. Goals were developed by the CPUC in 2008 for years 2012 through 2020, and each of the three investor-owned utilities in the state has distinct requirements for electricity savings and demand reduction.[94]

89 State and Local Energy Efficiency Action Network. Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures. September 2011. Page 6.

90 Arizona Public Service. 2012 Integrated Resource Plan. March 2012. Page 36.

91 Arizona Corporation Commission. Decision No. 71819. Docket No. RE-00000C-09-0427. August 10, 2010.

92 Chapter 19.285 of the Revised Code of Washington (RCW): Energy Independence Act.

93 The Northwest Power and Conservation Council (NWPCC) is a regional entity that helps the states in the Pacific Northwest ensure an affordable and reliable energy system while maintaining fish and wildlife health in the Columbia River Basin. One responsibility of the NWPCC is to publish a 20-year electric plan that serves as a guide for Bonneville Power and its customer utilities in the region. The regional plan drives best practices in energy efficiency and is a reference against which utility plans may be measured. In the Sixth Power Plan, published in 2010, the NWPCC recommended that energy efficiency be deployed aggressively such that it meets 85% of new demand for electricity over the next 20 years.

94 California Public Utilities Commission. Decision 08-07-047. Rulemaking 06-04-010. July 31, 2008.

In California, PacifiCorp is also subject to a separate "loading order" requirement that requires utilities to first meet growth in energy demand through energy efficiency and demand response. Only after all cost-effective demand-side measures have been taken should the utilities consider adding conventional generation technologies.[95] PacifiCorp's 2011 IRP creates levelized cost curves for demand-side resources, as described above and in previous sections, and is a good example of this type of energy efficiency modeling effort. This type of modeling may be too costly to be feasible for some utilities, but it is important that consideration of various levels of DSM savings be given in integrated resource planning in order to give stakeholders confidence that all cost-effective DSM has been included in utility resource plans.

Supply options

A full range of supply alternatives should be considered in utility IRPs, with reasonable assumptions about the costs, performance, and availability of each resource. There can be uncertainties regarding the availability and costs of raw materials and skilled labor, construction schedules, and future regulations. Because these cost uncertainties can affect technologies in different ways, it is prudent to model a range of possible costs and construction lead times for supply alternatives. And because planning periods examined in IRPs are typically a decade or more, it is also prudent to evaluate supply technologies that are not currently feasible from a cost perspective, but may become so later in the planning period.

Fuel prices

Coal prices have been on the rise in recent years, and natural gas prices have historically been quite volatile. Fuel prices can shift as a result of demand growth, climate legislation, development of export infrastructure, and supply conditions.[96] It is thus extremely important to use reasonable, recent, and consistent projections of fuel prices in integrated resource planning.

Environmental costs and constraints

Utility IRPs should include a projection of environmental compliance costs—including recognition, and evaluation where possible—of all reasonably expected future regulations. At this time, the EPA has announced several upcoming environmental regulations. A final version of the Mercury and Air Toxics Standards (the "MATS" Rule) has been released, and rules are pending for Coal Combustion Residuals ("CCR"), cooling water intake structures under the Clean Water Act ("316(b)"), updates to the National Ambient Air Quality Standards ("NAAQS"), and new Effluent Limitation Guidelines.

Within the next three to five years, certain generating units may also become subject to new requirements under the Clean Air Act's Regional Haze Program, sometimes known as the BART rule because it requires installation of "best available retrofit technology." The Cross-State Air Pollution Rule, which would have required emissions reductions of SO_2 and NO_x in many states but was vacated by the US Court of Appeals for the DC Circuit in 2012, may return in a revised form at some point in the future.[97] Finally, greenhouse-gas emissions limits for electric generating units may come into effect in the next decade.[98]

These rules, both individually and in combination, have the potential to dramatically change the electric power industry. Utilities, in their IRP filings, need to acknowledge these rules and prepare for them as best they can through evaluations of emissions allowance costs, emission controls, and changes to resource portfolios. Few utilities now do this in a comprehensive manner. Of those discussed here, APS does the best job in its IRP by providing a discussion of each of the rules and its potential impacts on APS operations. The process could be improved through analysis of different compliance strategy scenarios.

Existing resources

Examination of existing resources in utility IRPs has become especially important as the mandated emission

95 See California Assembly Bills 1890 and 995. Similar loading order requirements exist in a few other states. See for example Connecticut Public Act No. 07-242, Section 51: An Act Concerning Electricity and Energy Efficiency.

96 *Reviving Integrated Resource Planning.* Page 6.

97 Colburn, K., et al. "Least-Risk Planning: The Homer City Decision Increases Uncertainty—but Rewards Forward Thinking." Public Utilities Fortnightly, November 2012.

98 EPA has proposed but not yet finalized greenhouse gas emission limits for newly constructed power plants. After those rules are finalized, EPA is required under the Clean Air Act to develop standards for existing power plants.

reductions associated with the MATS rule, discussed above, have led to utility decisions across the country to install pollution control retrofits, repower, or retire their coal units. PacifiCorp drew the ire of stakeholders and the Oregon PUC by not including this type of analysis for its coal-fired units in its 2011 IRP. All types of modifications to existing resources should be included in a utility's analysis of the optimum resource portfolio.

Integrated analysis

There are various reasonable ways to model plans, generally requiring the use of optimization or simulation models. Common models used throughout the industry include Strategist, EGEAS, System Optimizer, MIDAS, AURORA, PROMOD, and Market Analytics. These models are supplied to utilities by various third-party vendors.

It is important that the integrated model does not inadvertently exclude combinations of options that deserve consideration. This might occur in one of two ways. The first is in the instances that future resource portfolios are user-defined, rather than selected by an industry model. This is one of the criticisms of the Arizona Public Service IRP: the use of production cost modeling without an optimization component may have resulted in a less than optimal addition of supply- and demand-side resources over time.

The second way in which this may occur is if users constrain optimization models so that a model may not, given the cost, select the quantity of a specific resource that it may want. For example, a utility may constrain a model in such a way that it is only allowed to add 100 MW of wind generation over the resource planning period; but depending on the nature of the utility's electric system, the model may want to add additional wind resources. In this way, a combination of resources that deserves consideration may be excluded.

Time frame

The study period for IRP analysis should be sufficiently long to incorporate much of the operating lives of any new resource options that may be added to a utility's portfolio—typically at least 20 years—and should consider an "end effects" period to avoid a bias against adding generating units late in the planning period. Arizona rules require a 15-year planning period, Oregon a 20-year planning period, and Colorado a utility-specified planning period of between 20 and 40 years. Of the rules examined here, only Oregon explicitly states that an end effects period should be considered.

Uncertainty

At a minimum, important and uncertain input assumptions should be tested with high and low cases to assess the sensitivity of results to changes in input values. These assumptions include, but are not limited to, load forecasts, fuel prices, emissions allowance prices, environmental regulatory regimes, costs and availability of demand-side management measures, and capital and operating costs for new generating units.[99] The types of inputs listed are common to most utilities across the United States, but there are additional input assumptions that are regional or local in nature.

As discussed in the section on Oregon's IRP rules, its PUC requires utilities to model cases that vary the amount of hydroelectric output in the region. Utilities in states like Arizona, New Mexico, or Florida may want to examine

99 Decisions in the face of uncertainty come with degrees of risk. A recent study by CERES entitled, "Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know (How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection) concludes that it is "essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition." According to CERES, "risk arises when there is potential harm from an adverse event that can occur with some degree of probability." Risks for electric system resources have both time-related (i.e., the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers) and cost-related aspects (the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations). Practicing Risk-Aware Regulation (April 2012) at 20-21 http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation

cases that vary the amount of solar output when doing long-term planning. Utilities located in arid regions, or those owning a significant number of generation assets that are dependent on the availability of a water source for power plant cooling, may want to analyze scenarios where water is scarce or is at too high a temperature to be useful for cooling. Individual utilities must determine those input assumptions that are subject to variability, and model sensitivity cases accordingly to properly account for risks and uncertainties that they face.

Performing single-factor sensitivities may not, however, be very informative. Many cases may warrant more sophisticated techniques, such as probabilistic techniques or those that combine uncertainties. "Testing candidate resource solutions against scenarios that address the range of plausible future trajectories of external factors, and their interrelationships, can more effectively support planning in an uncertain environment."[100]

Valuing and selecting plans

There are often multiple stages of running scenarios and screening in developing an IRP, and there are various reasonable ways to approach this. Traditionally, the present value of revenue requirements is the primary metric that is analyzed, and minimized, in utility IRPs. This metric alone may not, however, sufficiently address uncertainties. It may be useful also to evaluate plans along other dimensions like environmental cost or impact, fuel diversity, impact on reliability, rate or bill increases, or minimization of risk.

It is essential that the IRP process be executed in a manner that applies the selected metrics in a reasonably transparent and logical manner, without inappropriately screening out resources options or plans that deserve consideration at the next stage. Note also that it is highly unlikely that a single resource portfolio will be the best choice on every metric evaluated. A resource portfolio that performs well across several metrics, but perhaps is not the top performer on any single metric, may in fact be the best choice for utility planners.

Action plan

Even though IRPs should have a longer study period, a good plan will include a specific discussion of the implications of the analysis for near-term decisions and actions, and will also include specific plans for getting those near-term items accomplished. Demand-side measures take time to implement, and supply-side resources require months or years of lead time to permit and construct. Utilities must thus provide a thorough discussion of the steps they plan to take to implement, acquire, or construct resources that will meet energy and peak demand needs in their service territories in the three- to five-year period after the plan is filed. The availability of these near-term resources has a direct effect on the resources needed throughout the remainder of the planning period; so it is prudent for the utility to detail the ways in which it will go about acquiring the resources described in its IRP.

Documentation

A proper IRP will include discussion of the inputs and results, and appendices with full technical details. Only items that are truly sensitive business information should be treated as confidential, because such treatment can hinder important stakeholder input processes.

100 Reviving Integrated Resource Planning. Page 4.

V. Conclusion

Utility integrated resource planning has been in effect in various parts of the United States for more than 25 years. While some utilities are regulated by the original IRP rules developed more than a decade ago, many states have updated their IRP rules to reflect current conditions and concerns in regional and national electricity markets. In states where this has occurred, IRPs filed by utilities tend to be more comprehensive and to exhibit more of the "best practices" in utility resource planning that have been described in this report.

Nonetheless, there are still many ways in which utilities can improve both their resource planning processes and the plans that are generated as a result of these processes. Engaged stakeholders and state public utilities commissions can provide oversight to this process, helping to promote resource choices that lead to positive outcomes for society as a whole.

Appendix: State IRP Statutes and Rules

Arizona

Arizona Corporation Commission Decision No. 71722, in Docket No. RE-00000A-09-0249. June 3, 2010.[101]

Arkansas

Arkansas PSC. "Resource Planning Guidelines for Electric Utilities." Approved in Docket 06-028-R. January 4, 2007.[102] Rules are currently under review and updates have been proposed.

Colorado

Colorado PUC. 4 CCR 723-3, Part 3: Rules Regulating Electric Utilities. Decision No. C10-1111. Docket No. 10R-214E. November 22, 2010.[103]

Delaware

HB 6, the Delaware Electric Utility Retail Customer Supply Act of 2006.[104]

Georgia

Integrated Resource Planning Act of 1991 (O.C.G.A. § 46-3A-1), Amended.[105]

Georgia Public Service Commission. General Rules. Integrated Resource Planning 515-3-4.[106]

Hawaii

Public Utilities Commission, State of Hawaii, A Framework for Integrated Resource Planning, March 9, 1992.[107]

Idaho

Idaho Public Utilities Commission Order No. 22299, in Case No. U-1500-165.[108]

Indiana

170 Indiana Administrative Code 4-7-1: Guidelines for Integrated Resource Planning by an Electric Utility. New draft rules have been proposed in docket IURC RM 11-07.[109]

Kentucky

KY Administrative Regulation 807 KAR 5:058. Integrated Resource Planning by Electric Utilities. Relates to KRS Chapter 278.[110]

Louisiana

Louisiana Public Service Commission Corrected General Order. Docket No. R-30021. Decided at the Commission's March 21, 2012 Business and Executive Session.[111]

Minnesota

MN Statute §216B.2422.[112]

MN Rules Part 7843.[113]

Missouri

Rules of Dept. of Economic Development. Division 240 - PSC. Chapter 22—Electric Utility Resource Planning (4 CSR 240.22).[115]

Montana

Montana's Integrated Least-Cost Resource Planning and Acquisition Act (§§ 69-3-1201-1206, Montana Code Annotated).[116]

Administrative Rules of Montana 38.5.2001-2016, adopted by the Montana PSC, for traditional utilities.[117]

Administrative Rules of Montana 38.5.8201-8227, adopted by the Montana PSC, for restructured utilities.[118]

Nebraska

Nebraska Revised Statute 66-1060.[119]

Nevada

NRS 704.741.[120]

New Hampshire

Title XXXIV Public Utilities, Chapter 378: Rates and Charges, Section 38: Least Cost Energy Planning.[121]

New Mexico

Integrated Resource Plans for Electric Utilities, Title 17, Chapter 7, Part 3.[122]

North Carolina

North Carolina Utilities Commission Rule R8-60: Integrated Resource Planning and Filings.[123]

North Dakota

North Dakota PSC Order issued on January 27, 1987 in Case No. 10,799. Amended on March 11, 1992 in Case No. PU-399-91-689.[124]

Oklahoma

Title 165: Oklahoma Corporation Commission. Chapter 25: Electric Utility Rules, Subchapter 37: Integrated Resource Planning.[125]

Oregon

Oregon PUC Order No. 07-002, Entered January 8, 2007.[126]

South Carolina

Code of Laws of South Carolina, Chapter 37, Section 58 37 40. Integrated resource plans.[127]

Public Service Commission of South Carolina Order No. 91-885 in Docket No. 87-223-E. October 21, 1991.[128]

South Dakota

SL 1977, Ch. 390, § 23. Chapter 49-41B-3.[129]

Administrative Rule Chapter 20:10:21, Energy Facility Plans.[130]

Utah

Report and Order on Standards and Guidelines. Docket No. 90-2035-01. Issued June 18, 1992.[131]

Vermont

30VSA Sec 218c - Statute establishing least-cost integrated resource planning.[132]

Public Service Board Order of 4/16/1990 initiating the IRP progress (Docket No. 5270).[133]

Public Service Board Order of 7/16/2002 (Docket No. 6290).[134]

Virginia

Code of Virginia § 56-597 - § 56-599.[135]

Washington

Washington Administrative Code 480-100-238: Integrated Resource Planning.[136]

Wyoming

Wyoming Public Service Commission Rule 253 (submitted July 22, 2009), and associated Guidelines for Staff Review.[137]

101 This Decision amends Arizona Administrative Code, Title 14, Chapter 2, Article 7: Resource Planning. It is available at: http://images.edocket.azcc.gov/docketpdf/0000112475.pdf

102 Arkansas guidelines available at: http://www.sosweb.state.ar.us/elections/elections_pdfs/register/june_07/126.03.07-003.pdf

103 Colorado PUC Decision available at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=10R-214E

104 Delaware legislation available at: http://legis.delaware.gov/LIS/lis143.nsf/vwLegislation/HB+6/$file/legis.html?open

105 Georgia annotated code available at: http://www.lexisnexis.com/hottopics/gacode/Default.asp

106 Georgia PSC rules available at: http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1

107 Hawaii PUC Framework available at: http://www.heco.com/vcmcontent/Integrated%20Resource/IRP/PDF/IRP_Framework_052292.pdf

108 Idaho PUC Order available at: http://www.puc.state.id.us/search/orders/dtsearch.html

109 Indiana Administrative Code available at: http://www.in.gov/legislative/iac/title170.html

110 Indiana docket RM#11-07 available at: http://www.in.gov/iurc/2689.htm

111 Kentucky Administrative Regulation available at: http://www.lrc.ky.gov/kar/807/005/058.htm

112 Louisiana PUC Order available at: Rules from Arizona, Colorado and Oregon are described in detail in order to demonstrate ways in which states require comprehensive planning processes and resource plan outcomes from the utilities under their jurisdictions.

113 Minnesota Statute available at: https://www.revisor.mn.gov/statutes/?id=216B.2422

114 Minnesota rules available at: https://www.revisor.mn.gov/rules/?id=7843

115 Missouri rules available at: http://www.sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf, Final Order of Rulemaking was issued on March 3, 2011, as part of the Missouri Public Service Commission Rulemaking Case No. EX-2010-0254. That amendment is available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EX-2010-0254&attach_id=2011015905

116 Montana Annotated Code available at: http://data.opi.mt.gov/bills/mca_toc/69_3_12.htm

117 Montana Administrative Rules available at: http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5

118 Montana Administrative Rules available at: http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5

119 Nebraska Statute available at: http://nebraskalegislature.gov/laws/statutes.php?statute=66-1060

120 Nevada Statute available at: http://www.leg.state.nv.us/nrs/NRS-704.html#NRS704Sec741

121 New Hampshire Statute available at: http://www.gencourt.state.nh.us/rsa/html/NHTOC/NHTOC-XXXIV-378.htm

122 New Mexico PRC Rule available at: http://www.pnm.com/regulatory/pdf_electricity/irp_electricity.pdf

123 North Carolina PUC Rule available at: http://ncrules.state.nc.us/ncac/title%2004%20-%20commerce/chapter%2011%20-%20utilities%20commission/04%20ncac%2011%20r08-60.pdf

124 North Dakota PSC Order available at: http://www.raponline.org/docs/RAP_NDElectricResourceLongRangePlanningSurvey2005_09_17.pdf

125 Oklahoma Rule available at: http://www.occeweb.com/rules/2010Ch35ElectricpermanentMasterRuleseff7-11-10searchable.pdf

126 Oregon PUC Order available at: http://apps.puc.state.or.us/orders/2007ords/07-002.pdf

127 South Carolina Code available at: www.scstatehouse.gov/code/t58c037.docx

128 South Carolina PSC Order available at: http://dms.psc.sc.gov/pdf/orders/DF4FC4A9-EB41-2CB4-D44614AD02D02B8D.pdf

129 South Dakota Statute available at: http://legis.state.sd.us/statutes/DisplayStatute.aspx?Statute=49-41B-3&Type=Statute

130 South Dakota Rule available at: http://legis.state.sd.us/rules/DisplayRule.aspx?Rule=20:10:21

131 Utah Order available at: http://www.airquality.utah.gov/Public-Interest/Current-Issues/Regionalhazesip/RegionalHazeTSDdocs/Utah_PSC_Integrated_Planning_Rules.pdf

132 Vermont Statute available at: http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00218c

133 Public Service Board Orders issued prior to 1996 are not available online.

134 Vermont PSB Order available at: http://www.state.vt.us/psb/orders/2002/files/6290phaseIIextensionorder.pdf

135 Virginia Statute - content begins at: http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+56-597

136 Washington Administrative Code available at: http://apps.leg.wa.gov/wac/default.aspx?cite=480-100-238

137 Wyoming PSC Rule available at: http://legisweb.state.wy.us/ARULES/2009/AR09-043.htm; Guidelines for Staff Review available at: http://psc.state.wy.us/htdocs/electric/ElectricIRPGuidelines7-10.pdf



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50 State Street, Suite 3
Montpelier, Vermont 05602
802-223-8199
www.raponline.org

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PRACTICING RISK-AWARE ELECTRICITY REGULATION: What Every State Regulator Needs to Know

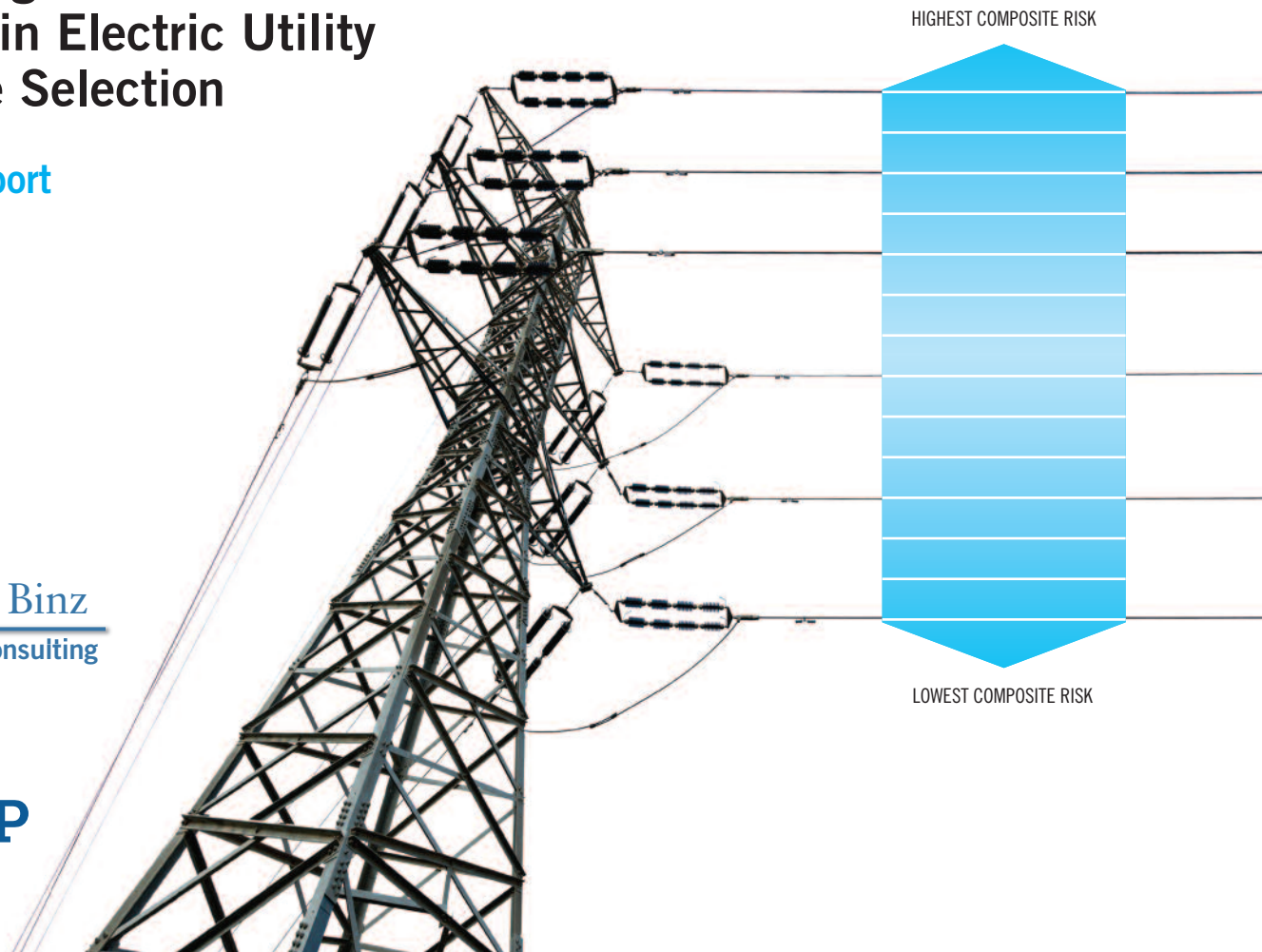
How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection

A Ceres Report
April 2012

Authored by
Ron Binz
and
Richard Sedano
Denise Furey
Dan Mullen

Ronald J. Binz
Public Policy Consulting

RAP



FOR MORE INFORMATION, CONTACT:

Dan Mullen
Senior Manager, Electric Power Programs
Ceres
99 Chauncy St., 6th fl.
Boston, MA 02111
617-247-0700, x126
mullen@ceres.org
www.ceres.org

Ceres is an advocate for sustainability leadership. It leads a national coalition of investors, environmental groups and other public interest organizations working with companies to address sustainability challenges. Ceres also directs the Investor Network on Climate Risk (INCR), a network of 100 institutional investors with collective assets totaling about $10 trillion.

ACKNOWLEDGEMENTS

This report was made possible through support from the Merck Family Fund, the Betsy and Jesse Fink Foundation, the Bank of America Foundation, and an anonymous donor. The opinions expressed in this report are those of the authors and do not necessarily reflect the views of the sponsors.

REPORT AUTHORS:

Ronald J. Binz
Public Policy Consulting
333 Eudora Street
Denver, CO 80220
720-425-3335
rbinz@rbinz.com
www.rbinz.com

Richard Sedano
Regulatory Assistance Project
50 State Street, Suite 3
Montpelier, VT 05602
802-223-8199
rsedano@raponline.org
www.raponline.org

Denise M. Furey
Regent Square Advisors
4256 Regent Square
Philadelphia, PA 19104
215-266-4121
denise.furey@wolfe.org

Dan Mullen
Ceres
99 Chauncy St., 6th fl.
Boston, MA 02111
617-247-0700, x126
mullen@ceres.org
www.ceres.org

Ceres and the authors would like to extend their deep appreciation to the experts who generously agreed to review a draft of this report:

Richard Cortright, Managing Director, Standard & Poor's

Jim Hempstead, Senior Vice President, Moody's Investors Service

Janine Migden-Ostrander, Principal, Regulatory Assistance Project

Sonny Popowsky, Consumer Advocate of Pennsylvania

Cheryl Roberto, Commissioner, Public Utilities Commission of Ohio

Sue Tierney, Managing Principal, Analysis Group

Dan Mullen and Rich Sedano would like to thank **Pamela Morgan** of Graceful Systems LLC for her contribution to early drafts of this report.

Graphic Design by Patricia Robinson Design.

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Ceres
99 Chauncy Street
Boston, MA 02111
www.ceres.org

ABOUT THIS REPORT

AUDIENCE

This report is primarily addressed to **state regulatory utility commissioners**, who will preside over some of the most important investments in the history of the U.S. electric power sector during perhaps its most challenging and tumultuous period. This report seeks to provide regulators with a thorough discussion of risk, and to suggest an approach—"risk-aware regulation"—whereby regulators can explicitly and proactively seek to identify, understand and minimize the risks associated with electric utility resource investment. It is hoped that this approach will result in the efficient deployment of capital, the continued financial health of utilities, and the confidence and satisfaction of the customers on whose behalf utilities invest.

Additionally, this report seeks to present a unique discussion of risk and a perspective on appropriate regulatory approaches for addressing it that will interest numerous **secondary audiences**, including **utility managements, financial analysts, investors, electricity consumers, advocates, state legislatures and energy offices, and other stakeholders** with a particular interest in ensuring that electric system resource investments—which could soon reach unprecedented levels—are made thoughtfully, transparently and in full consideration of all associated risks.

SCOPE

While we believe that the approach described herein is applicable to a broad range of decisions facing state regulators, the report focuses primarily on resource investment decisions by investor-owned electric utilities (IOUs), which constitute roughly 70 percent of the U.S. electric power industry. The findings and recommendations may be of particular interest to regulators in states facing substantial coal generating capacity retirements and evaluating a spectrum of resource investment options.

AUTHORS

Ron Binz, the lead author of this report, is a 30-year veteran of utility and energy policy and principal with Public Policy Consulting. Most recently, he served for four years as the Chairman of the Colorado Public Utilities Commission where he implemented the many policy changes championed by the Governor and the Legislature to bring forward Colorado's "New Energy Economy." He is the author of several reports and articles on renewable energy and climate policy has testified as an expert witness in fifteen states.

Richard Sedano is a principal with the Regulatory Assistance Project (RAP), a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors, providing technical and policy assistance to policymakers and regulators on a broad range of energy and environmental issues. RAP is widely viewed as a source of innovative and creative thinking that yields practical solutions. RAP members meet directly with government officials, regulators and their staffs; lead technical workshops and training sessions; conduct in-house research and produce a growing volume of publications designed to better align energy regulation with economic and environmental goals.

Denise Furey has over 25 years of experience with financial institutions, structuring and analyzing transactions for energy and utility companies. In 2011 she founded Regent Square Advisors, a consulting firm specializing in financial and regulatory concerns faced by the sector. She worked with Citigroup covering power and oil & gas companies, and worked with Fitch Rating, Enron Corporation and MBIA Insurance Corporation. Ms. Furey also served with the Securities and Exchange Commission participating in the regulation of investment companies.

Dan Mullen, Senior Manager for Ceres' Electric Power Programs, works to identify and advance solutions that will transform the U.S. electric utility industry in line with the urgent goal of sustainably meeting society's 21st century energy needs. In addition to developing Ceres' intellectual capital and external partnerships, he has engaged with major U.S. electric utilities on issues related to climate change, clean energy and stakeholder engagement, with a particular focus on energy efficiency. A Stanford University graduate, Dan has also raised more than $5 million to support Ceres' climate change initiatives and organizational development.

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FOREWORD

Today's electric industry faces a stunning investment cycle. Across the country, the infrastructure is aging, with very old parts of the power plant fleet and electric and gas delivery systems needing to be replaced. The regulatory environment is shifting dramatically as rules tighten on air pollution from fossil-burning power plants. Fossil fuel price outlooks have shifted. New options for energy efficiency, renewable energy, distributed generation, and smart grid and consumer technologies are pressing everyone to think differently about energy and the companies that provide it. Customers expect reliable electricity and count on good decisions of others to provide it.

The critical nature of this moment and the choices ahead are the subject of this report. It speaks to key decision-makers, such as: state regulators who have a critical role in determining utility capital investment decisions; utility executives managing their businesses in this era of uncertainty; investors who provide the key capital for utilities; and others involved in regulatory proceedings and with a stake in their outcomes.

The report lays out a suite of game-changing recommendations for handling the tremendous investment challenge facing the industry. As much as $100 billion will be invested each year for the next 20 years, roughly double recent levels. A large portion of those investments will be made by non-utility companies operating in competitive markets. But another large share will be made by utilities—with their (and their key investors') decisions being greatly affected by state regulatory policies and practices.

This is no time for backward-looking decision making. It is vital—for electricity consumers and utilities' own economic viability—that their investment decisions reflect the needs of tomorrow's cleaner and smarter 21st century infrastructure and avoid investing in yesterday's technologies. The authors provide useful advice to state regulators on how they can play a more proactive role in helping frame how electric utilities face these investment challenges.

A key report conclusion in this regard: sensible, safe investment strategies, based on the report's detailed cost and risk analysis of a wide range of generation resources, should include:

- Diversifying energy resource portfolios rather than "betting the farm" on a narrow set of options (e.g., fossil fuel generation technologies and nuclear);
- More emphasis on renewable energy resources such as onshore wind and distributed and utility-scale solar;
- More emphasis on energy efficiency, which the report shows is utilities' lowest-cost, lowest-risk resource.

At its heart, this report is a call for "risk-aware regulation." With an estimated $2 trillion of utility capital investment in long-lived infrastructure on the line over the next 20 years, regulators must focus unprecedented attention to risk—not simply keeping costs down today, but minimizing overall costs over the long term, especially in the face of possible surprises. And utilities' use of robust planning tools needs to be sharpened to incorporate risk identification, analysis, and management.

This report offers some good news amid pervasive uncertainty: the authors point out that planning the lowest-cost, lowest risk investment route aligns with a low-carbon future. From a risk management standpoint, diversifying utility portfolios today by expanding investment in clean energy and energy efficiency makes sense regardless of how and when carbon controls come into play. Placing too many bets on the conventional basket of generation technologies is the highest-risk route, in the authors' analysis.

We're in a new world now, with many opportunities as well as risks. More than ever, the true risks and costs of utility investments should be made explicit and carefully considered as decisions on multi-billion-dollar commitments are made.

As the industry evolves, so too must its regulatory frameworks. The authors point out why and offer guidance about how. This is news regulators and the industry can use.

Susan F. Tierney
Managing Principal
Analysis Group



EXECUTIVE SUMMARY

CONTEXT: INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY AND RISK

The U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence, now faces tremendous challenges. Navigant Consulting recently observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[1] These challenges include:

- an aging generation fleet and distribution system, and a need to expand transmission;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[2]
- disruptive changes in the economics of coal and natural gas;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- substantially weakened industry financial metrics and credit ratings, with over three-quarters of companies in the sector rated three notches or less above "junk bond" status.[3]



Many of these same factors are driving historic levels of utility investment. It is estimated that the U.S. electricity industry could invest as much as $100 billion each year for 20 years[4]—roughly twice recent investment levels. This level of investment will double the net invested capital in the U.S. electricity system by 2030. Moreover, these infrastructure investments are long lived: generation, transmission and distribution assets can have expected useful lives of 30 or 40 years or longer. This means that many of these assets will likely still be operating in 2050, when electric power producers may be required to reduce greenhouse gas emissions by 80 percent or more to avoid potentially catastrophic impacts from climate change.

1 Forrest Small and Lisa Frantzis, *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*, Navigant Consulting (Boston, MA: Ceres, 2010), 28, http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1.

2 Estimates of U.S. coal-fired generating capacity that could be retired in the 2015-2020 timeframe as a result of forthcoming U.S. Environmental Protection Agency (EPA) air quality regulations range from 10 to 70 gigawatts, or between three and 22 percent of U.S. coal-fired generation capacity. Forthcoming EPA water quality regulations could require the installation of costly cooling towers on more than 400 power plants that provide more than a quarter of all U.S. electricity generation. See Susan Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," *World Resources Institute*, January 18, 2011, http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

3 Companies in the sector include investor-owned utilities (IOUs), utility holding companies and non-regulated affiliates.

4 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008), vi, http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. From 2000-05, overall annual capital expenditures by U.S. IOUs averaged roughly $48 billion; from 2006-10 that number climbed to $74 billion; see Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry* (Washington DC: Edison Electric Institute, 2011), 18, http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FR2010_FullReport_web.pdf.

Greatly increased utility investment combined with minimal, zero or even declining electricity demand growth means that retail electricity prices for consumers will rise sharply, claiming a greater share of household disposable income and likely leading to ratepayer resistance.[5] Because the U.S. economy was built on relatively cheap electricity—the only thing many U.S. consumers and businesses have ever known—credit rating agencies are concerned about what this dynamic could mean for utilities in the long term. Rating analysts also point out that the overall credit profile for investor-owned utilities (IOUs) could decline even further since utilities' operating cash flows won't be sufficient to satisfy their ongoing investment needs.[6]

It falls to state electricity regulators to ensure that the large amount of capital invested by utilities over the next two decades is deployed wisely. Poor decisions could harm the U.S. economy and its global competitiveness; cost ratepayers, investors and taxpayers hundreds of billions of dollars; and have costly impacts on the environment and public health.

To navigate these difficult times, it is essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition.

CHALLENGES TO EFFECTIVE REGULATION

To be effective in the 21st century, regulators will need to be especially attentive to two areas: identifying and addressing risk; and overcoming regulatory biases.

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Put another way, risk is "the expected value of a potential loss." *Higher risk* for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Risks for electric system resources have both time-related and cost-related aspects. *Cost risks* reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. *Time risks* reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. **Figure ES-1** summarizes the many varieties of risk for utility resource investment.

Risk is the expected value of a potential loss. Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Figure ES-1

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT

Cost-related	*Time-related*
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

5 Moody's Investors Service, *Special Comment: The 21st Century Electric Utility* (New York: Moody's Investors Service, 2010). Importantly, customers who currently enjoy the lowest electricity rates can expect the largest rate increases, in relative terms, as providers of cheap, coal-generated electricity install costly pollution controls or replace old coal-fired units with more expensive new resources. This dynamic could prove especially challenging for regulators, utilities and consumers in the heavily coal-dependent Midwest.

6 Richard Cortright, "Testimony before the Pennsylvania Public Utility Commission," Harrisburg, Pennsylvania, November 19, 2009, http://www.puc.state.pa.us/general/RegulatoryInfo/pdf/ARRA_Testimony-SPRS.pdf.

RISK

Three observations about risk should be stressed:

1. **Risk cannot be eliminated, but it can be managed and minimized.** Since risks are defined as probabilities, it is by definition probable that some risks will be realized—that, sooner or later, risk will translate into dollars for consumers, investors or both. This report concludes with recommendations for how regulators can minimize risk by practicing "risk-aware regulation."
2. **It is unlikely that consumers will bear the full cost of poor utility resource investment decisions.** The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to burden ratepayers with the full cost of utility mistakes. As a result, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investment decisions than in years past.
3. **Ignoring risk is not a viable strategy.** Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

Traditional utility regulation also contains several built-in biases that effective regulators must overcome.[7] These biases, which result in part from the incentives that traditional regulation provides to utilities, encourage utilities to invest more than is optimal for their customers—which is to say, more than is optimal for the provision of safe, reliable, affordable and environmentally sustainable electricity—and discourage them from investing in the lowest-cost, lowest-risk resources (namely, demand-side resources such as energy efficiency) that provide substantial benefits to ratepayers and local economies. Bias can also lead utilities to seek to exploit regulatory and legislative processes as a means of increasing profits (rather than, for example, improving their own operational efficiencies). Finally, regulators face an inherent information deficit when dealing with utility managements. This can hamper effective collaboration around utility planning, which is arguably the most important function of electricity regulation today.

COSTS AND RISKS OF NEW GENERATION RESOURCES

We closely examine costs and risks of new generation resources for several reasons. First, as the largest share of utility spending in the current build cycle, generation investment is where the largest amount of consumer and investor dollars is at risk. Also, today's decisions about generation investment can trigger substantial future investments in transmission and distribution infrastructure. Proposed power plants can be a lightning rod for controversy, heightening public scrutiny of regulatory and corporate decision-makers. Finally, poor investment decisions about generation resources in IOUs' last major build cycle resulted in tens of billions of dollars of losses for consumers and shareholders.[8] For these and other reasons, it is especially important that regulators address, manage and minimize the risks associated with utility investments in new generation resources.[9]



Ignoring risk is not a viable strategy. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate.

Acquiring new electric system resources involves dimensions of both cost and risk. Of these two dimensions, the tools for estimating the cost elements of new generation, while imperfect, are more fully developed than the risk-related tools. As a starting point for our examination of the relative cost and risk of new generation resources, we rank a wide range of supply-side resources and one demand-side resource (energy efficiency) according to their levelized cost of electricity, or "LCOE" **(Figure ES-2, p. 8)**.[10] This ranking is based on 2010 data and does not include recent cost increases for nuclear or cost decreases for solar PV and wind. Because carbon controls could add significant costs to certain technologies but the exact timing and extent of these costs is unknown, we include a moderate estimate for carbon cost for fossil-fueled resources. And because incentives such as tax credits and loan guarantees can significantly affect LCOE, we examine the LCOE range for each technology with and without incentives where applicable.

7 These biases, which are discussed further in the report, are *information asymmetry; the Averch-Johnson effect; the throughput incentive; "rent-seeking";* and *the "bigger-is-better" bias.*

8 Frank Huntowski, Neil Fisher, and Aaron Patterson, *Embrace Electric Competition or It's Déjà Vu All Over Again* (Concord, MA: The NorthBridge Group, 2008), 18, http://www.nbgroup.com/publications/Embrace_Electric_Competition_Or_Its_Deja_Vu_All_Over_Again.pdf. The NorthBridge Group estimates that ratepayers, taxpayers and investors were saddled with $200 billion (in 2007 dollars) in "above-market" costs associated with the build cycle of the 1970s and 80s. Between 1981-91, shareholders lost roughly $19 billion as a result of regulatory disallowances of power plant investments by some regulated utilities; see Thomas P. Lyon and John W. Mayo, "Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry," *Rand Journal of Economics*, Vol. 36, No. 3 (Autumn 2005): 628–44, http://webuser.bus.umich.edu/tplyon/PDF/Published%20Papers/Lyon%20Mayo%20RAND%202005.pdf. The potential for negative consequences is probably higher today; since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially.

9 While our analysis of risks and costs of new generation resources may be of most interest to regulators in "vertically-integrated" states (where utilities own or control their own generation), it also has implications for regulators in restructured states. Regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as this report makes clear, are utilities' lowest-cost and lowest-risk resources.

10 LCOE indicates the cost per megawatt-hour for electricity over the life of the plant, encompassing all expected costs (e.g., capital, operations and maintenance, and fuel). We primarily reference LCOE data compiled by the Union of Concerned Scientists (UCS), which aggregates three common sources of largely consensus LCOE data: the U.S. Energy Information Administration (EIA), the California Energy Commission (CEC) and the investment firm Lazard; see Barbara Freese et al., *A Risky Proposition* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf. LCOE costs for technologies not included in UCS's analysis (viz., biomass co-firing, combined cycle natural gas generation with CCS, and distributed solar) were estimated by the authors based on comparable resources referenced by UCS.

Figure ES-2

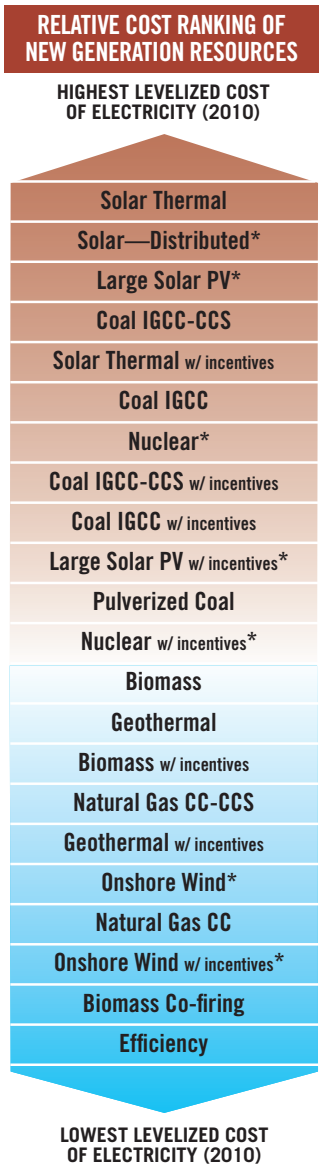
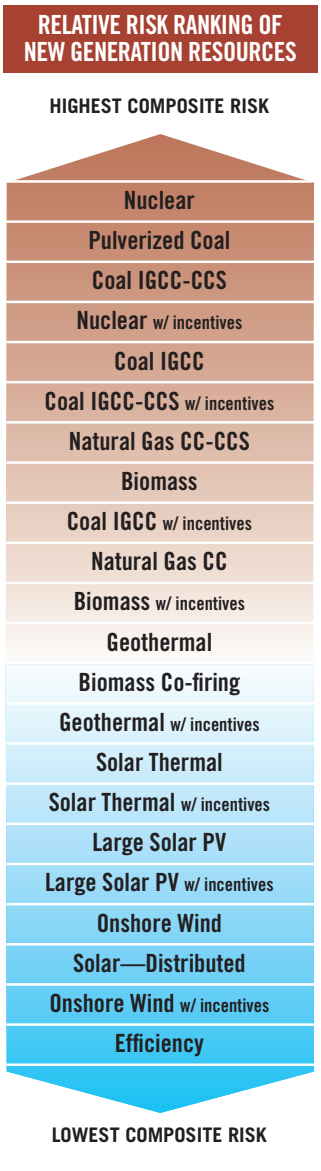


Figure ES-3



** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

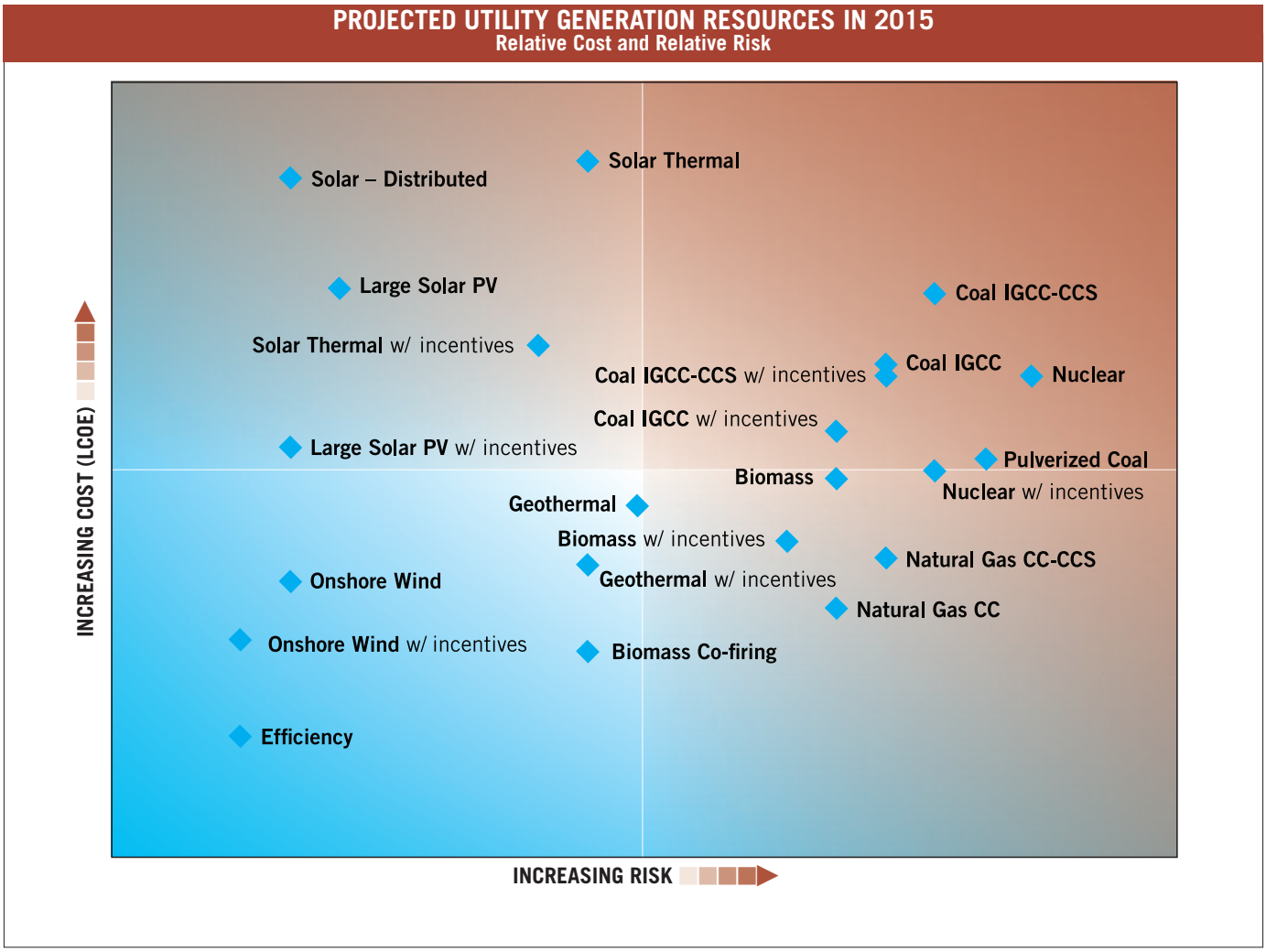
But the LCOE ranking tells only part of the story. The *price* for any resource in this list does not take into account the relative *risk* of acquiring it. To establish relative risk of new generation resources, we return to the many risks identified in Figure ES-1 and compress those risks into seven main categories:

- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

We then evaluate each resource profiled in the LCOE ranking and apply our informed judgment to quantify each resource's relative exposure to each type of risk.[11] This allows us to establish a composite risk score for each resource (with the highest score indicating the highest risk) and rank them according to their relative composite risk profile **(Figure ES-3)**.

11 Risk exposure in each risk category ranges from "None" to "Very High." We assigned scores (None = 0, Very High = 4) to each risk category for each resource and then summed them to establish an indicative quantitative ranking of composite risk. We also tested the robustness of the risk ranking by calculating two additional rankings of the risk scores: one that overweighted the cost-related risk categories and one that overweighted the environmental-related risk categories.

Figure ES-4



The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear division between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

With largely consensus quantitative LCOE data, and having developed indicative composite risk scores for each resource, we can summarize relative risks and costs of utility generation resources in a single graph **(Figure ES-4)**.[12]

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states.

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states. The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

12 Resources are assumed to come online in 2015.

PRACTICING RISK-AWARE REGULATION: SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

MANAGING RISK INTELLIGENTLY IS ARGUABLY THE MAIN DUTY OF REGULATORS WHO OVERSEE UTILITY INVESTMENT. EFFECTIVELY MANAGING RISK IS NOT SIMPLY ACHIEVING THE LEAST COST *TODAY*, BUT RATHER IS PART OF A STRATEGY TO *MINIMIZE OVERALL COSTS OVER THE LONG TERM*. WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS SHOULD EMPLOY TO MANAGE AND MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources and energy efficiency. Diversification—investing in different asset classes with different risk profiles—is what allows investors to reduce risk (or "volatility") in their investment portfolios. Similarly, diversifying a utility portfolio by including various supply and demand-side resources that behave independently from each other in different future scenarios reduces the portfolio's overall risk.

2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment. In many vertically integrated markets and in some organized markets, regulators use "integrated resource planning" (IRP) to oversee utilities' capital investments. IRP is an important tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of utility resource options; that the options are examined in a structured, disciplined way; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood by all.

3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk. For example, allowing a current return on construction work in progress (CWIP) to enable utilities to finance large projects doesn't actually reduce risk but rather transfers it from the utility to consumers.[13] While analysts and some regulators favor this approach, its use can obscure a project's risk and create a "moral hazard" for utilities to undertake more risky investments. Utility investment in the lowest-cost and lowest-risk resource, energy efficiency, requires regulatory adjustments that may include decoupling utility revenues from sales and performance-based financial incentives.

4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts. These allow utilities to lock in a price (e.g., for fuel), thereby avoiding the risk of higher market prices later. But these options must be used carefully since using them can foreclose an opportunity to enjoy lower market prices.

5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments. This helps to create a consistent, stable regulatory environment, which is highly valued in the marketplace and ensures that agreed-upon resource plans become reality.

6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk. In "judicial mode," a regulator takes in evidence in formal settings and resolves disputes; in contrast, a regulator operating in "legislative mode" proactively seeks to gather all relevant information and to find solutions to future challenges.

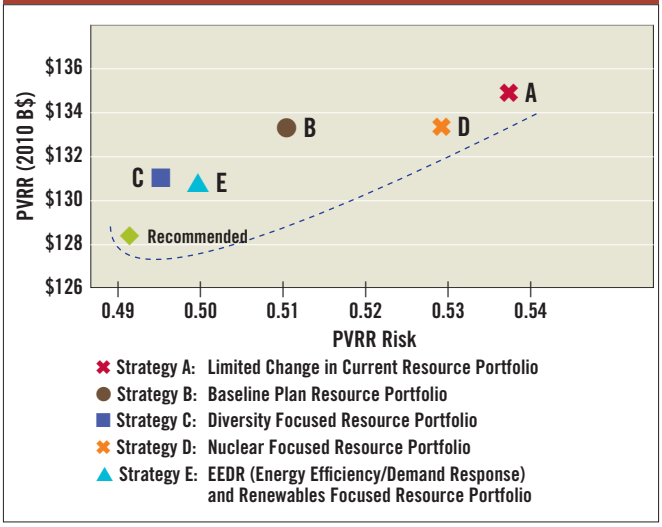
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate. Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades, which led regulators to modernize their tools and experiment with various types of incentive regulation. One area where electricity regulators might profitably question existing practices is rate design; existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

13 For example, the use of CWIP financing in Florida could result in Progress Energy customers paying the utility more than $1 billion for a new nuclear plant (the Levy County Nuclear Power Plant) that may never be built. Florida state law prohibits ratepayers from recouping their investment in Levy or other CWIP-financed projects.

Careful planning is the regulator's primary risk management tool. A recently completed IRP by the Tennessee Valley Authority (TVA) illustrates how robust planning enables risk-aware resource choices and avoids higher-cost, higher-risk supply portfolios. TVA considered five resource strategies and subjected each to extensive scenario analysis. **Figure ES-5** shows how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[14] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio[15] or emphasized new nuclear plant construction. The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy. The TVA analysis is careful and deliberate; analyses by other utilities that reach significantly different thematic conclusions must be scrutinized carefully to examine whether the costs and risks of all resources have been properly evaluated.

Figure ES-5

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK



Updating traditional practices will require effort and commitment from regulators and regulatory staff. Is it worth it? This report identifies numerous benefits from practicing "risk-aware regulation":

- **Consumer benefits** from improved regulatory decision-making and risk management, leading to greater utility investment in lower-cost, lower-risk resources;
- **Utility benefits** in the form of a more stable, predictable business environment that enhances long-term planning capabilities;
- **Investor benefits** resulting from lowered threats to utility cost recovery, which simultaneously preserves utility credit quality and capital markets access and keeps financing costs low, benefitting all stakeholders;
- **Systemic regulatory benefits** resulting from expanded transparency, inclusion and sophistication in the regulatory process, thereby strengthening stakeholder relationships, building trust and improving policy maker understanding of energy options—all of which enhances regulators' ability to do their jobs;
- **Broad societal benefits** flowing from a cleaner, smarter, more resilient electricity system.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

Effectively managing risk is not simply achieving the least cost today, but rather is part of a strategy to minimize overall costs over the long term.

14 Tennessee Valley Authority (TVA), *TVA's Environmental and Energy Future* (Knoxville, TN: Tennessee Valley Authority, 2011), 161, http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf.

15 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent) (TVA, 73).

CONCLUSIONS & RECOMMENDATIONS

- **The U.S. electric utility industry has entered what may be the most uncertain, complex and risky period in its history.** Several forces will conspire to make the next two decades especially challenging for electric utilities: large investment requirements, stricter environmental controls, decarbonization, changing energy economics, rapidly evolving technologies and reduced load growth. Succeeding with this investment challenge—building a smarter, cleaner, more resilient electric system for the 21st century at the lowest overall risk and cost—will require commitment, collaboration, shared understanding, transparency and accountability among regulators, policy makers, utilities and a wide range of stakeholders.
- **These challenges call for new utility business models and new regulatory paradigms.** Both regulators and utilities need to evolve beyond historical practice. Today's electricity industry presents challenges that traditional electricity regulation did not anticipate and cannot fully address. Similarly, the constraints and opportunities for electric utilities going forward are very different than they were a century ago, when the traditional (and still predominant) utility business model emerged.

  Regulators must recognize the incentives and biases that attend traditional regulation, and should review and reform their approaches to resource planning, ratemaking and utility cost recovery accordingly. Utilities must endorse regulatory efforts to minimize investment risks on behalf of consumers and utility shareholders. This means promoting an inclusive and transparent planning process, diversifying resource portfolios, supporting forward-looking regulatory policies, continually reevaluating their strategies and shaking off "we've always done it that way" thinking.
- **Avoiding expensive utility investment mistakes will require improved approaches to risk management in the regulatory process.** One of the most important duties of a 21st century electricity regulator is to understand, examine and manage the risk inherent in utility resource selection. Existing regulatory tools often lack the sophistication to do this effectively.

  Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both. Our analysis across seven major risk categories reveals that, almost without exception, the riskiest resources—the ones that could cause the most financial harm—are large base load fossil and nuclear plants. It is therefore especially important that regulators and utilities explicitly address and manage risk when considering the development of these resources.

  Regulators practicing "risk-aware regulation" must exhaust lower-risk investment options like energy efficiency before allowing utilities to commit huge sums to higher-risk projects. Regulators should immediately notify regulated utilities of their intention to address risks more directly, and then begin explicitly to include risk assessment in all decisions about utility resource acquisition.
- **More than ever, ratepayer funding is a precious resource.** Large investment requirements coupled with flat or decreasing load growth will mean higher utility rates for consumers. Increased consumer and political resistance to rising electricity bills, and especially to paying for expensive mistakes, leaves much less room for error in resource investment decisions and could pose a threat to utility earnings.



- **Risk shifting is not risk minimization.** Some regulatory practices that are commonly perceived to reduce risk (e.g., construction work in progress financing, or "CWIP") merely transfer risk from the utility to consumers. This risk shifting can inhibit the deployment of attractive lower-cost, lower-risk resources. Regulatory practices that shift risk must be closely scrutinized to see if they actually increase risk—for consumers in the short term, and for utilities and shareholders in the longer term.
- **Investors are more vulnerable than in the past.** During the 1980s, power plant construction cost overruns and findings of utility mismanagement led regulators to disallow more than six percent of utilities' overall capital investment, costing shareholders roughly $19 billion. There will be even less tolerance for errors in the upcoming build cycle and more pressure on regulators to protect consumers. Investors should closely monitor utilities' large capex decisions and consider how the regulatory practice addresses the risk of these investments. Investors should also observe how the business models and resource portfolios of specific utilities are changing, and consider engaging with utility managements on their business strategies going forward.
- **Cost recovery mechanisms currently viewed positively by the investment community including the rating agencies could pose longer-term threats to utilities and investors.** Mechanisms like CWIP provide utilities with the assurance of cost recovery before the outlay is made. This could incentivize utilities to take on higher-risk projects, possibly threatening ultimate cost recovery and deteriorating the utility's regulatory and business environment in the long run.
- **Some successful strategies for managing risk are already evident.** Regulators and utilities should pursue diversification of utility portfolios, adding energy efficiency, demand response, and renewable energy resources to the portfolio mix. Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios. In the other direction, failing to diversify resources, "betting the farm" on a narrow set of large resources, and ignoring potentially disruptive future scenarios is asking for trouble.

Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios.

- **Regulators have important tools at their disposal.** Careful planning is the regulator's primary tool for risk mitigation. This is true for regulators in both vertically-integrated and restructured electricity markets. Effective resource planning considers a wide variety of resources, examines possible future scenarios and considers the risk of various portfolios. Regulators should employ transparent ratemaking practices that reveal and do not obscure the level of risk inherent in a resource choice; they should selectively apply financial and physical hedges, including long-term contracts. Importantly, they must hold utilities accountable for their obligations and commitments.

1. CONTEXT:

INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY & RISK

U.S. ELECTRIC UTILITIES ARE FACING A SET OF CHALLENGES UNPARALLELED IN THE INDUSTRY'S HISTORY, PROVIDING MANY REASONS TO CONCLUDE THAT THE TRADITIONAL PRACTICES OF UTILITIES AND THEIR REGULATORS MUST BE UPDATED TO ADD A SHARPER FOCUS ON RISK MANAGEMENT IN THE REGULATORY PROCESS.

Consider the forces acting on the electricity sector in 2012:

- an aging generation fleet;
- infrastructure upgrades to the distribution system;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[16]
- disruptive changes in the economics of coal and natural gas;
- new transmission investments;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- tight credit in a difficult economy and substantially weakened industry financial metrics and credit ratings.

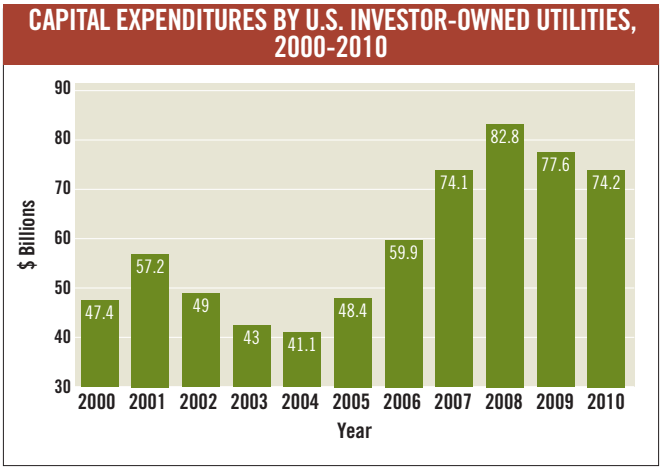
In a recent book, Peter Fox-Penner, principal and chairman emeritus of the Brattle Group, concluded that the sum of these forces is leading to a "second revolution" in the electric power industry.[17] Navigant Consulting has observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[18]

THE INVESTMENT CHALLENGE

The United States electric utility industry is a network of approximately 3,300 investor-owned utilities (IOUs), cooperative associations and government entities. In addition, about 1,100 independent power producers sell power to utilities, either under contract or through auction markets. The net asset value of the plant in service for all U.S. electric utilities in 2010 was about $1.1 trillion, broken down as $765 billion for IOUs, about $200 billion for municipal (publicly-owned) utilities (or "munis"), and $112 billion for rural electric cooperatives (or "co-ops").[19]

IOUs therefore constitute the largest segment of the U.S. electric power industry, serving roughly 70 percent of the U.S. population. **Figure 1** illustrates IOUs' capital expenditures from 2000-2010 and captures the start of the current "build cycle," beginning in 2006.[20] Between 2006 and 2010, capital spending by IOUs—for generation, transmission and distribution systems—was about 10 percent of the firms' net plant in service.

Figure 1



16 See footnote 2.

17 Peter Fox-Penner, *Smart Power* (Washington DC: Island Press, 2010). The "first revolution" was triggered by George Westinghouse, Thomas Edison, Nicola Tesla, Samuel Insull and others more than a century ago.

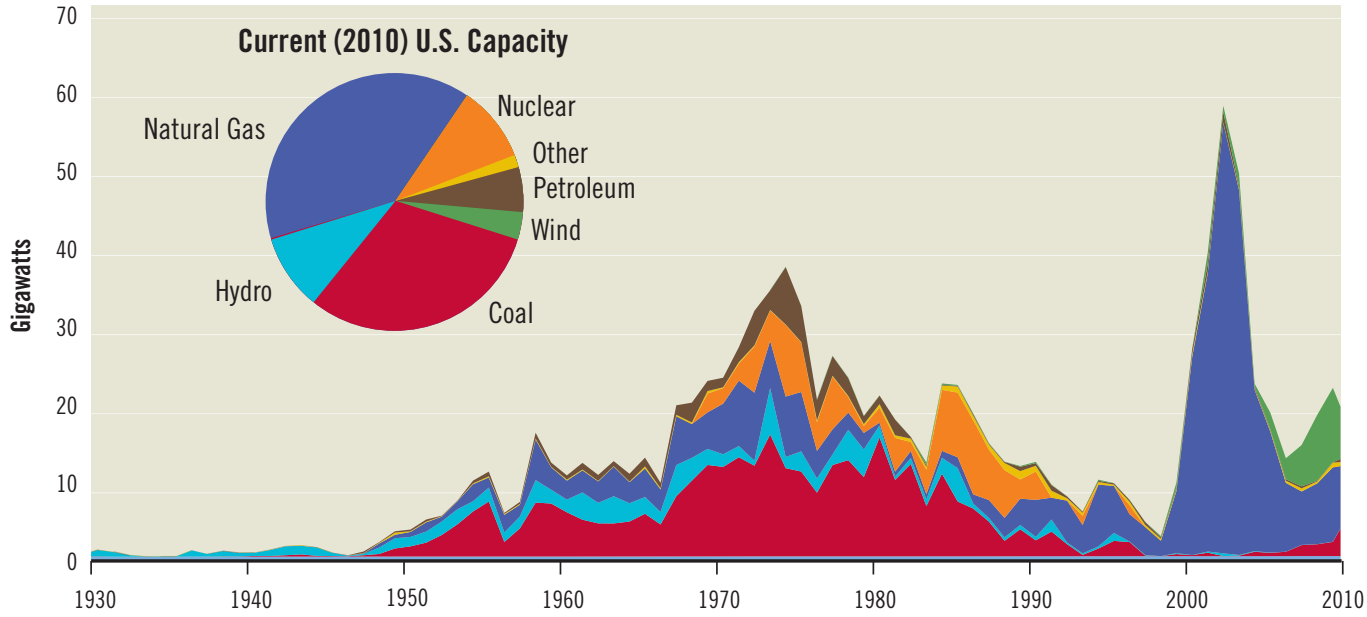
18 Small and Frantzis, *The 21st Century Electric Utility*, 28.

19 See U.S. Energy Information Administration, "Electric Power Industry Overview 2007," http://www.eia.gov/cneaf/electricity/page/prim2/toc2.html; National Rural Electric Cooperative Association, "Co-op Facts and Figures," http://www.nreca.coop/members/Co-opFacts/Pages/default.aspx; Edison Electric Institute, "Industry Data," http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Pages/default.aspx. Note that these numbers do not include investment by non-utility generators.

20 Edison Electric Institute, *2010 Financial Review*, 18.

Figure 2

U.S. ELECTRIC GENERATING CAPACITY BY IN-SERVICE YEAR AND FUEL TYPE



In 2008, the Brattle Group projected that the collected U.S. electric utility industry—IOUs, munis, and co-ops—would need to invest capital at historic levels between 2010 and 2030 to replace aging infrastructure, deploy new technologies, and meet future consumer needs and government policy requirements. In all, Brattle predicted that total industry-wide capital expenditures from 2010 to 2030 would amount to between $1.5 trillion and $2.0 trillion.[21] Assuming that the U.S. implements a policy limiting greenhouse gas emissions, the collected utility industry may be expected to invest at roughly the same elevated annual rate as in the 2006-2010 period *each year for 20 years.*

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital.

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital. This growth is considerably faster than the country has seen in many decades.

To understand the seriousness of the investment challenge facing the industry, consider the age of the existing generation fleet. About 70 percent of U.S. electric generating capacity is at least 30 years old (**Figure 2**).[22] Much of this older capacity is coal-based generation subject to significant pressure from the Clean Air Act (CAA) because of its emissions of traditional pollutants such as nitrous oxides, sulfur dioxides, mercury and particulates. Moreover, following a landmark Supreme Court ruling, the U.S. Environmental Protection Agency (EPA) is beginning to regulate as pollutants carbon dioxide and other greenhouse gas emissions from power plants.[23] These regulations will put even more pressure on coal plants, which produce the most greenhouse gas emissions of any electric generating technology. The nuclear capacity of the U.S., approximately 100,000 megawatts, was built mainly in the 1970s and 80s, with original licenses of 40 years. While the lives of many nuclear plants are being extended with additional investment, some of these plants will face retirement within the next two decades.

21 Chupka et al., *Transforming America's Power Industry,* vi. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. The range in Brattle's investment estimate is due to its varying assumptions about U.S. climate policy enactment.

22 U.S. Energy Information Administration, "Today in Energy: Age of electric power generators varies widely," June 16, 2011, http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

23 U.S. Supreme Court, *Massachusetts v. Environmental Protection Agency,* 549 U.S. 497 (2007), http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf.

Figure 3

PROJECTED GENERATION CAPEX BY REGION

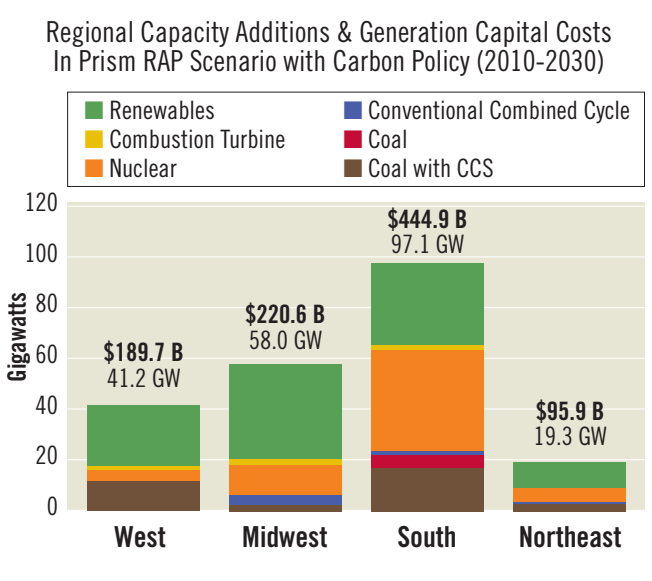


Figure 3 shows the Brattle Group's investment projections for new generating capacity for different U.S. regions,[24] while **Figure 4** predicts capacity additions for selected U.S. states. Importantly, the Brattle Group noted that some of this investment in new power plants could be avoided if regulators and utilities pursued maximum levels of energy efficiency.

DRIVERS OF UTILITY INVESTMENT

Technological change, market pressures and policy imperatives are driving these historic levels of utility investment. As we will see, these same forces are interacting to create unprecedented uncertainty, risk and complexity for utilities and regulators.

Figure 4

PROJECTED CAPACITY ADDITIONS BY STATE & AS A PERCENTAGE OF 2010 GENERATING CAPACITY

State	Predicted Capacity Additions (MW), 2010-2030[25]	Predicted Additions as a Percentage of 2010 Generating Capacity[26]
Texas	23,400	22%
Florida	12,200	21%
Illinois	11,000	25%
Ohio	8,500	26%
Pennsylvania	6,300	14%
New York	5,400	14%
Colorado	2,500	18%

Here are eight factors driving the large investment requirements:

1. **THE NEED TO REPLACE AGING GENERATING UNITS.** As mentioned earlier, the average U.S. generating plant is more than 30 years old. Many plants, including base load coal and nuclear plants, are reaching the end of their lives, necessitating either life-extending investments or replacement.
2. **ENVIRONMENTAL REQUIREMENTS.** Today's Clean Air Act (CAA) traces its lineage to a series of federal laws dating back to 1955. Until recent years, the CAA has enjoyed broad bipartisan support as it steadily tightened controls on emissions from U.S. electric power plants. These actions were taken to achieve science-based health improvements for people and the human habitat. While the current set of EPA rules enforcing the CAA has elicited political resistance, it is unlikely that the five-decade long movement in the United States to reduce acid rain, smog, ground ozone, particulates and mercury, among other toxic pollutants, will be derailed. Owners of many fossil-fueled plants will be forced to decide whether to make significant capital investments to clean up emissions and manage available water, or shutter the plants. Since the capacity is needed to serve consumers' demand for power (or "load"), these clean air and clean water policies will stimulate the need for new construction.

24 Chupka et al., *Transforming America's Power Industry,* x. Brattle's Prism RAP Scenario "assumes there is a new federal policy to constrain carbon emissions, and captures the cost of EPRI's [Electric Power Research Institute] Prism Analysis projections for generation investments (nuclear, advanced coal, renewables, etc.) that will reduce the growth in carbon emissions. This scenario further assumes the implementation of RAP [realistically achievable potential] EE/DR programs" (ibid., vi). Brattle used EPRI's original Prism analysis, published in September 2007; that document and subsequent updates are available online at http://my.epri.com/portal/server.pt?open=512&objID=216&&PageID=229721&mode=2.

25 State capacity addition predictions are based on Brattle's regional projections and assume that new capital expenditures will be made in proportion to existing investment levels.

26 State generating capacity data: U.S. Energy Information Administration, "State Electricity Profiles," January 30, 2012, http://www.eia.gov/electricity/state/. Percentage is rounded to the nearest whole number.

3 **NEW TRANSMISSION LINES AND UPGRADES.** Utility investment in transmission facilities slowed significantly from 1975 to 1998.[27] In recent years, especially after the creation of deregulated generation markets in about half of the U.S., it has become clear that the transmission deficit will have to be filled. Adding to the need for more transmission investment is the construction of wind, solar and geothermal generation resources, far from customers in areas with little or no existing generation or transmission. Regional transmission planning groups have formed across the country to coordinate the expected push for new transmission capacity.

4 **NETWORK MODERNIZATION/SMART GRID.** The internet is coming to the electric power industry. From synchrophasors on the transmission system (which enable system-wide data measurement in real time), to automated substations; from smart meters, smart appliances, to new customer web-based energy management, investments to "smarten" the grid are fundamentally changing the way electricity is delivered and used. While much of today's activity results from "push" by utilities and regulators, many observers think a "pull" will evolve as consumers engage more fully in managing their own energy use. Additionally, "hardening" the grid against disasters and to enhance national security will drive further investment in distribution infrastructure.

5 **HIGHER PRICES FOR CONSTRUCTION MATERIALS.** Concrete and steel are now priced in a world market. The demand from developing nations is pushing up the cost of materials needed to build power plants and transmission and distribution facilities.

6 **DEMAND GROWTH.** Overall U.S. demand for electric power has slowed with the recent economic recession and is projected to grow minimally in the intermediate term (though some areas, like the U.S. Southwest and Southeast, still project moderate growth). Further, the expected shift toward electric vehicles has the potential to reshape utility load curves, expanding the amount of energy needed in off-peak hours.

7 **DEPLOYING NEW TECHNOLOGIES AND SUPPORTING R&D.** To meet future environmental requirements, especially steep reductions of greenhouse gas emissions by 2050, utilities will need to develop and deploy new technologies at many points in the grid. Either directly or indirectly, utilities will be involved in funding for R&D on carbon capture and storage, new renewable and efficiency technologies, and electric storage.

8 **NATURAL GAS PRICE OUTLOOK.** Natural gas prices have fallen sharply as estimates of U.S. natural gas reserves jumped with the development of drilling technologies that can economically recover gas from shale formations. Longer-term price estimates have also dropped, inducing many utilities to consider replacing aging coal units with new gas-fired units. But in January 2012, the U.S. Energy Information Administration (EIA) sharply revised downward its estimates of U.S. shale gas reserves by more than 40 percent and its estimates of shale gas from the Marcellus region by two-thirds.[28] Reduced long-term supplies and a significant commitment to natural gas for new electric generation could obviously lead to upward pressure on natural gas prices.

FINANCIAL IMPLICATIONS

The credit quality and financial flexibility of U.S. investor-owned electric utilities has declined over the past 40 years, and especially over the last decade (**Figure 5, p. 18**).[29] The industry's financial position today is materially weaker than it was during the last major "build cycle" that was led by vertically-integrated utilities, in the 1970s and 80s. Then the vast majority of IOUs had credit ratings of "A" or higher; today the average credit rating has fallen to "BBB."



While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions.

This erosion of credit quality is mainly the result of intentional decisions by regulators and utility managements, who determined that maintaining an "A" or "AA" balance sheet wasn't worth the additional cost.[30] And while there isn't reason to believe that most utilities' capital markets access will become significantly constrained in the near future, the fact remains that more than a quarter of companies in the sector are now one notch above non-investment grade status (also called "Non-IG," "high yield" or "junk"), and nearly half of the companies in the sector are rated only two or three notches above this threshold.[31] While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions. Dropping below

27 Edison Electric Institute, *EEI Survey of Transmission Investment* (Washington DC: Edison Electric Institute, 2005), 3, http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Survey_Web.pdf.

28 U.S. Energy Information Administration, *AEO2012 Early Release Overview* (Washington DC: U.S. Energy Information Administration, 2012), 9, http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf.

29 Source: Standard & Poor's Ratings Service.

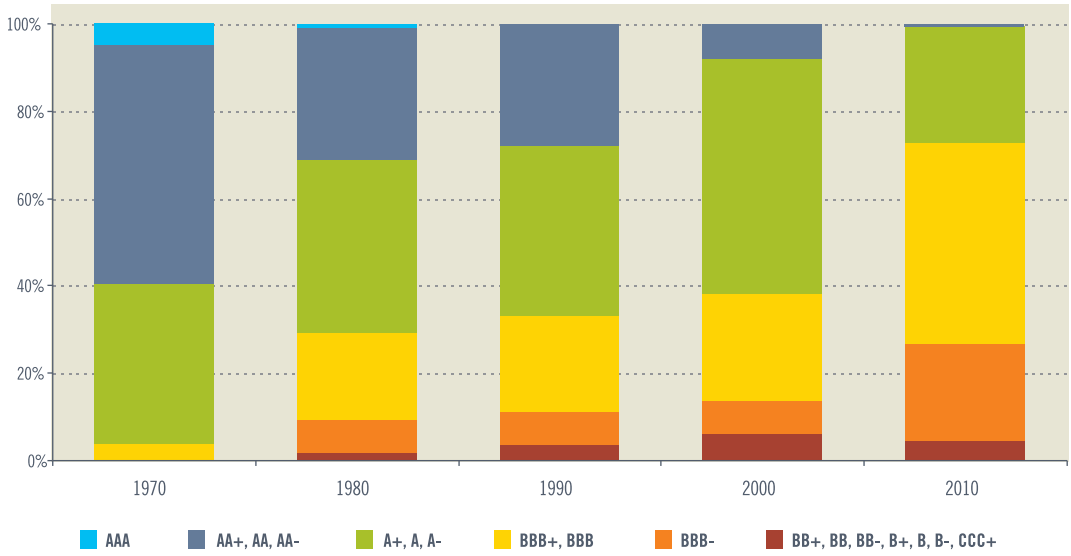
30 The difference in the interest rate on an "A" rated utility and BBB is on average over time rarely more than 100 basis points. By contrast, equity financing typically costs a utility at least 200 basis points more than debt financing.

31 Companies in the sector include IOUs, utility holding companies and non-regulated affiliates.

Figure 5

U.S. ELECTRIC IOUs CREDIT RATINGS HISTORY, 1970 – 2010

S&P Credit Ratings Distribution, U.S. Shareholder-Owned Electric Utilities



investment grade (or "IG") triggers a marked rise in interest rates for debt issuers and a marked drop in demand from institutional investors, who are largely prohibited from investing in junk bonds under the investment criteria set by their boards.

According to a Standard & Poor's analyst, utilities' capital expenditure programs will invariably cause them to become increasingly cash flow negative, pressuring company balance sheets, financial metrics and credit ratings: "In other words, utilities will be entering the capital markets for substantial amounts of both debt and equity to support their infrastructure investments as operating cash flows will not come close to satisfying these infrastructure needs."[32] Specific utilities that S&P has identified as particularly challenged are companies—such as Ameren, Dominion, FirstEnergy, and PPL—that have both regulated and merchant generation businesses and must rely on market pricing to recover environmental capital expenditures for their merchant fleets.[33]

Appendix 1 of this report presents an overview of utility finance.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery.

CUSTOMER IMPACTS

The surge in IOU capital investment will translate directly into higher electric rates paid by consumers. Increased capital investment means higher annual depreciation expenses as firms seek to recover their investment. Greater levels of investment mean higher revenue requirements calculated to yield a return on the investment. And since electric sales may not grow much or at all during the coming two decades, it is likely that unit prices for electricity will rise sharply.

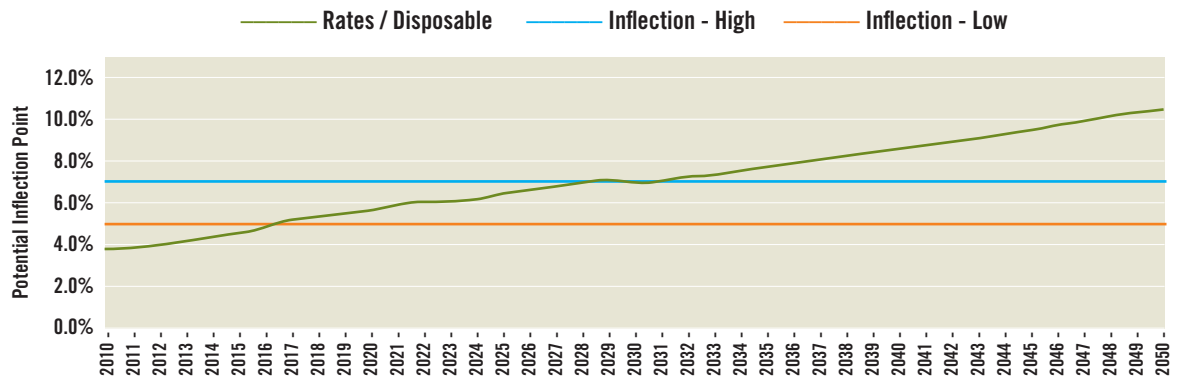
While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery. The rating agency Moody's Investors Service has noted that "consumer tolerance to rising rates is a primary concern"[34] and has identified political and regulatory risks as key longer-term challenges facing the sector.[35]

Further, Moody's anticipates an "inflection point" where consumers revolt as electricity bills consume a greater share of disposable income (**Figure 6, p. 19**),[36] pressuring legislators and regulators to withhold from utilities the recovery of even prudently incurred expenses.

32 Cortright, "Testimony."
33 Standard & Poor's, *The Top 10 Investor Questions for U.S. Regulated Electric Utilities in 2012* (New York: Standard & Poor's, 2012).
34 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2011).
35 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2010).
36 Moody's, *Special Comment: The 21st Century Electric Utility*, 12.

Figure 6

MOODY'S PROJECTED "INFLECTION POINT" OF CONSUMER INTOLERANCE FOR RISING ELECTRICITY BILLS



Source: Moody's

THE IMPORTANCE OF REGULATORS

With this background, the challenge becomes clear: how to ensure that the large level of capital invested by utilities over the next two decades is deployed wisely? How to give U.S. ratepayers, taxpayers and investors the assurance that $2 trillion will be spent in the best manner possible? There are two parts to the answer: *effective regulators* and the *right incentives for utilities*.

If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Each regulator will, on average, vote to approve more than $6.5 billion of utility capital investment during his or her term.[37] It is essential that regulators understand the risks involved in resource selection, correct for the biases facing utility regulation and keep in mind the impact their decisions will have on consumers and society.

Are U.S. regulatory institutions prepared? Consumers, lawmakers and the financial markets are counting on it. The authors are confident that well-informed, focused state regulators are up to the task. But energy regulation in the coming decades will be quite different from much of its history. The 21st century regulator must be willing to look outside the boundaries established by regulatory tradition. Effective regulators must be informed, active, consistent, curious and often courageous.

This report focuses on techniques to address the risk associated with utility resource selection. It provides regulators with some tools needed to understand, identify and minimize the risks inherent in the industry's investment challenge. In short, we hope to help regulators become more "risk-aware."

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37 In 2012, the median number of years served by a state regulator was 3.7 years; see Janice A. Beecher, Ph.D., *IPU Research Note: Commissioner Demographics 2012* (East Lansing, MI: Michigan State University, 2012), http://ipu.msu.edu/research/pdfs/IPU-Commissioner-Demographics-2012.pdf.

2. CHALLENGES

TO EFFECTIVE REGULATION



THE CHALLENGE FOR U.S. ELECTRIC UTILITIES IS TO RAISE, SPEND AND RECOVER A HISTORIC AMOUNT OF CAPITAL DURING A PERIOD OF UNPRECEDENTED UNCERTAINTY. THE CHALLENGE FOR STATE REGULATORS IS TO DO EVERYTHING POSSIBLE TO ENSURE THAT UTILITIES' INVESTMENTS ARE MADE WISELY. TO DO THIS EFFECTIVELY, REGULATORS WILL NEED TO BE ESPECIALLY ATTENTIVE TO TWO AREAS: IDENTIFYING AND ADDRESSING RISK, AND OVERCOMING REGULATORY BIASES. THIS SECTION DISCUSSES RISK AND BIAS IN MORE DETAIL.

RISK INHERENT IN UTILITY RESOURCE SELECTION

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Risk accumulates from multiple sources. In mathematical terms:

Risk = $\sum_i$ *Event$_i$ x (Probability of Event$_i$)*

for a situation in which a set of independent events will cause a loss with some probability. In English, this means that risk is the sum of each possible loss times the probability of that loss, assuming the events are independent of each other. If a financial instrument valued at $100 million would be worth $60 million in bankruptcy, and the probability of bankruptcy is 2 percent, then the bankruptcy risk associated with that instrument is said to be ($100 million - $60 million) x 2%, or $800,000. Thus, risk is the *expected value of a potential loss*. There is an obvious tie to insurance premiums; leaving aside transaction costs and the time value of money, an investor would be willing to pay up to $800,000 to insure against the potential bankruptcy loss just described.

Higher risk for a resource or portfolio means a larger expected value of a potential loss. In other words, higher risk means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Uncertainty is similar to risk in that it describes a situation where a deviation from the expected can occur, but it differs in two respects. First, the probability of the unexpected event cannot feasibly be determined with any precision. Consider the potential of much higher costs for natural gas used as a generation resource for an electric utility. Such an outcome is certainly possible (and perhaps even likely, given the potential for an increased rate of construction of new natural gas generation). But the likelihood and scope of such a change would be difficult to assess in terms of mathematical probabilities. Second, unlike risk, uncertainty can result in

The Historical Basis for Utility Regulation

Utilities aren't like other private sector businesses. Their services are essential in today's world, and society expects utilities to set up costly infrastructure networks supported by revenue from electric rates and to serve everyone without discrimination. Because of their special attributes, we say that investor-owned utilities are private companies that are "affected with the public interest." Indeed, this is often the statutory definition of utilities in state law.

Utility infrastructure networks include very long-lived assets. Power plants and transmission lines are designed to last decades; some U.S. transmission facilities are approaching 100 years old. The high cost of market entry makes competition impractical, uneconomic or impossible in many sectors of these markets. And because society requires universal service, it made economic sense to grant monopoly status to the owners of these essential facilities and then to regulate them.

State regulatory utility commissioners began administering a system of oversight for utilities at about the turn of the 20th century, filling a role that had previously been accorded to state legislatures. Regulatory commissions were tasked with creating a stable business environment for investment while assuring that customers would be treated "justly and reasonably" by monopoly utilities. Then as now, consumers wanted good utility services and didn't want to pay too much for them. Rules for accounting were supplemented by regulatory expectations, which were then followed by a body of precedents associated with cost recovery.

Because the sector's complexity and risks have evolved considerably since many regulatory precedents were established, today's regulators are well-advised to "think outside the box" and consider reforming past precedent where appropriate. The last section of this report, "Practicing Risk-Aware Regulation," contains specific ideas and recommendations in this regard.

Figure 7

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT	
Cost-related	***Time-related***
‣ Construction costs higher than anticipated	‣ Construction delays occur
‣ Availability and cost of capital underestimated	‣ Competitive pressures; market changes
‣ Operation costs higher than anticipated	‣ Environmental rules change
‣ Fuel costs exceed original estimates, or alternative fuel costs drop	‣ Load grows less than expected; excess capacity
‣ Investment so large that it threatens a firm	‣ Better supply options materialize
‣ Imprudent management practices occur	‣ Catastrophic loss of plant occurs
‣ Resource constraints (e.g., water)	‣ Auxiliary resources (e.g., transmission) delayed
‣ Rate shock: regulators won't put costs into rates	‣ Other government policy and fiscal changes

either upside or downside changes. As we will see later, uncertainty should be identified, modeled and treated much like risk when considering utility resource selection. In this report we will focus on risk and the negative aspect of uncertainty, and we will simplify by using the term "risk" to apply to both concepts.

The risks associated with utility resource selection are many and varied and arise from many possible events, as shown in **Figure 7**. There are several ways to classify these risks. One helpful distinction is made between cost-related risks and time-related risks.

Cost risks reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. Construction costs for a project can increase between regulatory approval and project completion. Transmission projects are notorious for this phenomenon due to unexpected obstacles in siting, or to unexpected changes in raw material costs.

Costs can change unexpectedly at any time. For example, a catastrophic equipment failure or the adoption of a new standard for pollution control could present unforeseen costs that a utility may not be willing to pay to keep an asset operating. Planned-for cost recovery can be disrupted by changes in costs for which regulators are unwilling to burden customers, or for other reasons. If an asset becomes obsolete, useless or uneconomic before the end of its predicted economic life, a regulator could find that it is no longer "used and useful" to consumers and remove it from the utility rate base. In these ways, decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

Time risks reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. Sometimes this risk can manifest itself even between the time a utility makes a decision and the time approval is sought. For example, anticipated load growth may not materialize, so that a planned generation resource is not needed, at least not now.

Time risks also reflect the fact that, for some investments, some essential condition may not occur on a schedule necessary for the investment to be approved and constructed. Consider the dilemma of the developer who wishes to build a low cost wind farm in an area with weak electric transmission. The wind project might require three to four years to build, but the transmission capacity needed to move the power to market may take five to seven years to build—*if* the development goes relatively smoothly. Investors may forego the wind farm due to uncertainty that the transmission will be built, while at the same time the transmission might not be built because, without the wind farm, it is simply too speculative.



Decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

In the power sector, investments are so long-lived that time can be measured in generations. Generally speaking, regulators consider it most fair if the generation of consumers that uses an asset is the same one that pays for the asset. Burdening customers before or after an asset is useful is often seen as violating the "just and reasonable" standard. The challenge to the utility, therefore, is to fit cost recovery for an asset into the timeframe in which it is used. Otherwise, the utility may bear the risk that regulators or consumers push back on assuming responsibility for the cost.

Perspectives on Risk

Risk means different things to different stakeholders. For example:

- For **utility management**, risks are a threat to the company's financial health, its growth, even its existence; a threat to the firm's competitiveness, to the firm's image, and to its legacy.
- For **customers**, risk threatens household disposable income, the profitability of businesses, the quality of energy service, and even comfort and entertainment.
- **Investors** focus on the safety of the income, value of the investment (stock or bond holders), or performance of the contract (counterparties). In addition, investors value utility investments based on their expectations of performance.
- **Employees** are uniquely connected to the utility. Their employment, safety and welfare is directly related to their company's ability to succeed and to avoid financial catastrophes.
- **Society generally** has expectations for utilities ranging from providing reliable, universal service, to aiding in economic development, to achieving satisfactory environmental and safety performance. Risk threatens these goals.

ELECTRICITY MARKET STRUCTURE AND RISK

Much has changed since non-utility power producers led the most recent industry build cycle in the 1990s and early 2000s. To begin with, financial reforms from Sarbanes-Oxley legislation, other "Enron fixes," and now the Dodd-Frank Act have substantially changed some accounting and corporate disclosure rules. Investors now receive more detailed and transparent information about asset value (which is "marked to market") and possible risks in contracts with counter-parties.

These changes, which protect investors, may have the associated effect of discouraging investments if cumulative risks are judged to be outsized for the circumstances. This is especially relevant for markets served by the competitive generation system that now supplies power to about half of U.S. consumers. It is unclear whether independent generators have the tolerance to take on large, risky investments; experience indicates that there is a frontier beyond which these companies and their backers may not go.

This dynamic could raise important questions for regulators in restructured markets, who need to be aware of the degree to which investment options might be limited by these concerns. In vertically-integrated markets, regulators' concern should be not to expose utilities, customers and investors to undue risk by approving large projects that informed market players would not pursue in the absence of regulatory approval.

One potentially risky but necessary area of investment is in low carbon generation technologies. The U.S. power sector, which has embraced generation competition, is required to develop these technologies. Some promising technologies—including coal-fired generation with carbon capture and storage or sequestration (CCS), advanced nuclear power technologies and offshore wind—have not reached a commercial stage or become available at a commercial price.

Risks requiring special attention are those associated with investments that "bet the company" on their success. Gigawatt-sized investments in any generation technology may trigger this concern, as can a thousand-mile extra high voltage transmission line. Any investment measured in billions of dollars can be proportionately out of scale with what a utility can endure if things go awry. Regulators should avoid a situation where the only choices left are a utility bankruptcy or a waiving of regulatory principles on prudence and cost recovery in order to save the utility, placing a necessary but unreasonable cost burden on consumers.

REGULATORS, RATING AGENCIES AND RISK

Investor-owned utilities sometimes attempt to get out in front of the event risk inherent in large investment projects by seeking pre-approval or automatic rate increase mechanisms. As discussed later, these approaches don't actually reduce risk, but instead shift it to consumers. This may give companies and investors a false sense of security and induce them to take on excessive risk. In the long run this could prove problematic for investors; large projects can trigger correspondingly large rate increases years later, when regulators may not be as invested in the initial deal or as willing to burden consumers with the full rate increase.

Given the influence of regulators on the operations and finances of IOUs, ratings agencies and investors closely monitor the interactions between utility executives and regulators. Constructive relationships between management and regulators are viewed as credit positive; less-than-constructive relationships, which can result from regulators' concerns about the competence or integrity of utility management, are seen as a credit negative and harmful to a utility's business prospects.

Analysts define a constructive regulatory climate as one that is likely to produce stable, predictable regulatory outcomes over time. "Constructive," then, refers as much to the quality

of regulatory decision-making as it does to the financial reward for the utility. Regulatory decisions that seem overly generous to utilities could raise red flags for analysts, since these decisions could draw fire and destabilize the regulatory climate. Analysts may also become concerned about the credit quality of a company if the state regulatory process appears to become unduly politicized.

While they intend only to observe and report, ratings agencies can exert a discipline on utility managements not unlike that imposed more formally by regulators. For example, ratings agencies can reveal to utility managements the range of factors they should consider when formulating an investment strategy, thereby influencing utility decision-making. Both regulators and ratings agencies set long-term standards and expectations that utilities are wise to mind; both can provide utilities with feedback that would discourage one investment strategy or another.

Since ratings reflect the issuer's perceived ability to repay investors over time, the ratings agencies look negatively on anything that increases event risk. The larger an undertaking (e.g., large conventional generation investments), the larger the fallout if an unforeseen event undermines the project. The pressure to maintain healthy financial metrics may, in practice, serve to limit utilities' capital expenditure programs and thus the size of rate increase requests to regulators.

TAKEAWAYS ABOUT RISK

Here are three observations about risk that should be stressed:

1. RISK CANNOT BE ELIMINATED—BUT IT CAN BE MANAGED AND MINIMIZED. Because risks are defined in terms of probabilities, it is (by definition) probable that some risk materializes. In utility resource selection, this means that risk will eventually find its way into costs and then into prices for electricity. Thus, taking on risk is inevitable, and risk will translate into consumer or investor costs—into dollars—sooner or later. Later in this report, we present recommendations to enable regulators to practice their trade in a "risk-aware" manner—incorporating the notion of risk into every decision.

2. IT IS UNLIKELY THAT CONSUMERS WILL BEAR THE FULL COST OF POOR UTILITY RESOURCE INVESTMENT DECISIONS. Put another way, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investments than in years past. In utility regulation, risk is shared between investors and customers in a complex manner. To begin, the existence of regulation and a group of customers who depend on utility service is what makes investors willing to lend utilities massive amounts of money (since most customers have few if any choices and must pay for utility service). But the actualization of a risk, a loss, may be apportioned by regulators to utility investors, utility consumers, or a combination of both. The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to make ratepayers pay for the full cost of utility mistakes.

3. IGNORING RISK IS NOT A VIABLE STRATEGY. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. In utility regulation, perhaps more so than anywhere else, making no choice is itself making a choice. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

NATURAL BIASES AFFECTING UTILITY REGULATION

Notwithstanding economic theory, we must admit that utilities are not perfectly rational actors and that their regulation is not textbook-perfect, either. Utility regulation faces several built-in biases, which one can think of as headwinds against which regulation must sail. For example, under traditional cost-of-service regulation, a considerable portion of fixed costs (i.e., investment in rate base) is often recovered through variable charges to consumers. In this circumstance, one would expect utilities to have a bias toward promoting sales of the product once rates are established—even if increasing sales might result in increased financial, reliability, or environmental risks and mean the inefficient use of consumer dollars.

Here are five natural biases that effective utility regulation must acknowledge and correct for:

- **Information asymmetry.** Regulators are typically handicapped by not having the same information that is available to the regulated companies. This becomes especially significant for the utility planning process, where regulators need to know the full range of potential options for meeting electric demand in future periods. In the same vein, regulators do not normally have adequate information to assess market risks. These are the considerations of CFOs and boardrooms, and not routinely available to regulators. Finally, operating utilities often exist in a holding company with affiliated interests. The regulator does not have insight into the interplay of the parent and subsidiary company—the role played by the utility in the context of the holding company.
- **The Averch-Johnson effect.** A second bias is recognized in the economic literature as the tendency of utilities to over-invest in capital compared to labor. This effect is known by the name of the economists who first identified the bias: the Averch-Johnson effect (or simply the "A-J effect"). The short form of the A-J effect is that permitting



a rate of return on investment will have the predictable effect of encouraging more investment than is optimal. This can manifest itself in the "build versus buy" decisions of integrated utilities and is often cited as a reason utilities might "gold plate" their assets. This effect can also be observed in the "invest versus conserve" decisions that utilities face. Under traditional regulatory rules, most utilities do not naturally turn toward energy efficiency investment, even though such investments are usually least cost for customers.

- **The throughput incentive.** A third bias that can be observed with utilities is the bias for throughput—selling more electricity. This is undoubtedly grounded in the vision that most utilities have traditionally had for themselves: providers of electricity. Importantly, the regulatory apparatus in most states reinforces the motivation to sell more electricity: a utility's short-run profitability and its ability to cover fixed costs is directly related to the utility's level of sales. The price of the marginal unit of electricity often recovers more than marginal costs, so utilities make more if they sell more. Only in recent years has the concept of an energy services provider developed in which the utility provides or enables energy efficiency, in addition to providing energy.
- **Rent-seeking.** A fourth bias often cited in the literature is "rent seeking," where the regulated company attempts to use the regulatory or legislative processes as a means of increasing profitability (rather than improving its own operational efficiency or competitive position). This can occur when firms use law or regulation to protect markets that should be open to competition, or to impose costs on competitors.
- **"Bigger-is-better"** syndrome. Another bias, related to the Averch-Johnson effect, might be called the "bigger is better" syndrome. Utilities tend to be conservative organizations that rely on past strategies and practices. Making large investments in relatively few resources had been the rule through the 1980s and into the 1990s. Because of this history, utilities may not naturally support smaller scale resources, distributed resources or programmatic solutions to energy efficiency.[38]

Regulation can compensate for these biases by conducting clear-headed analysis, using processes that bring forth a maximum of relevant information and, very importantly, identifying the risk that these biases might introduce into utility resource acquisition. In the next section, we will take a close look at the many risks facing generation resource investments, which involve some of the most important and complex decisions that regulators and utilities make.

38 To be fair, smaller scale resources can add transaction and labor expenses for which the utility would not earn a return under traditional cost of service regulation, which helps to explain limited utility interest in these options.

3. COSTS AND RISKS

OF NEW GENERATION RESOURCES

THE CAPITAL INVESTED BY U.S. ELECTRIC UTILITIES TO BUILD A SMARTER, CLEANER, MORE RESILIENT ELECTRICITY SYSTEM OVER THE NEXT TWO DECADES WILL GO TOWARDS UTILITIES' GENERATION, TRANSMISSION AND DISTRIBUTION SYSTEMS.

In this section we'll take an in-depth look at costs and risks of new generation resources, for several reasons:

- Generation investment will be the largest share of utility spending in the current build cycle; this is where the largest amount of consumer and investor dollars will be at stake.
- Today's decisions about generation investment can shape tomorrow's decisions about transmission and distribution investment (by reducing or increasing the need for such investment).
- Technology breakthroughs—in energy storage, grid management, solar PV, and elsewhere—could radically transform our need for base load power within the useful lives of power plants being built today.
- Generation resources are among utilities' most visible and controversial investments and can be a lightning rod for protest and media attention, intensifying scrutiny on regulatory and corporate decision-makers.
- The industry's familiarity with traditional generating resources (e.g., large centralized fossil and nuclear plants) and relative lack of familiarity with newer alternatives (e.g., demand-side resources such as energy efficiency and demand response, or smaller, modular generating resources like combined heat and power) could lead regulators and utilities to underestimate risks associated with traditional resources and overestimate risks of newer resources.
- Finally, investment decisions about generation resources (especially nuclear power) during the last major build cycle that was led by vertically-integrated utilities, in the 1970s and 80s, destroyed tens of billions of dollars of consumer and shareholder wealth.

For these and other reasons, a comprehensive look at risks and costs of today's generation resources is in order.

While this discussion is most directly applicable to regulators (and other parties) in vertically-integrated states where electric utilities build and own generation, it also has implications for regulators (and other parties) in restructured states. For example, regulators in some restructured states (e.g., Massachusetts) are beginning to allow transmission and distribution (T&D) utilities to own generation again, specifically small-scale renewable generation to comprise a certain percentage of a larger renewable portfolio standard. Further, enhanced appreciation of the risks embedded in T&D utilities' supply portfolios could induce regulators to require utilities to employ best practices with regard to portfolio management, thereby reducing the risks and costs of providing electricity service.[39] Finally, regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as the following discussion makes clear, are utilities' lowest-cost and lowest-risk resources.

PAST AS PROLOGUE: FINANCIAL DISASTERS FROM THE 1980s

The last time regulated U.S. utilities played a central role in building significant new generating capacity additions as part of a major industry-wide build cycle was during the 1970s and 80s.[40] At the time the industry's overwhelming focus was on nuclear power, with the Nuclear Regulatory Commission (NRC) licensing construction of more than 200 nuclear power plants.

The difficulties the industry experienced were numerous and well-known: more than 100 nuclear plants abandoned in various stages of development;[41] cost overruns so high that the average plant cost three times initial estimates;[42] and total "above-market" costs to society—ratepayers, taxpayers and shareholders—estimated at more than $200 billion.[43]

39 For a discussion of energy portfolio management, see William Steinhurst et al., *Energy Portfolio Management: Tools & Resources for State Public Utility Commissions* (Cambridge, MA: Synapse Energy Economics, 2006), http://www.naruc.org/Grants/Documents/NARUC%20PM%20FULL%20DOC%20FINAL1.pdf.

40 The natural gas build-out of the 1990s and early 2000s was led by independent power producers, not regulated utilities.

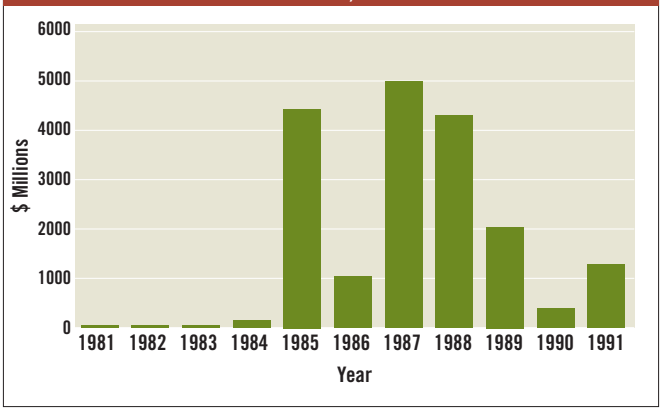
41 Peter Bradford, *Subsidy Without Borders: The Case of Nuclear Power* (Cambridge, MA: Harvard Electricity Policy Group, 2008).

42 U.S. Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs* (Washington, DC: U.S. Energy Information Administration, 1986).

43 Huntowski, Fisher and Patterson, *Embrace Electric Competition*, 18. Estimate is expressed in 2007 dollars.

Figure 8

U.S. UTILITY GENERATION INVESTMENT DISALLOWED BY REGULATORS, 1981-1991



While the vast majority of these losses were borne by ratepayers and taxpayers, utility shareholders were not immune. Between 1981 and 1991, U.S. regulators disallowed about $19 billion of investment in power plants by regulated utilities (**Figure 8**).[44] During this time, the industry invested approximately $288 billion, so that the disallowances equated to about 6.6 percent of total investment. The majority of the disallowances were related to nuclear plant construction, and most could be traced to a finding by regulators that utility management was to blame.

To put this in perspective for the current build cycle, consider **Figure 9**. For illustrative purposes, it shows what disallowances of 6.6 percent of IOU investment would look like for shareholders in the current build cycle, using Brattle's investment projections for the 2010-2030 timeframe referenced earlier. The table also shows what shareholder losses would be if regulators were to disallow investment a) at half the rate of disallowances of the 1981-91 period; and b) at twice the rate of that period.[45]

Figure 9

ILLUSTRATIVE PROSPECTIVE SHAREHOLDER LOSSES DUE TO REGULATORY DISALLOWANCES, 2010-2030

Disallowance Ratio	Investment	
	$1.5 T	$2.0 T
3.3%	$34.6 B	$46.2 B
6.6%	$69.3 B	$92.4 B
13.2%	$138.6 B	$184.8 B

Obviously, the *average* disallowance ratio from the 1980s doesn't tell the full story. A few companies bore the brunt of the regulatory action. One of the largest disallowances was for New York's Nine Mile Point 2 nuclear plant, where the $2 billion-plus disallowance was estimated to be 34 percent of the project's original capital cost.[46] When Niagara Mohawk, the lead utility partner in the project, wrote down its investment in the project by $890 million, Standard & Poor's lowered the company's credit rating by two notches, from A- to BBB. Thus the risk inherent in building the Nine Mile Point 2 plant was visited on investors, who experienced a loss of value of at least $890 million, and consumers, who faced potentially higher interest rates going forward. A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

Another large disallowance was levied on Pacific Gas and Electric for the Diablo Canyon nuclear station in California. The disallowance took the form of a "performance plan" that set consumers' price for power at a level that was independent of the plant's actual cost. In its 1988 decision, the California Public Utilities Commission approved a settlement whereby PG&E would collect $2 billion less, calculated on a net present value basis, than it had spent to build the plant. The CPUC's decision to approve the disallowance was controversial, and some felt it didn't go far enough. The California Division of Ratepayer Advocate (DRA) calculated PG&E's actual "imprudence" to be $4.4 billion (about 75 percent of the plant's final cost), and concluded that customers ultimately paid $2.4 billion more than was prudent for the plant—even after the $2 billion disallowance.[47]



A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

These two large disallowances could be joined by many other examples where unrecognized risk "came home to roost." Consider the destruction of shareholder equity that occurred when Public Service of New Hampshire (PSNH) declared bankruptcy in 1988 because of the burden of its investment in the Seabrook Nuclear Unit, or the enormous debt burden placed on ratepayers by the failure of New York's largest utility, Long Island Lighting Company (LILCO), or the 1983 multi-billion dollar municipal bond default by the Washington Public Power Supply System (WPPSS) when it abandoned attempts to construct five nuclear units in southeast Washington.

44 Lyon and Mayo, *Regulatory opportunism*, 632.

45 Assumes 70 percent of investment is by regulated entities. Illustrative estimates do not include potential losses for utility customers or taxpayers.

46 Fred I. Denny and David E. Dismukes, *Power System Operations and Electricity Markets* (Boca Raton, FL: CRC Press, 2002), 17.

47 The California Public Utilities Commission Decision is available on the Lexis database at: 1988 Cal. PUC LEXIS 886; 30 CPUC2d 189; 99 P.U.R.4th 141, December 19, 1988; As Amended June 16, 1989.



All of these financial disasters share four important traits:

- a weak planning process;
- the attempted development of large, capital-intensive central generation resources;
- utility management's rigid commitment to a preferred investment course; and
- regulators' unwillingness to burden consumers with costs judged retrospectively to be imprudent.

We do not propose to assess blame twenty-five years later, but we do question whether the regulatory process correctly interpreted the risk involved in the construction of these plants—whether, with all risks accounted for, these plants should actually have been part of a "least cost" portfolio for these utilities. The lesson is clear: both investors and customers would have been much better served if the regulators had practiced "risk-aware" regulation.

Finally, while the financial calamities mentioned here rank among the industry's worst, the potential for negative consequences is probably higher today. Since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially. And, as noted earlier, electric utilities have entered the current build cycle with lower financial ratings than they had in the 1980s.

CHARACTERISTICS OF GENERATION RESOURCES

A utility's generation portfolio typically consists of a variety of resources that vary in their costs and operating characteristics. Some plants have high capital costs but lower fuel costs (e.g., coal and nuclear) or no fuel costs (e.g., hydro, wind, solar PV). Other plants have lower capital costs but relatively high fuel and operating costs (e.g., natural gas combined cycle). Some plants are designed to operate continuously in "base load" mode, while others are designed to run relatively few hours each year, ramping up and down quickly.

Some resources (including demand response) offer firm capacity in the sense that they are able to be called upon, or "dispatchable," in real time, while other resources are not dispatchable or under the control of the utility or system operator (e.g., some hydro, wind, solar PV).

Generation resources also vary widely in their design lives and exposure to climate regulations, among other differences.

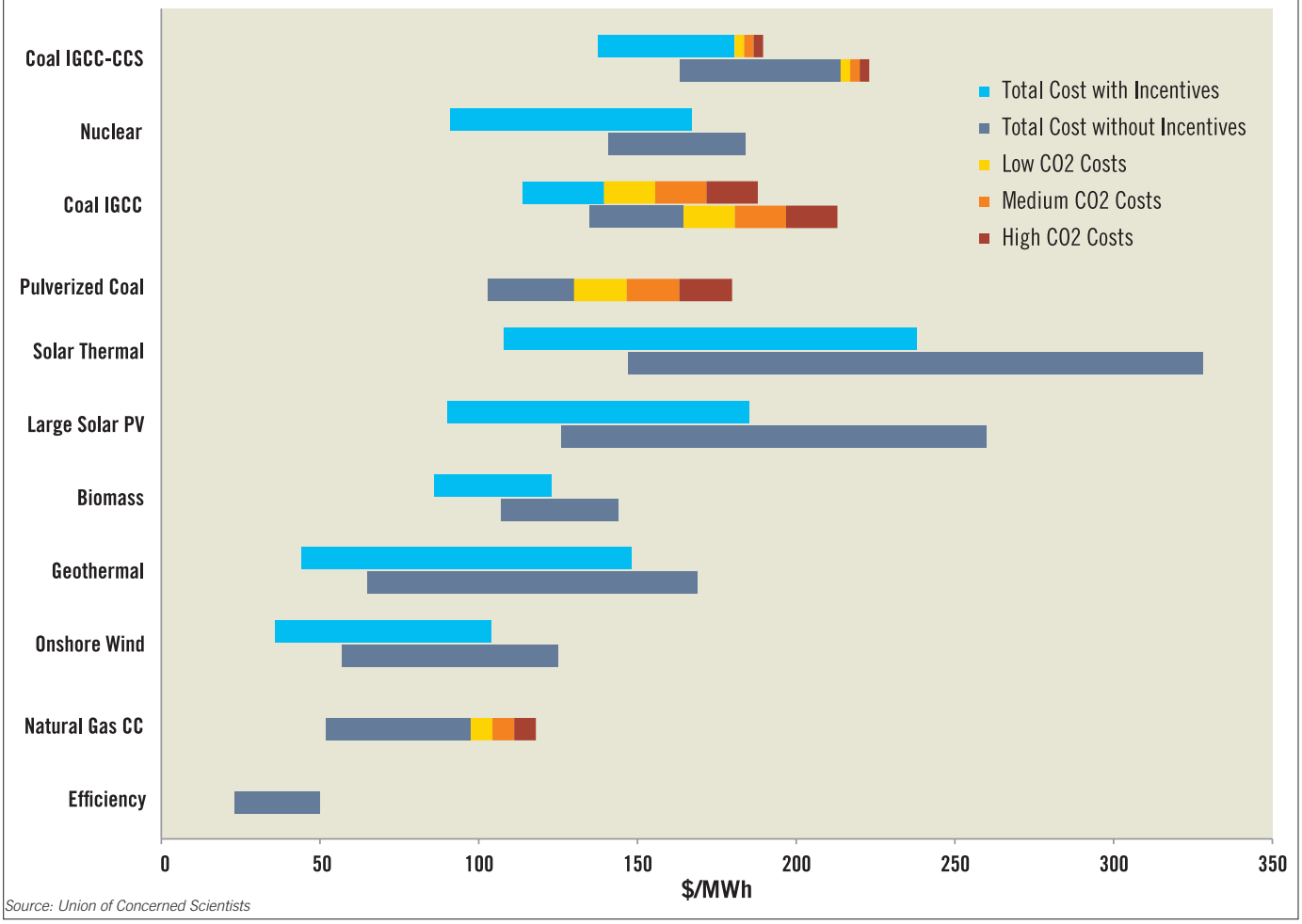
None of these characteristics *per se* makes a resource more or less useful in a utility's resource "stack." Some utility systems operate with a large percentage of generation provided by base load plants. Other systems employ a large amount of non-dispatchable generation like wind energy, combined with flexible gas or hydro generation to supply capacity. What's important is how the resources combine in a portfolio.

For example, in 2008 the Colorado Public Utilities Commission determined that an optimum portfolio for Xcel Energy would include a large amount of wind production, mixed in with natural gas generation and older base load coal plants. Xcel has learned how to manage its system to accommodate large amounts of wind production even though wind is not a "firm" resource. In October 2011, Xcel Energy set a world record for wind energy deployment by an integrated utility: in a one-hour period, wind power provided 55.6 percent of the energy delivered on the Xcel Colorado system.[48]

48 Mark Jaffe, "Xcel Sets World Record for Wind Power Generation," *The Denver Post*, November 15, 2011, http://www.denverpost.com/breakingnews/ci_19342896.

Figure 10

LEVELIZED COST OF ELECTRICITY FOR VARIOUS GENERATION TECHNOLOGIES IN 2015 (2010$)



Source: Union of Concerned Scientists

DECIPHERING THE LEVELIZED COST OF ELECTRICITY

Despite the differences between generation resources, it's possible to summarize and compare their respective costs in a single numerical measure. This quantity, called the "levelized cost of electricity," or "LCOE," indicates the cost per megawatt-hour for electricity over the life of the plant. LCOE encompasses all expected costs over the life of the plant, including costs for capital, operations and maintenance (O&M) and fuel.

Three of the most commonly cited sources of LCOE data for new U.S. generation resources are the Energy Information Administration (EIA); the California Energy Commission (CEC); and the international advisory and asset management firm Lazard. In a recent publication, the Union of Concerned Scientists (UCS) combined the largely consensus LCOE estimates from these three sources to produce a graphic illustrating LCOE for a range of resources (**Figure 10**).[49] The data is expressed in dollars per megawatt-hour, in 2010 dollars, for resources assumed to be online in 2015.

The UCS chart allows a visual comparison of the relative LCOEs among the selected group of resources. The width of the bars in the chart reflects the uncertainty in the cost of each resource, including the variation in LCOE that can result in different regions of the U.S. The UCS report also shows the resources' relative exposure to future carbon costs—not surprisingly, coal-based generation would be most heavily affected—as well as their dependence on federal investment incentives.[50]

49 Freese et al., *A Risky Proposition*, 41.

50 The UCS report estimated incentives by including tax credits for a wide range of technologies and both tax credits and loan guarantees for new nuclear plants. Tax credits currently available for wind and biomass were assumed to be extended to 2015 for illustrative purposes.

We'll use these LCOE estimates to illustrate the combined attributes of cost and risk for new generation resources. To do this, we'll take the midpoint of the cost ranges (including a medium estimate for costs associated with carbon controls) for each technology and create an indicative ranking of these resources by highest to lowest LCOE (**Figure 11**).

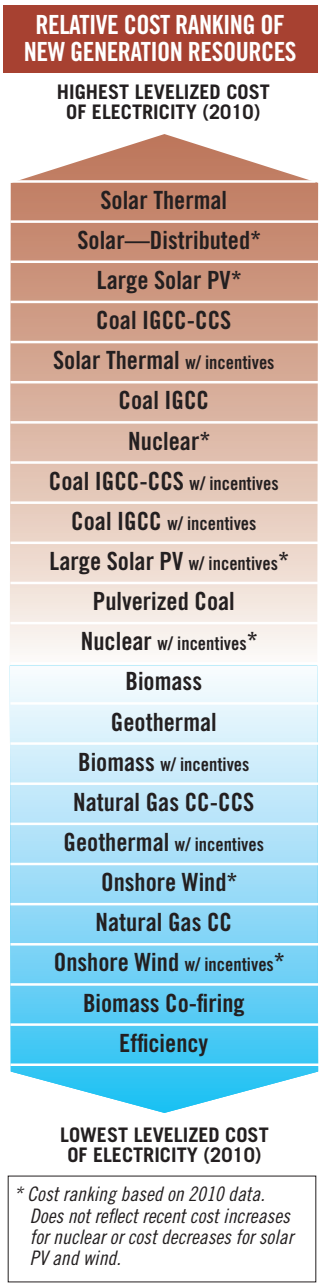
For consistency, we use UCS's data compilation, which is based on 2010 cost estimates, without modification. But the actual cost of nuclear power in 2015 is likely to be sharply higher than this estimate following the Fukushima nuclear accident and recent experience with new nuclear projects. For wind and photovoltaic power, the actual costs in 2015 are likely to be lower than the estimate due to recent sharp cost declines and the 2011 market prices for these resources.[51]

Several observations are in order about this ranking. First, some of the technologies show a very wide range of costs, notably geothermal, large solar PV and solar thermal. The breadth of the range represents, in part, the variation in performance of the technology in various regions of the country. In other words, the underlying cost estimates incorporate geographically varying geothermal and solar energy levels.

Second, the estimates used in this ranking are sensitive to many assumptions; the use of the midpoint to represent a technology in this ranking may suggest greater precision than is warranted. For this reason, the ranking shown in Figure 11 should be considered an indicative ranking. Two resources that are adjacent in the ranking might switch places under modest changes in the assumptions. That said, the ranking is useful for visualizing the relative magnitude of costs associated with various technologies and how those are projected to compare in the next few years.

Finally, the LCOE ranking tells only part of the story. The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it. In the next section we will examine these same technologies and estimate the composite risk to consumers, the utility and its investors for each technology.

Figure 11



The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it.

51 For example, in November 2011, the Colorado Public Utilities Commission approved a 25-year power purchase agreement between Xcel Energy and NextEra for wind generation in Colorado. The contract price is $27.50 per MWh in the first year and escalates at 2 percent per year. The levelized cost of the contract over 25 years is $34.75, less than the assumed lowest price for onshore wind with incentives in 2015 in Figure 10. For details, see Colorado PUC Decision No. C11-1291, available at http://www.colorado.gov/dora/cse-google-static/?q=C11-1291&cof=FORIDA10&ie=UTF-8&sa=Search. For more on wind power cost reductions, see Ryan Wiser et al., "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects" (presentation materials funded by the Wind and Water Power Program of the U.S. Department of Energy, February 2012), http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf. For information on recent PV cost reductions, see Solar Energy Industries Association (SEIA), *U.S. Solar Market Insight Report: 2011 Year in Review: Executive Summary* (Washington, DC: Solar Energy Industries Association, 2012), 10-11, http://www.seia.org/cs/research/solarinsight.

RELATIVE RISK OF NEW GENERATION RESOURCES

In Figure 7 on p. 21, we identified many of the time-related and cost-related risks that attach to a decision to choose a utility resource. We will now examine various generation resource choices in light of these risks, grouping those examples of risk into seven categories:

- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

These risks are discussed in detail below.

Intermittency vs. Risk

Certain resources, like wind, solar, and some hydropower facilities, are termed "intermittent" or "variable" resources. This means that while the power produced by them can be well characterized over the long run and successfully predicted in the short run, it cannot be precisely scheduled or dispatched. For that reason, variable resources are assigned a relatively low "capacity value" compared to base load power plants. The operating characteristics of any resource affect how it is integrated into a generation portfolio, and how its output is balanced by other resources.

This characteristic, intermittency, should not be confused with the concept of risk. Recall that risk is the expected value of a loss. In this case, the "loss" would be that the plant does not perform as expected—that it does not fulfill its role in a generation portfolio. For wind or solar resources, intermittency is expected and is accommodated in the portfolio design. Thus, while individual wind towers might be highly intermittent, and a collection of towers in a wind farm less so, a wind farm can also be termed highly reliable and present low risk because it will likely operate as predicted.

CONSTRUCTION COST RISK

Construction cost risk is the risk that the cost to develop, finance and construct a generation resource will exceed initial estimates. This risk depends on several factors, including the size of the project, the complexity of the technology, and the experience with developing and building such projects. The riskiest generation resources in this regard are technologies still in development, such as advanced nuclear and fossil-fired plants with carbon capture and storage. Construction cost risk is especially relevant for nuclear plants due to their very large size and long lead times. (Recall that a large percentage of the disallowed investment during the 1980s was for nuclear plants.) Transmission line projects are also subject to cost overruns, as are other large generation facilities. For example, Duke Energy's Edwardsport coal gasification power plant in Indiana has experienced billion-dollar cost overruns that have raised the installed cost to $5,593 per kilowatt, up from an original estimate of $3,364 per kilowatt.[52]

The lowest construction cost risk attaches to energy efficiency and to renewable technologies with known cost histories. In the middle will be technologies that are variations on known technologies (e.g., biomass) and resources with familiar construction regimes (e.g., gas and coal thermal plants).

FUEL AND OPERATING COST RISK

Fossil-fueled and nuclear generation is assigned "medium risk" for the potential upward trend of costs and the volatility familiar to natural gas supply.[53] Efficiency and renewable generation have no "fuel" risk. Biomass is assigned "medium" in this risk category because of a degree of uncertainty about the cost and environmental assessment of that fuel. Plants with higher labor components (e.g., nuclear, coal) have higher exposure to inflationary impacts on labor costs.

Analysts are split on the question of the future price of natural gas. The large reserves in shale formations and the ability to tap those resources economically through new applications of technology suggest that the price of natural gas may remain relatively low for the future and that the traditional volatility of natural gas prices will dampen. On the other hand, there remains substantial uncertainty about the quantity of economically recoverable shale gas reserves and controversy about the industrial processes used to develop these unconventional resources.

52 John Russell, "Duke CEO about plant: 'Yes, it's expensive,'" *The Indianapolis Star,* October 27, 2011, http://www.indystar.com/article/20111027/NEWS14/110270360/star-watch-duke-energy-Edwardsport-iurc.

53 Research conducted by the late economist Shimon Awerbuch demonstrated that adding renewable resources to traditional fossil portfolios lowers portfolio risk by hedging fuel cost variability; see Awerbuch, "How Wind and Other Renewables Really Affect Generating Costs: A Portfolio Risk Approach" (presentation at the European Forum for Renewable Energy Resources, Edinburgh, UK, October 7, 2005), http://www.eufores.org/uploads/media/Awerbuch-edinburgh_risk-portoflios-security-distver-Oct-20051.pdf. For a discussion of using renewable energy to reduce fuel price risk and environmental compliance in utility portfolios, see Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2005), http://eetd.lbl.gov/ea/ems/reports/58450.pdf.

There is also significant debate at the moment about the future price of coal. Some sources of low-sulfur coal are being depleted, raising the specter of higher production costs. Further, U.S. exports to China and other countries suggest upward pressure on this traditionally stable-priced fuel.

In this report we have steered a middle course on natural gas and coal prices, assuming that the risk of future surprises in natural gas and coal availability and price to be "medium." This is consistent with the price projection for these two generation fuels used by the Energy Information Administration in its current long-term energy forecast. In its most recent estimate, EIA assumes a real annual price escalation between 2010 and 2035 of about 1.3 percent for coal at the mine mouth and 1.8 percent for natural gas at the wellhead.[54]

Finally, operating cost risk includes the potential for catastrophic failure of a resource. This is especially significant for systems that could be taken down by a single point of failure. Contrast the impact of the failure of a turbine at a large steam plant as compared to the failure of a single turbine at a 100-turbine wind farm. The first failure causes the unavailability of 100 percent of capacity; the second failure causes a 1 percent reduction in capacity availability. Even if the probabilities of the failures are widely different, the size of the loss (risk) has cost implications for the reserve capacity (insurance) that must be carried on the large plant. Small outages are much easier to accommodate than large ones.[55]



Intermittency should not be confused with the concept of risk… For wind or solar resources, intermittency is expected and is accommodated in the portfolio design.

Modularity and unit size are also relevant to demand-side resources that are, by their nature, diverse. Designing good energy efficiency programs involves scrutinizing individual measures for the potential that they may not deliver the expected level of energy savings over time. This estimate can be factored into expectations for overall program performance so that the resource performs as expected. Since it would be extremely unlikely for individual measure failures to produce a catastrophic loss of the resource, diverse demand-side resources are, on this measure, less risky than large generation-side resources.

NEW REGULATION RISK

Nuclear generation is famously affected by accidents and the resulting changes in regulations. The recent accident at Fukushima in Japan illustrates how even a seemingly settled technology—in this case, GE boiling water reactors—can receive increased regulatory scrutiny. Further, the future of nuclear waste disposal remains unclear, even though the current fleet of reactors is buffered by reserves that are designed to cover this contingency. For these reasons, we consider nuclear power to face a high risk of future regulations.

Carbon sequestration and storage (CCS) appears to be subject to similar elevated risks regarding liability. The ownership and responsibility for long-term maintenance and monitoring for carbon storage sites will remain an unknown risk factor in coal and gas generation proposed with CCS.

Other thermal generation (e.g., biomass and geothermal) are also given a "medium" probability due to potential air regulations and land use regulations. Finally, as noted above, the price of natural gas, especially shale gas produced using "fracking" techniques, is at risk of future environmental regulation.

CARBON PRICE RISK

Fossil generation without CCS has a high risk of being affected by future carbon emission limits. Although there is no political agreement on the policy mechanism to place a cost on carbon (i.e., tax or cap), the authors expect that the scientific evidence of climate change will eventually compel concerted federal action and that greenhouse gas emissions will be costly for fossil-fueled generation. Energy efficiency, renewable and nuclear resources have no exposure to carbon risk, at least with respect to emissions at the plant.[56]

A more complex story appears when we consider the emissions related to the full life-cycle of generation technologies and their fuel cycles. For example, nuclear fuel production is an energy-intensive and carbon-intensive process on its own. As the cost of emitting carbon rises, we should expect the cost of nuclear fuel to rise.

Similar comments could apply to renewable facilities that require raw materials and fabrication that will, at least in the near-term, involve carbon-emitting production processes. However, these effects are second-order and much smaller than the carbon impact of primary generation fuels or motive power (e.g., coal, gas, wind, sun, nuclear reactions). The exposure of biomass to carbon constraints will depend on the eventual interpretation of carbon offsets and life-cycle analyses. For that reason, biomass and co-firing with biomass is assigned a non-zero risk of "low."

54 U.S. Energy Information Administration, *AEO2012 Early Release Overview*, 12-13.

55 This discussion refers to the *availability factor* of a resource; the *capacity factor* of a resource is a different issue, with implications for generation system design and operation.

56 For a discussion of how larger amounts of energy efficiency in a utility portfolio can reduce risk associated with carbon regulation, see Ryan Wiser, Amol Phadke and Charles Goldman, *Pursuing Energy Efficiency as a Hedge against Carbon Regulatory Risks: Current Resource Planning Practices in the West*, Paper 20 (Washington DC: U.S. Department of Energy Publications, 2008), http://digitalcommons.unl.edu/usdoepub/20.

"Retire or Retrofit" Decisions for Coal-Fired Plants

In this report, we've stressed how risk-aware regulation can improve the outcomes of utility selection of new resources. But many regulators will be focusing on existing power plants during the next few years. A key question facing the industry is whether to close coal plants in the face of new and future EPA regulations, or spend money on control systems to clean up some of the plant emissions and keep them running.

States and utilities are just coming to grips with these sorts of decisions. In 2010, Colorado implemented the new Clean Air Clean Jobs Act, under which the Colorado PUC examined Xcel Energy's entire coal fleet. The Colorado Commission entered a single decision addressing the fate of ten coal units. Some were closed, some were retrofitted with pollution controls, and others were converted to burn natural gas. Elsewhere, Progress Energy Carolinas moved decisively to address the same issue with eleven coal units in North Carolina.

We expect that three types of coal plants will emerge in these analyses: plants that should obviously be closed; newer coal plants that should be retrofitted and continue to run; and "plants in the middle." Decisions about these plants in the middle will require regulators to assess the risk of future fuel prices, customer growth, environmental regulations, capital and variable costs for replacement capacity, etc. In short, state commissions will be asked to assess the risks of various paths forward for the plants for which the economics are subject to debate.

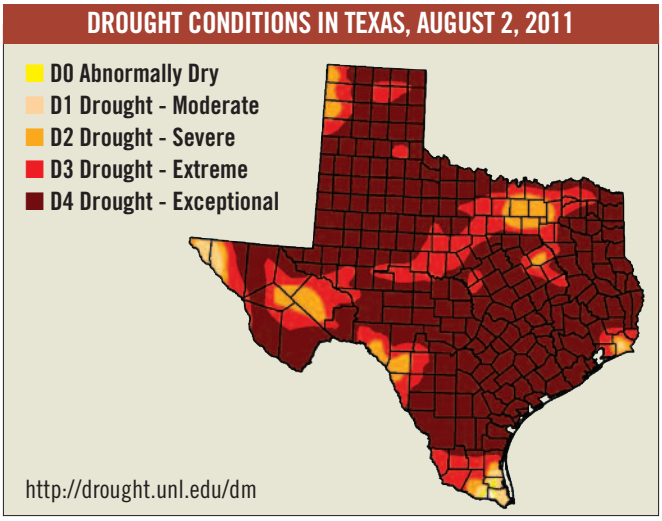
The tools we describe in this report for new resources apply equally well to these situations. Regulators should treat this much like an IRP proceeding (see "Utilizing Robust Planning Processes" on p. 40). Utilities should be required to present multiple different scenarios for their disposition of coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. At the end, regulators should enter a decision that addresses all of the relevant risks.

WATER CONSTRAINT RISK

Electric power generation—specifically the cooling of power plants—consumes about 40 percent of all U.S. freshwater withdrawals.[57] The availability and cost of water required for electricity generation will vary with geography but attaches to all of the thermal resources.[58] The recent promulgation by the EPA of the "once-through" cooling rule illustrates the impact that federal regulation can have on thermal facilities; one estimate predicts that more than 400 generating plants providing 27 percent of the nation's generating capacity may need to install costly cooling towers to minimize impacts on water resources.[59] One potential approach, especially for solar thermal, is the use of air-cooling, which significantly lowers water use at a moderate cost to efficiency. Non-thermal generation and energy efficiency have no exposure to this category of risk.

Water emerged as a significant issue for the U.S. electric power sector in 2011. A survey of more than 700 U.S. utility leaders by Black & Veatch indicated "water management was rated as the business issue that could have the greatest impact on the utility industry."[60] Texas suffered from record drought in 2011 at the same time that it experienced all-time highs in electricity demand. **Figure 12** depicts widespread "exceptional drought" conditions in Texas on August 2, 2011,[61] the day before the Electric Reliability Council of Texas (ERCOT) experienced record-breaking peak demand. ERCOT managed to avoid rolling blackouts but warned that continued drought and lack of sufficient cooling water could lead to generation outages totaling "several thousand megawatts."[62]

Figure 12



57 J.F. Kenny et al., "Estimated use of water in the United States in 2005," *U.S. Geological Survey Circular 1344* (Reston, VA: U.S. Geological Survey, 2009), http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf.

58 For a discussion of freshwater use by U.S. power plants, see Kristen Averyt et al., *Freshwater Use by U.S. Power Plants* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/ew3/ew3-freshwater-use-by-us-power-plants.pdf.

59 Bernstein Research, *U.S. Utilities: Coal-Fired Generation is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* (New York: Bernstein Research, 2010), 69.

60 "U.S. Utility Survey Respondents Believe Energy Prices Will Rise Significantly, Place Emphasis on Growing Nexus of Water and Energy Challenge," Black & Veatch press release, June 13, 2011, http://www.bv.com/wcm/press_release/06132011_9417.aspx.

61 National Drought Mitigation Center, "U.S. Drought Monitor: Texas," August 2, 2011, http://droughtmonitor.unl.edu/archive/20110802/pdfs/TX_dm_110802.pdf.

62 Samantha Bryant, "ERCOT examines grid management during high heat, drought conditions," *Community Impact Newspaper*, October 14, 2011, http://impactnews.com/articles/ercot-examines-grid-management-during-high-heat,-drought-conditions.



In addition to drought, water rights could be an issue for electricity generators in Texas (and elsewhere).[63] The North American Electric Reliability Corporation (NERC) points out that in an extreme scenario, up to 9,000 MW of Texas' generation capacity—over 10 percent of ERCOT's total installed capacity—could be at risk of curtailment if generators' water rights were recalled.[64]

CAPITAL SHOCK RISK

This risk is generally proportional to the size of the capital outlay and the time required for construction of a generating unit. Simply put, the larger the capital outlay and the longer that cost recovery is uncertain, the higher the risk to investors. In this regard, nuclear installations and large new coal facilities with CCS face the highest risk. Smaller, more modular additions to capacity and especially resources that are typically acquired through purchase power agreements record less risk. Finally, distributed solar generation, modifications to enable biomass co-firing and efficiency are accorded low exposure to the risk of capital shock.

PLANNING RISK

This risk relates to the possibility that the underlying assumptions justifying the choice of a resource may change, sometimes even before the resource is deployed. This can occur, for example, when electric demand growth is weaker than forecast, which can result in a portion of the capacity of the new resource being excess. In January 2012, lower-than-anticipated electricity demand, combined with unexpectedly low natural gas prices, led Minnesota-based wholesale cooperative Great River Energy to mothball its brand-new, $437 million Spiritwood coal-fired power plant immediately upon the plant's completion. The utility will pay an estimated $30 million next year in maintenance and debt service for the idled plant.[65]

Generation projects with a high ratio of fixed costs and long construction lead times are most susceptible to planning risk. This means that the exposure of base load plants is higher than peaking units, and larger capacity units have more exposure than smaller plants.

In addition to macroeconomic factors like recessions, the electric industry of the early 21st century poses four important unknown factors affecting energy planning. These are 1) the rate of adoption of electric vehicles; 2) the pace of energy efficiency and demand response deployment; 3) the rate of growth of customer-owned distributed generation; and 4) progress toward energy storage. These four unknowns affect various resources in different ways.

Electric vehicles could increase peak demand if customers routinely charge their cars after work, during the remaining hours of the afternoon electrical peak. On the other hand, if electric vehicle use is coupled with time-of-use pricing, this new load has the opportunity to provide relatively desirable nighttime energy loads, making wind generation and nuclear generation and underutilized fossil generation more valuable in many parts of the country.

Energy efficiency (EE) and demand response (DR) affect both electricity (kilowatt-hours) and demand (kilowatts). EE and DR programs differ in relatively how much electricity or demand they conserve. Depending on portfolio design, EE and DR may improve or worsen utility load factors, shifting toward more peaking resources and away from base load plants. Changing customer habits and new "behavioral" EE efforts add to the difficulty in forecasting demand over time.

Distributed generation, especially small solar installation, is expanding rapidly, spurred by new financing models that have lowered the capital outlay from consumers. In addition, we may expect commercial and industrial customers to continue to pursue combined heat and power applications, especially if retail electricity rates continue to rise. Both of these trends will have hard-to-predict impacts on aggregate utility demand and the relative value of different generation resources, but also impacts on primary and secondary distribution investment.

Finally, electric storage at reasonable prices would be a proverbial game-changer, increasing the relative value of intermittent resources such as wind and solar. Microgrids with local generation would also be boosted by low-cost battery storage.

63 For a discussion of how water scarcity could impact municipal water and electric utilities and their bondholders, see Sharlene Leurig, *The Ripple Effect: Water Risk in the Municipal Bond Market* (Boston, MA: Ceres, 2010), http://www.ceres.org/resources/reports/water-bonds/at_download/file. For a framework for managing corporate water risk, see Brooke Barton et al., *The Ceres Aqua Gauge: A Framework for 21st Century Water Risk Management* (Boston, MA: Ceres, 2011), http://www.ceres.org/resources/reports/aqua-gauge/at_download/file.

64 North American Electric Reliability Corporation, *Winter Reliability Assessment 2011/2012* (Atlanta, GA: North American Electric Reliability Corporation, 2011), 29, http://www.nerc.com/files/2011WA_Report_FINAL.pdf.

65 David Shaffer, "Brand new power plant is idled by economy," *Minneapolis StarTribune*, January 9, 2012, http://www.startribune.com/business/134647533.html.

Figure 13

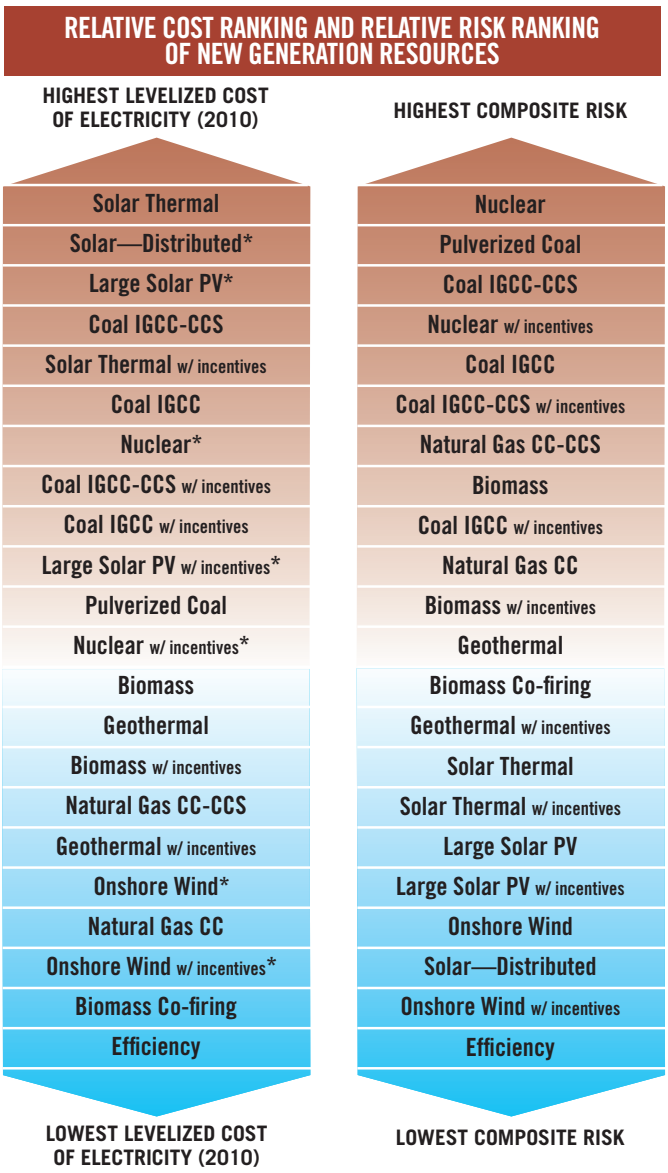
RELATIVE RISK EXPOSURE OF NEW GENERATION RESOURCES							
Resource	Initial Cost Risk	Fuel, O&M Cost Risk	New Regulation Risk	Carbon Price Risk	Water Constraint Risk	Capital Shock Risk	Planning Risk
Biomass	Medium	Medium	Medium	Medium	High	Medium	Medium
Biomass w/ incentives	Medium	Medium	Medium	Medium	High	Low	Medium
Biomass Co-firing	Low	Low	Medium	Low	High	Low	Low
Coal IGCC	High	Medium	Medium	Medium	High	Medium	Medium
Coal IGCC w/ incentives	High	Medium	Medium	Medium	High	Low	Medium
Coal IGCC-CCS	High	Medium	Medium	Low	High	High	High
Coal IGCC-CCS w/ incentives	High	Medium	Medium	Low	High	Medium	High
Efficiency	Low	None	Low	None	None	Low	None
Geothermal	Medium	None	Medium	None	High	Medium	Medium
Geothermal w/ incentives	Medium	None	Medium	None	High	Low	Medium
Large Solar PV	Low	None	Low	None	None	Medium	Low
Large Solar PV w/ incentives	Low	None	Low	None	None	Low	Low
Natural Gas CC	Medium	High	Medium	Medium	Medium	Medium	Medium
Natural Gas CC-CCS	High	Medium	Medium	Low	High	High	Medium
Nuclear	Very High	Medium	High	None	High	Very High	High
Nuclear w/ incentives	Very High	Medium	High	None	High	High	Medium
Onshore Wind	Low	None	Low	None	None	Low	Low
Onshore Wind w/ incentives	Low	None	Low	None	None	None	Low
Pulverized Coal	Medium	Medium	High	Very High	High	Medium	Medium
Solar - Distributed	Low	None	Low	None	None	Low	Low
Solar Thermal	Medium	None	Low	None	High	Medium	Medium
Solar Thermal w/ incentives	Medium	None	Low	None	High	Low	Medium

ESTABLISHING COMPOSITE RISK

In line with the foregoing discussion, the table in **Figure 13** summarizes the degree of exposure of various generation technologies to these seven categories of risk. The technologies listed are taken from UCS's LCOE ranking in Figure 10 on p. 28, plus three more: natural gas combined cycle with CCS, biomass co-firing and distributed solar PV generation. The chart estimates the degree of risk for each resource across seven major categories of risk, with estimates ranging from "None" to "Very High."

Three comments are in order. First, these assignments of relative risk were made by the authors, and while they are informed they are also subjective. As we discuss later, regulators should conduct their own robust examination of the relative costs and risks including those that are unique to their jurisdiction. Second, the assessment of risk for each resource is intended to be relative to each other, and not absolute in a quantitative sense. Third, while there are likely some correlations between these risk categories—resources with low fuel risk will have low carbon price exposure, for example—other variables exhibit substantial independence.

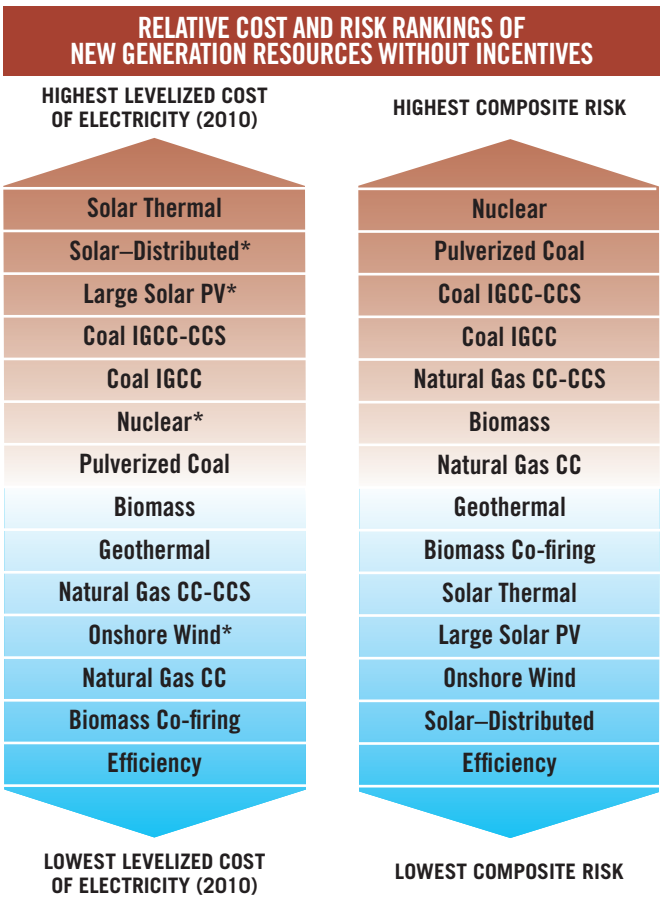
Figure 14



** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

The risk ranking shows a clear difference between renewable resources and non-renewable resources. Nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

Figure 15



** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

To derive a ranking of these resources with respect to risk, we assigned numeric values to the estimated degrees of risk (None=0, Very High=4) and totaled the rating for each resource. The scores were then renormalized so that the score of the highest-risk resource is 100 and the others are adjusted accordingly. The composite relative risk ranking that emerges is shown in **Figure 14**, which, for ease of comparison, we present alongside the relative cost ranking from Figure 11.

The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear difference between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

To illustrate how resources stack up against each other in more general terms, and for simplicity of viewing, **Figure 15** presents those same rankings without information about incentives.

To test the robustness of the composite risk ranking, we also examined two rankings where the scores were weighted. In one case, the environmental factors were given double weight; in the other, the cost factors were given double weight. As before, the scores were renormalized so that the highest-scoring resource is set to 100. The results of the unweighted ranking, together with the two weighted rankings, are shown in **Figure 16**. By inspection, one can see that the rank order changes very little across the three methods, so that the risk ranking in Figure 14 appears to be relatively robust. Once again, we emphasize that these figures are intended to show the relative risk among the resources, not to be absolute measures of risk.[66]

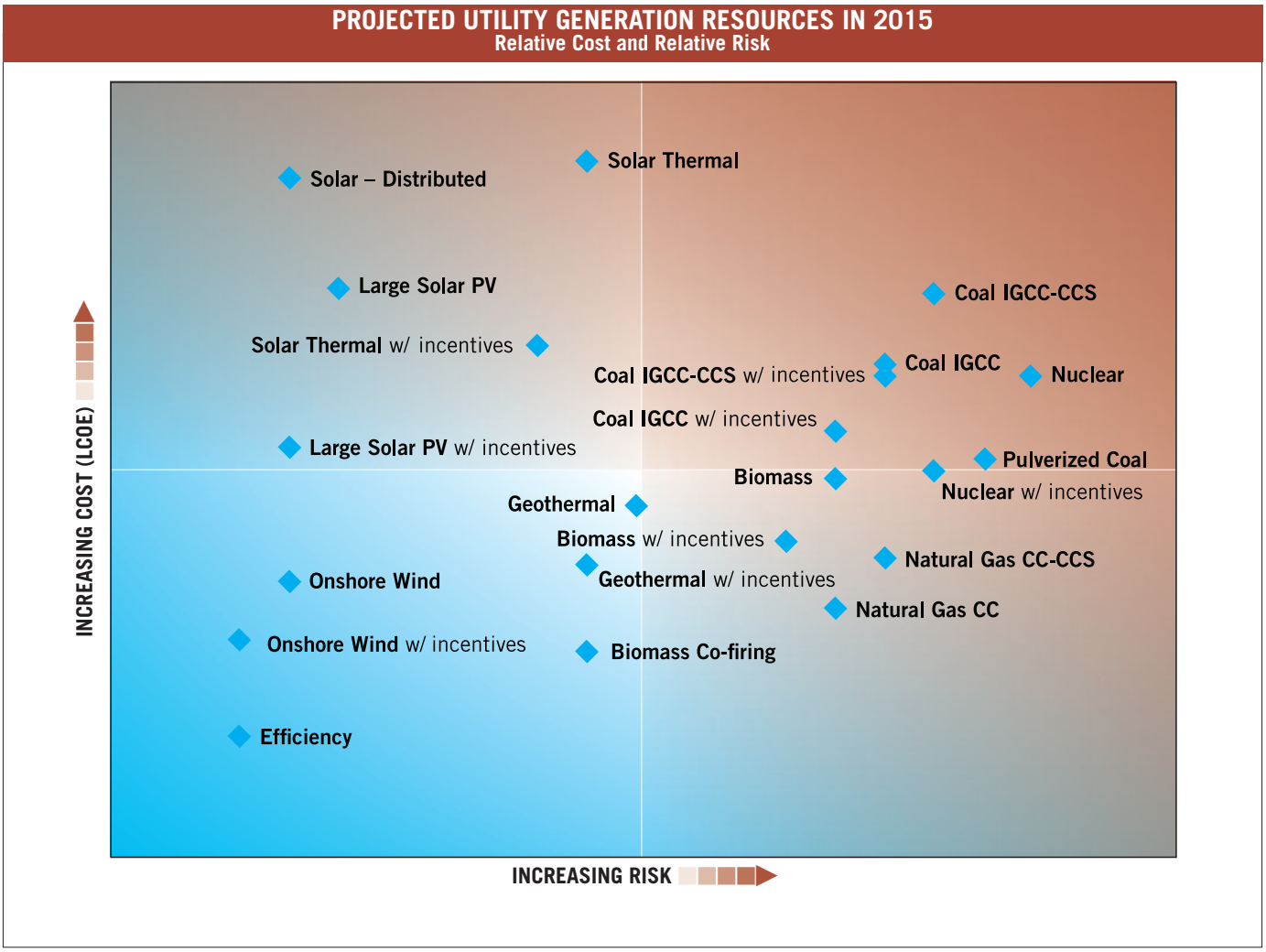
Figure 16

SUMMARY OF RISK SCORES FOR NEW GENERATION RESOURCES

Resource	Composite Score	Environmental Weighted Score	Cost Weighted Score
Biomass	79	79	72
Biomass w/ incentives	74	76	66
Biomass Co-firing	53	57	44
Coal IGCC	84	83	79
Coal IGCC w/ incentives	79	79	72
Coal IGCC-CCS	89	84	87
Coal IGCC-CCS w/ incentives	84	81	80
Efficiency	16	14	16
Geothermal	58	59	52
Geothermal w/ incentives	53	55	46
Large Solar PV	26	22	28
Large Solar PV w/ incentives	21	19	21
Natural Gas CC	79	76	75
Natural Gas CC-CCS	84	79	82
Nuclear	100	91	100
Nuclear w/ incentives	89	83	89
Onshore Wind	21	19	21
Onshore Wind w/ incentives	16	16	15
Pulverized Coal	95	100	82
Solar - Distributed	21	19	21
Solar Thermal	53	52	49
Solar Thermal w/ incentives	47	48	43

66 Dr. Mark Cooper, a longtime utility sector analyst and supporter of consumer interests, recently arrived at similar conclusions about composite risk; see Cooper, *Least-Cost Planning For 21st Century Electricity Supply* (So. Royalton, VT: Vermont Law School, 2011), http://www.vermontlaw.edu/Documents/21st%20Century%20Least%20Cost%20Planning.pdf. Cooper's analysis incorporated not only variations in "risk" and "uncertainty," but also the degrees of "ignorance" and "ambiguity" associated with various resources and the universe of possible future energy scenarios.

Figure 17



Finally, we can combine the information in the cost ranking and the risk ranking into a single chart. **Figure 17** shows how resources compare with each other in the two dimensions of cost and risk. The position of a resource along the horizontal axis denotes the relative risk of each resource, while the position on the vertical axis shows the relative cost of the resource.

4. PRACTICING RISK-AWARE REGULATION:

SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

UTILITY REGULATORS ARE FAMILIAR WITH A SCENE THAT PLAYS OUT IN THE HEARING ROOM: DIFFERENT INTERESTS—UTILITIES, INVESTORS, CUSTOMER GROUPS, ENVIRONMENTAL ADVOCATES AND OTHERS—COMPETE TO REDUCE COST AND RISK FOR THEIR SECTOR AT THE EXPENSE OF THE OTHERS. WHILE THE ADVERSARIAL PROCESS MAY MAKE THIS COMPETITION SEEM INEVITABLE, AN OVERLOOKED STRATEGY (THAT USUALLY LACKS AN ADVOCATE) IS TO REDUCE OVERALL RISK TO EVERYONE. MINIMIZING RISK IN THE WAYS DISCUSSED IN THIS SECTION WILL HELP ENSURE THAT ONLY THE UNAVOIDABLE BATTLES COME BEFORE REGULATORS AND THAT THE PUBLIC INTEREST IS SERVED FIRST.

Managing risk intelligently is arguably the main duty of regulators who oversee utility investment. But minimizing risk isn't simply achieving the least cost today. It is part of a strategy to *minimize overall long term costs*. And, as noted earlier, while minimizing risk is a worthy goal, eliminating risk is not an achievable goal. The regulatory process must provide balance for the interests of utilities, consumers and investors in the presence of risk.

One of the goals of "risk-aware" regulation is avoiding the kind of big, costly mistakes in utility resource acquisition that we've seen in the past. But there is another, more affirmative goal: ensuring that society's limited resources (and consumers' limited dollars) are spent wisely. By routinely examining and addressing risk in every major decision, regulators will produce lower cost outcomes in the long run, serving consumers and the public interest in a very fundamental way.

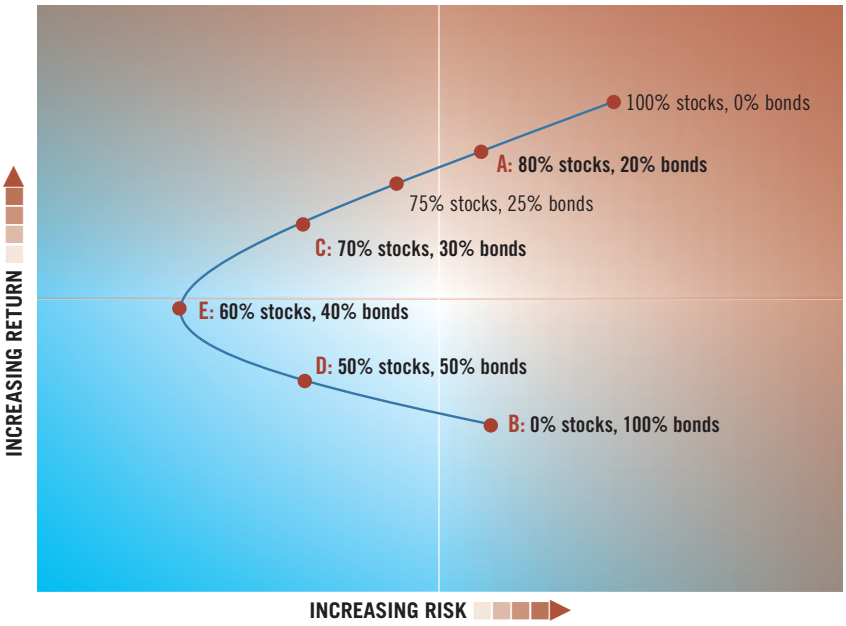
An overlooked strategy (that usually lacks an advocate) is to reduce overall risk to everyone.

WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS CAN EMPLOY TO MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources;
2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment (i.e., generation, transmission, distribution, and demand-side resources like energy efficiency);
3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk;
4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts;
5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments;
6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk;
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate.

Figure 18

RISK/RETURN RELATIONSHIPS AMONG DIFFERENT FINANCIAL PORTFOLIOS
(Illustrative)



We now discuss each of these strategies in more detail.

1. DIVERSIFYING UTILITY SUPPLY PORTFOLIOS

The concept of diversification plays an important role in finance theory. Diversification—investing in different asset classes with different risk profiles—is what allows a pension fund, for example, to reduce portfolio volatility and shield it from outsized swings in value.

Properly chosen elements in a diversified portfolio can increase return for the same level of risk, or, conversely, can reduce risk for a desired level of return. The simple illustration in **Figure 18** allows us to consider the relative risk and return for several portfolios consisting of stocks and bonds. Portfolio A (80% stocks, 20% bonds) provides a higher predicted return than Portfolio B (0% stocks, 100% bonds) even though both portfolios have the same degree of risk. Similarly, Portfolios C and D produce different returns at an identical level of risk that is lower than A and B. Portfolio E (60% stocks, 40% bonds) has the lowest risk, but at the cost of a lower return than Portfolios A and C. The curve in Figure 18 (and the corresponding surface in higher dimensions) is called an *efficient frontier*.

We could complicate the example—by looking at investments in cash, real estate, physical assets, commodities or credit default swaps, say, or by distinguishing between domestic and international stocks, or between bonds of various maturities—but the general lesson would be the same: diversification helps to lower the risk in a portfolio.

Portfolios of utility investments and resource mixes can be analyzed similarly. Instead of return and risk, the analysis would examine cost and risk. And instead of stocks, bonds, real estate and gold, the elements of a utility portfolio are different types of power plants, energy efficiency, purchased power agreements, and distributed generation, among many other potential elements. Each of these elements can be further distinguished by type of fuel, size of plant, length of contract, operating characteristics, degree of utility dispatch control, and so forth. Diversification in a utility portfolio means including various supply and demand-side resources that behave independently from each other in different future scenarios. Later we will consider these attributes in greater detail and discuss what constitutes a diversified utility portfolio.

For a real-world illustration of how diversifying resources lowers cost and risk in utility portfolios, consider the findings of the integrated resource plan recently completed by the Tennessee Valley Authority (TVA).[67] TVA evaluated five resource strategies that were ultimately refined into a single "recommended planning direction" that will guide TVA's resource investments. The resource strategies that TVA considered were:

- **Strategy A:** Limited Change in Current Resource Portfolio[68]
- **Strategy B:** Baseline Plan Resource Portfolio
- **Strategy C:** Diversity Focused Resource Portfolio
- **Strategy D:** Nuclear Focused Resource Portfolio
- **Strategy E:** EEDR (Energy Efficiency/Demand Response) and Renewables Focused Resource Portfolio

67 TVA, a corporation owned by the federal government, provides electricity to nine million people in seven southeastern U.S. states; see http://www.tva.com/abouttva/index.htm.

68 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent); see TVA, 73.

Figure 19

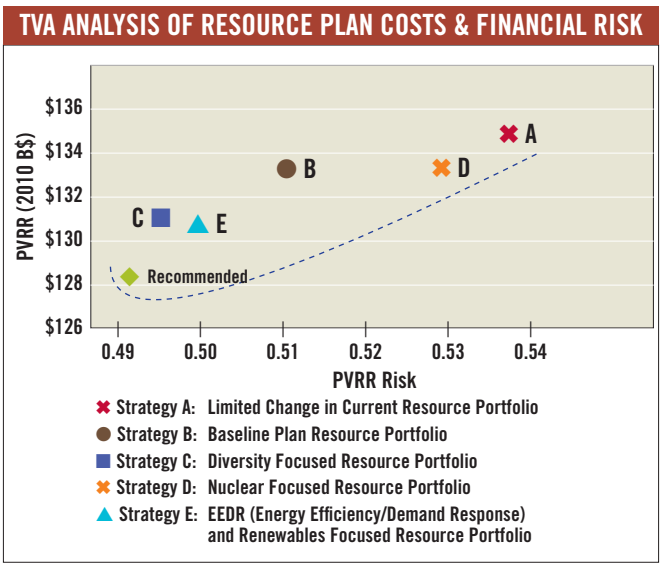


Figure 19 illustrates how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[69] The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy.[70] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio (mostly coal, natural gas and nuclear) or emphasized new nuclear plant construction.

The TVA analysis is very careful and deliberate. To the extent that other analyses reached conclusions thematically different from TVA's, we would question whether the costs and risks of all resources had been properly evaluated. We would also posit that resource investment strategies that differ directionally from TVA's "recommended planning direction" would likely expose customers (and, to some extent, investors) to undue risk. Finally, given the industry's familiarity with traditional resources—and the possibility that regulators and utilities may therefore underestimate the costs and risks of those resources—the TVA example illustrates how careful planning reveals the costs and risks of maintaining resource portfolios that rely heavily on large base load fossil and nuclear plants.

Robust planning processes like TVA's are therefore essential to making risk-aware resource choices. It is to these planning processes that we now turn.

2. UTILIZING ROBUST PLANNING PROCESSES

In the U.S., there are two basic utility market structures: areas where utilities own or control their own generating resources (the "vertically integrated" model), and areas where competitive processes establish wholesale prices (the "organized market" model).

In many vertically integrated markets and in some organized markets, regulators oversee the capital investments of utilities with a process called "integrated resource planning," or IRP. Begun in the 1980s, integrated resource planning is a tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of possible utility resources; that the options are examined in a structured, disciplined way in administrative proceedings; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood (if not necessarily accepted) by all.

Elements of a Robust IRP Process

IRP oversight varies in sophistication, importance and outcomes across the states. Because a robust IRP process is critical to managing risk in a utility, we describe a model IRP process that is designed to produce utility portfolios that are lower risk and lower cost.[71]

These elements characterize a robust IRP process:

- The terms and significance of the IRP approval (including implications for cost recovery) are clearly stated at the outset, often in statute or in a regulatory commission's rules.
- The regulator reviews and approves the modeling inputs used by the utility (e.g., demand and energy forecasts, fuel cost projections, financial assumptions, discount rate, plant costs, fuel costs, energy policy changes, etc.).
- The regulator provides guidance to utility as to the policy goals of the IRP, perhaps shaping the set of portfolios examined.
- Utility analysis produces a set of resource portfolios and analysis of parameters such as future revenue requirement, risk, emissions profile, and sensitivities around input assumptions.
- In a transparent public process, the regulator examines competing portfolios, considering the utility's analysis as well as input from other interested parties.
- Demand resources such as energy efficiency and demand response are accorded equal status with supply resources.
- The regulator approves a plan and the utility is awarded a "presumption of prudence" for actions that are consistent with the approved IRP.
- The utility acquires (i.e., builds or buys) the resources approved in the IRP, possibly through a competitive bidding regime.
- Future challenges to prudence of utility actions are limited to the execution of the IRP, not to the selection of resources approved by the regulator.

69 TVA, 161.

70 In the end, TVA settled on a "recommended planning direction" that calls for demand reductions of 3,600 to 5,100 MW, energy efficiency savings of 11,400 to 14,400 GWh, and renewable generating capacity additions of 1,500 to 2,500 MW by 2020. At the same time, TVA plans to retire 2,400 to 4,700 MW of coal-fired capacity by 2017. See TVA, 156.

71 For an example of an IRP that uses sophisticated risk modeling tools, see PacifiCorp, *2011 Integrated Resource Plan* (Portland, OR: PacifiCorp, 2011), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.

IRP: "Accepted" vs. "Approved" Plans

There are two varieties of IRP plans: "accepted plans" and "approved plans." Accepted plans are those where regulators examine the utility's process for developing its proposed plan. This can be a thorough review in which the Commission solicits the opinion of other parties as to whether the utility undertook a transparent, inclusive, and interactive process. If the regulator is convinced, the regulator "accepts" the utility's plan. This allows the utility to proceed but does not include any presumption about the Commission's future judgment concerning the prudence of actions taken under the plan.

With an "approved plan" the regulator undertakes a thorough review of the utility's preferred plan, possibly along with competing IRP plans submitted by other parties. Typically the scrutiny is more detailed and time-consuming in this version of IRP and the regulatory agency is immersed in the details of competing plans. At the end of the process, the regulator "approves" an IRP plan. This approval typically carries with it a presumption that actions taken by the utility consistent with the plan (including its approved amendments) are prudent. Over time, a Commission that approves an IRP plan will typically also examine proposed changes to the plan necessitated by changing circumstances.

In this report, we will focus on the "approved plan" process, although many of our findings apply equally to regulators that employ the "accepted plan" process.

A few of these elements deserve more elaboration.

Significance. The IRP must be meaningful and enforceable; there must be something valuable at stake for the utility and for other parties. From the regulator's point of view, the resource planning process must review a wide variety of portfolio choices whose robustness is tested and compared under different assumptions about the future. From the utilities' perspective, acceptance or approval of an IRP should convey that regulators support the plan's direction, even though specific elements may evolve as circumstances change. If a utility ignores the approved IRP or takes actions that are inconsistent with an IRP without adequate justification, such actions may receive extra scrutiny at the point where the utility seeks cost recovery.

Multiple scenarios. Many different scenarios will allow a utility to meet its future load obligations to customers. These scenarios will differ in cost, risk, generation characteristics, fuel mix, levels of energy efficiency, types of resources, sensitivity to changes in fuel cost, and so forth. While one scenario might apparently be lowest cost under baseline assumptions, it may not be very resilient under different input assumptions. Further, scenarios will differ in levels of risk and how that risk may be apportioned to different parties (e.g., consumers or shareholders). Regulators, with input from interested parties, should specify the types of scenarios that utilities should model and require utilities to perform sensitivity analyses, manipulating key variables.

Consistent, active regulation. An IRP proceeding can be a large, complex undertaking that occurs every two or three years, or even less frequently. It is critical that regulators become active early in the process and stay active throughout. The regulator's involvement should be consistent, even-handed and focused on the big-ticket items. Of course, details matter, but the process is most valuable when it ensures that the utility is headed in the right direction and that its planning avoids major errors. The regulator should then monitor a utility's performance and the utility should be able to trust the regulator's commitment to the path forward laid out in the IRP.

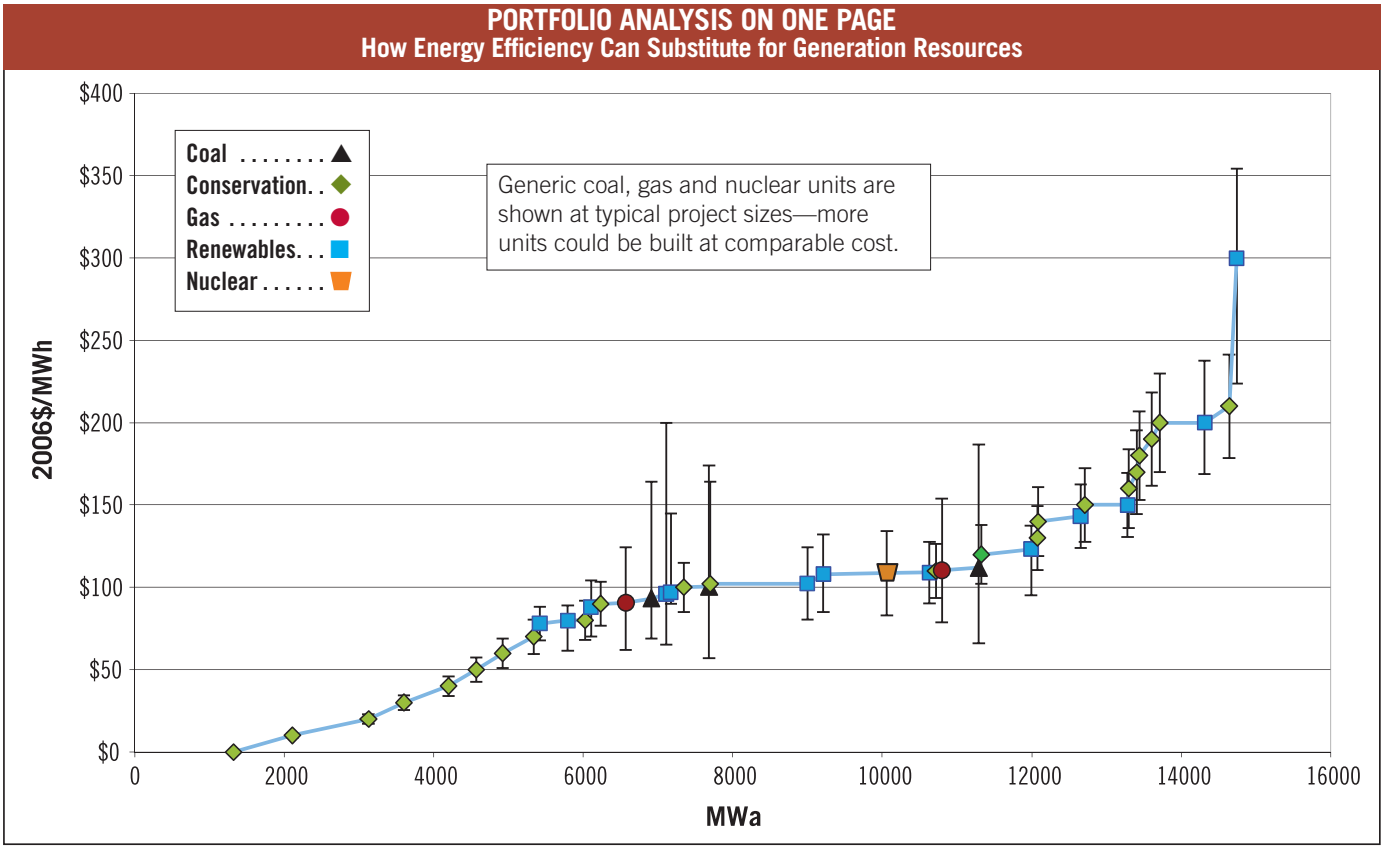
Stakeholder involvement. There are at least two good reasons to encourage broad stakeholder involvement in an IRP process. First, parties besides the utility will bring new ideas, close scrutiny and contrasting analysis to the IRP case, all of which helps the regulator to make an informed, independent decision. Second, effective stakeholder involvement can build support for the IRP that is ultimately approved, heading off collateral attacks and judicial appeals. An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources. Because an IRP decision is something of a political document in addition to being a working plan, regulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.



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Transparency. Regulators must ensure that, to the greatest extent possible, all parties participating in the IRP process have timely access to utility data. Certain data may be competitively sensitive and there is often pressure on the regulator to restrict unduly the access to such data. One possible solution to this challenge is to use an "independent evaluator" who works for the commission, is trusted by all parties and has access to all the data, including proprietary data. The independent evaluator can verify the modeling of the utility and assist the regulator in making an informed decision. The cost of an independent evaluator will be small in comparison to the benefits (or avoided mistakes) that the evaluator will enable. An independent evaluator will also add

Figure 20



credibility to the regulators' decision. In any event, the integrity of the IRP process will depend on regulators' ability to craft processes that are trusted to produce unbiased results.

Competitive bidding. A successful IRP will lower risk in the design of a utility resource portfolio. After the planning process, utilities begin acquiring approved resources. Some states have found it beneficial to require the utility to undertake competitive bidding for all resources acquired by a utility pursuant to an IRP. If the utility will build the resource itself, the regulator may require the utility to join the bidding process or commit to a cap on the construction cost of the asset.[72]

Role of Energy Efficiency. A robust IRP process will fully consider the appropriate levels of energy efficiency, including demand response and load management, that a utility should undertake. Properly viewed and planned for, energy efficiency can be considered as equivalent to a generation resource. Regulators in some states list projected energy efficiency savings on the "loads and resources table" of the utility, adjacent to base load and peaking power plants. In Colorado, energy efficiency is accorded a "reserve margin" in the integrated resource plan, as is done with generation resources.[73]

Since its inception in 1980, the Northwest Power and Conservation Council, which develops and maintains a regional power plan for the Pacific Northwest, has stressed the role of energy efficiency in meeting customers' energy needs. **Figure 20** shows the Council's analysis, demonstrating the elements of a diversified energy portfolio and the role that energy efficiency (or "conservation") can play in substituting for generation resources at various levels of cost.[74]

Appendix 2 contains additional discussion of some of the modeling tools available to regulators.

3. EMPLOYING TRANSPARENT RATEMAKING PRACTICES

Economist Alfred Kahn famously observed that "all regulation is incentive regulation," meaning that any type of economic regulation provides a firm with incentives to make certain choices. Indeed, utility rate regulation's greatest effect may not be its ability to limit prices for consumers in the short run, but rather the incentives it creates for utilities in the longer run.

72 For a discussion of the use of competitive bidding in resource acquisition, see Susan F. Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices* (Boston, MA: Analysis Group, 2008), http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Competitive_Procurement.pdf.

73 For Xcel Energy in Colorado, energy efficiency is listed on the "loads and resources" table as a resource. As such, it is logical that some fraction of the planned-for load reduction might not materialize. That portion is then assigned the standard resource reserve margin of approximately 15 percent. The planning reserve margin is added to the projected peak load, which must be covered by the combined supply-side and demand-side resources in the table.

74 Tom Eckman, "The 6th Power Plan… and You" (presentation at the Bonneville Power Administration Utility Energy Efficiency Summit, Portland, Ore., March 17, 2010), http://www.bpa.gov/Energy/N/utilities_sharing_ee/Energy_Smart_Awareness/pdf/0A_EESummit_Gen-Session_Public_Power.pdf.

There have been many debates through the years about the incentives that utility cost of service regulation provides. These range from the academic and formal (e.g., the aforementioned Averch-Johnson effect, which says that rate-regulated companies will have an inefficiently high ratio of capital to labor) to the common sense (e.g., price cap regulation can induce companies to reduce quality of service; the throughput incentive discourages electric utilities from pursuing energy efficiency, etc.).

While regulators may want to limit their role to being a substitute for the competition that is missing in certain parts of the electric industry, it is rarely possible to limit regulation's effects that way. The question is usually not how to eliminate stray incentives in decisions, but rather which ones to accept and address.

To contain risk and meet the daunting investment challenges facing the electric industry, regulators should take care to examine exactly what incentives are being conveyed by the details of the regulation they practice. We examine four components of cost of service regulation that affect a utility's perception of risk, and likely affect its preference for different resources.

Current Return on Construction Work in Progress. There is a long-standing debate about whether a utility commission should allow a utility to include in its rates investment in a plant during the years of its construction. Construction Work in Progress, or "CWIP," is universally favored by utility companies and by some regulators, but almost universally opposed by advocates for small and large consumers and by other regulators. CWIP is against the law in some states, mandated by law in others.

The main argument against CWIP is that it requires consumers to pay for a plant often years before it is "used and useful," so that there isn't a careful match between the customers who pay for a plant and those who benefit from it. Proponents of CWIP point out that permitting a current return on CWIP lessens the need for the utility to issue debt and equity, arguably saving customers money, and that CWIP eases in the rate increase, compared to the case where customers feel the full costs of an expensive plant when the plant enters service. Opponents counter by noting that customers typically have a higher discount rate than the utilities' return on rate base, so that delaying a rate hike is preferred by consumers, even if the utility borrows more money to finance the plant until it enters service.

Setting aside the near-religious debate about the equity of permitting CWIP in rate base, there is another relevant consideration. Because CWIP can help utilities secure financing and phase in rate increases, CWIP is often misunderstood as a tool for reducing risk. This is not true.

CWIP, Risk Shifting and Progress Energy's Levy Nuclear Plant

In late 2006, Progress Energy announced plans to build a new nuclear facility in Levy County, Florida, a few months after the state legislature approved construction work in progress (CWIP) customer financing. The site is about 90 miles north of Tampa, near the Gulf of Mexico. In 2009, Progress customers began paying for the Levy plant, which was expected to begin service in 2016 and be built at a cost of $4-6 billion. By the end of 2011, Progress customers had paid $545 million toward Levy's construction expenses.

The Levy plant is now projected to cost up to $22 billion, roughly four times initial estimates, and that number could keep climbing. (In March 2012, Progress Energy's market value as a company was almost $16 billion; the combined market value of Duke Energy and Progress Energy, which are seeking to merge and are pursuing construction of five nuclear facilities between them, is about $44 billion.) Levy's expected in-service date has pushed beyond 2021 and possibly as late as 2027—eighteen years after Progress customers began paying for the plant. Progress has estimated that by 2020, Levy-related expenses could add roughly $50 to the average residential customer's monthly bill.

The Levy plant's development appeared to take a step forward in December 2011 when the Nuclear Regulatory Commission approved its reactor design. But in February 2012, the Florida Public Service Commission approved a settlement agreement allowing Progress to suspend or cancel Levy's construction and recover $350 million from customers through 2017.

It is unclear whether Levy will ever be built. If the plant is canceled, Progress customers will have paid more than $1 billion in rates for no electricity generation, and Florida state law prohibits their recouping any portion of that investment. Such an outcome could help to deteriorate the political and regulatory climate in which Progress operates, which could ultimately impact credit ratings and shareholder value.

CWIP does nothing to actually reduce the risks associated with the projects it helps to finance. Construction cost overruns can and do still occur (see the text box about Progress Energy's Levy County nuclear power plant); O&M costs for the plant can still be unexpectedly high; anticipated customer load may not actually materialize; and so forth. What CWIP does is to reallocate part of the risk from utilities (and would-be bondholders) to customers. CWIP therefore provides utilities with both the incentive and the means to undertake a riskier investment than if CWIP were unavailable.

Regulators must be mindful of the implications of allowing a current return on CWIP, and should consider limiting its use to narrow circumstances and carefully drawn conditions of oversight. Regulators should also pay close attention to how thoroughly utility management has evaluated the risks associated with the projects for which it requests CWIP. Regardless of CWIP's other merits or faults, an important and too-often unacknowledged downside is that it can obscure a project's risk by shifting, not reducing, that risk.

Use of Rider Recovery Mechanisms. Another regulatory issue is the use by utilities of rate "riders" to collect investment or expenses. This practice speeds up cash flow for utilities, providing repayment of capital or expense outlays more rapidly than would traditional cost of service regulation. This allows utilities to begin collecting expenses and recovering capital without needing to capitalize carrying costs or file a rate case. Once again, regulators must consider whether these mechanisms could encourage a utility to undertake a project with higher risk, for the simple reason that cost recovery is assured even before the outlay is made.

Allowing a current return on CWIP, combined with revenue riders, is favored by many debt and equity analysts, who perceive these practices as generally beneficial to investors. And indeed, these mechanisms allow bondholders and stock owners to feel more assured of a return of their investment. And they might marginally reduce the utility's cost of debt and equity. But these mechanisms (which, again, transfer risk rather than actually reducing it) could create a "moral hazard" for utilities to undertake more risky investments. A utility might, for example, proceed with a costly construction project, enabled by CWIP financing, instead of pursuing market purchases of power or energy efficiency projects that would reduce or at least delay the need for the project. If negative financial consequences of such risky decisions extended beyond customers and reached investors, the resulting losses would be partially attributable the same risk-shifting mechanisms that analysts and investors originally perceived as beneficial.

Construction Cost Caps. Some regulatory agencies approve a utility's proposed infrastructure investments only after a cap is established for the amount of investment or expense that will be allowed in rates. Assuming the regulator sticks to the deal, this action will apportion the risk between consumers and investors. We wouldn't conclude that this actually reduces risk except in the sense that working under a cap might ensure that utility management stays focused on the project, avoiding lapses into mismanagement that would raise costs and likely strain relationships with regulators and stakeholders.

Rewarding Energy Efficiency. Another relevant regulatory practice concerns the treatment of demand-side resources like energy efficiency and demand response. It is well understood that the "throughput incentive" can work to keep a utility from giving proper consideration to energy efficiency; to the extent that a utility collects more than marginal costs in its unit price for electricity, selling more electricity builds the bottom line while selling less electricity hurts profitability. There are several adjustments regulation can make, from decoupling revenues from sales, to giving utilities expedited cost recovery and incentives for energy efficiency performance. Decoupling, which guarantees that a utility will recover its authorized fixed costs regardless of its sales volumes, is generally viewed by efficiency experts and advocates as a superior approach because it neutralizes the "throughput incentive" and enables utilities to dramatically scale up energy efficiency investment without threatening profitability. Ratings agencies view decoupling mechanisms as credit positive because they provide assurance of cost recovery, and Moody's recently observed "a marked reduction in a company's gross profit volatility in the years after implementing a decoupling type mechanism."[75] Whatever the chosen approach, the takeaway here is that without regulatory intervention, energy efficiency will not likely be accorded its correct role as a low cost and low risk strategy.[76]



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4. USING FINANCIAL AND PHYSICAL HEDGES

Another method for limiting risk is the use of financial and physical hedges. These provide the utility an opportunity to lock in a price, thereby avoiding the risk of higher market prices later. Of course, this means the utility also foregoes the opportunity for a lower market price, while paying some premium to obtain this certainty.

Financial hedges are instruments such as puts, calls, and other options that a utility can purchase to limit its price exposure (e.g., for commodity fuels) to a certain profile. If the price of a commodity goes up, the call option pays off; if the price goes down, the put option pays off. Putting such a collar around risk is, of course, not free: the price of an option includes transaction costs plus a premium reflecting the instrument's value to the purchaser. Collectively these costs can be viewed as a type of insurance payment.

Another example of a financial hedge is a "temperature" hedge that can limit a utility's exposure to the natural gas price spikes that can accompany extreme weather conditions. A utility may contract with a counter-party so that, for an agreed price, the counter-party agrees to pay a utility if the number of heating-degree-days exceeds a certain level during a certain winter period. If the event never happens,

75 Moody's Investors Service, *Decoupling and 21st Century Rate Making* (New York: Moody's Investors Service, 2011), 4.

76 For a discussion of regulatory approaches to align utility incentives with energy efficiency investment, see Val Jensen, *Aligning Utility Incentives with Investment in Energy Efficiency*, ICF International (Washington, DC: National Action Plan for Energy Efficiency, 2007), http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

Long-term Contracts for Natural Gas

In recent decades, utilities have mostly used financial instruments to hedge against volatile natural gas prices, and natural gas supply used for power generation has not been sold under long-term contracts. An exception is a recent long-term contract for natural gas purchased by Xcel Energy in Colorado. The gas will be used to fuel new combined cycle units that will replace coal generating units. The contract between Xcel Energy and Anadarko contained a formula for pricing that was independent of the market price of natural gas and runs for 10 years.

The long-term natural gas contract between Xcel Energy and Anadarko was made possible by a change in Colorado's regulatory law. For years, utilities and gas suppliers had expressed concern that a long-term contract, even if approved initially as prudent, might be subject to a reopened regulatory review if the price paid for gas under the contract was, at some future date, above the prevailing market price. Colorado regulators supported legislation making it clear in law that a finding of prudence at the outset of a contract would not be subject to future review if the contract price was later "out of the money." An exception to this protection would be misrepresentation by the contracting parties.

the utility forfeits the payment made for the hedge. If the event does happen, the utility might still need to purchase natural gas at an inflated price; even so, the hedge would pay off because it has reduced the company's total outlay. Simply stated, financial hedges can be used by a utility to preserve an expected value.

An illustration of a physical hedge would be when a utility purchases natural gas at a certain price and places it into storage. The cost of that commodity is now immune to future fluctuations in the market price. Of course, there is a cost to the utility for the storage, and the utility forgoes the possible advantage of a future lower price. But in this case the payment (storage cost) is justifiable because of the protection it affords against the risk of a price increase.

Long-term contracts can also serve to reduce risk. These instruments have been used for many years to hedge against price increases or supply interruptions for coal. Similarly, long-term contracts are used by utilities to lock in prices paid to independent power producers. Many power purchase agreements (PPAs) between distribution utilities and third party generators lock in the price of capacity, possibly with a mutually-agreed price escalator. But due to possible fuel price fluctuations (especially with natural gas), the fuel-based portion of the energy charge is not fixed in these contracts. So PPAs can shield utilities from some of the risks of owning the plants, but they do not hedge the most volatile portion of natural gas generation: the cost of fuel.

Regulated utilities and their regulators must come to an understanding about whether and how utilities will utilize these options to manage risk, since using them can foreclose an opportunity to enjoy lower prices.

5. HOLDING UTILITIES ACCOUNTABLE

From the market's perspective, one of the most important characteristics of a public utilities commission is its consistency. Consumers don't like surprises, and neither do investors. Financial analysts who rate regulatory climates across the states typically rank stability as one of the highest virtues for regulators. Indeed, this quality is often viewed to be as important as the absolute level of return on equity approved by a commission.



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Effective regulation—regulation that is consistent, predictable, forward-thinking and "risk-aware"—requires that regulators hold utilities accountable for their actions. Earlier, we stressed the value of regulators being actively involved in the utility resource planning process. But this tool works well only if regulators follow through—by requiring utilities to comply with the resource plan, to amend the resource plan if circumstances change, to live within an investment cap, to adhere to a construction schedule, and so forth. If the utility doesn't satisfy performance standards, regulatory action will be necessary.

This level of activity requires a significant commitment of resources by the regulatory agency. Utility resource acquisition plans typically span ten years or more, and a regulator must establish an oversight administrative structure that spans the terms of sitting commissioners in addition to clear expectations for the regulated companies and well-defined responsibilities for the regulatory staff.

6. OPERATING IN ACTIVE, "LEGISLATIVE" MODE

As every commissioner knows, public utility regulation requires regulators to exercise a combination of judicial and legislative duties. In "judicial mode," a regulator takes in evidence in formal settings, applies rules of evidence, and decides questions like the interpretation of a contract or the level of damages in a complaint case. In contrast, a regulator operating in "legislative mode" seeks to gather all information relevant to the inquiry at hand and to find solutions to future challenges. Judicial mode looks to the past, legislative mode



to the future. In his 1990 essay, former Ohio utilities regulator Ashley Brown put it this way:

> *Gathering and processing information is vastly different in judicial and legislative models. Legislating, when properly conducted, seeks the broadest data base possible. Information and opinions are received and/or sought, heard, and carefully analyzed. The process occurs at both formal (e.g., hearings) and informal (e.g., private conversation) levels. The goal is to provide the decision maker with as much information from as many perspectives as possible so that an informed decision can be made. Outside entities can enhance, but never be in a position to limit or preclude, the flow of information. The decision maker is free to be both a passive recipient of information and an active solicitor thereof. The latter is of particular importance in light of the fact that many of the interests affected by a decision are not likely to be present in the decision making forum.*[77]

Being a risk-aware regulator requires operating in legislative mode in regulatory proceedings, and especially in policy-making proceedings such as rulemakings. But the courts have also found that ratemaking is a proper legislative function of the states.[78] And since this state legislative authority is typically delegated by legislatures to state regulators, this means that, to some extent, regulators may exercise "legislative" initiative even in rate-setting cases.

In a recent set of essays, Scott Hempling, the former executive director of the National Regulatory Research Institute, contrasts regulatory and judicial functions and calls for active regulation to serve the public interest:

> *Courts and commissions do have commonalities. Both make decisions that bind parties. Both base decisions on evidentiary records created through adversarial truth-testing. Both exercise powers bounded by legislative line-drawing. But courts do not seek problems to solve; they wait for parties' complaints. In contrast, a commission's public interest mandate means it literally looks for trouble. Courts are confined to violations of law, but commissions are compelled to advance the public welfare.*[79]

Utility resource planning is one of the best examples of the need for a regulator to operate in legislative mode. When examining utilities' plans for acquiring new resources, regulators must seek to become as educated as possible. Up to a point, the more choices the better. The regulator should insist that the utility present and analyze multiple alternatives. These alternatives should be characterized fully, fairly, and without bias. The planning process should seek to discover as much as possible about future conditions, and the door should be opened to interveners of all stripes. Knowing all of the options—not simply the ones that the utility brings forward—is essential to making informed, risk-aware regulatory decisions.



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7. REFORM AND RE-INVENT RATEMAKING PRACTICES

It is increasingly clear that a set of forces is reshaping the electric utility business model. In addition to the substantial investment challenge discussed in this report, utilities are facing challenges from stricter environmental standards, growth in distributed generation, opportunities and challenges with the creation of a smarter grid, new load from electric vehicles, pressure to ramp up energy efficiency efforts—just to mention a few. As electric utilities change, regulators must be open to new ways of doing things, too.

77 Ashley Brown, "The Over-judicialization of Regulatory Decision Making," *Natural Resources and Environment* Vol. 5, No. 2 (Fall 1990), 15-16.

78 See, e.g., U.S. Supreme Court, *Munn vs. Illinois*, 94 U.S. 113 (1876), http://supreme.justia.com/cases/federal/us/94/113/case.html.

79 Scott Hempling, *Preside or Lead? The Attributes and Actions of Effective Regulators* (Silver Spring, MD: National Regulatory Research Institute, 2011), 22.

Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades. To deal with the digital revolution in telecommunications and the liberalization of those markets, regulators modernized their tools to include various types of incentive regulation, pricing flexibility, lessened regulation in some markets and a renewed emphasis on quality of service and customer education.

One area where electric utility regulators might profitably question existing practices is rate design. Costing and pricing decisions, especially for residential and small business customers, have remained virtually unchanged for decades. The experience in other industries (e.g., telecommunications, entertainment, music) shows that innovations in pricing are possible and acceptable to consumers. Existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

The risk-aware regulator must be willing to think "way outside the box" when it comes to the techniques and strategies of effective regulation. Earlier we observed that effective regulators must be informed, active, consistent, curious and often courageous. These qualities will be essential for a regulator to constructively question status quo regulatory practice in the 21st century.

THE BENEFITS OF "RISK-AWARE REGULATION"

We have stressed throughout this report that effective utility regulators must undertake a lot of hard work and evolve beyond traditional practice to succeed in a world of changing energy services, evolving utility companies and consumer and environmental needs. What can regulators and utilities reasonably expect from all this effort? What's the payback if regulators actively practice "risk-aware regulation"?

- **FIRST**, there will be benefits to consumers. A risk-aware regulator is much less likely to enter major regulatory decisions that turn out wrong and hurt consumers. The most costly regulatory lapses over the decades have been approval of large investments that cost too much, failed to operate properly, or weren't needed once they were built. It's too late for any regulator to fix the problem once the resulting cost jolts consumers.
- **SECOND**, there will be benefits to regulated utilities. Risk aware regulation will create a more stable, predictable business environment for utilities and eliminate most regulatory surprises. It will be easier for these companies to plan for the longer-term. If regulators use a well-designed planning process, examining all options and assessing risks, utilities and their stakeholders will have greater reliance on the long-term effect of a decision.
- **THIRD**, investors will gain as well. Steering utilities away from costly mistakes, holding the companies responsible for their commitments and, most importantly, maintaining a consistent approach across the decades will be "credit-positive," reducing threats to cost-recovery. Ratings agencies will take notice, lowering the cost of debt, benefitting all stakeholders.
- **FOURTH**, governmental regulation itself will benefit. Active, risk-aware regulators will involve a wide range of stakeholders in the regulatory process, building support for the regulators' decision. Consistent, transparent, active regulation will help other state officials—governors and legislators—develop a clearer vision of the options for the state's energy economy.
- **FINALLY**, our entire society will benefit as utilities and their regulators develop a cleaner, smarter, more resilient electricity system. Regulation that faithfully considers all risks, including the future environmental risks of various utility investments, will help society spend its limited resources most productively. In other words, risk-aware regulation can improve the economic outcome of these large investments.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

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APPENDIX 1:

UNDERSTANDING UTILITY FINANCE



MOST INVESTOR-OWNED UTILITIES (IOUS) IN THE UNITED STATES ARE IN A CONSTRUCTION CYCLE OWING TO THE NEED TO COMPLY WITH MORE STRINGENT AND EVOLVING ENVIRONMENTAL POLICIES AND TO IMPROVE AGING INFRASTRUCTURE. NEW INFRASTRUCTURE PROJECTS INCLUDE SMART GRID, NEW GENERATION AND TRANSMISSION. THE IOUS, THEREFORE, WILL BE LOOKING TO THE CAPITAL MARKETS TO HELP FINANCE THEIR RATHER LARGE CAPITAL EXPENDITURE PROGRAMS.

DEBT FINANCING

While the IOUs will be issuing some additional equity, a higher percentage of the new investment will be financed with debt. In general, utilities tend to be more leveraged than comparably-rated companies in other sectors (see the Rating Agencies section below). The electric utility sector's debt is primarily publicly issued bonds, including both first mortgage bonds (FMB) and senior unsecured bonds. While the utilities also issue preferred stock and hybrid debt securities, these instruments tend to represent a small portion of a company's capital structure. Non-recourse project finance is rare for utilities, but it is commonly used by unregulated affiliates.

Most regulated IOUs in the U.S. are owned by holding companies whose assets are primarily their equity interests in their respective subsidiaries. These operating company subsidiaries are typically wholly owned by the parent, so that all publicly-held stock is issued by the parent. Because most of these holding companies are quite large, the market for a holding company's stock is usually highly liquid.

In contrast to equity, bonds are issued by both the utility holding company and individual operating subsidiaries. Typically, holding and operating company bonds are non-recourse to affiliates. This means that each bond issuer within the corporate family will have its own credit profile that affects the price of the respective bonds. To illustrate this point, compare two American Electric Power subsidiaries, Ohio Power and Indiana Michigan. The companies have different regulators, generation mix, customer bases and, consequently, different senior unsecured Moody's bond ratings of Baa1 and Baa2, respectively. For this reason, each bond issuance of the corporate family trades somewhat independently.

Utility bonds trade in secondary markets and are traded over-the-counter rather than in exchanges like equities. For bond issuance of less than $300 million, the secondary market is illiquid and not very robust. Smaller utilities are frequently forced into the private placement market with their small issuances and accordingly pay higher interest rates compared to similarly-rated larger companies. Even if these smaller issues are placed in the public market, there is a premium for the expected lack of liquidity.

Secured debt in the form of FMBs is common in the electric utility sector. Such bonds are usually secured by an undivided lien on almost all of the assets of an operating utility. Bond documentation (called an "indenture") prohibits the issuance of such bonds in an amount that exceeds a specified percentage (usually in the range of 60 percent) of the asset value of the collateral. The maturities of these bonds are frequently as long as 30 years, and in rare occasions longer). While the lien on assets may limit a company's financing flexibility, the interest rate paid to investors is lower than for unsecured debt. The proceeds from FMBs are usually used to finance or refinance long-lived assets.

Senior unsecured bonds can be issued at any maturity, but terms of five and ten years are most common. These instruments are "junior" to FMBs, so that, in an event of default, these debt holders would be repaid only after the secured debt. But these bonds are "senior" to hybrids and preferred stock. In a bankruptcy, senior unsecured bonds are usually deemed equal in standing with trade obligations, such as unpaid fuel and material bills.

Utilities typically have "negative trade cycles," meaning that cash receipts tend to lag outlays. IOUs' short-term payables such as fuel purchases, salaries and employee benefits are due in a matter of days after the obligation is incurred. In contrast, the utility's largest short-term assets are usually customer receivables which are not due for 45—60 days after the gas or electricity is delivered. Therefore, utilities have short term cash needs referred to as "working capital" needs. To finance these short term needs utilities have bank credit lines and sometimes trade receivable facilities.

For larger utility corporate families, these bank lines can amount to billions of dollars. For example, American Electric Power has two large bank lines of $1.5 and $1.7 billion that

mature in 2015 and 2016, respectively. AEP's lines and most of those of other utilities are revolving in nature. While termination dates typically range from one to five years for these lines, the utility usually pays down borrowings in a few months and accesses the line again when needed.

Interest on bank lines of credit is paid only when the lines are used, with a much lower fee paid on the unused portion of the lines. For financially weak utility companies, banks often require security for bank lines . But because utility operating companies are rarely rated below BBB-/Baa3, bank lines are, for the most part, unsecured.

Some larger utilities have receivable facilities in addition to revolving bank lines. The lender in a receivables facility usually purchases the customer receivables. There is an assumed interest expense in these transactions which is usually lower than the rate charged by banks for unsecured revolving lines.

Although preferred stock is a form of equity, it is usually purchased by a bond investor who is comfortable with the credit quality of the issuer and willing to take a junior position in order to get a higher return on its investment. There are also hybrid securities. Although they are technically debt instruments, they are so deeply subordinate and with such long repayment periods that investors and the rating agencies view these instruments much like equities. Frequently, hybrids allow the issuer to defer interest payments for a number of years. Some hybrids can be converted to equity at either the issuer's or investor's option.

S&P is the most rigorous of the rating agencies in treating the fixed component of power purchase agreements (PPA) as debt-like in nature. Also, some Wall Street analysts look at PPAs as liabilities with debt-like attributes. That being said, those analysts who do not consider PPAs as debt-like still incorporate in their analysis the credit implications of these frequently large obligations.

EQUITY FINANCING

In order to maintain debt ratings and the goodwill of fixed income investors, utility managers must finance some portion of their projects with equity. Managements are usually reluctant to go to market with large new stock issuances. Equity investors often see new stock as being dilutive to their interests, resulting in a decrease in the market price of the stock. But if a utility has a large capital expenditure program it may have no choice but to issue equity in order maintain its credit profile.

For more modest capital expenditure programs, a company may be able to rely on incremental increases to equity to maintain a desired debt to equity ratio. While the dividend payout ratios are high in this sector, they are rarely 100 percent, so that for most companies, equity increases, at least modestly, through retained earnings. Many companies issue equity in small incremental amounts every year to fulfill commitments to employee pension or rewards programs. Also, many utility holding companies offer their existing equity holders the opportunity to reinvest dividends in stock. For larger companies these programs can add $300 - $500 million annually in additional equity. Since these programs are incremental, stock prices are usually unaffected.

OTHER FINANCING

Project finance (PF) can also be used to fund capital expenditures. These instruments are usually asset-specific and non-recourse to the utility, so that the pricing is higher than traditional investment-grade utility debt. Project finance is usually used by financially weaker non-regulated power developers.

Some companies are looking to PF as a means of financing large projects so that risk to the utility is reduced. However, the potential of cost overruns, the long construction/development periods and use of new technology will make it hard to find PF financing for projects like new nuclear plants. This also applies to carbon capture/sequestration projects, as the technology is not seasoned enough for most PF investors. This means that, utilities may need to finance new nuclear and carbon capture/sequestration projects using their existing balance sheets.

In order to reduce risk, a utility can pursue projects in partnership with other companies. Currently proposed large gas transport and electric transmission projects are being pursued by utility consortiums. Individual participants in gas transport projects in particular have used Master Limited Partnerships (MLPs) as a way to finance their interests. MLPs are owned by general and limited partners. Usually the general partner is the pipeline utility or a utility holding company. Limited partner units are sold to passive investors and are frequently traded on the same stock exchanges that list the parent company's common stock. One big difference between the MLP and an operating company is that earnings are not subject to corporate income tax. The unit holders pay personal income tax on the profits.

Companies have used both capital and operating lease structures to finance discrete projects, including power plants. The primary difference between an operating and capital lease is that the capital lease is reflected on the company's balance sheet. The commitment of the utility to the holder of the operating lease is deemed weaker. Most fixed income analysts, as well as the rating agencies, do not view these instruments as being materially different and treat operating leases for power plants as debt.

TYPICAL UTILITY INVESTORS

The largest buyers of utility equities and fixed income securities are large institutional investors such as insurance companies, mutual funds and pension plans. As of September 2011, 65 percent of utility equities were owned by institutions. While insurance companies and pension plans own utility equities, both trail mutual funds in the level of utility stock holdings. For example, the five largest holders of Exelon stock are mutual fund complexes.

Most retail investors own utility stock and bonds indirectly through mutual funds and 401k plans. But many individual investors also own utility equities directly, including utility employees. Small investors tend not to buy utility bonds because the secondary market in these instruments is rather illiquid, especially if the transaction size is small.

Common stock mutual funds with more conservative investment criteria are most interested in utility equities. While the market price of these stocks can vary, there is a very low probability of a catastrophic loss. Also, utility stocks usually have high levels of current income through dividend distributions. Another attractive attribute of these equities is that they are highly liquid. Essentially all utilities in the U.S. are owned by utility holding companies that issue common stock. Due to extensive consolidation in the sector over the past 20 years, these holding companies are large and have significant market capitalization. For these reasons, utility stocks are highly liquid and can be traded with limited transaction costs.

Utility fixed-income investments are far less liquid than equities. Thus, the typical bond investor holds onto the instruments much longer than the typical equity investor. Bonds are issued both by the utility holding company and individual operating subsidiaries. Because bonds are less liquid in the secondary market, investors in these instruments, such as pension plans and insurance companies, tend to have longer time horizons. Four of the top five investors in Exelon Corp bonds due 2035 are pension plans and insurance companies. Mutual bond funds tend to buy shorter-dated bonds.

The buyers of first mortgage bonds (FMBs) are frequently buy-and-hold investors. As FMBs are over-collateralized, bondholders are comfortable that they will be less affected by unforeseen negative credit events. It is not unusual for a large insurance company to buy a large piece of an FMB deal at issuance and hold it to maturity. Retail investors in utility bonds also tend to be buy-and-hold investors, as it is hard for them to divest their positions which are typically small compared to the large institutions. The relative illiquidity of utility bonds means that transaction costs can be high and greatly reduce the net proceeds from a sale.

Utility employees frequently own the stock of the companies for which they work. Employees with defined benefit pensions, however, are not large holders of utility stocks because pension plans hold little if any of an employer's stock owing to ERISA rules and prudent asset management practices. Mid-level non-unionized employees frequently have 401ks that are typically invested in mutual funds or similar instruments. However, it is not unusual for company matching of the employees' 401k contributions to be in company stock. Finally, senior management's incentive compensation is frequently paid in the company's common equity, in part to ensure that management's interests are aligned with those of the shareholders.

RATING AGENCIES

Most utilities have ratings from three rating agencies: Moody's Investors Services, Standard & Poor's Ratings Services, and Fitch Ratings. Having three ratings is unlike other sectors, which frequently use two ratings—Moody's or Standard & Poor's. Most utility bonds are held by large institutional investors who demand that issuers have at least Moody's and Standard & Poor's ratings.

Failing to have two ratings would cause investors to demand a very high premium on their investments, far more than the cost to utilities of paying the agencies to rate them. Having a third rating from Fitch usually slightly lowers the interest rate further. While investors have become less comfortable with the rating agencies' evaluations of structured finance transactions, this dissatisfaction has not carried over greatly into the corporate bond market, and especially not the utility bond market.

The agencies usually assign a rating for each company referred to as an *issuer rating*. They also rate specific debt issues, which may be higher or lower than the issuer rating. Typically a secured bond will have a higher rating than its issuer; preferred stock is assigned a lower rating than the issuer. Ratings range from AAA to D.[80] The "AAA" rating is reserved for entities that have virtually no probability of default. A "D" rating indicates that the company is in default.

The three agencies each take into account both the probability of default, as well as the prospects of recovery for the bond investor if there is a default. Utilities traditionally are considered to have high recovery prospects because they are asset-heavy companies. In other words, if liquidation were necessary, bond holders would be protected because their loans are backed by hard assets that could be sold to cover the debt. Further, the probability of default is low because utility rates are regulated, and regulators have frequently increased rates when utilities have encountered financial

80 Standard & Poor's and Fitch use the same ratings nomenclature. It was designed by Fitch and sold to S&P. For entities rated between AA and CCC the agencies break down each rating category further with a plus sign or a minus sign. For example, bonds in the BBB category can be rated BBB+, BBB and BBB-. Moody's ratings nomenclature is slightly different. The corresponding ratings in BBB category for Moody's are Baa1, Baa2 and Baa3. The agencies will also provide each rating with an outlook that is stable, positive or negative.

problems owing to events outside of companies' control. However, there are a few notable instances where commissions could not or would not raise rates to avoid defaults including the bankruptcies of Public Service of New Hampshire and Pacific Gas and Electric.

It is unusual for a utility operating company to have a non-investment grade rating (Non-IG, also referred to as high yield, speculative grade, or junk). Typically Non-IG ratings are the result of companies incurring sizable expenses for which regulators are not willing or able to give timely or adequate rate relief. Dropping below IG can be problematic for utilities because interest rates increase markedly. Large institutional investors have limited ability to purchase such bonds under the investment criteria set by their boards. Another problem with having an Non-IG rating is that the cost of hedging rises owing to increased collateral requirements as counterparties demand greater security from the weakened credit.

In developing their ratings, the agencies consider both quantitative and more subjective factors. The quantitative analysis tends to look at cash flow "coverage" of total debt and of annual fixed income payment obligations, as well as overall debt levels. In contrast, the typical equity analyst focuses on earnings. The rating agencies are less interested in the allowed returns granted by regulators than they are in the size of any rate decrease or increase and its effect on cash flow.

That said, the rating agency may look at allowed returns to evaluate the "quality" of regulation in a given state. All things being equal, they may give a higher rating to a company in a state with "constructive" regulation than to a company in a state with a less favorable regulatory climate. Constructive regulation to most rating agencies is where regulatory process is transparent and consistent across issuers in the state. Also, the agencies favor regulatory constructs that use forward-looking test years and timely recovery of prudently-incurred expenses. The agencies consider tracking mechanisms for fuel and purchased power costs as credit supportive because they help smooth out cash fluctuations. The agencies believe that while trackers result in periodic changes in rates for the customer, these mechanisms are preferable for consumers than the dramatic change in rates caused by fuel factors being lumped in with other expenses in a rate case.

Analysts also will look to see how utility managers interact with regulators. The agencies deem it a credit positive if management endeavors to develop construct relationships with regulators. The agencies may become concerned about the credit quality of a company if the state regulatory process becomes overly politicized. This may occur if a commission renders decisions with more of an eye toward making good press than applying appropriate utility regulatory standards. Politicized regulatory environments can also occur when a commission is professional and fair, but outside political forces, such as governors, attorneys general or legislators challenge a prudently decided case.

The rating agencies themselves can at times act as *de facto* regulators. Because utilities are more highly levered than most any other sector, interest expenses can be a significant part of a company's cost structure. Ratings affect interest rates. The agencies will look negatively at anything that increases event risk. The larger an undertaking, the greater the fallout if an unforeseen event undermines the project. A utility embarking on the development of a large facility like a large generation or transmission project, especially if is not preapproved by the regulators, might result in a heightened focus on the company by the agencies. The rating action could merely be change in outlook from stable to negative, which could in turn have a negative impact on the market price of outstanding bonds, interest rates on new issuances and even on equity prices. Many utility stock investors are conservative and pay more attention to rating agency comments and actions than investors with holdings in more speculative industries.

APPENDIX 2:

TOOLS IN THE IRP PROCESS

REGULATORS HAVE SEVERAL TOOLS AT THEIR DISPOSAL IN THE IRP PROCESS. ONE OF THE MOST IMPORTANT IS THE UTILITY REDISPATCH MODEL. THIS IS A COMPLEX COMPUTER PROGRAM THAT SIMULATES THE OPERATION OF A UTILITY'S SYSTEM UNDER INPUT ASSUMPTIONS PROVIDED BY THE USER. THE TERM "REDISPATCH" REFERS TO THE FACT THAT THE SOFTWARE MIMICS THE OPERATION OF AN ACTUAL UTILITY SYSTEM, "DISPATCHING" THE HYPOTHETICAL GENERATION RESOURCES AGAINST A MODEL LOAD SHAPE, OFTEN HOUR-BY-HOUR FOR MOST COMMONLY USED MODELS.

Three examples of these models are Prosym, licensed by Henwood Energy Services; Strategist, licensed by Ventyx; and GE MAPS, licensed by General Electric.

A model typically creates a 20- or 40-year future utility scenario, based on load projections provided by the user. The utility's energy and peak demand is projected for each hour of the time period, using known relationships about loads during different hours, days of the week and seasons of the year. The model then "dispatches" the most economic combination of existing or hypothetical new resources to meet the load in every hour of that time period.

The operating characteristics of each generating resource is specified as to its availability, fuel efficiency, fuel cost, maintenance schedule, and, in some models, its emissions profile. The resources available to the model will be a mixture of existing plants, taking note of their future retirement dates, plus any hypothetical new resources required by load growth. The model incorporates estimates of regional power purchases and their price, transmission paths and their constraints, fuel contracts, the retirement of existing facilities, etc.

In this way, the user of the model can test various combinations (scenarios) of proposed new generating plants, including base load plants, intermediate and peaking plants, intermittent renewable resources, etc. The model will calculate the utility's revenue requirement, fuel costs, and purchased power expenses in each scenario. The model might be used to estimate the cost of operating the system with a specific hypothetical portfolio, predict the level of emissions for a portfolio, measure the value of energy efficiency programs, test the relative value of different resources, measure the reliability of the system, etc.

The reader might analogize this modeling to "fantasy" baseball, where hypothetical teams play hypothetical games, yielding win-loss records, batting averages and pennant races.

As powerful as these modeling tools are, they are *production* models, first and foremost. As such, they are not particularly good at dealing with assumptions about energy efficiency and demand response. In using such models, the regulator must insist that the utility gives appropriate treatment to demand-side resources. It may be possible to re-work models to do this, or it may be necessary to conduct extra sensitivity analyses at varying levels of energy efficiency and demand response.

IRP SENSITIVITY ANALYSES

A redispatch modeling tool allows a utility and the regulator to test the resilience of portfolios against different possible futures. For example, a regulator might want to know how five different generation portfolios behave under situations of high natural gas prices, or tougher environmental regulations. By varying the input assumptions while monitoring the relevant output (e.g., net present value of future revenue requirements) the regulator can assess the risk that contending portfolios pose to future rates if, for example, fuel prices vary from their predicted levels.

To illustrate this idea, consider the following material from a case in Colorado. **Figure Appendix - 1** is a page excerpted from Xcel Energy's 2009 analysis in support of a resource plan filed before the Colorado Public Utilities Commission. The page shows the results of sensitivity analyses for the price of natural gas (high and low) and the cost of carbon emissions (high and low) for twelve different portfolios being considered by the Colorado PUC.

In all, the Colorado PUC studied 48 different generation portfolios in this IRP case. The portfolios differed based on how much natural gas generation was added, how much wind and solar generation was added, the schedule for closing some existing coal-fired power plants, the level of energy efficiency assumed, etc. (The actual generation units in each portfolio are not identified in this public document.

Figure Appendix - 1

EXAMPLE OF IRP SENSITIVITY ANALYSES

Base Scenario Assumption: High Efficiency, Medium Solar

Representative of Preferred Plan

Primary Scenario
High DSM (130% Goal)
Medium Section 123 (200 MW)
Base Load

Portfolios 1-12

Key Portfolio Characteristic		Portfolio Number 1	2	3	4	5	6	7	8	9	10	11	12
		Portfolio Rank within Scenario (PVRR) 1	2	3	4	5	6	7	8	9	10	11	12
Wind (MW)													
Solar (MW)													
Intermittent (MW)													
Solar Storage (MW)													
Gas (MW)													
Other (MW)	1												
Total (MW)		1,872	1,902	1,907	1,932	1,977	1,966	1,911	1,860	1,936	2,039	1,982	2,078
Owned %													
Owned MW													
Total 123 (MW)													
CO2 (M ton)	2	26.8	26.7	26.8	26.7	26.6	26.8	26.8	26.8	26.9	26.6	26.5	26.6
% New Build	3												
Externalities	4	2	2	2	2	2	1	2	2	1	2	3	2
PVRR rank		1	2	3	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	49,344	49,361	49,365	49,387	49,402	49,478	49,490	49,526	49,645	49,675	49,675	49,822
PVRR Delta ($M)	6	-	17	21	43	58	134	146	182	301	331	331	478
PV Rate ($/MWh)	7	71.87	71.90	71.90	71.94	71.96	72.07	72.09	72.14	72.31	72.36	72.36	72.57
CO2 Delta (M ton)	8	-	(0.30)	(0.02)	(0.50)	(0.68)	1.79	(0.09)	(0.04)	0.80	(0.57)	(0.81)	(0.65)
$10/ton CO2 Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	43,695	43,722	43,716	43,758	43,786	43,805	43,845	43,877	43,981	44,054	44,080	44,203
Change ($M)	10	(5,649)	(5,638)	(5,649)	(5,628)	(5,616)	(5,673)	(5,645)	(5,649)	(5,664)	(5,622)	(5,596)	(5,619)
PVRR Delta ($M)	11	-	27	21	63	91	110	150	182	286	358	384	508
$40/ton CO2 Sensitivity													
PVRR rank	9	3	2	5	4	1	7	6	8	11	10	9	12
PVRR ($M)	5	60,066	60,061	60,087	60,067	60,056	60,247	60,204	60,250	60,392	60,311	60,285	60,451
Change ($M)	10	10,723	10,701	10,723	10,680	10,654	10,769	10,714	10,724	10,747	10,636	10,610	10,629
PVRR Delta ($M)	11	10	5	31	11	-	191	148	194	336	255	229	395
Low Gas Price Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	10	9	11	12
PVRR ($M)	5	47,935	47,959	47,956	47,992	48,016	48,055	48,075	48,118	48,234	48,230	48,318	48,371
Change ($M)	10	(1,409)	(1,402)	(1,409)	(1,395)	(1,386)	(1,423)	(1,415)	(1,407)	(1,411)	(1,445)	(1,357)	(1,451)
PVRR Delta ($M)	11	-	24	22	57	81	121	140	184	299	295	383	436
High Gas Price Sensitivity													
PVRR rank	9	5	4	6	3	1	7	8	10	9	11	2	12
PVRR ($M)	5	57,122	57,091	57,144	57,070	57,025	57,295	57,326	58,234	57,421	58,268	57,059	58,464
Change ($M)	10	7,778	7,730	7,780	7,684	7,623	7,817	7,836	8,708	7,776	8,593	7,384	8,642
PVRR Delta ($M)	11	97	66	120	46	-	270	302	1,209	396	1,244	34	1,439

PVRR & Rank

PVRR & Rank

Otherwise, it would have created problems for the competitive bidding process used to award contracts to supply the power to the utility.)

Each column in the table represents a different portfolio, numbered 1 to 12. Portfolio 2 is the Xcel's preferred plan. The rows show the modeling results for each portfolio. For example, the Present Value of Revenue Requirements (PVRR) is calculated for each portfolio and is shown the line indicated by the first PVRR arrow, along with the ranking of that portfolio. The lower half of the chart shows the cost of each portfolio under different assumptions about the cost of carbon emissions (higher or lower than base case predictions) and for natural gas prices (higher or lower than base case predictions).

CAVEATS

Models are a terrific way to keep track of all the moving parts in the operation of a utility portfolio. But it is one thing to know that each resource has certain operating characteristics; it is quite another to see these qualities interact with each other in dynamic fashion. And while utility modeling tools, such as production cost models can be helpful, care must be taken with their use.

Obviously the models are helpful only to the extent that the inputs are reasonable and cover the range of possibilities the regulator wishes to examine. Load forecast must be developed with care; assumptions about future fuel costs are really educated guesses, and should be bracketed with ranges of sensitivity.

Because there are so many possible combinations, variations and sensitivities, the regulator in an IRP case must make a decision early in the process about the scope of the portfolios to be examined. The utility should be directed to analyze and present all scenarios requested by the regulator, together with any portfolios preferred by the utility.

Finally, the model's best use is to inform judgment, not substitute for it. The amount of data produced by models can be overwhelming and may give a false sense of accuracy. The risk-aware regulator will always understand the fundamental uncertainties that accompany projections of customer demand, future fuel costs and future environmental requirements.



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99 Chauncy Street
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T: 617-247-0700
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The Resource Value Framework

Reforming Energy Efficiency Cost-Effectiveness Screening

The National Efficiency Screening Project

March 28, 2014

National Home Performance Council

A Division of the Home Performance Coalition

The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening

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The National Efficiency Screening Project

The National Efficiency Screening Project (NESP) is a group of organizations and individuals that are working together to improve the way that utility customer-funded electricity and natural gas energy efficiency resources are screened for cost-effectiveness. NESP is coordinated by the National Home Performance Council, a division of the Home Performance Coalition. The purpose of this project is to improve efficiency screening practices throughout the United States, and to help inform decision makers regarding which efficiency resources are in the public interest and what level of investment is appropriate.

Project Members

The following organizations are members of the National Efficiency Screening Project, and support the principles and recommendations presented here.

National Home Performance Council / Home Performance Coalition
Alliance to Save Energy
American Council for an Energy Efficient Economy
Clinton Foundation: Home Energy Affordability Program
Conservation Services Group
Energy Federation Inc.
Northeast Energy Efficiency Council

NESP welcomes additional organizations to join this list of members. If your organization wishes to participate in this project, please sign up using the web site provided below.

Further Information

This document, and related materials from the NESP, are available at the following web site: nhpci.org/caimpaigns.html.

About this document

This document provides an overview of NESP's recommendations for using the Resource Value Framework (RVF) to improve cost-effectiveness testing. The rationale for and description of the RVF are intentionally succinct and compact in this report, despite the complexity of some of the issues. In the future, we may revise this report, as well as develop accompanying support documents or follow-up reports, to reflect stakeholder input and further analysis by the authors and project advisors.

Authors

This document was prepared by Tim Woolf, Synapse Energy Economics, Inc.; Chris Neme, Energy Futures Group; Pat Stanton, Conservation Services Group, Inc.; Robin LeBaron, National Home Performance Council; Kara Saul-Rinaldi, National Home Performance Council; and Steve Cowell, Conservation Services Group, Inc.

Project Advisors

Philippe Dunsky, Dunsky Energy Consulting
Tom Eckman, Northwest Power and Conservation Council
Sami Khawaja, Cadmus
Marty Kushler, American Council for an Energy Efficient Economy
Julie Michals, Northeast Energy Efficiency Partnerships
Peter Miller, Natural Resources Defense Council
Steve Schiller, Lawrence Berkeley National Laboratory
Rodney Sobin, Alliance to Save Energy

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1. MISSION STATEMENT

The National Efficiency Screening Project (NESP) is a group of organizations and individuals that are working together to improve the way that electricity and natural gas energy efficiency resources are screened for cost-effectiveness. The purpose of this initiative is to improve efficiency screening practices throughout the United States, and to help inform decision makers regarding which efficiency resources are in the public interest and what level of investment is appropriate.

Customer-funded energy efficiency programs have generated tens of billions of dollars of savings for households and businesses throughout the nation. In addition to reducing energy bills of program participants, efficiency programs create real benefits for all energy consumers, by deferring the need for new power plants, by avoiding transmission and distribution costs, by reducing risk on the utility system, and by helping to achieve a variety of important energy policy goals.

States have a tremendous opportunity to expand upon these benefits through on-going and future energy efficiency initiatives. However, to take full advantage of this opportunity many states need to revisit and update their cost effectiveness screening methods and practices.

The California Standard Practice Manual has been widely used for many years as a guide for how to apply energy efficiency screening tests. However, this manual is out of date and does not address several of the key challenges facing regulators today. Its treatment of many issues is also very general, leaving significant details to interpretation. As a result, what are commonly thought to be "standard" tests are in fact applied inconsistently across states, including in ways that do not accurately reflect the value of energy efficiency.[1]

The NESP was formed with a view to encouraging more consistent application of energy efficiency screening tests. To this end, we will prepare an initial framework and, going forward, intend to design a new Standard Practice Manual to assist states in improving their efficiency screening.

2. THE RESOURCE VALUE FRAMEWORK

The NESP recommends that each state use the Resource Value Framework (RVF) for developing and implementing efficiency screening tests. The RVF includes the following elements. [2]

a. Both Flexibility and Guidance

The Resource Value Framework is not a recommendation for a single energy efficiency screening test. It is a framework of principles and recommendations to provide guidance for states to develop and

[1] For more information see National Home Performance Council, Best Practices in Energy Efficiency Program Screening: How to Ensure that the Value of Energy Efficiency is Properly Accounted For, July 2012.

[2] For more information see National Efficiency Screening Project, Recommendations for Reforming Energy Efficiency Cost-Effectiveness Screening in the United States, November 2013.

implement tests that are consistent with sound principles and best practices. It is intentionally designed to provide each state with the flexibility to ensure that the test they use meets their state's distinct needs and interests, as provided in relevant energy policies and regulatory orders.

b. Principles

In designing an energy efficiency screening test, each state should adhere to the following principles.

- The Public Interest. The ultimate objective of efficiency screening is to determine whether a particular energy efficiency program, or portfolio of programs, is in the public interest.
- Energy Policy Goals. Efficiency screening practices should account for the energy policy goals of each state, as articulated in legislation, commission orders, regulations, guidelines and other policy directives. These policy goals provide guidance with regard to which efficiency programs are in the public interest.
- Symmetry**.** Efficiency screening practices should ensure that tests are applied symmetrically, where both relevant costs and relevant benefits are included in the screening analysis. For example, a state that chooses to include participant costs in its screening test should also include participant benefits, including non-energy benefits, otherwise the test will be skewed against energy efficiency resources.
- Hard-to-Quantify Benefits. Efficiency screening practices should not exclude relevant benefits on the grounds that they are difficult to quantify and monetize. Several methods are available to approximate the magnitude of relevant benefits, as described below.
- Transparency. Efficiency program administrators should use a standard template to explicitly identify their state's energy policy goals and to document their assumptions and methodologies.
- Applicability to all resources. In general, these principles should be applied to all types of electric and gas utility resources; both demand-side and supply-side resources. For the purpose of efficiency resource screening, supply-side resource costs and benefits should be treated comparably to demand-side resources, so that they are explicitly evaluated on equivalent terms.

c. Designing an Appropriate Screening Test with the Resource Value Framework

At the outset it is important to recognize that there are essentially two overall regulatory "perspectives" that may be appropriate to use when screening efficiency: a utility system perspective and a societal perspective. A utility system perspective includes all of the costs and benefits that are experienced by the utility system, i.e., the utility costs to implement the energy efficiency resources and the utility system benefits in terms of avoided costs. As soon as a state decides to be more expansive and to include program participant costs and benefits, it has shifted from the utility perspective to a societal perspective.

Note that when we refer to a "utility system perspective" and a "societal perspective," we are not referring to the standard Utility Cost test, or the standard Societal Cost test. One of the key concepts underlying the Resource Value Framework is that states are not limited to these two strictly-defined tests. We are referring to these two perspectives as two regulatory outlooks upon which a state's screening test can be based.

Furthermore, regardless of whether a state has chosen a utility perspective or a societal perspective, it should also account for its specific energy policy goals in designing its screening test. In other words, the utility perspective and the societal perspective provide two theoretical foundations upon which each state should design its screening test. Additional costs and benefits should be added to either of these foundations, based upon the energy policy goals of the state.

To summarize, each state that uses the Resource Value Framework to design (or modify) its efficiency screening test should take the following steps:

1. Decide which overall perspective is appropriate for the state to begin development of its screening test. We recommend starting with a utility perspective or a societal perspective.
2. Identify the state's energy policy goals that are relevant to, and might be affected by, energy efficiency resources. Such goals might include, for example: assist low-income customers with high energy burdens, increase the diversity of energy resources, improve system reliability, reduce energy price volatility, reduce the environmental impacts of energy, or promote economic development.
3. Identify a way of accounting for those energy policy goals in the state's screening test. Below we describe several methods to account for hard-to-quantify costs and benefits. Each state should identify which method will be used to account for each of its relevant energy goals.
4. Use the Resource Value Framework template to explicitly identify the assumptions and methodologies necessary to ensure that the test is balanced, transparent, and takes the appropriate energy policy goals into account. Below we provide some information and an example of what such a template should include.

We recognize that there may be value to applying more than one screening test when evaluating the cost-effectiveness of energy efficiency. In practice, however, it is often necessary to choose a *primary* test for screening energy efficiency, for those cases where an efficiency resource passes one test but not another. We recommend that states use the Resource Value Framework to design the primary test used to screen efficiency.

d. How the Standard Screening Tests Fit Within the Resource Value Framework

Here we briefly summarize how the Resource Value Framework compares with the standard efficiency screening tests described in the California Standard Practice Manual.[3] (See Attachment 1 for an overview of the standard screening tests.) We also summarize some recommendations about how the standard screening tests should, or should not, be used when evaluating cost-effectiveness.

Note that while almost all states indicate that they are using the TRC test, the Utility Cost test, or the Societal test, in practice states use many different variations of these tests. In fact, very few states use the exact same screening test, because each modifies the "standard" tests in a variety of ways. The

[3] We use the term "standard" screening tests to refer to the theoretical definition of the test, as distinct from the tests that are applied in practice, which vary considerably across states.

primary purpose of the Resource Value Framework is to provide a set of principles and concepts that allow states to continue this practice of developing their own screening test, but ensures that it is done in a way that is explicit, transparent, balanced, and methodologically consistent.

The Utility Cost Test[4]

The utility system costs and benefits should be included in any efficiency screening test, regardless of whether a state uses a utility system perspective or a societal perspective. Therefore, any efficiency screening test should include the components of the standard Utility Cost test. However, states that use the Resource Value Framework should recognize that utility system impacts are often not the only components to consider in a screening test. Every state should also ensure that its screening test properly accounts for its energy policy goals.

The Societal Cost Test

The Societal Cost test, as is sometimes applied today, typically includes utility system impacts, plus participant impacts, plus selected societal impacts (e.g., environmental externalities, economic development). States that use the Resource Value Framework to design a screening test, choose to apply a societal perspective, and have policy goals that address societal impacts (e.g., reduce environmental impacts of energy, promote job creation), will end up with a screening test that is similar to the Societal cost test as it is commonly applied today. It is important that if this perspective is chosen, *both* all participant costs *and* all participant benefits are included in the analysis.

The Total Resource Cost Test

We recommend caution in using the TRC test to screen energy efficiency resources. First, in practice, most states that currently use the TRC include participant costs, but do not include any relevant participant non-energy benefits, with the result being a test that is both biased against efficiency resources and that provides decision-makers with inaccurate information regarding “total resource" costs and benefits. States that decide to use the TRC test should ensure that participant costs and participant benefits are fully captured, using reasonable estimates of non-energy benefits. Second, a decision to fully include participant costs and benefits in the screening test essentially leads toward adoption of a societal perspective. By including participant costs of efficiency resources - costs which are outside of the scope of utility costs - the TRC test crosses a fundamental boundary and moves toward a societal scope. If the goal of the test is to include total costs and benefits beyond a utility cost framework, a societal perspective is more appropriate than the TRC test perspective.

The Participant Cost Test

We recommend that the standard Participant Cost test not be used for screening energy efficiency resources. While the impacts on program participants may be an important consideration, it is a secondary consideration relative to the impacts captured in the other tests. This test should be used for

[4] This test is sometimes referred to as the Program Administrator Cost (PAC) test.

program design and customer information purposes, but not for portfolio or program cost-effectiveness screening.

The Ratepayer Impact Measure Test

We recommend that the standard Ratepayer Impact Measure test not be used for screening energy efficiency resources. Rate impacts are not a matter of cost-effectiveness; they concern transfers from non-participants to participants. Furthermore, the RIM test is not a good indicator of customer equity: It is overly narrow, ignores many of the benefits of energy efficiency programs, is inconsistent with the assessment of supply-side resources, does not necessarily reflect the actual impact on rates, and deprives customers of the opportunity to lower their bills through energy efficiency measures. Utilities and regulators that are concerned about the rate impacts of efficiency resources should address customer equity concerns separately from the cost-effectiveness screening, by comprehensively analyzing rate, bill and customer participation impacts, and by ensuring that all customer classes and segments have reasonable access to energy efficiency program opportunities.[5]

e. Treatment of Benefits

Efficiency screening practices should not exclude relevant benefits on the grounds that they are difficult to quantify.[6] Applying rough or qualitative approximations of hard-to-quantify benefits is preferable to assuming that those benefits do not exist or have no value. We recommend that the following options be used to account for relevant benefits:

- Relevant benefits should be put into monetary terms to the greatest extent possible.
- In the absence of monetary terms, relevant benefits should be accounted for using proxies (either in terms of a percent of benefits or in terms of $/MWh or $/therm) to approximate the value of the non-monetized benefits.
- In the absence of monetary terms or proxies, relevant benefits should be accounted for using alternative screening benchmarks, i.e., allowing efficiency programs to be considered cost-effective at pre-determined benefit-cost ratios of less than one.
- In the absence of better alternatives, relevant benefits should be accounted for using regulatory judgment, i.e., allowing regulators and program administrators to account for hard-to-quantify benefits without using any of the options above.
- Those relevant benefits that are not put into monetary terms should nonetheless be quantified (e.g., estimated in terms of tons of emissions avoided, number of jobs produced, reduced sick days) to the extent possible. Quantification of relevant benefits can help inform the application of proxies, alternative benchmarks and regulatory judgment.

5 See State Energy Efficiency Action Network 2011. Analyzing and Managing Bill Impacts of Energy Efficiency Programs: Principles and Recommendations.

6 These recommendations and methodologies also apply to relevant hard-to-quantify costs.

f. Documentation and Transparency

We recommend that states use a Resource Value Framework template to provide a transparent, consistent structure for presenting efficiency costs and benefits. The template should clearly document the key screening assumptions (e.g., discount rate, measure life, savings levels), as well as the quantitative and qualitative cost and benefit findings. A sample Resource Value Framework template is provided below.

Section 1 of this template should include the key pertinent assumptions used in screening the efficiency resource. If the resource is screened at the program level, then there should be one template filled out for each program. If the resource is screened at the sector or portfolio level, then the template should be applied to the sector or portfolio.

Section 2 should include the monetized utility system costs and benefits. These costs and benefits should be the foundation for any efficiency screening test.

Section 3 should include monetized participant costs and participant benefits – for those states that have explicitly decided to include participant costs and benefits. If a state chooses not to include participant benefits (including reasonable estimates of participant non-energy benefits), then it cannot include participant costs either. In such a case, Section 3 should be left blank.

Section 4 should account for monetized public costs and benefits, as appropriate, in order to reflect the state's articulated energy policies. These impacts can be added in to all of the other monetized costs and benefits. Finally, Section 5 should include all of the non-monetized public costs and benefits deemed necessary to reflect the state's energy policies, so that these can be considered separately from the total monetized costs. These public costs and benefits should be accounted for in any efficiency screening test. Including these public impacts is necessary to align the efficiency screening test with the state's energy policy goals. This alignment with a state's energy policy goals is what distinguishes the Resource Value Framework from the standard efficiency screening tests.

It is important to reiterate that Section 2 presents a list of the utility system costs and benefits that should be included in any efficiency screening test. Sections 3, 4 and 5, however, present an illustrative list of costs and benefits that a state should take into account, depending upon its energy policy goals. States may choose to account for impacts beyond the illustrative impacts presented above. Also note that this template should be accompanied by references that provide full documentation for all the assumptions and results presented.[7]

[7] These assumptions are often documented in a Technical Reference Manual.

Resource Value Framework - Template			
Program Name:		Date:	
1. Key Assumptions, Parameters and Summary of Results			
Analysis Level	☐ Program		
	☐ Portfolio		
Measure Life		Discount Rate	
Projected Annual Savings		Projected Lifetime Utility Savings	
2. Monetized Utility Costs		**Monetized Utility Benefits**	
Program Administration		Avoided Energy Costs	
Incentives Paid to Participants		Avoided Capacity Costs	
Shareholder Incentive		Avoided T&D Costs	
Other Utility Costs		Wholesale Market Price Suppression	
		Avoided Environmental Compliance Costs	
		Other Utility System Benefits	
NPV Total Utility Cost		NPV Total Utility Benefits	
3. Monetized Participant Costs		**Monetized Participant Benefits**	
Participant Contribution		Participants' Savings of Other Fuels	
Participant's Increased O&M Costs		Participant Non-Energy Benefits:	
Other Participant Costs		Participants' Water and Sewer Savings	
		Participants' Reduced O&M Costs	
		Participants' Health Impacts	
		Participant Employee Productivity	
		Participant Comfort	
		Additional Low-Income Participant Benefits	
		Other Participant Non-Energy Benefits	
NPV Total Participant Cost		NPV Total Participant Benefits	
4. Monetized Public Costs		**Monetized Public Benefits**	
Public Costs		Public Benefits of Low Income Programs	
		Reduced Environmental Impacts (if monetized)	
		Public Fuel and Water Savings	
		Reduced Public Health Care Costs	
		Other Public Benefits	
NPV Total Public Costs		NPV Total Public Benefits	
Total Monetized Costs and Benefits			
Total Costs		**Total Benefits**	
Benefit- Cost Ratio		**Net Benefits**	
5. Non-Monetized Public Costs and Benefits			
Non-Monetized Benefits		Comments	
Promotion of Customer Equity			
Promotion of Market Transformation			
Reduced Environmental Impacts (if not monetized)			
Increased Jobs and Economic Development			
6. Determination:			
☐ Program is in the public interest		☐ Program is not in the Public Interest	

3. ADDITIONAL SCREENING METHODOLOGIES AND ASSUMPTIONS

Regardless of how each state ultimately designs a screening test, we recommend that each state apply the following best practices for screening energy efficiency:

- Avoided costs. States should require that efficiency screening analyses account for all relevant utility system costs avoided by efficiency resources, including: generation costs; transmission costs; distribution costs; environmental compliance costs; the price suppression effects in wholesale markets; and utility-perspective non-energy benefits.
- Additional utility system benefits. Energy efficiency screening practices should recognize the benefits that some programs offer regarding customer equity, risk reduction, DRIPE, and market transformation. These should be considered benefits that accrue to the utility system, and should therefore be included in any cost-effectiveness test.
- Discount rates. States should require that the discount rates used to screen energy efficiency be based on the overall regulatory perspective underlying the screening test, and the risk associated with the energy efficiency investment. For example, states that use the societal perspective should use a societal discount rate, such as a U.S. Treasury Note rate for a period of time equivalent to the efficiency portfolio lifetime.
- Risk benefits. States should account for risk mitigation benefits when screening energy efficiency. Risk benefits accrue to the utility system, and therefore should be included in any screening test. Risk benefits should be accounted for either in selecting a discount rate, in modeling avoided costs, or as an explicit benefit to be included in the cost-effectiveness analysis.
- Screening level. States should screen energy efficiency resources at the program, sector or portfolio level; not at the measure level.
- Study period. Efficiency screening analyses should use a study period that is long enough to include the full operating lives of all the measures included in the energy efficiency programs.

4. ADDITIONAL RESEARCH

We recommend that research be undertaken to address several efficiency screening issues that warrant additional analysis and discussion. For example, additional research on the following topics would help contribute to the improvement of energy efficiency screening in many states:

- An analysis of the appropriate choice of specific discount rates to use when screening energy efficiency resources to represent a utility or societal perspective. This would include an assessment of the cost of capital for funding energy efficiency, as well as the expected risk associated with the resource.
- An analysis providing generic estimates of proxy values for the most important participant non-energy benefits. The purpose of this would be to provide states with readily-available, well-documented, transparent and credible proxy values for non-energy benefits, making it more practical to account for these benefits without the need for sometimes costly research.
- An analysis of the appropriate way to account for rate and bill impacts when screening energy efficiency programs. This would include an assessment of how to quantitatively assess customer

equity issues associated with energy efficiency resources, without relying upon the flawed Rate Impact Measure test.

- An analysis of the appropriate way to account for free-riders, spillover, market transformation. The purpose of this would be to provide guidance for how states should use "gross" savings and "net" savings estimates in a consistent, sound manner over both the short-term and long-term planning horizon.
- An analysis of the true incremental cost of an efficiency measure. This would include recommendations for how to account for the incremental measure cost caused by improved efficiency, as distinguished from the incremental measure cost caused by non-efficiency features.
- An analysis of the proper application of measure lives and study periods.

Finally, we recommend that a new Energy Efficiency Standard Practice Manual be developed to build off of the concepts outlined in this document. The purpose of this new manual would be to update and expand upon the California Standard Practice Manual, and to provide comprehensive guidance for all states on how to improve their energy efficiency screening practices. We intend to develop such a manual and to include a wide range of stakeholders in that process.

Attachment 1 – The Standard Cost-Effectiveness Tests

Components of the Standard Cost-Effectiveness Tests

	Participant Cost Test	RIM Test	Utility Cost Test	TRC Test	Societal Cost Test
Energy Efficiency Program Benefits:					
Avoided Energy Costs	---	Yes	Yes	Yes	Yes
Avoided Capacity Costs	---	Yes	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	---	Yes	Yes	Yes	Yes
Wholesale Market Price Suppression Effects	---	Yes	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (utility)	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (participant)	Yes	---	---	Yes*	Yes*
Non-Energy Benefits (societal)	---	---	---	---	Yes
Customer Bill Savings	Yes	---	---	---	---
Energy Efficiency Program Costs:					
Program Administrator Costs	---	Yes	Yes	Yes	Yes
EE Measure Cost: Program Financial Incentive	---	Yes	Yes	Yes	Yes
EE Measure Cost: Participant Contribution	Yes	---	---	Yes	Yes
Lost Revenues to the Utility	---	Yes	---	---	---

* In theory, participant non-energy benefits should be included in the TRC and the Societal tests. However, in practice they are typically underestimated or wholly neglected. As a result, most TRC assessments understate the efficiency benefits.

Implications of the Standard Cost-Effectiveness Tests

Test	Key Question Answered	Summary Approach	Implications
Societal Cost	Will total costs to society decrease?	Includes the costs and benefits experienced by all members of society.	Most comprehensive comparison.
Total Resource Cost	Will utility system costs plus program participants' costs decrease?	Includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants.	By including impacts beyond the utility's costs and benefits, this test is essentially based on a societal perspective.
Utility Cost	Will utility system costs decrease?	Includes the costs and benefits experienced by the utility system.	Limited to impacts on utility revenue requirements. Indicates net impact on utility costs and utility bills.
Participant	Will program participants' costs decrease?	Includes the costs and benefits experienced by the customers who participate in the program.	Useful in program design to improve participation. Of limited use for cost-effectiveness screening.
Rate Impact Measure	Will utility rates decrease?	Includes the costs and benefits that will affect utility rates, including utility system costs and benefits as well as lost revenues.	Does not provide useful information regarding rate impacts or customer equity. Should not be used for cost-effectiveness screening.



A Division of the Home Performance Coalition

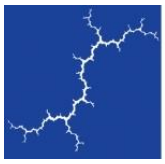
2013 Carbon Dioxide Price Forecast

November 1, 2013

(Minor corrections February 2014)

AUTHORS

Patrick Luckow
Elizabeth A. Stanton
Bruce Biewald
Jeremy Fisher
Frank Ackerman
Ezra Hausman



Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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1. EXECUTIVE SUMMARY

Prudent planning requires electric utilities and other stakeholders in carbon-intensive industries to use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. However, forecasting a CO_2 price can be difficult. While several bills have been introduced in Congress, the federal government has yet to legislate a policy to reduce greenhouse gas emissions in the United States.

Although this lack of a defined policy that sets a price on carbon poses a challenge in CO_2 price forecasting, an assumption that there will be no CO_2 price in the long run is not, in our view, reasonable. The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable, as are the type and scale of damages expected to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear. Any policy requiring or leading to greenhouse gas emission reductions will result in higher costs to the electricity resources that emit CO_2.

The Synapse 2013 CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. The current forecast updates Synapse's 2012 CO_2 price forecast, published in October 2012.[1] Our 2013 forecast incorporates new data that have become available since 2012, in order to provide useful CO_2 price estimates for utility resource planning purposes.

1.1. Key Assumptions

Synapse's 2013 CO_2 price forecast reflects our expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation passed by Congress, will result in significant pressure to decarbonize the electric power sector. The key assumptions of our forecast include:

- A federal program establishing a price for greenhouse gases is the probable eventual outcome, as it allows for a least-cost path to emissions reduction.
- Initial climate-focused policy actions are more likely to take a regulatory approach, e.g. Section 111(d) of the Clean Air Act. In the longer-term, federal legislation setting a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
    - New technological opportunities that lower the cost of carbon mitigation;

[1] Wilson et al., "2012 Carbon Dioxide Price Forecast," October 2012. http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

- A patchwork of state policies that achieve state emission targets for 2020, spurring industry demands for federal action;
- A series of executive actions taken by the President that spur demand for Congressional action;
- A Supreme Court decision that permits nuisance lawsuits, making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
- Mounting public outcry in response to increasingly compelling evidence of human-driven climate change.

Given the growing interest in reducing greenhouse gas emissions by states and municipalities throughout the nation, a lack of timely, substantive federal action will result in the enactment of diverse state and local policies. Heterogeneous—and potentially incompatible—sub-national climate policies would present a challenge to any company seeking to invest in CO_2 emitting power plants, both existing and new. Historically, there has been a pattern of states and regions leading with energy and environmental initiatives that have in time been superseded at the national level. It seems likely that this will be the dynamic going forward: a combination of state and regional actions, together with federal regulations, that are eventually eclipsed by a comprehensive federal carbon price.

We expect that federal regulatory measures together with regional and state policies will lead to the existence of a cost associated with greenhouse gas reductions in the near term. Prudent utility planning requires that utilities take this cost into account when engaging in resource planning, even before a federal carbon price is enacted.

1.2. Study Approach

To develop the 2013 CO_2 price forecast, Synapse reviewed several key developments that have occurred over the past year. These include:

- Proposed federal regulatory measures to limit CO_2 emissions from new power plants and administrative initiatives to advance regulation for existing units;
- Updates to the U.S. carbon price used to assess the climate benefit of federal rulemakings;
- Revisions to the Northeast's Regional Greenhouse Gas Initiative (RGGI) CO_2 policy and the first allowance auctions under California's AB 32 Cap-and-Trade program;
- The results of a multi-year Energy Modeling Forum (EMF) research effort on the costs of U.S. emissions abatement from nine integrated assessment modeling teams; and
- Carbon price forecasts from the most recent IRP efforts of 28 utilities.

1.3. Synapse's 2013 CO_2 Price Forecast

Based on analyses of the sources described in sections 3 through 9, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure ES-1 (below) shows the range covered by the Synapse forecasts. These projections assume that state and regional policies will combine with federal regulatory measures to put economic pressure on carbon-emitting resources in the next several years such that the costs of operating a high-carbon-emitting plant increase—followed later by a broader federal, market-based policy. In states other than the RGGI region[2] and California, we assume a zero carbon price for the next several years; by 2020, we expect that federal regulatory measures will begin to put economic pressure on carbon-emitting power plants throughout the United States. All annual carbon prices are reported in 2012 dollars per short ton of CO_2.[3]

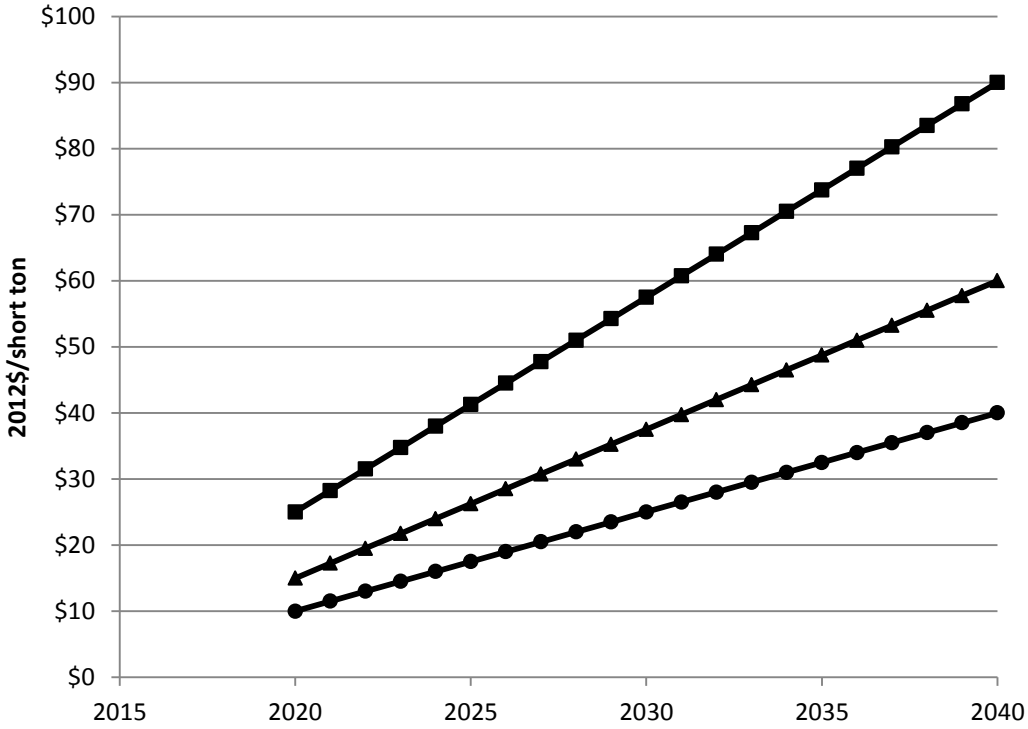
Each of the forecasts shown in Figure ES-1 represents a different level of political will for reducing carbon emissions, as described below.

- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

[2] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[3] Results from public modeling analyses were converted to 2012 dollars using price deflators taken from the U.S. Bureau of Economic Analysis, and are available at: http://www.bea.gov/national/nipaweb/SelectTable.asp. Consistent with U.S. Energy Information Administration and U.S. Environmental Protection Agency modeling analyses, a 5 percent real discount rate was used in all levelization calculations.

ES-1: Synapse 2013 CO_2 Price Trajectories



2. STRUCTURE OF THIS REPORT

This report presents Synapse's 2013 Low, Mid and High CO_2 price forecasts, along with the evidence assembled to inform these forecasts:

- Section 3 discusses broader concepts of CO_2 pricing.
- Sections 4 through 8 discuss existing state and federal legislation, potential future legislation, recent cap-and-trade results from the research community, and a range of current CO_2 price forecasts from utilities.
- Section 9 presents Synapse's 2013 Low, Mid, and High CO_2 price forecast, along with a comparison to recent utility forecasts.

Unless otherwise indicated, all prices are in 2012 dollars and CO_2 emissions are given in short tons.

3. WHAT IS A CARBON PRICE?

There are several co-existing meanings for the term "carbon price" or "CO_2 price": each of these meanings is appropriate in its own context. Here we give a brief introduction to five common types of carbon prices, along with a quick guide to which of the carbon price estimates reviewed in this report are based on which of these meanings. (Note that the definition of an additional term—the "price of carbon"—is ambiguous because it can at times mean several of the following.)

Carbon allowances (sometimes called credits or certificates, and best known for their use in policies called "cap and trade"): Allowances are certificates that give their holder the right to emit a unit of a particular pollutant. A fixed number of carbon allowances are issued by a government, some sold and, perhaps, some given away.[4] Subsequent trade of allowances in a secondary market is common to this policy design. The price that firms must pay to obtain allowances increases their cost of doing business, thereby giving an advantage to firms with cleaner, greener operations, and creating an incentive to lower emissions whenever it can be done for less than the price of allowances. The number of allowances—the "cap" in the cap-and-trade system—reflects the required society-wide emission reduction target. A greater reduction target results in a lower cap and a higher price for allowances. In the field of economics, pricing emissions is called "internalizing an externality": The external (not borne by the polluting enterprise) cost of pollution damages is assigned a market price (thus making it internal to the enterprise).

In this report: The Northeast's RGGI and California's Cap-and-Trade Program are both carbon allowance trading systems. In addition, the Kerry-Lieberman, Waxman-Markey, and Cantwell-Collins bills all proposed policy measures that included carbon allowance trading.

Carbon tax: A carbon tax also internalizes the externality of carbon pollution, but instead of selling or giving away rights to pollute (the allowance approach), a carbon tax creates an obligation for firms to pay a fee for each unit of carbon that they emit. In theory, if the value of damages were known with certainty, a tax could internalize the damages more accurately, by setting the tax rate equal to the damages; in practice, the valuation of damages is typically uncertain. In contrast to the government issuance of allowances, with a carbon tax there is no fixed amount of possible emissions (no "cap"). A cap-and-trade system specifies the amount of emission reduction, allowing variation in the price; a tax specifies the price on emissions, allowing variation in the resulting reductions. In both cases there is an incentive to reduce emissions whenever it can be done for less than the prevailing price. In both cases there is the option to continue emitting pollution, at the cost of either buying allowances or paying the tax. While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a general aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate.

[4] Whether or not allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder.

Effective price of carbon (sometimes called the notional, hypothetical, or voluntary price): Carbon allowances and carbon taxes internalize the climate change externality by making polluters pay. However, many other types of climate policies work not by making polluting more expensive per se, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions. Non-market-based emission control regulatory policies are called "command and control." For any such non-market policy there is an "effective" price: a market price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy. An effective price may be used internally within a firm, government agency, or other entity to represent the effects of command and control policies for the purpose of improved decision making. Renewable Portfolio Standards, energy efficiency measures, and other policies designed to mitigate CO_2 emissions impose an effective price on carbon.

In this report: Utility carbon price forecasts are effective prices used for state-required IRPs and internal planning purposes. The U.S. Environmental Protection Agency's (EPA's) proposed carbon pollution standard for new sources of electric generation is a non-market-based policy that would represent an effective price.

Marginal abatement cost of carbon: An abatement cost refers to an estimate of the expected cost of reducing emissions of a particular pollutant. Estimation of a marginal abatement cost requires the construction of a "supply curve": all of the possible solutions to controlling emissions (these may be technologies or policies) are lined up in order of their cost per unit of pollution reduction. Then, starting from the least expensive option, one tallies up the pollution reduction from various solutions until the desired total reduction is almost achieved, and then asks: what would it cost to reduce emissions by one more unit to achieve the target? The answer is the "marginal" cost of that level of pollution reduction; a greater reduction target would have a higher marginal cost. The marginal abatement cost of carbon is not a market price used to internalize an externality. Rather, it is a method for estimating the price that, if it were applied as a market price, would have the effect of achieving a given emission reduction target. In a well-functioning cap-and-trade system, the allowance price would tend towards the marginal abatement cost of carbon.

In this report: We do not analyze any marginal abatement costs in this report—see the *2012 Synapse Carbon Dioxide Price Forecast* for further information. McKinsey & Company has been a consistent producer of this type of analysis, an example being their 2010 report *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*.

Social cost of carbon: Whereas the marginal abatement cost estimates the price of stopping pollution, the social cost of carbon estimates the cost, per unit of emissions, of allowing pollution to continue. The social cost of carbon is the societal cost of current and future damages related to climate change from the emission of one additional unit of pollutant. Estimating the uncertain costs of uncertain future damages from uncertain future climatic events is, of course, a tricky business. If enough information were available, a marginal abatement cost for each level of future emissions (the supply of emission reductions) could be compared to a social cost of carbon for each level of future emissions (the demand for emission reductions) to determine an "optimal" level of pollution (such that the next higher unit of

emission reduction would cost more to achieve than its value in reduced damages). More commonly, the social cost of carbon is used as part of the calculation of benefits of emission-reducing measures.

In this report: The U.S. federal government's internal carbon price for use in policy making is estimated as the social cost of carbon.

4. FEDERAL CLIMATE ACTION IS INCREASINGLY LIKELY

In the near term, comprehensive federal climate legislation appears unlikely to come out of a divided Congress. The Executive Branch, however, is moving forward with regulatory actions to limit greenhouse gas emissions. Following a directive issued by President Obama, EPA released revised CO_2 performance standards for new power plants on September 20, 2013.[5] In June 2013, President Obama also instructed EPA to use its Clean Air Act authority to propose CO_2 standards for existing power plants by June 2014 and to finalize these standards by June 2015.[6] While this report is focused on electric sector CO_2 policies, similar regulatory measures have been proposed for the transportation, buildings, and industrial sectors; policies enacted in other sectors include vehicle efficiency standards set to rise to 54.5 miles per gallon by 2025 for new cars and light-duty trucks, and new energy efficiency standards for federal buildings set to reduce energy consumption by nearly 20 percent.[7,8]

We continue to expect that a federal cap-and-trade program for greenhouse gases is the most likely policy outcome in the long term, because it permits reductions to come from sources that can mitigate emissions at the lower cost. While state and regional policies combined with federal regulatory actions appear to be more likely than a federal cap-and-trade policy in the near term, according to a WRI analysis these local measures are unlikely to be able to meet long-term goals of reducing total greenhouse gas emissions to 83 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[9]

[5] EPA. "2013 Proposed Carbon Pollution Standard for New Power Plants." Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

[6] Memorandum from President Obama to Administrator of the Environmental Protection Agency, Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[7] Vlasic, Bill. "US Sets Higher Fuel Efficiency Standards." *The New York Times*. August 28th, 2012. Available at: http://www.nytimes.com/2012/08/29/business/energy-environment/obama-unveils-tighter-fuel-efficiency-standards.html.

[8] "Energy Efficiency Design Standards for New Federal Commercial and Multi-Family High-Rise Residential Buildings." A Rule by the Department of Energy. July 9th, 2013. Available at: https://www.federalregister.gov/articles/2013/07/09/2013-16297/energy-efficiency-design-standards-for-new-federal-commercial-and-multi-family-high-rise-residential#h-9.

[9] See WRI's analysis of these scenarios in the 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

4.1. Regulatory Measures for Reducing Greenhouse Gas Emissions

Clean Air Act

As a result of the 2007 Supreme Court finding in *Massachusetts v. EPA*, greenhouse gas emissions were determined to be subject to the Clean Air Act and (in a later ruling) to contribute to air pollution anticipated to endanger public health and welfare. In 2009, EPA issued an "endangerment finding," obligating the agency to regulate emissions of greenhouse gases from stationary sources such as power plants.[10] EPA released draft New Source Performance Standards (NSPS) in April 2012 and revised NSPS standards on September 20, 2013. The revised standards limit CO_2 emissions from new fossil-fuel power plants to 1,000-1,100 pounds of CO_2 per MWh (lbs/MWh)—a level achievable by a new natural gas combined-cycle plant. The exact limit of CO_2 emissions within that range depend on the type of plant and period over which the emission rate would be averaged.[11]

Under Section 111(d) of the Clean Air Act, the EPA is required to propose standards for existing power plants by June 2014, but there remains substantial uncertainty over what form these regulations will take. Unit-specific emission rates standards, such as the NSPS for greenhouse gases, are only one of several plausible options. Unit-specific standards could apply to power plants based on categories by fuel type and technology type, each with its own maximum emission rate. Units that are not in compliance could undertake upgrades to improve efficiency; however, these kinds of upgrades can be expensive, can only achieve small, one-time changes to emission rates, and could trigger New Source Review/Prevention of Significant Deterioration (NSR/PSD) provisions, increasing the cost further.[12,13]

Other regulatory design options for existing plants under 111(d) include maintaining a state-wide average maximum emission rate, and market-based (e.g. cap-and-trade) approaches. More flexible mechanisms like these could lower the cost of compliance, but could also result in additional legal challenges as compared to a simpler but more rigid system of unit-specific regulation.[14] An Edison Electric Institute white paper on potential regulation of existing sources notes that "because of concerns about legal challenges to the guidelines, EPA may be reluctant to incorporate a wide range of

[10] EPA. "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act." Available at: http://www.epa.gov/climatechange/endangerment/.

[11] EPA. "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units." Available at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

[12] EEI. "Existing Source GHGH NSPS White Paper," Page 5. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[13] Tarr J., Monast J., Profeta T. "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act." The Nicholas Institute. January 2013. Available at: http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

[14] Fine, Steven and MacCracken, Chris. "President Obama's Climate Action Plan: What It Could Mean to the Power Sector." ICF International. August 2013. Available at: http://www.icfi.com/insights/white-papers/2013/president-obama-climate-action-plan.

compliance flexibility mechanisms in the guidelines, but may be more receptive to such mechanisms if proposed by the states in compliance plans."[15]

End-use energy efficiency may be an important part of a comprehensive compliance strategy in a regulation that averages emission rates across states. States may be able to achieve emissions reductions at a lower cost through the structures of their existing energy efficiency resource standards.

Methods for demonstrating compliance with 111(d) may be similar to existing regulations: in a process similar to Section 110 of the Clean Air Act, under which EPA sets National Ambient Air Quality Standards (NAAQS), states will be required to submit State Implementation Plans (SIPs) that specify how they intend to comply with 111(d). EPA can then decide whether a proposed SIP meets the terms of the regulation; in the absence of an acceptable SIP, EPA can impose a Federal Implementation Plan (FIP). Under the schedule outlined by President Obama in his Climate Action Plan, regulations for existing sources under 111(d) will be finalized by June 2015, and states would be required to submit SIPs to the EPA by June 2016.

Performance standards for new and existing sources will affect decisions made by utilities regarding operation, expansion, and retirements. Enforcement of the Clean Air Act creates an opportunity cost of greenhouse gas abatement: prudent utilities will take Clean Air Act compliance into consideration in their planning, either explicitly as a maximum allowable emissions rate, or implicitly as an effective carbon price. An NRDC analysis of the impacts of 111(d) implementation estimated compliance costs under this policy at $7.53 per ton of CO_2 avoided.[16]

Other regulatory measures put economic pressure on carbon-intensive power plants

A suite of current and proposed EPA regulations require pollution-intensive power plants to install environmental controls for compliance. The cost of complying with environmental regulations reduces the profitability of the worst polluters, sometime rendering them uneconomic. These policies demonstrate momentum towards appropriately regulating or pricing environmentally harmful activities in the electric sector. To the extent that plants with high emissions of other pollutants also have high carbon emissions, these policies would tend to *lower* the future CO_2 price necessary to achieve a given reduction; as more pollution-intensive plants retire in response to other EPA regulations, the necessary carbon price is reduced. Specific regulatory measures include:

- *National Ambient Air Quality Standards (NAAQS)* set maximum air quality limitations that must be met at all locations across the nation. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10

[15] Edison Electric Institute. "Existing Source GHG NSPS White Paper," Page 2. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[16] Natural Resources Defense Council. "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013. Available at: http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.

micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

- *The Cross State Air Pollution Rule (CSAPR)*, finalized in 2011, establishes the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia on August 21, 2012. In June 2013, the U.S. Supreme Court announced that it would review CSAPR. Even if EPA fails to salvage CSAPR through the courts, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. In the meantime, the court left the requirements of the 2005 Clean Air Interstate Rule in place.
- *Mercury and Air Toxics Standards (MATS)*: The final MATS rule, approved in December 2011, sets stack emissions limits for mercury, other metal toxins, organic and inorganic hazardous air pollutants, and acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016. Many utilities have already committed to capital improvements at their coal plants to comply with the standard.
- *Coal Combustion Residuals (CCR) Disposal Rule:* On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required. In addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.
- *Steam Electric Effluent Limitation Guidelines (ELGs):* On June 7, 2013, EPA released eight regulatory options for new, proposed steam-electric ELGs to reduce or eliminate the release of toxins into U.S. waterways. A final rule is required by May 22, 2014.[17] New requirements will be implemented in 2014 to 2019 through the five-year National Pollutant Discharge Elimination System permit cycle.[18]

Other regulations which may raise costs for carbon-intensive resources include Regional Haze rules and cooling water rules under the Clean Water Act.

[17] See U.S. Environmental Protection Agency website. Accessed February 21, 2013. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm.

[18] See U.S. Environmental Protection Agency. Steam Electric ELG Rulemaking. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf.

4.2. Proposed Cap-and-Trade Legislation

Over the past decade, there have been several Congressional proposals to legislate cap-and-trade programs, with the goal of reducing greenhouse gas emissions by up to 83 percent below recent levels by 2050 through a federal cap. Such programs would allow trading of allowances to promote least-cost reductions in greenhouse gas emissions.

Comprehensive climate legislation was passed by the House in the 111th Congress: the American Clean Energy and Security Act of 2009, also known as Waxman-Markey or H.R. 2454. However, the Senate did not vote on either of the two climate bills before it in that session (Kerry-Lieberman APA 2010 and Cantwell-Collins S. 2877). Waxman-Markey was a cap-and-trade program that would have required a 17 percent reduction in emissions from 2005 levels by 2020, and an 83 percent reduction by 2050.[19] Further analysis of these proposals is provided in Synapse's 2012 Carbon Dioxide Price Forecast.

Congressional interest in climate policy has been ongoing. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S. 2146), which would have required larger utilities to meet a percentage of their sales with electric generation from sources that produce less greenhouse gas emissions than a conventional coal-fired power plant. Credits generated by these clean technologies would have been tradable with a market price. In February 2013, Senators Sanders and Boxer introduced new comprehensive climate change legislation, the Climate Protection Act of 2013. This bill proposed a carbon fee of $20 per ton of CO_2 or CO_2 equivalent content of methane, rising at 5.6 percent per year over a ten-year period. The bill has not yet been brought to a vote.

We expect that federal cap-and-trade legislation will eventually be enacted but that it is unlikely to happen in the near term. In contrast, federal carbon regulations are in effect or under development today, and the economic pressure—or opportunity cost—that they create may be represented as an effective price of greenhouse gas emissions. Regulatory measures may be successful in achieving near-term targets of 17 percent below 2005 levels by 2020, but according to a WRI analysis are unlikely to meet long-term goals of reducing total greenhouse gas emissions to approximately 80 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[20] A broader approach will be increasingly attractive in order to meet these goals at lower costs, and our judgment indicates this is most likely to take the form of a federal cap-and-trade system.

[19] U.S. Energy Information Administration (EIA); Energy Market and Economic Impacts of the American Power Act of 2010 (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html. EIA; Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[20] See WRI's analysis of these scenarios in their 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

5. STATE AND REGIONAL CLIMATE POLICIES

Since the October 2012 release of our 2012 CO_2 price forecasts, there have been significant updates to the two existing regional and state cap-and-trade programs, the Northeast's RGGI and California's Cap-and-Trade Program under AB32. In addition, a total of 20 states plus the District of Columbia have set greenhouse gas emissions targets as low as 80 percent below 1990 levels by 2050.[21]

Recent Revisions to RGGI

RGGI is a cap-and-trade greenhouse gas program for power plants in the northeastern United States. Current participant states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Pennsylvania, Québec, New Brunswick, and Ontario are official "observers" in the RGGI process. RGGI recently marked five years of successful CO_2 allowance auctions, with Auction 21 resulting in a clearing price of $2.67 per ton.[22] RGGI is designed to reduce electricity sector CO_2 emissions to at least 45 percent below 2005 levels by 2020.[23]

When RGGI was established in 2007, the expectation was that the CO_2 emissions allowance auction would generate revenues for consumer benefit programs such as energy efficiency, renewable energy, and clean energy technologies. While RGGI has provided significant revenues for consumer benefit, its allowance prices have generally remained near the statutory minimum price. External influences, including changes to fuel prices, caused a shift from coal and oil to lower-carbon natural gas generation. Compared to those external factors, the effect of the original RGGI cap requirements were relatively minor in meeting the goals of reducing CO_2 emissions in the power sector.[24]

In 2012 and 2013, the RGGI states evaluated a number of plans for tighter emissions caps with the goal of raising allowance prices. In February of 2013, participating states agreed to lower the CO_2 cap from 165 million to 91 million short tons in 2014, to be reduced by 2.5 percent each year from 2015 to 2020. RGGI analysis indicates that with these lower caps, allowance prices will rise to $4.16 per short ton in 2014, increasing to $10.40 per ton in 2020.[24]

California's Cap-and Trade-Program under AB32

With the goal of reducing the state's emissions to 1990 levels by 2020, California's Global Warming Solutions Act (AB32) has created the world's second largest carbon market, after the European Union's

[21] "Greenhouse Gas Emissions Targets." Center for Climate and Energy Solutions. Accessed September 13, 2013. Available at: http://www.c2es.org/us-states-regions/policy-maps/emissions-targets.

[22] RGGI Auction 21 results available at: http://www.rggi.org/market/co2_auctions/results/Auction-21

[23] RGGI. "RGGI States Propose Lowering Regional CO_2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." February 2013. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf.

[24] Environment Northeast. "RGGI at One Year: An Evaluation of the Design and Implementation of the Regional Greenhouse Gas Initiative." February 2010. Available at: http://www.env-ne.org/public/resources/pdf/ENE_2009_RGGI_Evaluation_20100223_FINAL.pdf.

Emissions Trading System. The first compliance period for California's Cap-and-Trade Program began on January 1, 2013 and covers electricity generators, CO_2 suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 27,600 tons of CO_2e per year.[25,26] On August 16, 2013, the California Air Resources Board held its fourth quarterly allowance auction, resulting in a clearing price of $11.11 per ton.[27] This first phase of the program includes electricity generators and large industrials. Phase II, beginning in 2015, will also include transportation fuels and smaller industrial sources.

6. ASSESSMENT OF CARBON PRICE FOR FEDERAL RULEMAKING

In 2010, the U.S. federal government began including a carbon cost in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions;[28] updated values were released in 2013.[29] The 2013 Economic Report of the President acknowledges that these values will continue to be updated as scientific understanding improves.[30]

An Interagency Working Group on the Social Cost of Carbon—composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others—was tasked with the development of a consistent value for the social benefits of climate change abatement. Four values were developed (see Section 3 for more explanation of the "social cost of carbon" methodology). These values--$11, $36, $55, and $101 per ton of CO_2 in 2013, rising over time— represent average (most likely) damages at three discount rates, along with one estimate at the 95th percentile of the assumed distribution of climate impacts.[31,32,33,34] While

[25] "CO_2e" refers to CO_2-equivalent, the combination of CO_2 and an equivalent value for other greenhouse gases.

[26] CARB 2013a. "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments by Linked Jurisdictions." July 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/ctlinkqc.pdf. Legislated value is 25,000 metric tons, converted here to short tons.

[27] CARB 2013b. "CARB Quarterly Auction 4, August 2013: Summary Results Report." August 21, 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/august-2013/results.pdf.

[28] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

[29] Interagency Working Group on the Social Cost of Carbon (2013) Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866. Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

[30] 2013 Economic Report of the President (2013). Chapter 6. March 2013. Available at: http://www.whitehouse.gov/sites/default/files/docs/erp2013/ERP2013_Chapter_6.pdf.

[31] These values represent recently revised costs for the SCC. Originally, these values were $5, $21, $35, and $65 per metric tonne for the year 2010 in 2007 dollars.

[32] In a 2012 paper, Ackerman and Stanton modified the Interagency Working Group's assumptions regarding uncertainty in the sensitivity of temperature change to emissions, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater. Similarly, Laurie Johnson and Chris Hope modified discount rates and methodologies and found results up to twelve times larger than the Working Group's central estimate.

subject to significant uncertainty, this multi-agency effort represents an initial attempt at incorporating the benefits associated with CO_2 abatement into federal policy.

As of May 2012, these estimates had been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[35, 36] In the first rule in which the revised 2013 values were used—improving energy efficiency in microwave ovens—the net present value of benefits over a 30-year timeframe increased by $400 million as a result of the increase in effective carbon price.[37] While a carbon price for federal rulemaking assessments is a fundamentally different kind of cost metric than the others discussed in this report, it nonetheless represents a dollar value for greenhouse gas emissions currently in use by the U.S. federal government.

7. RECENT CO_2 PRICE FORECASTS FROM THE RESEARCH COMMUNITY

The Energy Modeling Forum (EMF), a working group of government and private modeling teams, has been convening to explore energy system issues since the late 1970s. The group recently completed its EMF 24 analysis with the objective of evaluating what CO_2 price trajectories are consistent with proposed emission reduction targets under different technology scenarios. This analysis also incorporated several complementary policies in a cap-and-trade proposal, including: transportation emissions reduction through vehicle gas mileage standards; renewable portfolio standards in the electric sector; and mandates that all new coal facilities employ carbon capture and storage (CCS) technology—a

[33] Frank Ackerman and Elizabeth A. Stanton (2012). "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal*, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10.

[34] Laurie T. Johnson, Chris Hope. "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." *Journal of Environmental Studies and Sciences*, 2012; DOI: 10.1007/s13412-012-0087-7.

[35] Robert E. Kopp and Bryan K. Mignone (2012). "The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement." Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15.

[36] See, for example, "Rulemaking for Microwave Ovens Energy Conservation Standard: Technical Support Document." May 2013. Available at: http://www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx/ruleid/37

[37] Brad Blumer (2013). "The social cost of carbon is on the rise." The Washington Post, June 6th, 2013. Available at: http://articles.washingtonpost.com/2013-06-06/business/39789409_1_carbon-dioxide-emissions-obama-administration.

policy similar to EPA's proposed NSPS for coal plants. Nine modeling teams participated in this study.[38,39]

Results from the EMF 24 exercise show a range of CO_2 price trajectories depending on availability of new technologies, policy type, model baseline trajectories, and other more structural characteristics of the models. One question asked by this study that is of particular relevance to users of the Synapse CO_2 price forecast is: which economic sectors would emissions reductions come from in an economically efficient approach to emissions mitigation? Consistent with earlier EMF analyses, the electric sector was found to be the largest contributor to CO_2 emissions reductions across all models.

Under a cap-and-trade scenario designed to reduce energy system emissions 50 percent below 2005 levels by 2050, most of the EMF 24 models reduced electric sector emissions by 75 percent by 2050. Under an 80 percent emissions reduction scenario, most of the additional emissions reductions came from other sectors. Although CO_2 prices are higher under the 80 percent scenario, most electricity customers are not paying these prices, as the electricity sector is largely decarbonized before 2050.

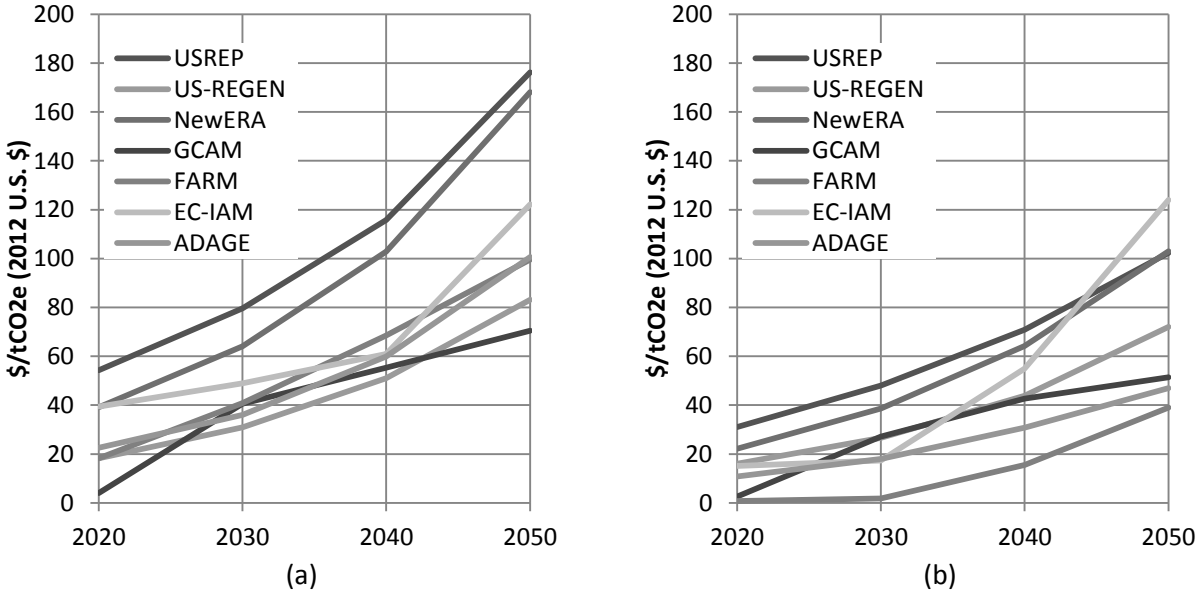
CO_2 prices estimated by the EMF 24 models show substantial variation. While it is difficult to distinguish the roles of model structure and model assumptions in this variation, the results present a reasonable range across which prices may fall. Under the most optimistic technology assumptions, with low-cost renewables, high levels of energy efficiency, and availability of new nuclear and CCS, CO_2 prices in 2020 fell between \$10 per tCO_2 and \$40 per tCO_2. In contrast, prices fell between \$20 per tCO_2 to \$80 per tCO_2 under the most pessimistic assumptions. Complementary policies, such as renewable portfolio standards or fuel economy standards, reduce carbon prices, as indicated in Figure 1.

Universally, the models show that substantial emissions reductions are not achievable in the absence of a policy. Even in the most optimistic technology scenario, the most aggressive emissions reductions from any model in the absence of a policy was 0.19 percent per year, resulting in emissions 7 percent below 2005 levels in 2050.

[38] Clarke, L.C., A.A. Fawcett, J.P. Weyant, V. Chaturvedi, J. MacFarland, Y. Zhou, "Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise," (forthcoming). *The Energy Journal.*

[39] Fawcett, A.A., L.C. Clarke, S. Rausch, J.P. Weyant. "Overview of EMF 24 Policy Scenarios," (forthcoming). *The Energy Journal*.

Figure 1: Allowance prices from EMF study under (a) 50 percent cap-and-trade policy and with (b) the addition of several complementary policies (optimistic CCS/nuclear technology assumptions) [35,36]



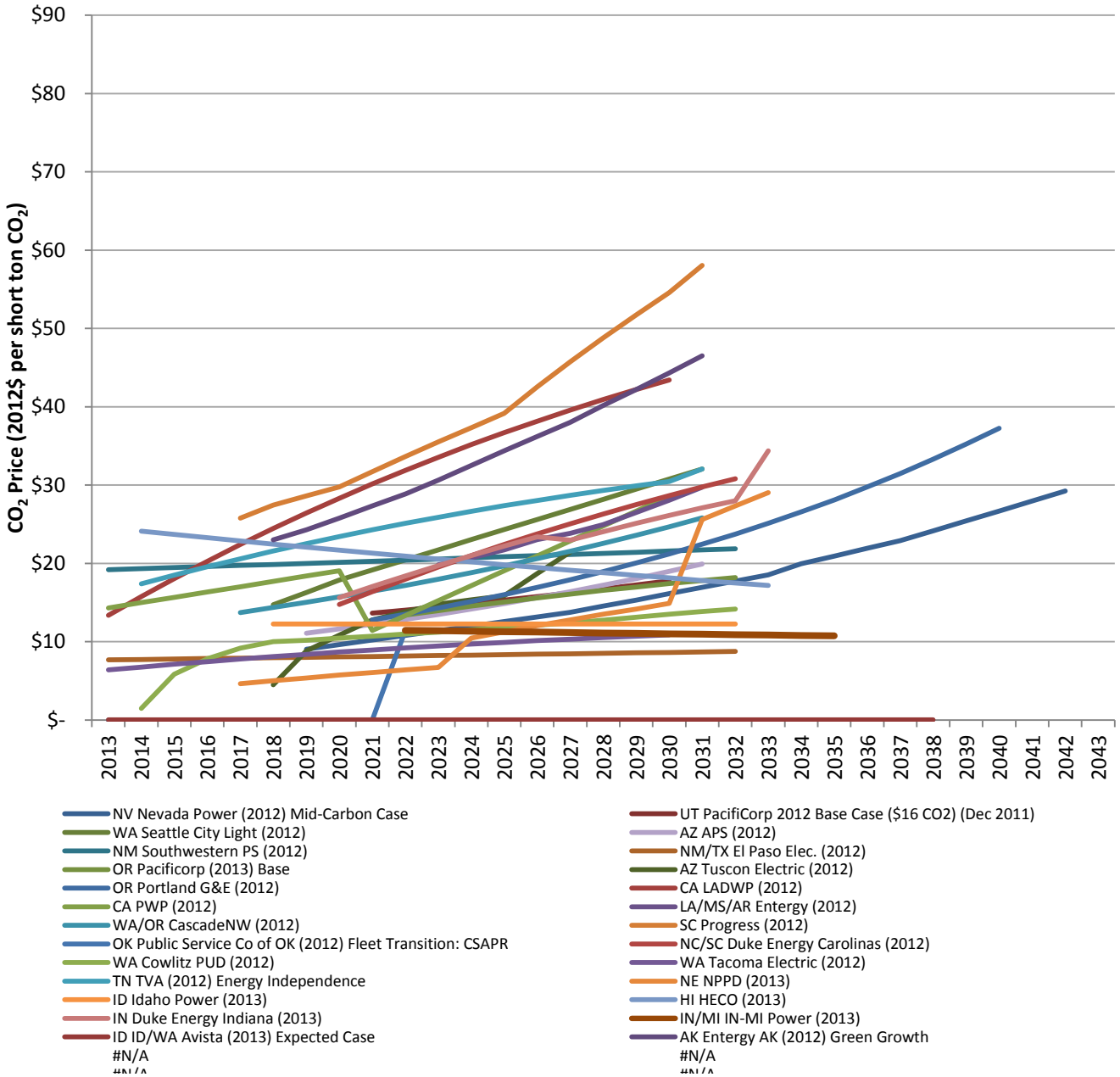
8. CO_2 Price Forecasts in Utility IRPs

A growing number of electric utilities include projections of the costs that will be associated with greenhouse gas emissions in their resource planning procedures. Figure 2 summarizes the reference case values (often described as their "mid" or "central" values) of publicly available forecasts used by utilities in resource planning over the past two years.[40]

Despite ongoing obstacles to a federally legislated CO_2 price and challenges in Congress to addressing climate or energy policy in a meaningful way, many utilities are including an effective price for carbon in their planning. The majority of utility reference case carbon price forecasts start in the 2015-2020 timeframe, and rise gradually (in real terms) throughout the study period.

[40] Where a utility has released multiple IRP or IRP updates in the past two years, we have included only the most recent value. The IRPs shown here represent those publicly available by internet as of the October 2013.

Figure 2: Utility Reference Case Forecasts from 2012 and 2013



9. OVERVIEW OF THE EVIDENCE FOR A FUTURE CO_2 PRICE

Our CO_2 price forecasts are developed based on the data sources and information presented above and reflect a reasonable range of expectations regarding future efforts to limit greenhouse gas emissions. The following items have guided the development of the Synapse forecasts:

- **Regulatory measures limiting CO_2 emissions from power plants will be implemented in the near term**. The EPA is required to propose emissions standards for existing power plants under Section 111(d) of the Clean Air Act by June 2014. Standards for new power plants were proposed on September 20, 2013. These actions represent an effective price that will affect utility planning and operational decisions.

- **State and regional action limiting CO_2 is ongoing and growing more stringent**. In the Northeast, the RGGI CO_2 cap has been tightened, resulting in higher CO_2 prices for electric generators in the region. California's Cap-and-Trade Program, which represents an even larger carbon market than RGGI, has held many successful allowance auctions, and has been successfully defended against numerous legal challenges.

- **A price for CO_2 is already being factored into federal rulemakings.** The federal government has demonstrated a commitment to considering the benefits of CO_2 abatement in rulemakings such as fuel economy and appliance standards.

- **Ongoing analysis of emissions caps suggests a wide range of possible prices.** Important factors include the stringency of any future climate policy, the existence of complementary policies, technology availability, and how quickly old capital stock can be phased out in favor of new technologies.

- **Electric suppliers continue to account for the opportunity cost of CO_2 abatement in their resource planning.** Prudent planning requires utilities to consider adequately the potential for future policies. The range of carbon prices reported in section 8 indicates that many utilities believe that by 2020 there will likely be significant economic pressure towards low-carbon electric generation.

10. SYNAPSE 2013 CO_2 PRICE FORECAST

Based on analyses of the sources described in sections 3 through 8 (above), and relying on our own expert judgment, Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure 3 and Table 1 show the Synapse forecasts over this period.

Figure 3: Synapse 2013 CO_2 Price Trajectories

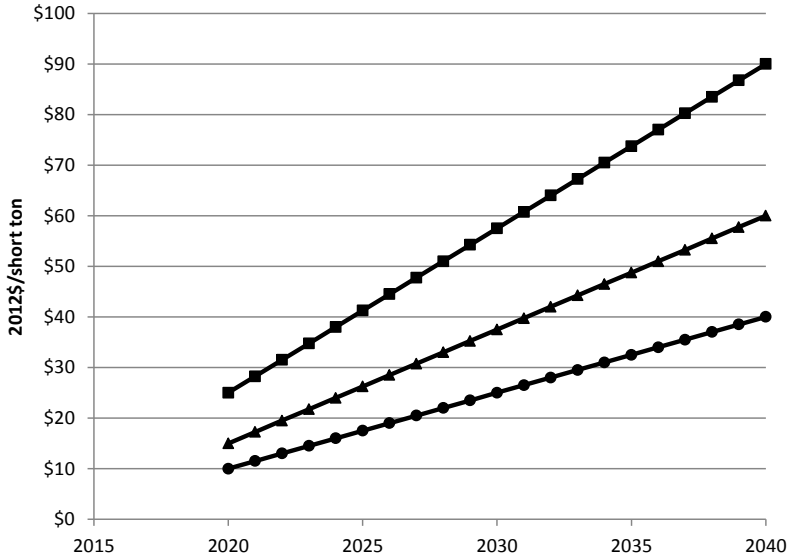


Table 1: Synapse 2013 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$10.00	$15.00	$25.00
2021	$11.50	$17.25	$28.25
2022	$13.00	$19.50	$31.50
2023	$14.50	$21.75	$34.75
2024	$16.00	$24.00	$38.00
2025	$17.50	$26.25	$41.25
2026	$19.00	$28.50	$44.50
2027	$20.50	$30.75	$47.75
2028	$22.00	$33.00	$51.00
2029	$23.50	$35.25	$54.25
2030	$25.00	$37.50	$57.50
2031	$26.50	$39.75	$60.75
2032	$28.00	$42.00	$64.00
2033	$29.50	$44.25	$67.25
2034	$31.00	$46.50	$70.50
2035	$32.50	$48.75	$73.75
2036	$34.00	$51.00	$77.00
2037	$35.50	$53.25	$80.25
2038	$37.00	$55.50	$83.50
2039	$38.50	$57.75	$86.75
2040	$40.00	$60.00	$90.00
Levelized 2020-2040	$22.36	$33.54	$51.79

In these forecasts, state and regional policies, together with federal regulatory measures, place economic pressure on CO_2 emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect that federal regulatory measures will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2012 dollars per short ton of carbon dioxide.

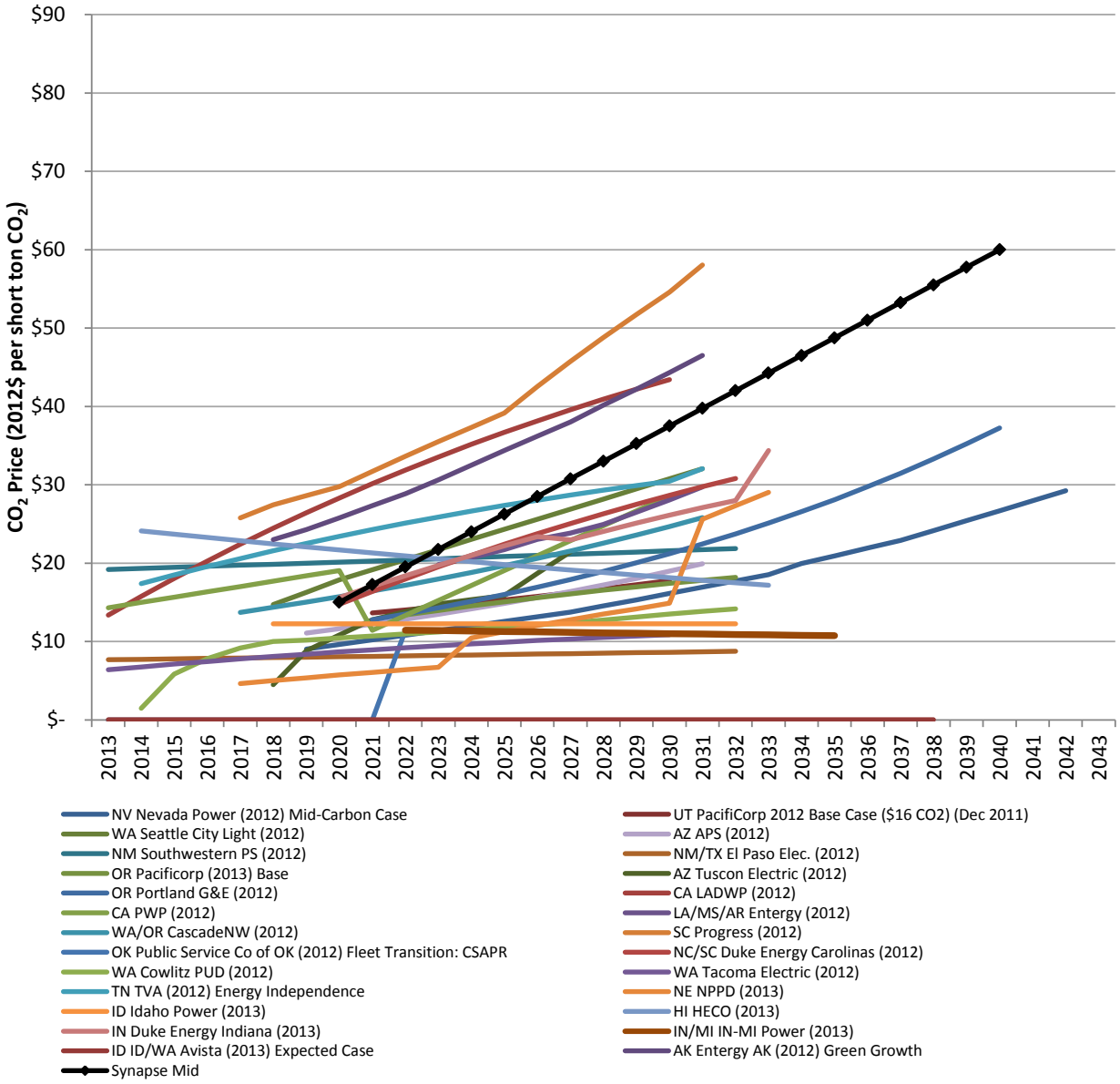
- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; more

aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

These price trajectories are designed for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 4, the Synapse Mid forecast is shown in comparison to the reference case utility forecasts presented earlier. See Appendix A for comparisons to utilities' Low and High case forecasts.

Figure 4: Synapse Mid Forecast Compared to Recent Utility Mid Case Forecasts



In Figure 5, the Synapse forecasts are compared to the carbon price used in federal rulemaking. While

the federal price starts out higher in 2020, the Synapse Mid forecast approaches this value at the end of the projected period. In Figure 6, the Synapse forecasts for 2020 are compared to several of the sources identified in this report: the carbon price used in federal rulemakings, EMF 24 study results, and recent utility forecasts. The high and low ends of these sources span a wide range, but the central values show less variation.

Figure 5: Synapse Forecast Compared to Carbon Price Used in Federal Rulemakings

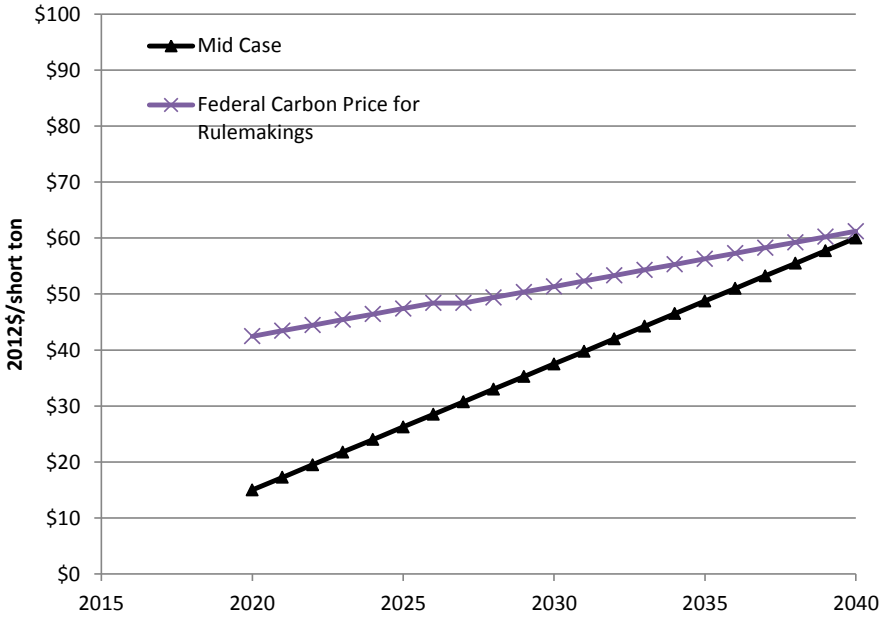
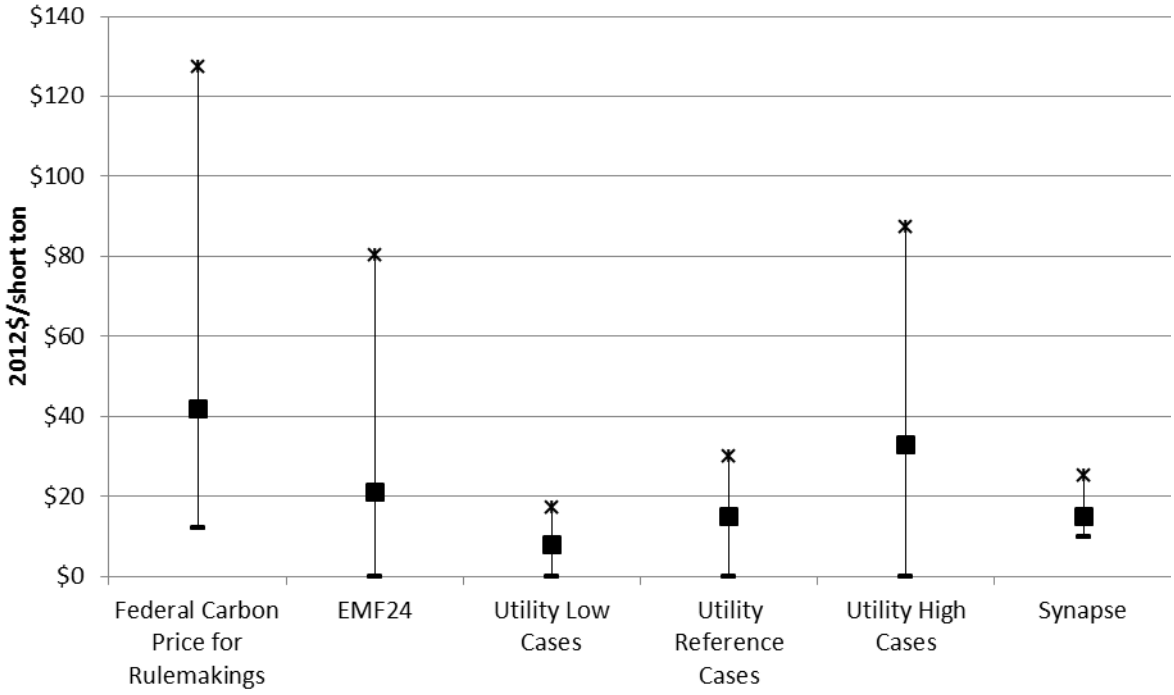


Figure 6: Synapse CO_2 Forecasts for 2020 Compared to Other Sources



APPENDIX A: SYNAPSE FORECAST COMPARED TO UTILITY FORECASTS

Figure 7: Synapse CO_2 Price Forecast Compared to Recent Utility Low-case Forecasts

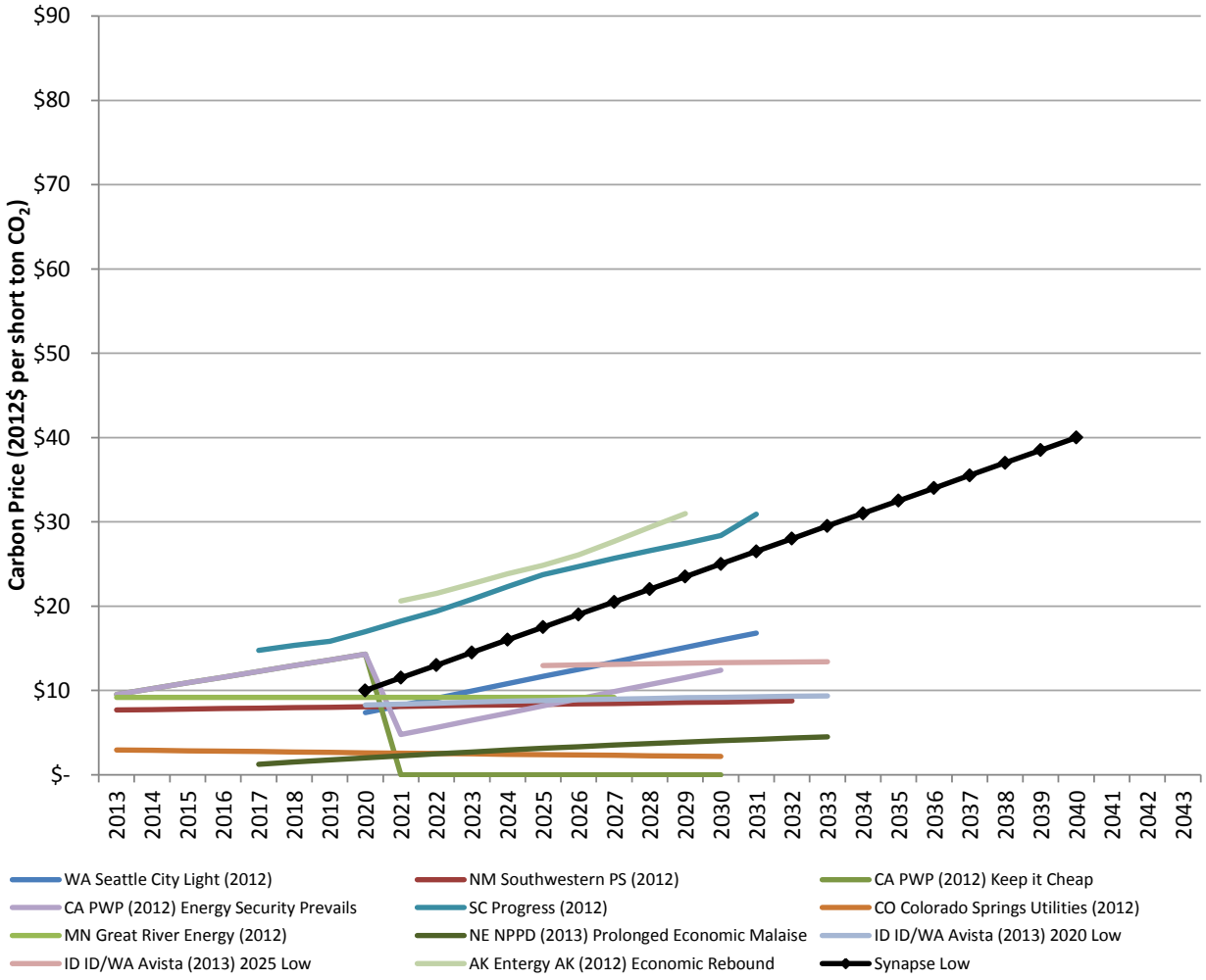
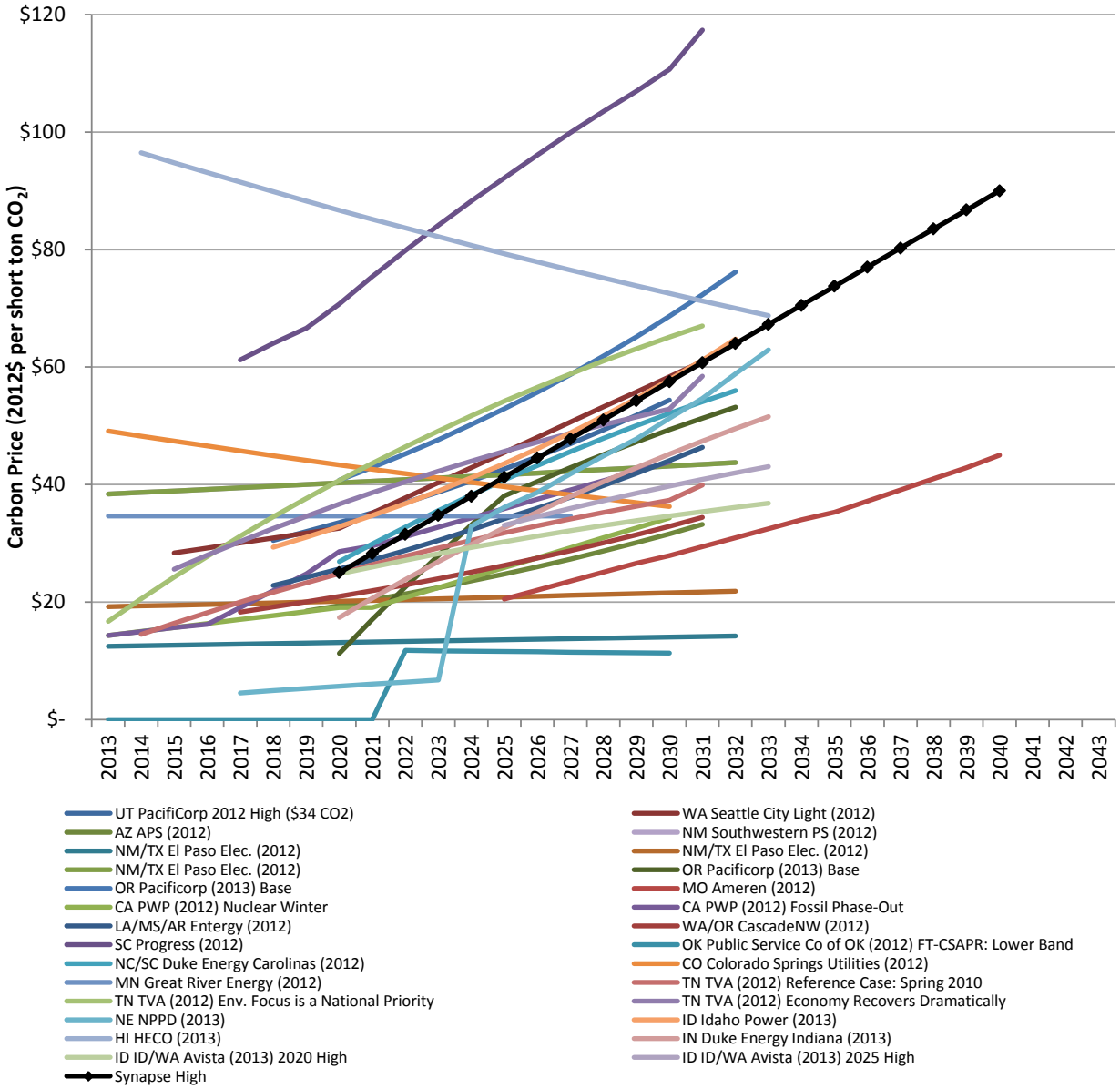


Figure 8: Synapse CO_2 Price Forecast Compared to Recent Utility High-case Forecasts



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Energy Efficiency Cost-Effectiveness Screening

How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs

Authors
Tim Woolf
William Steinhurst
Erin Malone
Kenji Takahashi

Synapse Energy Economics, Inc.

November 2012

Acknowledgements

The authors would like to thank the following persons for taking the time to provide helpful comments on earlier drafts of this paper: Chris Neme, Julie Michaels, Elizabeth Titus, Jerrold Oppenheim, Jamie Barber, John Plunkett, and Walter Poor.

Other reviewers who made valuable contributions include Riley Allen, David Farnsworth, David Lamont, Ajith Rao, Richard Sedano, and Rick Weston from the Regulatory Assistance Project.

This paper was produced in part through support from the John D. and Catherine T. MacArthur Foundation.

Prepared for the Regulatory Assistance Project and the Vermont Housing Conservation Board.

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Foreword

Why do we in the electric and natural gas regulation business spend so much time and money on energy efficiency cost-effectiveness? Several reasons are highlighted below.

Compliance with energy efficiency obligations is one reason. If an efficiency program administrator (utility or otherwise) is charged with a mission to deliver cost-effective energy efficiency, regulators overseeing the programs need tools to evaluate administrators' claims. Tried-and-true programs may appear to require less work after years of performance data, but the evidence-based oversight process typical in most states requires persistent thoroughness.

Value for consumers is another reason. On behalf of the captive consumers paying for these savings, regulators need reassurance that costs added to electric bills are justified investments that will more than offset those costs over time. History shows that making this case clearly and continuously is important to maintain public support with an ever-changing crop of new regulators, elected officials, editorial writers, and other opinion leaders.

Value to the economy and broader society is still another important reason. Unlike most other utility resource investments, energy efficiency influences an impressive array of other aspects of society, as this paper explores. Thus, a narrower focus only on the value that energy efficiency brings to utility consumers is too limiting an analysis. However, analysis of the effects of energy efficiency investment on other program impacts, such as fuel and water savings, are often ignored or mishandled, and should be properly recognized.

Evaluating utility risk is often over-looked. Cost-effectiveness analyses for energy efficiency and other utility investments do not usually evaluate impact on utility risk. Many risks to the power sector that may drive up costs to consumers, or add regulatory risk to utilities, could be mitigated by energy efficiency. The ability of energy efficiency to mitigate utility risk is factored into the evaluation in only a few states, and these methods are rough and conservative.

We recognize that **energy efficiency is evolving**. As states increase their ambitions for energy efficiency savings from utility consumer-funded programs, the stakes for measuring cost-effectiveness escalate. Justifying the cost to pursue savings is not the only objective. Decisions of whether or not to integrate energy efficiency into utility system planning, capital budgeting, and even system operations are motivated by cost-effectiveness analyses. In the future, states will consider integrating energy efficiency with demand response, distributed generation, and other customer-side services enabled by technology. As they do this, the essentials for cost-effectiveness will still apply, but may be applied in new ways.

State identities may interact with regional approaches. States' values vary as represented by their customized cost-effectiveness tests. Perhaps this will persist, then again it may not. Convergence in approaches among states is also possible, driven by regional imperatives to use energy efficiency and other demand resources as preferred resources.

States want to ensure that energy efficiency investments reflect their values. Why do we in the electric and natural gas regulation business spend so much time and money on energy efficiency cost-effectiveness? Because regulation requires it, but also because the process itself reflects our priorities, and allows us to reassess them from time to time to ensure we are valuing energy efficiency in ways consistent with our values. RAP staff hopes this paper provides useful perspective to regulators and others interested in doing just that. Thanks to the staff at Synapse Energy Economics for providing this useful and clear analysis.

Rich Sedano
Principal and Director, US Program
Regulatory Assistance Project

Executive Summary

Energy efficiency is widely recognized as a low-cost, readily available resource that offers a variety of benefits to utility customers and to society as a whole. Many states have established efficiency savings targets, some states require that energy efficiency be the first choice among resource options, and an increasing number of states require energy efficiency program administrators to pursue all cost-effective energy efficiency. As states continue to advance ratepayer-funded energy efficiency initiatives and establish increasingly aggressive savings goals, it is vitally important that effective practices be communicated and used in screening energy efficiency resources for cost-effectiveness.

The purpose of this report is to address two elements of energy efficiency screening that are frequently treated improperly, namely: other program impacts and the cost of complying with environmental regulations.

There is a great amount of variation across the states in the ways that energy efficiency programs are screened for cost-effectiveness. Many states are applying methodologies and assumptions that do not capture the full value of efficiency resources, leading to under-investment in this low-cost resource, and thus higher costs to utility customers and society.

The purpose of this report is to address two elements of energy efficiency program screening that are frequently treated improperly: other program impacts (OPIs)[1] and the costs of complying with environmental regulations. In some states, proper treatment of these two elements would likely result in a significantly larger amount of energy efficiency being deemed cost-effective relative to today's practices. We begin our report with a discussion of the cost-effectiveness tests used to evaluate energy efficiency programs, because the choice and use of these tests is directly related to our discussion of these two key elements of program screening.

A goal of this paper is to address some key issues related to application of cost-effectiveness tests that are often overlooked; it is not the goal of this paper to address all aspects of costs and benefits that may be relevant to one or more tests. Many issues relevant to the tests are addressed with only a passing reference, or are left off the discussion entirely. As noted, the focus of this paper is on what we refer to in this paper as the OPIs that are appropriate to include in certain cost-effectiveness tests, and the costs of complying with environmental regulation.

The Best Tests for Screening Energy Efficiency

Five standard tests are used to evaluate energy efficiency programs, three of which are predominately used by states as the primary test for screening efficiency programs: the Societal Cost Test, the Total Resource Cost (TRC) Test, and the Program Administrator Cost (PAC) Test. The choice of which test to use – and whether it is appropriately applied – will have a significant impact on the amount of energy efficiency resources that are identified as being cost-effective.

First, we note that ideally all three tests, the broader Societal Cost Test and the TRC Test, as well as the PAC Test, should be considered when assessing energy efficiency cost-effectiveness. We recognize, however, that this still leaves the ultimate question of which test results to use in determining the programs to implement, and that in practice it is more common and straightforward to use a single, primary test to answer this ultimate question. Our recommendations below include a primary test applied at the program level, but a secondary test applied, at a

1 We use the term "other program impacts" (OPIs) to describe what are commonly referred to as non-energy benefits (NEBs) or non-energy impacts (NEIs). OPIs are those costs and benefits that are not part of the costs, or the avoided costs, of the energy provided by the utility that funds the efficiency program. In addition to NEIs, OPIs also include "other fuel savings," which are the savings of fuels that are not provided by the utility that funds the efficiency program.

minimum, at the portfolio level. This approach offers the benefits of both breadth and simplicity.

We recommend that the Societal Cost Test be used to screen energy efficiency programs. This test includes the broadest range of energy efficiency costs and benefits, and provides the best measure of public policy benefits that are of great importance to legislators and regulators, including environmental benefits. If a state chooses to use the Societal Cost Test, the test should account for all the public policy benefits to the greatest extent possible.

We recommend that all states that choose not to rely on the Societal Cost Test use the TRC Test to screen energy efficiency programs. If a state chooses the TRC (or Societal Cost) Test, the test should account for OPIs to the greatest extent possible. If OPIs are excluded, then the analysis would include all of the relevant costs but not all of the relevant benefits. As a result, the TRC Test will provide misleading results that are skewed against energy efficiency, and will result in underinvestment in energy efficiency programs and higher costs for customers.

We also recommend that efficiency resources be screened using the Societal Cost Test or the TRC Test at the program level. Although there may be, in theory, advantages to measure-level screening, these advantages are outweighed by the practical benefits associated with program-level screening, including accounting for the interactive effects between efficiency measures, increasing customer adoption of efficiency measures, promoting comprehensive efficiency solutions, and avoiding lost opportunities. Screening energy efficiency at the program level achieves an appropriate balance between achieving important efficiency goals and sufficient regulatory oversight. Energy efficiency resources should be *analyzed* at the measures level, in order to provide program administrators and other stakeholders with the greatest level of detail regarding their costs and benefits, but the *screening* is best performed at the program level in order to reduce the risk of screening out measures that provide program-level benefits.

However, when evaluating ratepayer-funded energy efficiency programs with either the Societal Cost Test or the TRC Test it is important to consider potential bill impacts and customer equity concerns. Properly accounting for OPIs and the associated public policy benefits may increase the universe of efficiency measures that are deemed cost-effective. This may lead to increased energy efficiency budgets, or in the case of limited efficiency budgets it may result in the adoption of a different, more expensive mix of efficiency measures. In addition, properly accounting for OPIs and the associated public policy benefits may be seen as burdening utility customers with costs for achieving benefits that are not related to utility services. This is a critical consideration, particularly for states that are pursuing aggressive levels of energy efficiency savings or pursuing all cost-effective energy efficiency.

To address these equity concerns, we recommend that the PAC Test be applied, at a minimum, to the entire portfolio of efficiency programs to ensure that the entire package of programs will result in a net reduction in revenue requirements and a net reduction in costs to utility customers. The PAC test includes only those costs and benefits that affect utility revenue requirements, and thus provides a clear indication of potential impacts on customer bills. Under this approach, either the Societal Cost Test or the TRC Test would be the primary test for screening each energy efficiency program. Programs that do not pass the primary test would not be considered cost-effective and would not be included in the efficiency portfolio. Then the PAC Test would be applied, at a minimum, to the portfolio of programs that do pass the primary test. If a portfolio of programs does not pass the PAC Test, then one or more of the programs would need to be modified in such a way that the entire portfolio eventually passes the PAC Test. More granular ratepayer equity concerns can be addressed at the measure or program level by applying the PAC Test review at those levels in program design.

This combined screening approach should be simple to apply because it would rely upon a single, primary test (either the Societal Cost Test or the TRC Test) for screening at the program level, and a secondary test (the PAC Test) that would be applied as a check on behalf of utility customers. Regulators and other stakeholders could use the results of the portfolio-level PAC test (expressed as millions of dollars in net reductions in utility costs) to assess the overall value of the efficiency portfolio to utility customers as a whole. Applying the tests in this manner helps regulators and other stakeholders ensure that public policy objectives for acquisition of cost-effective energy efficiency also result in a net reduction in utility costs to utility customers.

Other Program Impacts

OPIs are those costs and benefits that are not part of the cost, or the avoided cost, of energy. OPIs fall into three categories:

- **Utility-perspective OPIs** include, for example, reduced customer arrearages and reduced bad debt write-offs.
- **Participant-perspective OPIs** include, for example, improved health, increased safety, other fuel savings, reduced maintenance costs, reduced sick days from work or school, increased worker or student productivity, improved aesthetics, and increased comfort. Many of these participant-perspective OPIs are especially significant for low-income customers.
- **Societal-perspective OPIs** include, for example, reduced environmental impacts and reduced costs of providing health care.

These OPIs should be included in cost-effectiveness tests for which the relevant costs and benefits are applicable. The primary rationale for including OPIs is to ensure that the tests are internally consistent. This is especially important in the application of the TRC Test. By definition, this test includes the participant cost of the energy efficiency measures, which can be quite large in many cases. For the TRC Test to be internally consistent, it must also include the participant benefits from the energy efficiency measures, including OPIs. Excluding the participant-perspective OPIs from the TRC Test will provide misleading results that are skewed against energy efficiency, and will result in underinvestment in energy efficiency programs and higher costs for utility customers.

Unfortunately OPIs are often not accounted for in a comprehensive manner and are frequently ignored altogether. A recent survey found that most states use the TRC Test as the primary test for screening energy efficiency programs; however, only 12 states quantify participant OPIs, and even in those states the quantification is only partial and generally conservative. As a result, many states are applying the TRC Test in a way that is skewed and understates the true value of energy efficiency. This may be the most significant problem with energy efficiency program screening methods in the United States today.

Excluding the participant-perspective OPIs from the TRC Test will provide misleading results that are skewed against energy efficiency, and will result in underinvestment in energy efficiency programs and higher costs for utility customers.

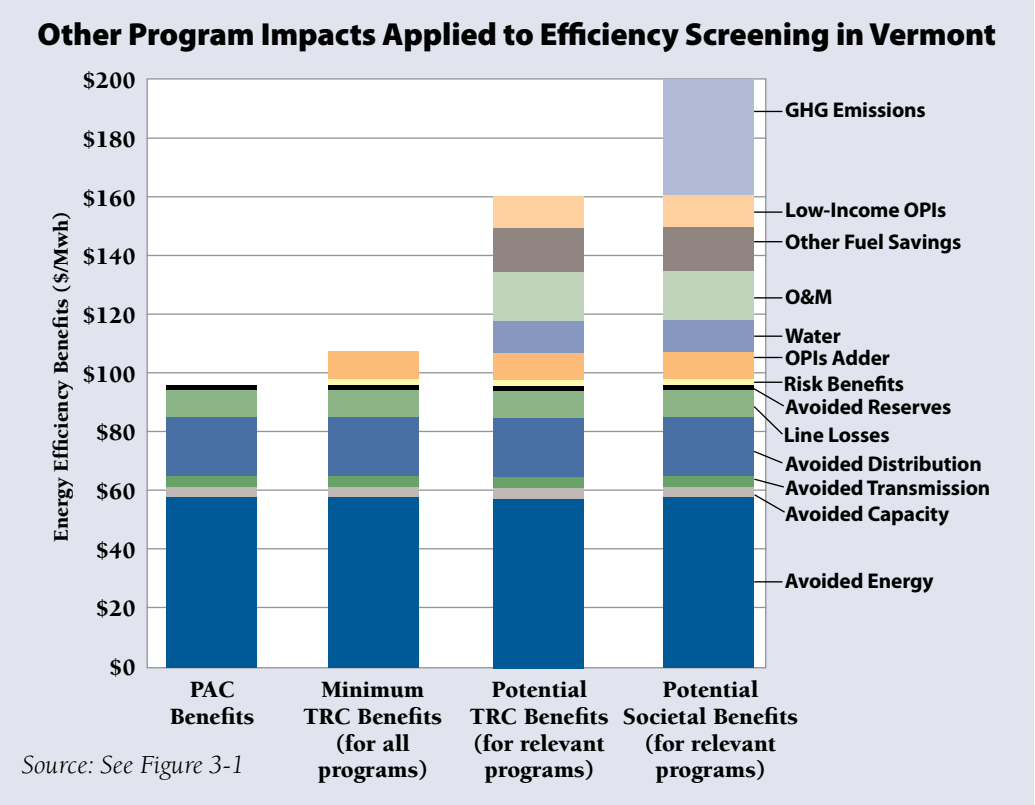
Those states that do account for OPIs have found that they can be quite large. Figure ES-1 presents a summary of the OPIs that are accounted for in energy efficiency screening in Vermont, in terms of levelized costs (in $/MWh). The leftmost column indicates the benefits that would be applied to all programs under the PAC Test. The second column from the left indicates the risk benefits and the non-energy benefits that would be applied to all energy efficiency programs under the TRC Test. The second column from the right indicates the potential magnitude of the water, operations and maintenance (O&M), other fuel savings, and low-income benefits under the TRC Test. The rightmost column also includes the avoided emissions benefit that is applied under the Societal Cost Test.

There are two types of participant-perspective OPIs that deserve particular attention: low-income benefits and other fuel savings. These impacts tend to be of significant magnitude, and if they are not correctly accounted for, then some programs, including low-income programs, residential retrofit programs, and new construction programs, may be improperly deemed uneconomic.[2] All of these programs offer significant public policy benefits by serving a broad range of customer types; achieving comprehensive, whole-house savings; promoting customer equity; and reducing lost opportunities.

The importance of properly applying OPIs is apparent in many program administrators' energy efficiency screening results. We recommend caution when considering quantitative estimates of OPIs, such as those presented in Figure ES-1. It is very difficult to fully quantify and monetize all of the OPIs, especially all of the participant-perspective non-energy benefits, associated with all energy efficiency programs. Furthermore, experience indicates that most attempts to do so result in very

2 OPIs can be significant for commercial and industrial programs as well. Commercial and industrial programs may be less likely to be uneconomic, however, if the OPIs are not accounted for.

Figure ES-1

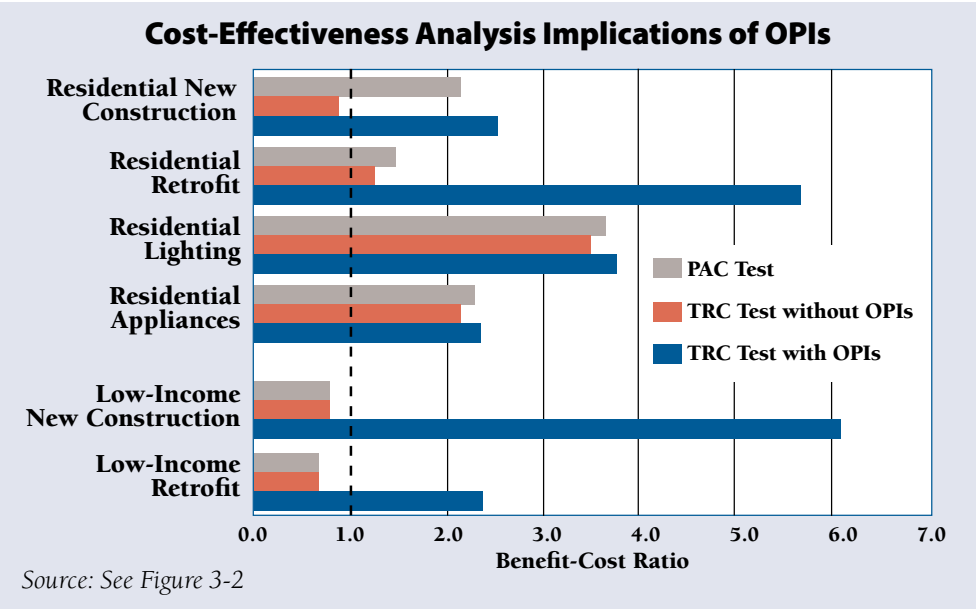


Source: See Figure 3-1

Figure ES-2 presents the actual cost-effectiveness results for an electric utility's 2012 residential efficiency programs. The figure presents the benefit-cost ratios under the PAC Test, the TRC Test with OPIs included, and the TRC Test without OPIs included. When the OPIs are not included in the TRC Test, the low-income, residential new construction, and residential retrofit programs are all at risk for being improperly deemed not cost-effective – even though these are some of the most important residential efficiency programs available.

It is important to recognize that including OPIs in the Societal Cost and TRC Tests is likely to expand the universe of efficiency resources that are deemed cost-effective and may lead to increased energy efficiency budgets, or in the case of limited efficiency budgets, it may result in the adoption of a different, more expensive mix of efficiency measures. In addition, properly accounting for OPIs and the associated conservative estimates and a continued understatement of the full benefits of energy efficiency. Nonetheless, when applying the Societal Cost Test or the TRC Test, using the best estimates available is a significant improvement over using no estimates at all.

*Figure ES-2**



Source: See Figure 3-2

**Figure ES-2 represents an example of how the choice of economic tests can have significant impacts on the results. These results should not be misinterpreted as extending to other regions and circumstances. The results will likely vary significantly by region, available fuels, and other program impacts that are customer-class and location specific. Further, the fact that some benefit-cost ratios exceed others should not be misinterpreted to favor investments in programs with higher ratio to the exclusion of lower ratios. The objective of the energy efficiency investments should be to get the greatest net economic benefit for the available investment.*

public policy benefits may be seen as burdening utility customers with costs for achieving benefits that are not related to utility services.

These concerns are addressed by applying the PAC Test to the entire portfolio of energy efficiency programs at the culmination of the testing process, as described previously. This approach can be used to assure regulators and other stakeholders that utility customer funds spent on energy efficiency programs will result in a net reduction in utility costs for utility customers.

Recommendations

When using the Societal Cost Test, it is important to account for the utility-perspective, participant-perspective, and societal-perspective OPIs to the greatest extent possible.

When using the TRC Test, it is important to account for the utility-perspective and participant-perspective OPIs to the greatest extent possible. It is particularly important to account for the participant-perspective OPIs, because otherwise the TRC Test will be internally inconsistent and will lead to cost-effectiveness results that are skewed against energy efficiency. This in turn will cause program administrators to underinvest in energy efficiency programs, and will impose higher costs on utility customers.

We recommend that each state adopt OPIs for screening energy efficiency initiatives. Each state will inevitably need to develop its own approach for accounting for OPIs that best suits its needs and best accounts for values of the OPIs relevant to it. One of the key barriers to adopting some OPIs is that they are difficult to quantify. Nonetheless, it is important for states to attempt to quantify OPIs to the greatest extent possible, because assuming that they do not exist or assuming that they are worth nothing is clearly inaccurate and incorrect. To this end, we recommend that each state do the following:

- Develop quantitative, monetary estimates for all OPIs that can be readily monetized. At a minimum, this should include the other fuel and water savings, because these savings can be relatively easily monetized using forecasts of the prices for those fuels.
- Develop some methodology for addressing those OPIs that are not monetized, for example, by conducting sensitivities or using an adder to the benefits as a proxy. Although there are limits to these approaches, and adders are sometimes critiqued for being too conservative, these approaches may be necessary to ensure that some of the significant OPIs are not ignored simply because they are difficult to quantify.
- Address the OPIs associated with low-income customers. Many studies have shown that these are among the most significant OPIs and can have a substantial impact on the cost-effectiveness of low-income programs.
- Identify those OPI assumptions, methodologies, and outcomes that can be transferred across utilities and across states, in order to increase awareness of the issues, promote consistency where appropriate, increase acceptance of hard-to-quantify values, and reduce costs.

There is no doubt that energy efficiency should play a significant role, even the primary role, in meeting climate change requirements.

Environmental Compliance Costs

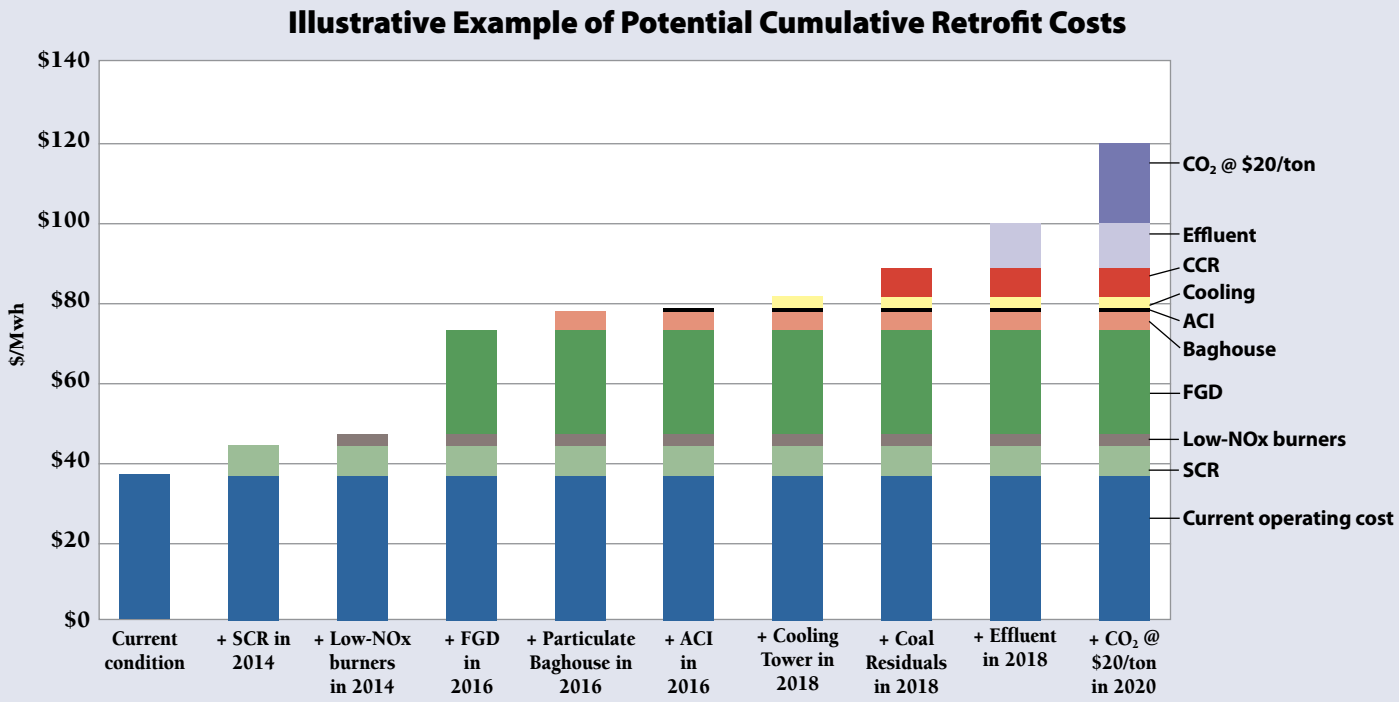
Current and Anticipated EPA Regulations

The US Environmental Protection Agency (EPA) has proposed and promulgated a number of environmental rulemakings that have significant implications for the operation of existing and new power plants. Costs associated with complying with these regulations should be included in the PAC, the TRC, and the Societal Cost Tests when evaluating energy efficiency resources.

Figure ES-3 provides an illustrative example of potential retrofit costs at an older 300-MW coal-fired power plant. This figure shows how various forthcoming environmental regulations can contribute to total power plant costs relative to the current operating cost. These costs are illustrative; many coal plants will not require all of these controls, and costs are likely to vary considerably between plants. The extent to which any one coal plant will have to install one or more of these controls will depend upon the age of the plant, the efficiency with which the plant operates, and the extent to which some of these controls have already been installed.

Several recent studies have estimated the amount of US coal capacity that is at risk for being retired as a result of the costs associated with the recent EPA regulations. Some of the most recent studies, which include the possibility of federal climate change requirements, estimate that up to one third of the US coal fleet may be uneconomic. This

Figure ES-3



Source: See Figure 4-2

will clearly have important implications for the avoided energy and capacity costs associated with energy efficiency resources.

Current and Anticipated Climate Change Requirements

There are currently many initiatives for reducing greenhouse gas (GHG) emissions from power plants at the federal, regional, state, and local levels. Costs associated with complying with these initiatives should be included in the PAC, TRC, and Societal Cost Tests when evaluating energy efficiency resources.

Despite several attempts in the past, the US Congress has yet to pass legislation requiring GHG emission reductions. However, this may change at some point in the near- to midterm future. In addition, the EPA has announced that it will issue New Source Performance Standards for GHG emissions, which will result in compliance costs for new and modified power plants.

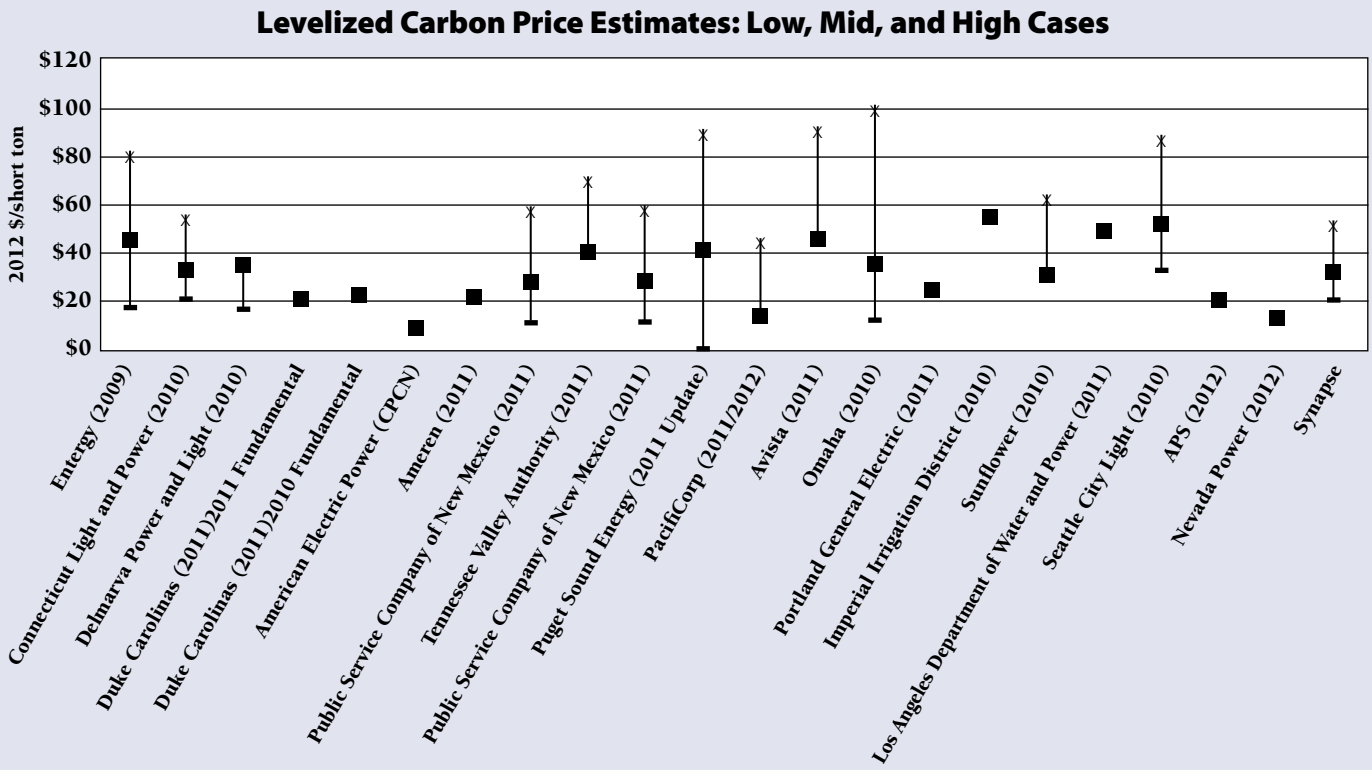
Some recent studies estimate that up to one third of the US coal fleet may be uneconomic as a result of the recent EPA regulations.

Many utilities recognize the likelihood of federal climate change requirements, and have developed forecasts of the potential CO_2 allowance costs that might result from such requirements. Figure ES-4 presents a summary of the range of recent CO_2 price forecasts that have been used by utilities, as well as independent forecasts from the Edison Electric Institute and from Synapse Energy Economics.

Many states have undertaken initiatives to reduce GHGs. Twenty-three US states and five Canadian Provinces currently participate in regional initiatives to reduce GHG emissions from power plants, and are seen as laboratories for future regional climate change activities. Furthermore, roughly 43 states have adopted a GHG inventory and/or registry, 36 states have adopted a state climate change action plan (with additional states in the process of developing such plans), and 23 states have established GHG emission reduction targets. Some of these state targets are relatively stringent, for example, requiring the reduction of CO_2 emissions of 80 percent below 1990 levels by 2050.

Energy efficiency is typically one of the lowest cost options for reducing GHG emissions. In fact, cost-effective energy efficiency programs reduce overall costs, whereas

Figure ES-4



Source: See Figure 4-7. The CO_2 prices are in levelized terms. The low value for each forecast represents the levelized value of the Low Case; the middle value represents the levelized value of the Mid Case or Reference Case; and the high value represents the levelized value of the High Case.

many GHG abatement options lead to increased costs. There is no doubt that energy efficiency should play a significant role, and maybe even the primary role, in meeting climate change requirements. If states do not properly assess the value of energy efficiency in complying with climate change requirements, then they will understate the cost-effectiveness of energy efficiency and will impose higher costs on utility customers over the long-term.

Recommendations

All states should recognize that the costs of compliance with current and anticipated EPA regulations and climate change requirements must be included in the PAC, TRC, and Societal Cost Tests. These costs are not environmental externalities; they will be incurred by utilities and passed on to ratepayers, and therefore should be included in all of these tests.

We recommend that all states recognize the importance of accounting for climate change compliance costs now. Uncertainty regarding the timing and size of those costs does not justify inaction. Many energy efficiency resources have measure lives of 15 years, 20 years, or more. Supply-side resources have operating lives that are even longer. Resource decisions made today should be based on the best assumptions available about the conditions that will exist over these long periods of time.

Energy efficiency resources should be screened on a frequent, periodic basis (e.g., every one to three years), because energy efficiency programs may take several years to ramp up to the levels needed to respond to evolving environmental requirements or to replace a retiring power plant.

Energy efficiency program administrators should account for all anticipated environmental compliance costs (EPA regulations, climate change requirements, and others), because this is the most accurate reflection of the future, and these environmental requirements can have significant cumulative effects. Piecemeal analyses of environmental

compliance costs can lead to uneconomic decisions and higher costs to customers.

All states should establish energy efficiency screening methodologies that account for the cost of complying with federal climate change requirements. Although some uncertainty about the timing of federal GHG emissions regulations remains, it is likely that limits will be imposed at some point over the near- to mid-term future. If a state or utility does not have its own forecast of federal CO_2 allowance prices, then it could rely upon publicly available forecasts such as those described in this study. Other options include conducting sensitivity analyses or using probabilistic modeling.

Piecemeal analyses of environmental compliance costs can lead to uneconomic decisions and higher costs to customers.

All states that have state-specific climate change requirements should account for the costs of complying with those requirements in screening energy efficiency programs. Ideally states should use state-specific, economy-wide marginal GHG abatement costs. In the absence of these, states can use reasonable proxies for marginal GHG abatement costs. Such proxies can be developed based on other resources that the state has decided to implement to address climate change concerns (e.g., renewable resources). The key issue here is that energy efficiency resources are evaluated for cost-effectiveness relative to other GHG abatement options that the state has decided are necessary to address climate change.

1. Introduction

For more than two decades, many states have relied upon a standard set of economic tests to decide what level of energy efficiency is cost-effective. The standard tests include the Ratepayer Impact Measure (RIM) Test, the Participant Test, the Program Administrator Cost (PAC) Test, the Total Resource Cost (TRC) Test, and the Societal Cost Test. These tests have played a significant role in determining the amount and type of efficiency programs implemented to date.

In theory, these tests provide regulators and other stakeholders with the full range of perspectives and the full range of costs and benefits with which to determine energy efficiency cost-effectiveness. In practice, however, these tests are frequently not applied properly. In many cases important benefits are excluded, energy efficiency is undervalued, and utility customers bear higher costs as a result.

Some of the energy efficiency program impacts are difficult to quantify, such as benefits to low-income customers, and are often ignored altogether. Other energy efficiency program impacts are uncertain, such as the cost of compliance with future climate change requirements, and are often understated or ignored altogether.

This report briefly describes the current state of energy efficiency cost-effectiveness analyses and makes recommendations for how to fill in the missing pieces. We focus on two key issues: accounting for other program impacts (OPIs) and accounting for the cost of compliance with environmental regulations.

We use the term "other program impacts" to describe what are commonly referred to as non-energy impacts (NEIs) or non-energy benefits (NEBs). OPIs are those costs and benefits that are not part of the cost, or the avoided cost, of energy provided by the utility funding the efficiency program. In addition to NEIs, OPIs also include "other fuel savings," which are the savings of fuels that are not provided by the utility that funds the efficiency program. For efficiency programs that are funded by electric utilities, the other fuels would primarily include gas, oil, propane, and wood. These other fuel savings are typically included in non-energy impacts, even though they actually involve energy savings. We use the term OPIs to refer to both NEIs and other fuel savings. OPIs can include both other program benefits and other program costs.

One of the premises underlying this report is that energy efficiency program administrators should implement all cost-effective energy efficiency, and therefore it is critical that the cost-effectiveness tests be properly designed and implemented. Another is that regulatory commissioners, consumer advocates, and other key energy efficiency stakeholders need to have confidence that the design and application of the energy efficiency cost-effectiveness screening is in the public interest and will result in reduced costs to utility customers.

We note that this report was prepared in conjunction with a similar report for the National Home Performance Council (Synapse, 2012). Some of the analyses, conclusions, and recommendations are the same in both reports. The purpose of this report is to provide more depth on the two issues of OPIs and environmental compliance costs.

While a goal of this report is to address these key issues related to application of cost-effectiveness tests, it is not the goal of this report to address all aspects of costs and benefits that may be relevant to one or more tests.

2. Cost-Effectiveness Tests and Their Uses

2.1 Defining the Cost-Effectiveness Tests

The costs and benefits of energy efficiency are qualitatively different from those of supply-side resources in that they can have different implications for different parties. As a result, five cost-effectiveness tests have been developed to consider efficiency costs and benefits from different perspectives. Each of these tests combines the various costs and benefits of energy efficiency programs in different ways, depending upon which costs and which benefits pertain to the different parties. These tests are described below and summarized in Table 2-1 and Figure 2-1.[3]

- **The Societal Cost Test**[4] – This test includes the costs and benefits experienced by all members of society. The costs include all of the costs incurred by any member of society: the program administrator, the customer, and anyone else. Similarly, the benefits include all of the benefits experienced by any member of society.

Table 2-1

Components of the Energy Efficiency Cost-Effectiveness Tests

	Participant Test	RIM Test	PAC Test	TRC Test	Societal Cost Test
Energy Efficiency Program Benefits					
Customer Bill Savings	X	—	—	—	—
Avoided Energy Costs	—	X	X	X	X
Avoided Capacity Costs	—	X	X	X	X
Avoided Transmission and Distribution Costs	—	X	X	X	X
Wholesale Market Price Suppression Effects	—	X	X	X	—
Avoided Cost of Environmental Compliance	—	X	X	X	X
Other Program Impacts (Utility Perspective)	—	—	X	X	X
Other Program Impacts (Participant Perspective)	X	—	—	X	X
Other Program Impacts (Societal Perspective)	—	—	—	—	X
Energy Efficiency Program Costs					
Program Administrator Costs	—	X	X	X	X
EE Measure Cost: Program Financial Incentive	—	X	X	X	X
EE Measure Cost: Participant Contribution	X	—	—	X	X
Non-Energy Costs	X	—	X	X	X
Lost Revenues to the Utility	—	X	—	—	—

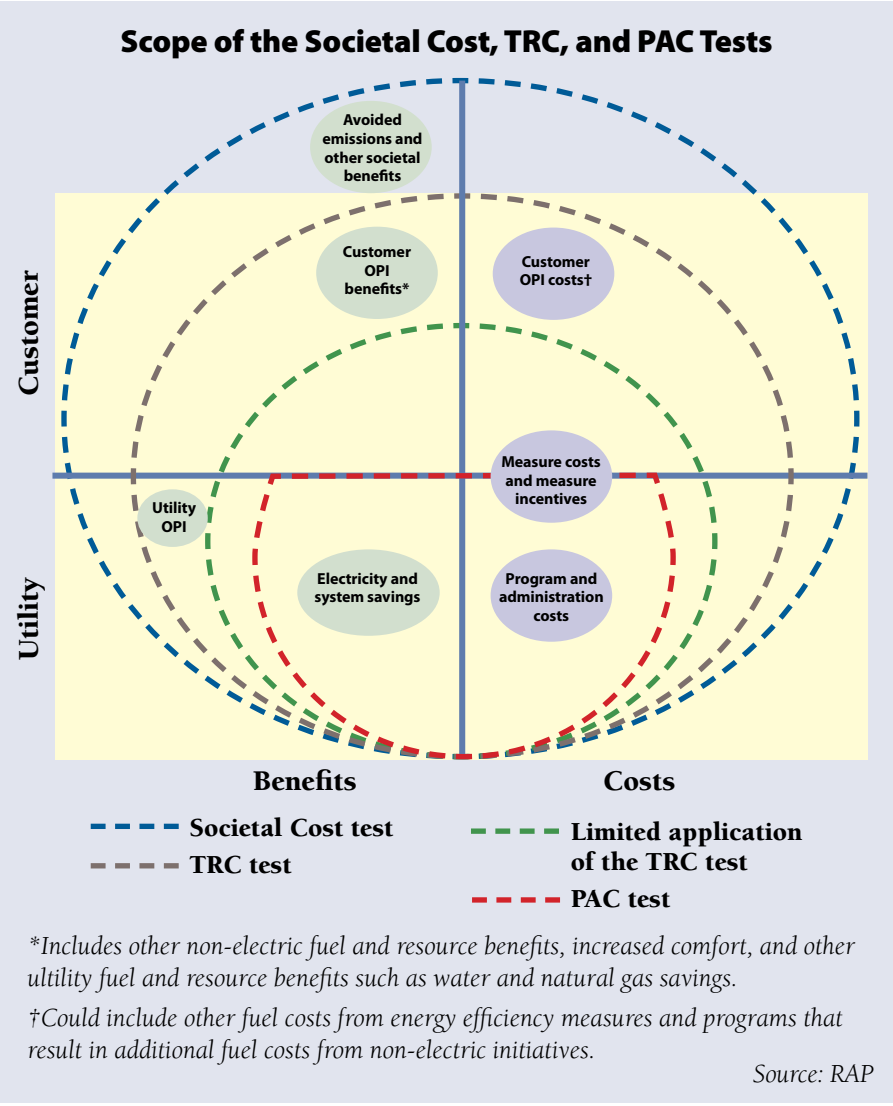
3 These tests are sometimes defined slightly differently by different public utility commissions. For comprehensive descriptions and discussions of these tests, see CA PUC, 2001 and NAPEE, 2008.

4 The California Standard Practice Manual (SPM) considers the Societal Cost Test to be a variant on the TRC Test (CA PUC, 2001, p. 18). Many states and studies depart from the SPM by drawing a more complete distinction between these two tests.

The costs and benefits are the same as for the TRC Test, except that they also include externalities, such as environmental costs and reduced costs for government services. The Societal Cost Test also includes the use of a lower societal discount rate.

- **The Total Resource Cost (TRC) Test** – This test includes the costs and benefits experienced by all utility customers, including both program participants and non-participants. The costs include all the costs incurred by the program administrator, plus all the costs incurred by the customers. The benefits include all the avoided utility costs, plus any OPIs experienced by the participating customers, such as avoided water costs, other fuel savings, reduced O&M costs, improved productivity in school and at work, improved sales for businesses with improved aesthetics, improved comfort levels, health and safety benefits, and more.
- **The Program Administrator Cost (PAC) Test**[5] – This test includes the energy costs and benefits that are experienced by the energy efficiency program administrator. The costs include all expenditures by the program administrator to design, plan, administer, deliver, monitor, and evaluate efficiency programs offset by any revenue from the sale of freed-up energy supply. The benefits include all the avoided utility costs, including avoided energy costs, avoided capacity costs, avoided transmission and distribution costs, and any other costs incurred by the utility to provide electric services (or gas services in the case of gas energy efficiency programs).
- **The Participant Test** – This test includes the costs and benefits experienced by the customer who participates in the efficiency program. The costs include all the direct expenses incurred by the customer to purchase, install, and operate an efficiency measure. The benefits include the reduction in the customer's electricity bills, any financial incentive paid by the program administrator, and OPIs experienced by the participating customer.[6]
- **The Ratepayer Impact Measure (RIM) Test**[7] – This test provides an indication of the impact of energy efficiency programs on utility rates. The results of this test provide an indication of the impact of energy

Figure 2-1



**Includes other non-electric fuel and resource benefits, increased comfort, and other utility fuel and resource benefits such as water and natural gas savings.*

†Could include other fuel costs from energy efficiency measures and programs that result in additional fuel costs from non-electric initiatives.

Source: RAP

5 This is sometimes referred to as the Utility Cost Test or the Energy System Test.

6 Throughout this analysis we use the term "program administrator" to refer to the entity that implements energy efficiency programs, whether it be a vertically integrated utility, a distribution utility, or a third-party administrator.

7 This has previously been referred to as the Non-Participant Test and the No-Losers Test.

efficiency on those customers who do not participate in the energy efficiency programs. The costs include all the expenditures by the program administrator, plus the "lost revenues" to the utility as a result of the inability to recover fixed costs over fewer sales. The benefits include the avoided utility costs.

How the Cost-Effectiveness Tests are Being Used Today

A recent survey by the American Council for an Energy-Efficient Economy (ACEEE) provides a useful summary of how the cost-effectiveness tests are used across the states.[8] Nationwide, a total of 45 jurisdictions have some level of formally approved ratepayer-funded energy efficiency programs in operation.[9] All of these jurisdictions use some type of benefit-cost test in connection with their ratepayer-funded energy efficiency programs.[10] Most states have some type of legal requirement for the use of such tests, either by legislation or regulatory order (ACEEE, 2012, p. 30).

Many states examine more than one benefit-cost test. The ACEEE survey found that 36 states (85 percent) apply the TRC Test; 28 states (63 percent) apply the PAC Test; 23 states (53 percent) apply the Participant Test; 22 states (51 percent) apply the RIM Test; and 17 states (40 percent) apply the Societal Cost Test (ACEEE, 2012, p. 12).

However, regulators tend to adopt one of these tests as the primary guideline for screening energy efficiency programs. The ACEEE survey found that 95 percent of states rely on a single, primary screening test for defining energy efficiency cost-effectiveness, as follows:

- The TRC Test is used by 29 states (71 percent) as the primary test for screening efficiency.
- The Societal Cost Test is used by six states (15 percent) as the primary test for screening efficiency.[11]
- The PAC Test is used by five states (12 percent) as the primary test for screening efficiency.
- The RIM Test is used by one state (2 percent) as the primary test for screening efficiency.[12]

Most states (70 percent) apply the cost-effectiveness tests, often with exceptions, at both the program and the portfolio level. A minority of states (30 percent) apply the cost-effectiveness tests at the measure level (ACEEE, 2012, p. 5).

2.2 Implications of the Cost-Effectiveness Tests

In theory, all of the cost-effectiveness tests should be considered in the evaluation of ratepayer-funded energy efficiency resources to provide the most complete picture of the impacts on different parties. This approach is rarely used in practice, however, due to the challenges of working with multiple tests showing different results. Most states rely upon one or two tests as the primary standard for screening energy efficiency programs.

Also, it is important to recognize that the different tests provide different types of information and should be used for different purposes. The RIM Test and the Participant

8 The ACEEE report provides the results of a comprehensive survey and assessment of the current "state of the practice" of utility-sector energy efficiency program evaluations across the 50 states and the District of Columbia. The study examines many aspects relating to how states conduct their evaluations and the key assumptions employed, including the use of cost-effectiveness tests (ACEEE, 2012).

9 The 45 jurisdictions include 44 states and the District of Columbia. The states that have essentially no formally approved utility ratepayer-funded energy efficiency programs are Alabama, Alaska, Louisiana, Mississippi, North Dakota, and West Virginia (ACEEE, 2012, p. 3).

10 This is not the case for load management/demand response programs or renewable energy programs, where only 67 percent and 28 percent of states, respectively, report using benefit-cost tests for those ratepayer-funded programs (ACEEE, 2012, p. 30).

11 Note that, while only six states were identified as using the Societal Cost Test for screening energy efficiency programs, a larger number of states include environmental impacts in their resource planning and siting practices in general. A 2001 study found that a majority of states include environmental protection in certification and citing decisions by regulatory commissions, and 16 state commissions have general authority or responsibility to consider environmental matters in regulatory decisions (Dworkin et. al., 2001). Several states also require electric and gas utilities to account for environmental impacts in their integrated resource plans.

12 Shortly after ACEEE published its findings, the one state using the RIM test as the primary test (Virginia) enacted a new law providing that a program or portfolio of programs "shall not be rejected solely based on the results of a single test" (see Code of Virginia, C. 821, §§ 56-576 (Approved April 18, 2012)). The practical impact of this new law on efficiency screening in Virginia is not yet clear.

Test provide "distributional" information, that is, information regarding how the impacts of energy efficiency are distributed across customers. In particular, the RIM Test provides an indication of the primary impacts of energy efficiency on those customers who do not participate in the energy efficiency programs, because the main impacts on these customers are the adjustments in rates resulting from energy efficiency. The Participant Test, on the other hand, provides an indication of the primary impact of energy efficiency on the program participants. These two tests together provide a rough indication of how the benefits are distributed between program participants and non-participants.

In the paragraphs that follow we summarize some of the key implications of each of the five cost-effectiveness tests. Table 2-2 summarizes some of the key points. In Appendix A, we provide some additional detail about the important differences between the cost-effectiveness tests, with some clarifications regarding the differences between the PAC, the TRC, and the Societal Cost Tests.

The Societal Cost Test is the most comprehensive standard for evaluating the cost-effectiveness of efficiency, because this is the only test that includes all benefits and costs to all members of society. Ideally, the Societal Cost Test should include all costs and benefits, including externalities, regardless of who experiences them.

The TRC Test is the next most comprehensive standard for evaluating the cost-effectiveness of energy efficiency by including all the impacts to the program administrator and its customers.[13] It offers the advantage of including the full incremental cost of the efficiency measure, regardless of which portion of that cost is paid for by the utility and

13 The name of this test is misleading, because it does not include "total" costs of an energy efficiency resource. A more accurate and descriptive name for this test would be the All Customers Test, because it includes the total costs and benefits to all customers.

Table 2-2

Implications of the Five Principal Cost-Effectiveness Tests

Test	Key Question Answered	Summary Approach	Implications
Societal Cost	Will total costs to society decrease?	Includes the costs and benefits experienced by all members of society	Most comprehensive comparison
Total Resource Cost	Will utility costs and program participants' costs decrease?	Includes the costs and benefits experienced by all utility customers, including energy efficiency program participants and non-participants	Includes the full incremental costs and benefits of the efficiency measure, including participant and utility costs and benefits
Program Administrator Cost	Will utility costs decrease?	Includes the costs and benefits experienced by the energy efficiency program administrator	Limited to impacts on utility revenue requirements; indicates net impact on utility costs and utility bills
Participant	Will program participants' costs decrease?	Includes the costs and benefits experienced by the customer who participates in the efficiency program	Provides distributional information; useful in program design to improve participation; of limited use for cost-effectiveness screening
Rate Impact Measure	Will utility rates decrease?	Includes the costs and benefits that will affect utility rates, including program administrator costs and benefits as well as lost revenues	Provides distributional information; useful in program design to find opportunities for broadening programs; should not be used for cost-effectiveness screening

Adapted from NAPEE, 2008, p. 2-2, with modifications.

which portion is paid for by the customer. In practice, however, the TRC Test is frequently misapplied. Many states that use the TRC Test do not include all of the costs and benefits to customers, in particular the non-energy costs and benefits. Applying the TRC Test in this way skews cost-effectiveness results, typically skewed against energy efficiency. This issue is discussed in detail in Section 3.

The PAC Test is more restrictive than the TRC Test in that it only compares the program administrator costs to the costs of avoided supply-side resources. One way to think of this test is that it is limited to the impacts that would eventually be charged to all customers through the revenue requirements; the costs being those costs passed on to ratepayers for implementing the efficiency programs, and the benefits being the supply-side costs that are avoided and not passed on to ratepayers as a result of the efficiency programs.[14] This test is most consistent with the way that utilities typically evaluate the cost-effectiveness of supply-side resources. The PAC Test, however, does not include several significant impacts that have important public policy implications and are important in planning energy efficiency programs, most notably other fuel savings, other resource savings (e.g., water), and improved health and safety.

The Participant Test is fundamentally different from the other tests in that it limits benefits to customer bill savings as the primary benefit of the programs. Customer rates are typically higher than the marginal avoided costs of the energy system, leading to higher energy efficiency benefits per unit of energy saved. Also, the only costs in this test are the customer costs, which in many cases are lower than the costs incurred by the program administrator to plan, design, and deliver the energy efficiency programs. Consequently, this test is typically the least restrictive of all the cost-effectiveness tests. As noted, it provides an indication of the distributional effects of the energy efficiency program, along with the RIM Test, and may be useful in optimizing program design for participation.

It is important to note that there are additional benefits of energy efficiency that accrue to the utility system as a whole that are not necessarily captured in the benefits listed earlier. Energy efficiency offers significant benefits in terms of reducing risk (e.g., the risks associated with fossil fuels and the risks inherent in load forecasting), as well as benefits in terms of improving the overall reliability of the utility system (e.g., by reducing peak demand and by slowing the rate of growth of peak demand). A comprehensive assessment of energy efficiency resources should include these benefits in all of the cost-effectiveness tests described previously.

The Rate Impact Measure Test tends to be the most restrictive of all the efficiency tests, because the utility lost revenues can make very large contributions to the energy efficiency program costs. Most, if not all, states have ruled that the RIM Test should not be used as the primary test for evaluating energy efficiency cost-effectiveness. There are several reasons for this.

- Applying the RIM Test to screen efficiency programs will not result in the lowest cost to society or the lowest cost to customers on average. Instead it will lead to the lowest rates (all else being equal). Achieving the lowest rates is not the primary goal of utility planning and regulation, however, especially if lower rates lead to higher costs to customers on average.
- The RIM Test is heavily influenced by the lost revenues to the utility. Lost revenues are not a true cost to society, however. Lost revenues represent a "transfer payment" between efficiency program participants and non-participants; the bill savings to the program participants result in the lost revenues that are collected from all customers, including non-participants.[15] In this way, lost revenues are not a new or an incremental cost in the same way that the program administration costs are a new and incremental cost of implementing energy efficiency programs, and they should not be applied as such in screening a new energy efficiency resource.
- A strict application of the RIM Test can result in the rejection of large amounts of energy savings and the opportunity for large reductions in many

14 The name of this test is a little misleading, because it does not include the costs and benefits to the program administrator itself (e.g., utility profits). A more descriptive name for this test would be the Revenue Requirements Test.

15 Note that in those jurisdictions where utilities are not allowed to collect lost revenues and do not have decoupling, this transfer payment is actually between the utility shareholders and program participants for the years in between rate cases.

customers' bills in order to avoid what are often small impacts on non-participants' bills. From a public policy perspective, such a trade-off is illogical and inappropriate.

- The RIM Test does not provide useful information about what happens to rates as a result of program implementation. A RIM Test benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact. And it says nothing at all about the amount of cost savings associated with the energy efficiency program.
- Screening efficiency programs with the RIM Test is inconsistent with the way that supply-side resources are screened, and creates an uneven playing field for the consideration of supply- and demand-side resources. There are many instances in which utilities invest in new power plants or transmission and distribution facilities in order to meet the needs of a subset of customers (e.g., new residential divisions, an expanding industrial base, geographically-based upgrades). These supply-side resources are not evaluated on the basis of their equity effects, nor are the "non-participants" seen as cross-subsidizing the "participants."

Nonetheless, efficiency programs can lead to increased rates, and rate impacts are an important consideration for regulators and other efficiency stakeholders. It is important to recognize, however, that the rate impacts of energy efficiency programs are not a matter of cost-effectiveness. (As noted previously, the lost revenues are simply a transfer payment and do not represent an incremental cost.) Instead, they are a matter of customer equity between program participants who experience reduced bills and non-participants who experience increased rates and therefore increased bills.[16]

The RIM Test therefore should not be used in screening energy efficiency programs for cost-effectiveness. Instead, efficiency program administrators should take steps to (1) analyze rate and bill impacts in a fashion that provides much more information than what is available from the RIM Test; (2) design programs in a way that mitigates rate impacts without sacrificing energy efficiency savings; and (3) work to increase the number of program participants so as to mitigate the equity concerns between participants and non-participants.[17]

2.3 Considerations in Applying the Cost-Effectiveness Tests

Which Test to Use as the Primary Test?

The decision of which cost-effectiveness test to use for screening efficiency programs has been a matter of debate since the introduction of energy efficiency programs, and continues to be a subject of debate today (Neme & Kushler, 2010; CA PUC, 2012b). This decision requires consideration of several factors, including economic factors and public policy issues. Below we describe the key issues to consider in making this decision.

First is the question of scope. Although the cost-effectiveness tests are frequently described as pertaining to different perspectives, another way to distinguish them is that they vary by the scope of the impacts to be accounted for. If the scope of the test is to be limited to revenue requirements, then the PAC Test is most appropriate. If the scope of the test is to include the total incremental impacts of the efficiency measure on all customers, then the TRC Test is most appropriate. If the scope of the test is to include all impacts to society, then the Societal Cost Test is most appropriate. The decision of which scope to use is a policy decision that will need to balance several public policy considerations, discussed subsequently.

The Societal Cost Test is the most comprehensive test, and is most appropriate for those states that wish to give consideration to the societal benefits of energy efficiency programs, particularly the environmental and health benefits. The disadvantages of this test are that some stakeholders may view the scope as outside the interests and jurisdiction of regulatory commissions; some of the societal impacts are uncertain and difficult to forecast; and this test might lead to undesirable cost impacts on utility customers.

16 It is important to note that all customers benefit from energy efficiency programs in certain ways, regardless of whether they participate in the programs. For example, all customers will experience reduced risk, improved reliability, reduced transmission and distribution costs, reduced costs of environmental compliance, reduced environmental impacts, and the benefits of price suppression effects in wholesale electric markets.

17 For additional information regarding the management of rate and bill impacts, see US DOE, 2011.

The TRC Test is the next most comprehensive test and is the most widely used test. Regulators and legislators are apparently drawn to this test because it includes the total incremental impacts of efficiency measures. The TRC Test creates a dilemma for policymakers, however. In order to be internally consistent, the test must include OPIs on the program participants, but regulators are often wary of doing so because some of the benefits are uncertain and difficult to quantify. In addition, including OPIs in the TRC test is likely to expand the universe of efficiency resources that are deemed cost-effective and may lead to increased energy efficiency budgets, or a more expensive mix of efficiency measures. Properly accounting for OPIs in the TRC test may burden utility customers with higher-cost efficiency measures in order to achieve benefits that are not related to utility services.

The PAC Test is most appropriate for those states that want to limit the energy efficiency cost-effectiveness analysis to the impacts on revenue requirements. There are many advantages to this test: it is consistent with the way that supply-side investments are frequently evaluated; it includes costs that are relatively easy to identify and quantify; and it includes the energy costs and energy benefits that are most important to utility ratepayers. Probably the most important benefit of the PAC Test is that it provides legislators, regulators, consumer advocates, and others with confidence that the energy efficiency programs will result in lower costs to utility customers. This is an extremely important consideration, particularly for those states that seek to implement all cost-effective energy efficiency resources.

Relying on the PAC Test has one significant disadvantage, however, in that the costs and benefits to energy efficiency program participants are not taken into consideration. There are two implications of this. First, by not including the participant's cost, the PAC Test does not include the full incremental cost of efficiency measures, which may be important to policymakers. Second, the PAC Test does not include the other program benefits of efficiency measures, some of which are clearly important to policymakers. The other program benefits that are typically most important to regulators are (1) benefits that pertain to low-income customers, due to the significant public policy implications of this sector; and (2) other fuel savings, as these savings are important for promoting comprehensive, whole-house, one-stop-shopping residential retrofit programs, as well as new construction programs where customers tend to use multiple fuels. In Section 4.1 we provide an illustration of how these two types of benefits can have a significant impact on program cost-effectiveness.

Once the scope is established, it is important to ensure that the test being applied includes all of the appropriate costs and benefits in a way that is internally consistent. For example, when applying the PAC Test, it is important to include all the costs and all the benefits that are expected to affect utility revenue requirements. Similarly, when applying the TRC Test, it is important to include all the participant benefits, as well as the participant costs in order to maintain internal consistency. Otherwise the test results will be skewed and misleading. These issues are discussed in more detail in Section 4.1. In addition, it is important to ensure that there is no double counting of costs or benefits in the test being applied. Finally, it is important to ensure that transfer payments are properly accounted for when deciding which costs and benefits to include in each test.

To summarize, in choosing the appropriate test to use, policymakers must consider and balance several key questions. How important is it to include all societal impacts, including environmental and health impacts? How important is it to include the full incremental cost of the efficiency measures? How important is it to include OPIs and the associated public policy benefits (e.g., low-income benefits, other fuel savings)? How important is it to ensure that utility revenue requirements are minimized?

At What Level Should the Screening be Performed?

Cost-effectiveness tests for energy efficiency resources can be applied at different levels of detail. In general, there are three levels to evaluate cost-effectiveness when planning energy efficiency programs: the "measure" level, the "program" level, and the "portfolio" level. Evaluating cost-effectiveness at the measure level means that each individual component (i.e., measure, equipment, or other action) of an efficiency program must be cost-effective. Evaluation at the program level means that collectively the measures within a program must be cost-effective, but some measures might not be if there are other measures that more than make up for them. (There must, however, be sound reasons for including measures that do not screen, such as sound program design.) Evaluating cost-effectiveness at the portfolio level means that all of the

programs taken together must be cost-effective, but some programs might not be. (Here too, there must be sound reasons for including programs that are not cost-effective on their own.)

We note that there is an important distinction between *analyzing* energy efficiency resources and *screening* them. Analyzing includes comparing the costs and benefits for the purpose of understanding the broad economic impact, whereas screening includes making a decision as to which programs should be implemented through ratepayer-funded programs and which should be redesigned or not funded.

We recommend that all energy efficiency resources be *analyzed* at the measure level. This is important so that the energy efficiency assessment can (1) be based on the most detailed level of information; (2) provide the greatest transparency for regulators and other stakeholders; and (3) allow program administrators and other stakeholders the ability to consider the implications of energy efficiency resources at the greatest level of detail.

Efficiency resources, however, do not need to be *screened* at the same level at which they are analyzed. We recommend that energy efficiency resources be screened at the program level. In theory, measure-level screening offers the advantage of ensuring that every component of the efficiency program will result in net benefits, and that programs will not include measures that are exorbitantly expensive or uneconomic. In practice, however, these advantages can be outweighed by several benefits associated with program-level screening.

Program level screening allows for program administrators to account for the interactive effects between efficiency measures, including the fact that some measures may be uneconomic but may have a big impact on encouraging customers to participate in the program or to adopt other, more cost-effective measures in the program. Program-level screening also allows for comprehensive, whole-house or whole-building energy efficiency improvements, which may be important to customers, program administrators, or other stakeholders. Additionally, program-level screening helps prevent lost opportunities by allowing program administrators to implement all appropriate energy efficiency measures while they are engaging with program participants (Synapse, 2012).

Allowing for program-level screening does not mean that program administrators should be allowed to implement efficiency measures that are clearly not cost-effective. Program administrators should be encouraged to include in their programs only those efficiency measures that are cost-effective, unless there are marginally uneconomic measures that are appropriate to include in a program because of their ability to promote customer participation, their interactive effects with other measures, their ability to promote comprehensive efficiency solutions, or their ability to avoid lost opportunities.

2.4 Recommendations for Applying the Tests

With all of these considerations in mind, we offer the following recommendations.

First, we note that ideally all three tests, the broader Societal Cost Test and TRC Test, as well as the PAC Test, should be considered when assessing energy efficiency cost effectiveness. We recognize, however, that this still leaves the ultimate question of which test results to use in determining the programs to implement, and that in practice it is more common and straightforward to use a single, primary test to answer this ultimate question. Our recommendations below include a primary test applied at the program level, but a secondary test applied at the portfolio level. This approach offers the benefits of both breadth and simplicity.

We recommend that the Societal Cost Test be used to screen energy efficiency programs, for all those states that have the authority to account for the societal impacts of efficiency programs. This test includes the broadest range of energy efficiency costs and benefits, and provides the best measure of the public policy benefits that are of great importance to legislators and regulators, such as low-income benefits, other fuel savings, and environmental benefits. Many of the concerns about quantifying the societal impacts can be addressed through rigorous analysis or sound public policy decision-making.

We recommend that all states that do not use the Societal Cost Test use the TRC Test to screen energy efficiency programs at the program level, and that this test should include OPIs to the greatest extent possible. At a minimum, the TRC Test should include the OPIs associated with low-income programs and with other fuel savings. Not accounting for OPIs will result in a biased application of

the test, leading to undervaluing of energy efficiency and higher costs for customers.

When evaluating ratepayer-funded energy efficiency programs with either the Societal Cost Test or the TRC Test, however, it is important to consider potential bill impacts and customer equity concerns. Properly accounting for OPIs and the associated public policy benefits may increase the universe of efficiency measures that are deemed cost-effective. This may lead to increased energy efficiency budgets, or in the case of limited efficiency budgets, it may result in the adoption of a different, more expensive mix of efficiency measures. In addition, properly accounting for OPIs and the associated public policy benefits may be seen as burdening utility customers with costs for achieving benefits that are not related to utility services. This is a critical consideration, particularly for states that are pursuing aggressive levels of energy efficiency savings or pursuing all cost-effective energy efficiency.

To address these equity concerns, we recommend that the PAC Test be applied, at a minimum, to the portfolio of efficiency programs to ensure that the entire package of programs will result in a net reduction in revenue requirements and a net reduction in costs to utility customers. The PAC test includes only those costs and benefits that affect utility revenue requirements, and thus provides a clear indication of potential impacts on customer bills. Under this approach, either the Societal Cost Test or the TRC Test would be the primary test for screening each energy efficiency program. Programs that do not pass the primary test would not be considered cost-effective and not be included in the efficiency portfolio. Then, the PAC Test would be applied, at a minimum, to the portfolio of programs that do pass the primary test. If the portfolio of programs does not pass the PAC Test, then one or more of the programs would need to be modified in such a way that the entire portfolio eventually passes the PAC Test. More granular ratepayer equity concerns can be addressed at the measure or program level by applying the PAC Test review at those levels in program design.

This combined screening approach should be simple to apply because it would rely upon a single, primary test (either the Societal Cost Test or the TRC Test) for screening at the program level, and a secondary test (the PAC Test) that would be applied as a check on behalf of utility customers. Regulators and other stakeholders could use the results of the portfolio-level PAC Test (expressed as millions of dollars in net reductions in utility costs) to assess the overall value of the efficiency portfolio to utility customers as a whole. Applying the tests in this manner helps regulators and other stakeholders ensure that public policy objectives for acquisition of cost-effective energy efficiency also result in a net reduction in utility costs to utility customers.

We note that good judgment should always be applied at all levels of cost-effectiveness screening. This should apply at all levels of screening using both the TRC and the PAC Tests. Program administrators should design programs to ensure that on a portfolio basis the PAC net benefits are significant relative to the PAC costs (i.e., that the PAC benefit-cost ratio is significantly greater than one).

3. Other Program Impacts

3.1 Description of Other Program Impacts

OPIs are those costs and benefits that are not part of the cost, or the avoided cost, of energy. There is a wide range of OPIs associated with energy efficiency programs. OPIs are categorized by the perspective of the party that experiences the impact: the utility, the participant, or society at large.

Below we present a summary of the OPIs that have been identified for inclusion in cost-effectiveness tests. This list is not intended to be all-inclusive; instead it presents those OPIs that are most frequently cited in the literature and are expected to have a significant impact on energy efficiency program cost-effectiveness.

Utility-Perspective OPIs

Utility-perspective OPIs are indirect costs or savings to the utility and its ratepayers. These OPIs can be further divided into the following subcategories.

- **Financial and accounting:** From the utility perspective, a number of NEBs are realized from efficiency program implementation in the form of financial savings. Energy-efficient technologies often result in reduced energy bills for participants, which can decrease the likelihood that customers experience difficulties with paying their utility bills. In turn, utilities realize financial savings through reduced costs associated with events such as arrearages and late payments (NMR, 2011, p. 4-1). These NEBs are often separately identified as the following: reduced arrearages, reduced carrying costs on arrearages (interest), reduced bad debt written off, and rate discounts (NMR, 2011; Hall, 2002).
- **Customer service:** Timely customer bill payments can result in fewer customer calls, late payment notices, shut-off notices, terminations, reconnections, and other collection activities. The utility realizes savings in staff time and materials (NMR, 2011, p. 4 11).
- **Safety:** Utilities may realize savings from their efficiency programs due to a reduction in safety-related emergency calls and insurance costs due to reduced fires and other emergencies (NMR, 2011, pp. 4-1, 4-15).

Participant-Perspective OPIs

Participants in energy efficiency programs can realize a variety of OPIs (NMR, 2011, pp. 2-6, 5-1). Most of these participant-perspective OPIs are relevant to both low-income and non-low-income customers. Some of these OPIs, however, may have significantly greater value for low-income customers than for non-low-income customers. Participant-perspective OPIs can be divided into the following categories:

- **Resource savings:** Energy efficiency can result in reduced water and/or sewage costs. Resource savings can also include heat (or lack thereof) generated by efficient equipment, as well as other fuel savings or costs (NMR, 2011; SERA, 2010).
- **Equipment cost and performance:** Participants often experience efficient equipment performing better than previous equipment or inefficient equipment, resulting in reduced (or increased) maintenance costs, improved lighting quality, and so on (NMR, 2011, pp. 5-13–5-15; SERA, 2010).
- **Health and safety:** Energy efficiency programs may have direct impacts on health through improved home environments, reduced exposure to hypothermia or hyperthermia – particularly during heat waves and cold spells – improved indoor air quality, and potential reductions in moisture and mold, leading to amelioration of asthma triggers and other respiratory ailments. Reduced incidence of fire and carbon monoxide exposure are also commonly identified as safety-related benefits resulting from

weatherization. Safety is also improved from better, more durable lighting equipment (NMR, 2011, pp. 5-30–5-34; SERA, 2010; NZ EEAC, 2012).

- **Comfort:** Participants in energy efficiency programs commonly experience greater perceived comfort, either due to fewer drafts and more steady temperatures with HVAC equipment or reduced noise from better equipment. Improved (or worsened) aesthetics can also be considered a comfort NEI (NMR, 2011, p. 5-9; SERA, 2010).
- **Reduced costs for businesses:** There are a variety of OPIs that pertain to commercial and industrial customers, including reductions in O&M costs, administration costs, materials handling, other labor costs, spoilage/defects, water usage, and waste disposal (Tetra Tech, 2012, p. 3-9).
- **Economic stability:** Low-income households spend a disproportionate amount of their income on energy costs when compared to the population at large. Reducing energy costs decreases rates of mobility among low-income households, and allows income to be made available for other uses, such as healthcare (NMR, 2011, p. 5-19; SERA, 2010).
- **Improved productivity:** Improvements in comfort and lighting can result in increased worker and student productivity. Health and safety benefits can result in reduced student and worker sick days (NZ EECA, 2012).
- **Increased sales revenues:** Customer service-oriented businesses can increase sales as a result of improved aesthetics and improved comfort levels in stores (Tetra Tech, 2012, p. 3-9).
- **Property value:** Increased property value is frequently recognized as a non-energy benefit associated with program participation. The benefit of increased property value has been estimated through the value of anticipated ease of selling or renting, or in some cases, increased resale or rental value. The improved durability and reduced maintenance for the home is also taken into consideration (NMR, 2011, p. 5-16; SERA, 2010).[18]
- **Benefits for owners of low-income rental housing:**[19] Owners of low-income rental properties can experience NEBs such as marketability/ease of finding renters, reduced tenant turnover, property value increases, reduced equipment maintenance for heating and cooling systems, reduced maintenance for lighting, greater durability of property, and reduced tenant complaints (NMR, 2011, pp. 1-8, 7-1).
- **Utility-related benefits:** Just as utilities incur costs associated with making bill-related calls to payment-troubled participants or service terminations and reconnections, participants also incur opportunity costs of time spent addressing utility billing issues. Participants are impacted through reduced bill-related calls to utilities, greater control over their utility bills, reduced termination and reconnections, reduced transaction costs, and buffers against energy price increases (NMR, 2011, p. 5-45; SERA, 2010; Hall and Riggert, 2002).

Societal-Perspective OPIs

Societal-perspective OPIs are indirect program effects that accrue to society at large beyond those realized by utilities, their ratepayers, or program participants (SERA, 2010, p. 2). These OPIs can be further divided into the following subcategories.

- **Environmental impacts:** Electricity generation can have a variety of environmental impacts, including emissions of GHGs, SO_2, NO_X, particulates, and air toxics; emissions of solid wastes; consumption of water; land use; mining impacts; aesthetic impacts, and more. By reducing the need to generate, transmit, and distribute electricity, energy efficiency can result in a variety of significant environmental benefits that will accrue to society as a whole (NMR, 2011, p. 6-1; SERA, 2010).

18 Although increased property value is frequently cited as a significant benefit of home energy retrofit programs, some parties argue that the increased property value is primarily a function of the reduced utility bills and that to include both would be double-counting. We include this item in our list in order to be comprehensive, but caution that the property value NEI should include only those changes in property value that are not accounted for in the other categories of energy efficiency benefits. Also, from a societal perspective, increases to property value may be a benefit to owners but a cost to buyers and renters.

19 It is important to ensure that any impacts included in this category are not double counting the impacts in other categories listed here (e.g., reduced maintenance, increased property value).

- **Healthcare:** To the extent that energy efficiency programs can improve health and reduce healthcare costs, they provide a benefit to society. Examples include reduced hospitalization and visits to doctors due to reduced incidences of illness or reduced incidence rates of chronic conditions (NMR, 2011, pp. 6-3, 6-4; SERA, 2010; NZ EEAC, 2012). Healthcare costs can fall on individuals, insurance providers (which are generally passed to individuals through higher premiums), or taxpayers.
- **Economic development:** Efficiency programs can impact economic conditions such as employment, tax revenues, earnings, and economic output (NMR, 2011, pp. 6 1–6-4; SERA, 2010). Energy efficiency can offer significant benefits in terms of creating jobs, even relative to alternative supply-side resources. These employment impacts tend to be particularly important to legislators and regulators, as well as other efficiency stakeholders. These benefits are rarely accounted for in energy efficiency program screening practices, however.
- **Reduced tax burden:** Energy efficiency programs provided to government facilities, including public schools, town halls, libraries, police and fire stations, military facilities, and others, will help lower the costs of supporting those facilities. These lower costs will often translate into lower taxes to the local, state, or federal taxpayers.[20]
- **National security:** A benefit of efficiency comes from reducing the need for energy imports, thereby enhancing national security (NMR, 2011, p. 6-6; SERA, 2010).

It is important to note that some OPIs can have benefits to more than one perspective. For example, reduced bill-related calls save time and money for the utility and the participant, or improved health can affect a participant and reduce the societal costs of healthcare.

The decision of whether and how to include OPIs has significant implications for the cost-effectiveness of energy efficiency programs. The inclusion of OPIs can frequently make the difference between a program being cost-effective or not.

In theory, the different categories of OPIs should be included in those tests in which the relevant costs and benefits are applicable. In other words, the Societal Cost Test should include the utility-, participant-, and societal-perspective OPIs because this test accounts for the impacts from all these perspectives; the TRC Test should include the utility- and participant-perspective OPIs because this test accounts for the impacts on utilities and participants; and the PAC Test should include the utility-perspective OPIs because this test accounts for the impacts on utilities and customer revenue requirements.

3.2 The Rationale for Accounting for Other Program Impacts

The primary reason for including OPIs in the cost-effectiveness tests is that they provide a more complete and balanced indication of the impacts of energy efficiency programs on customers. In fact, including OPIs in the cost-effectiveness tests is necessary to ensure that the tests are internally consistent. The whole premise of the tests is to assess the costs and benefits from different perspectives so that regulators and other stakeholders can consider the implications of the programs from those perspectives. If any one test includes some of the costs (or benefits) from one perspective, but excludes some of the costs (or benefits) from that same perspective, then the test results will be skewed (i.e., they will not provide an accurate indication of cost-effectiveness from that perspective). Test results that are skewed are misleading at best, and could lead program administrators to significantly underinvest or overinvest in energy efficiency. In some cases, the test results could be skewed so much as to render them meaningless.

This is especially important in the application of the TRC Test.[21] By definition, the TRC Test includes the participant's cost of the energy efficiency measure. In some cases, this cost can be quite large. In order for this test to be internally consistent, it must also include the participant benefits associated with the energy efficiency measure, including other program benefits. Excluding the participant-perspective OPIs from the TRC Test will

20 The reduced bills from energy efficiency programs are already accounted for in the participant's benefits. Energy efficiency at government facilities, however, can help to reduce taxes, which can provide incremental benefits to society.

21 This is also important for the Societal Cost Test. Here we focus on the TRC Test because of its widespread use.

provide cost-effectiveness results that are skewed against energy efficiency. This results in underinvestment in energy efficiency programs and will result in higher costs for all customers on average.

A second reason for including OPIs in the cost-effectiveness tests is that they help achieve important public policy goals. Achieving other fuel savings, improving health and safety for low-income customers, and reducing O&M costs for struggling businesses are all public policy objectives that are important to regulators and other stakeholders. In addition, accounting for OPIs helps to support more comprehensive, whole-building programs and to offer a more diverse set of efficiency measures to a broader range of customers. This promotes greater customer equity, both within sectors and between sectors, which is clearly an important public policy goal of regulators.

A third reason for including OPIs in the cost-effectiveness tests is that they often play an important role in customers choosing to implement energy efficiency measures. Customers will frequently adopt efficiency measures because of the resulting improvements to comfort, improved aesthetics, reduced O&M costs, improved quality of energy services, and more. Sometimes these benefits are more important to customers than the reductions in their energy bills. This indicates that these OPIs are of significant magnitude and should not be ignored in assessing the full costs and benefits of the energy efficiency programs.

Regulators and other stakeholders, however, may understandably be concerned that including OPIs when screening energy efficiency programs is too comprehensive. Including OPIs in the TRC Test is likely to expand the universe of efficiency resources that are deemed cost-effective and may lead to increased energy efficiency budgets to support increased numbers of measures, or they may lead to a more expensive mix of efficiency measures for those program administrators with fixed budgets. In addition, properly accounting for OPIs in the TRC Test may burden utility customers with higher-cost efficiency measures in order to achieve benefits that are not related to utility services. These concerns are very important and should be addressed when deciding which cost-effectiveness tests to apply and how to apply them. We recommend that these concerns be addressed by applying the Societal Cost Test or the TRC Test when screening efficiency at the program level, and then applying the PAC Test at the portfolio level as a check on whether the impacts on utility costs are appropriate. We discuss this recommendation in more detail in Section 2.4.

It is important to recognize that the issue of scope (i.e., whether to include impacts on participants) arises at the point when a commission (or legislature) decides on which test to use as the primary screening test. If the TRC Test is chosen as the primary test, then the commission (or legislature) is making an explicit or implicit decision to include costs to participants that are typically outside the scope of regulators' primary objectives in the same way that other program benefits are outside that scope. Once this decision is made, the scope is established (i.e., impacts on both non-participants and participants); then it is necessary to determine how to maintain internal consistency within this scope.

Among the participant-perspective OPIs that should be included in the TRC Test, there are two types that deserve mention at this point: low-income other program benefits and other fuel savings. First, these two types of OPIs tend to have the biggest impact on the cost-effectiveness of certain programs. This is demonstrated in our illustrative example below. Second, these two types of OPIs tend to support important public policy goals of regulators and other stakeholders. Low-income other program benefits are vital because they help justify programs that serve an important, hard-to-reach, disadvantaged set of customers. Other fuel savings are important because they help justify comprehensive residential retrofit and residential new construction programs that are designed to treat multiple fuels in customers' homes. Consequently we recommend that regulators place priority on finding ways to account for at least these two participant-perspective OPIs.

3.3 The Application of Other Program Impacts Today

As described in Section 2.1, a recent survey by ACEEE provides a summary of how the cost-effectiveness tests are used across the states. The study finds that, although 36 states use the TRC Test (which includes participant costs) as their primary test, only 12 of those states treat any type of participant non-energy benefits as a benefit (ACEEE, 2012, p. 31).

Of those states that do include non-energy benefits, most

of them were limited to water and other fuel savings. Only two states quantify a benefit for participant operation and maintenance savings, and no state quantifies benefits for things like comfort, health, safety, or improved productivity in their primary benefit-cost test (ACEEE, 2012, p. 32).

This survey clearly documents the fundamental imbalance in how the TRC Test is often applied today, where many states account for the participant costs of efficiency measures, but few of them account for the full participant benefits. In sum, the majority of states currently conduct cost-effectiveness tests that are inherently skewed against energy efficiency.

On the other hand, several states have taken steps to incorporate OPIs into energy efficiency program screening.[22] Some of the more interesting regulatory approaches are described below.

- **California:** The California Public Utility Commission (PUC) requires program administrators to account for utility-perspective and participant-perspective NEBs when assessing the low-income efficiency programs (SERA, 2010, p. 34). The participant-perspective NEBs include: water and sewer savings; fewer shutoffs; fewer calls to the utility; fewer reconnects; property value benefits; fewer fires; reduced moving costs; fewer illnesses and lost days from work or school; net benefits for comfort and noise; and net benefits for additional hardship (CA PUC, 2012b). The state hired a consultant to construct a model to monetize the low-income NEBs (SERA, 2010, p. 34). Historically NEBs have not been applied to the non-low-income efficiency programs. The PUC is currently investigating modifications to its energy efficiency cost-effectiveness practices, however, including whether to account for NEBs in assessing all programs (CA PUC, 2012a, 2012b).

- **Colorado:** The PUC of Colorado requires a 10-percent adder in TRC Test cost-effectiveness calculations to represent non-energy benefits. The percentage is applied to the sum of the other quantifiable benefits and is used when calculating TRC Test values for specific DSM programs and the overall portfolio. The Colorado PUC also allows for the option of including specific non-energy benefits, on a program-by-program basis, when such benefits are clearly occurring and can be easily calculated. Furthermore, in applying the TRC Test to low-income DSM programs, the benefits included in the calculation are increased by 20 percent to reflect the higher level of non-energy benefits that are likely to accrue from DSM services to low-income customers (CO PUC, 2008, p. 26-27, 43).

- **Massachusetts:** OPIs that can be quantified and monetized are included in cost-effectiveness screenings, including reduced operation and maintenance, increased health, safety, and comfort, increased property value, and others. In 2011 a study was prepared for the Massachusetts program administrators assessing and monetizing the OPIs applicable to the residential and low-income programs in the state (NMR, 2011). The results of this study have been incorporated into the Massachusetts Technical Resource Manual to ensure that all program administrators include the same NEI assumptions. In 2012 a second study was prepared for the Massachusetts program administrators assessing and monetizing the OPIs applicable to the commercial and industrial programs in the state (Tetra Tech, 2012). The results of these studies are discussed in more detail in Section 3.4.

- **New York:** Detailed evaluation of OPIs is conducted for many or all of the programs in the program administrator's residential, commercial, and industrial portfolio. OPIs such as comfort, safety, air quality, productivity, and so on are included in regulatory cost-effectiveness evaluations for informational purposes only, but are not used for specific decision-making with respect to cost-effectiveness. Program administrators present the benefit-cost results both with and without OPIs. Occasionally program administrators use a scenario approach in which regulators are shown the benefit-cost results including zero OPIs, 50 percent of OPIs, and 100 percent

22 Skumatz Economic Research Associates, Inc. (SERA) recently published a paper that provides a comprehensive analysis of the "state of the art" in NEIs, and reports on the status and recommendations on estimation approaches for low-income programs in California (SERA, 2010, p. 1).

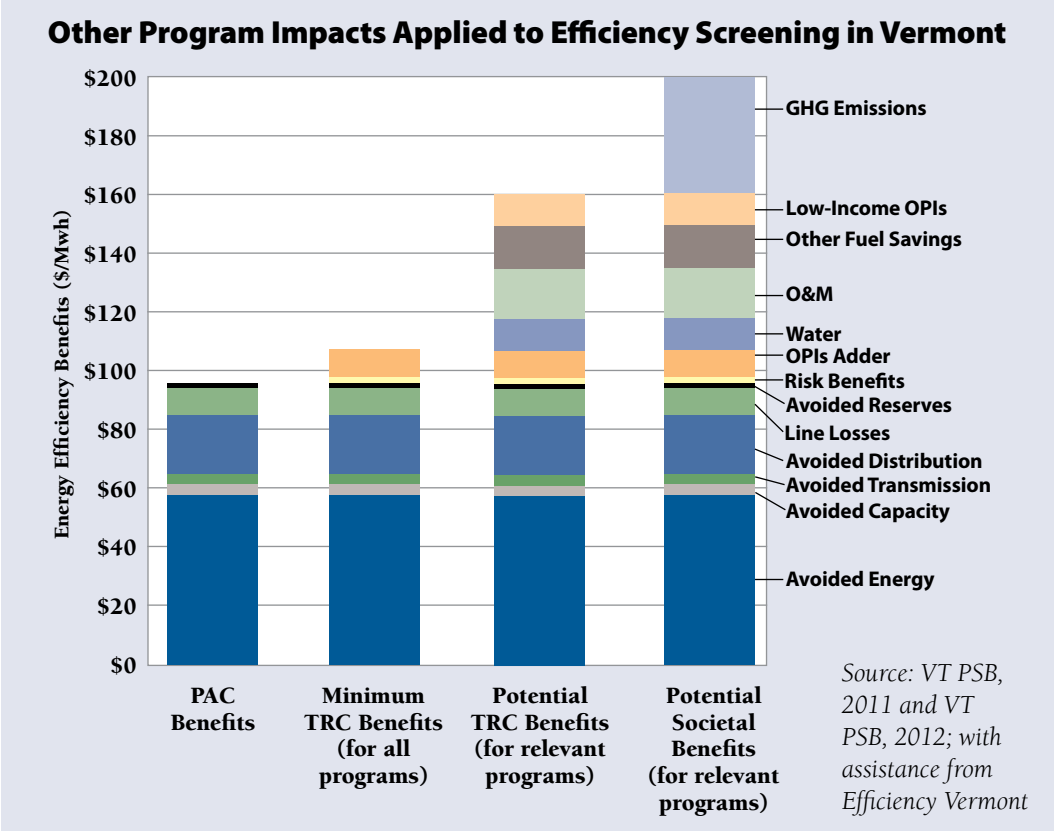
of OPIs (or similar). For utility OPIs, the program administrators generally rely on defaults and proxy values from the literature, adjusted for New York, and do not generally conduct arrearage or similar studies. For participant OPIs, they generally use the survey method developed in the literature. For societal figures (emissions and jobs), they use specialized regional models developed by a consulting firm (SERA, 2010, p. 34-35; NYSERDA, 2005; NYSERDA, 2012).

- **Oregon:** The PUC of Oregon has a long-standing policy that utilities (now the Energy Trust of Oregon) should calculate non-energy benefits if they are significant and there is a reasonable and practical method for calculating them (OR PUC, 1994, p. 15; SERA, 2010, p. 34-35).

- **Washington:** Puget Sound Energy: Puget Sound Energy categorizes OPIs as quantifiable and non-quantifiable. Where possible and easily quantifiable, Puget Sound Energy may include dollar values for non-energy benefits in its TRC Test, including values for water usage savings or maintenance savings. Non-quantifiable OPIs may include legislative or regulatory mandates, support for regional market transformation programs, low-income health and safety, low-income energy efficiency, or experimental and pilot programs. Where there is a significant amount of non-quantifiable OPIs, then Puget Sound Energy is able to accept energy efficiency programs with a benefit-cost ratio of less than 1.0, as long as the ratio exceeds 0.667 (PSE, 2012; SERA, 2010, p. 35).

- **Vermont:** The Vermont Public Service Board requires that several OPIs be accounted for in energy efficiency screening. First, the risk benefits of energy efficiency resources should be accounted for by applying a 10-percent discount to the energy efficiency costs. Second, the non-energy benefits of energy efficiency resources should be accounted for by applying a 15-percent adder to the energy benefits (Vermont PSB, 2012). Third, water, O&M, and other fuel savings should be accounted for with quantified and monetized estimates of those benefits, and applied to those programs in which these savings are expected to occur. Fourth, the non-energy benefits of low-income programs should be accounted for by applying a 15-percent adder to the energy benefits associated with those programs. The Board acknowledges that this adder is an approximate, conservative estimate of the value of low-income benefits, but notes that such a value is better than assuming zero, which is clearly not correct (VT PSB, 2012, p. 30). Finally, the environmental externalities associated with GHG emissions should be accounted for by assuming a CO_2

Figure 3-1



Source: VT PSB, 2011 and VT PSB, 2012; with assistance from Efficiency Vermont

allowance price of $80/ton (VT PSB, 2011). Note that the Vermont Public Service Board requires program administrators to use the Societal Cost Test to screen energy efficiency resources, which includes the costs of environmental externalities.

Figure 3-1 presents a summary of the OPIs that are accounted for in energy efficiency screening in Vermont. These costs are presented in terms of levelized costs (in $/MWh). The leftmost column indicates the benefits that would be applied to all programs under the PAC Test, using the avoided costs currently applied in Vermont. The second column from the left indicates the risk benefits and the non-energy benefits that would be applied to all energy efficiency programs under the TRC Test. The second column from the right indicates the potential magnitude of the water, O&M, other fuel savings, and low-income benefits under the TRC Test. These benefits would not necessarily be applied to all programs; they would be applied only to those programs in which the measures are expected to result in the relevant benefits. Also, the size of the benefit can vary depending upon the amount of savings from any one measure or program; the values presented in Figure 3-1 are averages based upon the actual savings for Efficiency Vermont in program year 2010.

The rightmost column includes the avoided emissions benefit that is applied under the Societal Cost Test. The sum of all the benefits in the rightmost column should be seen as the potential amount of societal benefits; the water, O&M, other fuel savings, and low-income benefits would only apply to relevant programs.

3.4 Estimating the Value of Other Program Impacts

Methodologies for Monetizing Other Program Impacts

Some OPIs are priced by markets; many are not. Those OPIs that are market-based (e.g., other fuel savings, water savings) should be quantified and monetized using market prices to the extent possible.

Two primary approaches are used to quantify OPIs that are not priced by a market: computational and survey-based. Computational approaches use primary or secondary data assembled from program records or literature-based sources (SERA, 2010, p. 17).

Survey-based approaches rely on commonly used types of survey-based data gathering and estimation approaches, including stated preference surveys and revealed preference approaches. Revealed preference approaches include willingness to pay and willingness to accept contingent valuation studies, comparative or relative valuations, and other revealed preference and stated preferences approaches (SERA, 2010, p. 18).

Direct computation approaches have obvious benefits. Unfortunately an extensive array of less tangible but potentially important benefits cannot generally be estimated directly by a computational approach, including comfort, aesthetics, and other factors. Relying solely on computational methods thus is not sufficient in deriving overall estimates of participant-perspective OPIs. Economists, social scientists, and researchers in the environmental and advertising fields have used a variety of survey-based valuation methods to develop estimates of the monetary value of externalities and intangible goods. Examples of a few methods with particular applicability to energy include the following:[23]

- Computational approach using primary data;
- Computational approach using secondary data;
- Computational approach using statistical techniques, including regression analysis;
- Survey methods, including contingent valuation (e.g., willingness to pay and willingness to accept techniques); and
- Other survey methods, including relative scaling approaches, ranking approaches such as conjoint analysis, and customer motivation approaches.

It is important to emphasize that many OPIs, especially the non-energy benefits, are extremely challenging to measure, to quantify, and to put into monetary terms. In addition, some of the NEBs may be unique to certain customer types, and some of the NEBs may depend upon the unique preferences or conditions of different customers. Under even the best of circumstances it will be very difficult to ensure that all relevant NEBs are accounted for, and that their magnitudes are properly assessed. Experience to date indicates that adders and other proxies designed to account for NEBs typically understate the magnitude of these benefits. Program administrators, regulators, and

23 For a more detailed discussion of these options, see SERA, 2010, p. 17-24.

other stakeholders should be aware of these limitations when attempting to estimate the value of OPIs and NEBs.

Examples of Recent Estimates of Non-Energy Impacts

This section provides an illustrative list of the NEIs that have been monetized and recommended for inclusion in cost-effectiveness tests by recent studies.[24] Most of the NEI values reported were derived from the existing literature or by developing modified algorithms from the literature, whereas some values were derived by surveys of program participants.

In some cases, quantifying an NEI is not recommended for one of several reasons. Sometimes quantifying the NEI would amount to double counting, as it is already accounted for through a separate NEI or benefit. In other scenarios, an NEI is not monetized because there is insufficient evidence for its existence or because the NEI is too intangible (NMR, 2011, p. 1-1-2; 2-1). On occasion, a case might be made that an NEI is too hard to quantify meaningfully, but that outcome should be an exception rather than a rule for the reasons discussed previously and because experience shows that reasonable methods clearly exist for quantifying most NEIs.

For the discussion in this section, we have included only NEIs that have been monetized. It is important to note that many significant NEIs have not previously been monetized, and therefore the information below should not be seen as an exhaustive list of the most significant NEIs. It is also important to note that the NEI estimates presented in the tables below do not necessarily represent the full range of NEIs that have been monetized to date. These tables should be seen as an illustrative list of monetized NEIs, based on recent literature reviews. Finally, we do not recommend that only monetized NEIs be accounted for when screening energy efficiency programs, as described in more detail in Section 3.6.

Typically NEIs are considered either as a one-time or an annual impact, and are applicable on either a per-housing unit basis (also referred to as per-participant) or per-measure basis. The values presented in this section are expressed in dollars per housing unit or dollars per participant on an annual basis, unless otherwise noted.[25]

Utility-Perspective NEIs

Utility-perspective NEIs represent tangible benefits in the form of direct monetary savings to the utility, and therefore tend to be relatively easy to quantify. Most of the NEIs used are monetized from the literature or from algorithms using inputs from utilities. In general, the utility-perspective NEIs are relatively low in value, ranging from less than a dollar to nearly $9 per participant (NMR, 2011, p. 1-3-6; 4-1). Table 3-1 summarizes the range of values associated with utility-perspective impacts.

Table 3-1

Utility-Perspective Non-Energy Impacts

Impacts Quantified to Date	Value or Range of Values
Financial and Accounting NEIs	
Reduced arrearages	$2.61
Carrying costs on arrearages	$2.00 - $32.00
Bad debt written off	$2.00 - $3.74
Customer Service NEIs	
Terminations and reconnections	$0.00 - $50.00
Customer calls	$0.58
Collection notices	$0.34
Safety-related energy calls	$0.50-$8.43

Source: SERA, 2010; NMR, 2011. The values presented in this table are expressed in dollars per housing unit or dollars per participant on an annual basis.

Participant-Perspective NEIs

Table 3-2 presents a summary of participant-perspective NEIs for residential efficiency programs from two recent studies. This table is not meant to represent an exhaustive summary of the literature or the potential NEIs, nor is it meant to suggest that the values of NEIs are limited to the values and the ranges presented. Instead, the table is meant

24 In this section we present estimates of NEIs but not OPIs, because estimates of other fuel savings are highly dependent on the relevant efficiency measure, the fuel type, and the utility.

25 The values presented in the following tables from NMR are in 2010 dollars. The SERA study does not explicitly state which year's dollars it uses. Because the report was prepared in 2010, we assume that the SERA values are also in 2010 dollars.

to provide an indication of the types and potential values for NEIs as identified in two recent, relevant studies.

Note that the values in Table 3-2 are presented in terms of dollars per housing unit treated. If these values were to be used in screening residential energy efficiency programs, they would be multiplied by the number of housing units served to get the total value for the program. Some housing units might experience several of these NEIs from program participation, depending upon the measures installed in each unit.

Table 3-2

Participant-Perspective Non-Energy Impacts – Residential

Impacts Quantified to Date	Value or Range of Values
Comfort NEIs	
Higher comfort levels	$14.00 - $125.00
Quieter interior environment	$13.00 - $40.00
Aesthetics/appearance	Few dollars to more than $20.00
Equipment/NEIs	
Lighting quality and lifetime	$3.50 per CFL fixture; $3.00 per CFL bulb, one-time impact
Equipment maintenance	$17.00 - $124.00
Equipment performance	$14.00 - $18.00
Property Value	
Increased housing property value	Few dollars to more than $2,000
More durable home and less maintenance	$35.00 - $149.00
Health and Safety	
Fewer fire deaths, injuries, and property loss	$0.03 - $37.40
Improved safety (lighting)	Approximately $20.00
Health-related NEIs	$4.00 - $19.00
Utility-Related NEIs	
(Bill-related) calls to utility	Approximately $0.30
Control over bill	Approximately $30.00
Termination and reconnection	$0.00 - $12.00
Resource NEIs	
Reduced water usage and sewer costs	$3.70 - $12.00
Economic Stability NEIs	
Reduced need to move and costs of moving, including homelessness	Less than $1.00 to $60.00
Owners of Low-Income Housing	
Marketability/ease of finding renters	$0.96
Property value	$17.03 one-time impact only
Equipment maintenance (heating and cooling systems)	$3.91
Reduced maintenance (lighting)	$66.73
Durability of property	$36.85
Tenant complaints	$19.61

Source: SERA, 2010; NMR, 2011. Note: The values presented in this table are expressed in dollars per housing unit or dollars per participant on an annual basis, except where noted otherwise.

As indicated, some of the values are quite large and will have a significant impact on the cost-effectiveness of energy efficiency programs. (See Section 3.5 for an example of how some of these values affect program screening results.) Also, note that some of the benefits have a wide range of estimated values, indicating the uncertainties and the variability of these estimates.[26]

Commercial and industrial (C&I) customer NEIs have not been subject to the same level of research as residential NEIs, perhaps because C&I programs tend to be highly cost-effective anyway. A groundbreaking study was recently conducted to quantify participant-perspective NEIs for C&I retrofit programs in Massachusetts through in-depth interviews with program participants (Tetra Tech, 2012).

The Tetra Tech study specifically addressed the following NEI categories: O&M, administration, materials handling, materials movement, other labor, spoilage/defects, water usage, waste disposal, fees, other costs, sales revenue, rent revenues, and other revenues (Tetra Tech, 2012, p.

26 With regard to the recent NMR study, some stakeholders have raised questions and concerns about the study's results, with several specific arguments that certain values are too low. These concerns are currently being addressed as part of an ongoing proceeding with the Massachusetts Department of Public Utilities (see docket number D.P.U. 11 120).

3-9). O&M benefits are the most significant category of C&I NEIs, representing 74 percent of total electric NEIs. After O&M, sales revenues represented roughly seven percent of electric NEIs, other labor benefits represented roughly six percent, and reduced administration costs represented roughly five percent (Tetra Tech, 2012, p. 4-39).

The Tetra Tech study investigated the potential NEIs from 789 different types of electric and gas C&I efficiency measures. They found that 57 percent of the measures had some form of non-energy benefit, 3 percent of the measures had some form of non-energy cost, and the remaining 40 percent of measures had neither a non-energy cost nor a non-energy benefit. Of those measures that had a positive non-energy benefit, most of the benefits were in the range of $5,000 per measure or less (Tetra Tech, 2012, p. 4-34).

Table 3-3 presents the participant-perspective NEI values for electric C&I prescriptive efficiency programs. C&I NEIs are presented by measure end-use to provide statistically reliable NEI estimates across each of the key end-use categories (Tetra Tech, 2012, p. 4-38). As indicated, HVAC and lighting measures show the highest estimated NEI values.

The values presented in Table 3-3 are specific to Massachusetts customers and focus only on C&I retrofit programs, which may limit the applicability of the NEI estimates in other jurisdictions (Tetra Tech, 2012, p. 1-7). Nonetheless, this study suggests that the C&I NEIs can be numerous and quite large. Program administrators in other states may experience C&I NEIs of similar magnitude.

Table 3-3

Participant-Perspective Non-Energy Impacts – C&I [27]

Measure End-Use	Average Annual NEI per Measure	Benefit/MWh Saved
HVAC	$7,687.00	$96.60
Lighting	$1,636.00	$27.40
Motors and Drives	$541.00	$4.30
Refrigeration	$5.00	$1.30
Other	$28.00	$3.90
Average	$1,439.00	$27.40

Source: Tetra Tech, 2012

Societal-Perspective Other Program Impacts

There is a large amount of research and literature regarding the environmental externality benefits and the economic development benefits of energy efficiency. Conversely there is much less literature regarding the other types of societal OPIs, such as national security and healthcare cost savings.

This category of OPIs is beyond the scope of our study, thus we do not provide a summary of these values here. Nonetheless, states choosing to apply the Societal Cost Test to evaluate energy efficiency should consider ways to account for these important OPIs.

Prioritizing Other Program Impacts

Given the large number of OPIs and the difficulty in measuring and accounting for all of them, it may be helpful for regulators to prioritize the impacts to identify those that are most likely to affect the outcome of the energy efficiency cost-effectiveness screening.

Utility-perspective OPIs are generally considered to be relatively small, as indicated in Table 3-1. Some studies, however, have identified significant benefits associated with reduced shutoffs and reconnects, as well as bad debt write-offs and carrying costs on arrearages. In addition, utility-perspective OPIs can be significantly larger for low-income customers, particularly in states where low-income customers are offered discounted rates or shutoff protection provisions that can sometimes result in large arrearages.

Participant-perspective OPIs have been found to be quite large, sometimes even exceeding the value of the energy savings (NMR, 2011, p. 5 1; NZ EECA, 2012). The participant-perspective OPIs that are considered to be most valuable include: health and safety related impacts; improved comfort; improved home durability; reduced home maintenance; improved equipment performance; and reduced equipment maintenance (ACEEE, 2006, p. 12; SERA, 2010, p. 28). Many of these impacts, such as health,

27 The values provided in Table 3-3 are for electric measures within the prescriptive C&I retrofit program. The Tetra Tech study also provides OPI values for custom C&I retrofit programs, as well as gas prescriptive and custom C&I retrofit programs.

safety, and comfort, are higher for whole-building retrofit programs than for individual measure programs.

Many of these participant-perspective OPIs are particularly large for low-income customers, because of the conditions of their dwellings, the other demands on their limited resources, and other hardships they may face. In addition, low-income energy efficiency programs are often less cost-effective than other efficiency programs because the customers are harder to reach and the barriers are more difficult to overcome. Consequently regulators frequently place a higher priority on the participant-perspective OPIs that apply to low-income efficiency programs.

It is important to avoid giving greater priority to those impacts that are readily measurable and quantifiable simply because they are easier to obtain. The utility-perspective OPIs tend to be relatively easy to quantify, but they also tend to be low in value. Conversely some participant-perspective NEIs can be difficult to quantify, but are expected to be quite large.

For example, health-related OPIs can be difficult to quantify, but some research indicates that the benefits can be very large. A recent New Zealand study found that health benefits of some residential retrofit programs were even larger than the original energy benefits. In some cases, more than 90 percent of the total program benefits (energy plus non-energy) were attributable to health-related improvements, including reduced hospital admissions for respiratory conditions, reduced days off from school and work, psychologic and stress benefits, and reduced health issues from indoor dampness and mold (NZ EECA, 2012).

Part of the difficulty in quantifying and prioritizing OPIs is that the impact can be very specific to the location, utility, customer, property, or measure. For example, health and safety benefits are significantly greater for customers whose homes are in disrepair prior to the efficiency improvements. Improved comfort benefits can be very dependent upon the climate where the customer is located, where the benefits are greater in regions experiencing either extreme cold or extreme heat conditions. These variations partly explain the ranges of values found in the literature for many of the OPIs discussed earlier. These variations also suggest that analysts need to be cautious about applying OPIs from one utility, state, or region in another.

3.5 Implications for Efficiency Program Screening

The importance of properly applying OPIs is apparent in many program administrators' energy efficiency screening results. Figure 3-2 presents the actual cost-effectiveness results for an electric utility in Massachusetts, for energy efficiency programs implemented in 2012. The figure presents the benefit-cost ratios under the PAC Test, the TRC Test with OPIs included, and the TRC Test without OPIs included. The OPIs that we use here are the ones that are currently in use by Massachusetts energy efficiency program administrators.

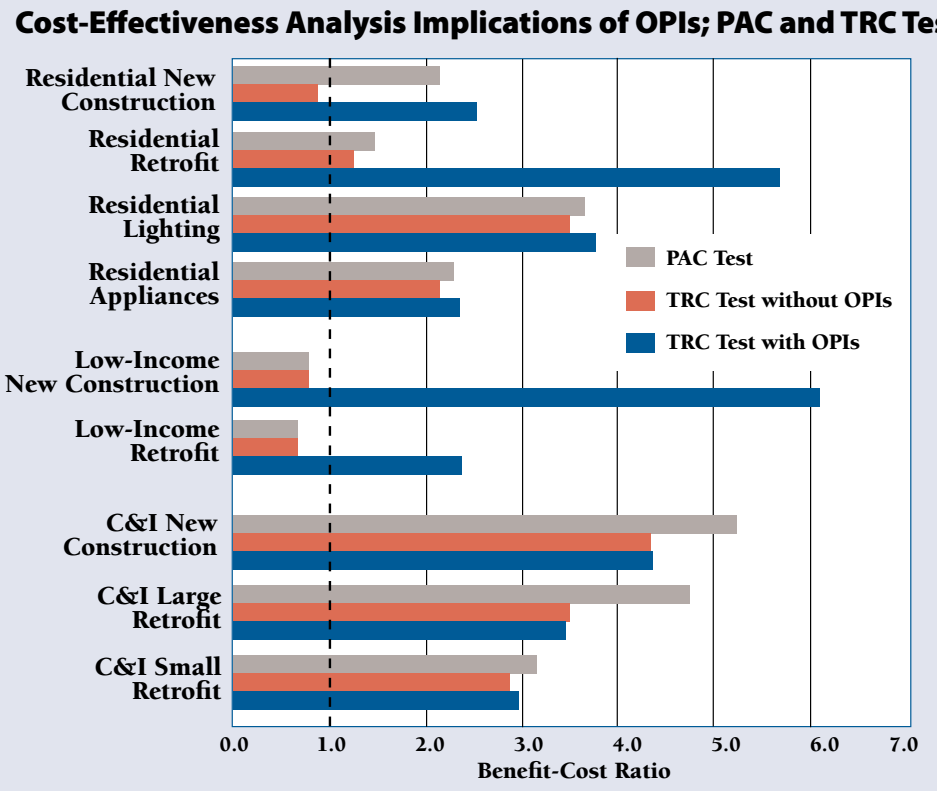
First, it is interesting to note the difference between the results under the PAC Test relative to the TRC Test without OPIs. The low-income programs are identical under these two tests because the customers are not required to make any contribution toward the incremental cost of efficiency measures. The C&I programs are more cost-effective under the PAC Test than the TRC Test because customers contribute toward the incremental efficiency measure cost, and the OPIs for C&I programs are currently assumed to be relatively small.

Second, it is interesting to note the difference between the results under the TRC Test with and without OPIs. The low-income programs are much more cost-effective with the OPIs included because of the low-income other program benefits and the other fuel savings. The residential new construction and retrofit programs are much more cost-effective with the OPIs included because of the other fuel savings. These two OPIs (low-income other program benefits and other fuel savings) account for the vast majority of the differences between the cases with and without OPIs.

Most important, note that if the OPIs are not included in the TRC Test, then the low-income, residential new construction, and residential retrofit programs are all at risk for being improperly deemed not cost-effective. These energy efficiency programs are especially important because they help to support more comprehensive efficiency services to a more diverse set of residential customers, which promotes greater customer equity, both within the residential sector and between the residential and other sectors. Promoting customer equity is clearly an important objective underlying the energy efficiency programs.

Many program administrators find that low-income efficiency programs are not cost-effective without the

*Figure 3-2**



Source: Synapse Energy Economics, 2012a

**Figure 3-2 represents an example of how the choice of economic tests can have significant impacts on the results. These results should not be miss-interpreted as extending to other regions and circumstances. The results will likely vary significantly by region, available fuels, and other program impacts that are customer-class and location specific. Further, the fact that some benefit-cost ratios exceed others should not be misinterpreted to favor investments in programs with higher ratio to the exclusion of lower ratios. The objective of the energy efficiency investments should be to get the greatest net economic benefit for the available investment.*

inclusion of OPIs. Low-income programs are generally more expensive than other programs because they require higher incentive levels; they require additional marketing delivery costs; they must overcome barriers such as the landlord-tenant split incentive; and they may face other barriers such as the need to serve customers with limited ability to speak English.

At the same time, most utility regulators recognize that low-income customers are an important sector to serve with energy efficiency programs. The average low-income household in the United States spends upward of 15 to 20 percent of their total monthly income on energy costs. Energy efficiency upgrades to low-income homes help struggling families use less energy and lower their utility bills while still meeting their daily energy needs. A family living in an older home, for example, could cut their yearly energy bill in half with a full home weatherization (Center for American Progress, 2012).

Note that for the C&I sector there is very little difference between the TRC Test results with and without OPIs. This is because at the time these programs were screened (fourth quarter 2011) the program administrators in Massachusetts assumed very few OPIs for C&I programs, primarily because they did not have much information available regarding the magnitude of those OPIs. As described in Section 3.4, a recent study for the Massachusetts program administrators indicates that the C&I OPIs can be quite significant. If the analysis presented in Figure 3 2 were conducted again with the results of the new study, the benefit-cost ratios for the TRC Test with OPIs would be significantly higher than those in the figure.

3.6 Considerations in Setting Customer Financial Incentives

Including OPIs in energy efficiency screening not only allows more measures and programs to be considered cost-effective, it also allows program administrators to provide greater financial incentives to customers to participate in the programs. This raises an important question for regulators and other efficiency stakeholders. Should program administrators be allowed to pay customer

financial incentives that exceed the energy benefits of the efficiency measure or program? In particular, will such incentives result in uneconomic decision-making by customers or inequities across customers?

The first thing to note here is that under the Societal Cost and the TRC Tests, the assessment of whether an efficiency measure is cost-effective is independent of the decision of what the customer financial incentive should be. Energy efficiency screening provides an indication of *whether* it is in the public interest to promote an efficiency measure. The choice of customer financial incentive will affect *how* to promote the measure.

The rationale for offering a customer financial incentive is to help the customer overcome the market barriers to energy efficiency. The amount of customer financial incentive (in combination with technical support, education, and other support) thus should be as large as necessary to overcome the market barriers to energy efficiency, but no larger. Once an efficiency measure has been deemed to be cost-effective, the size of the customer financial incentive can be determined based on this principle. Under both the Societal Cost and the TRC Tests, the amount of the customer financial incentive will not affect the cost-effectiveness results.[28]

Nonetheless, the two questions remain. First, if a program administrator offers a financial incentive that exceeds the energy benefits of the efficiency measure, could this result in an uneconomic decision from the customer? In other words, could the customer choose to implement a measure that was not in the public interest as a result of such high financial incentives? One might argue that the customer already experiences the participant-perspective non-energy benefits, and therefore does not need to be paid a financial incentive that covers both the energy benefits and a portion of the non-energy benefits. Receiving such a high financial incentive could result in a customer choosing a very costly efficiency measure that is not in the public interest (i.e., is not cost-effective).

We believe that offering customers financial incentives that exceed the energy benefits will not lead to customers making uneconomic decisions. First, the efficiency measures and programs are screened by the program administrators, using the methods described in this study, and thus the program administrators identify the universe of measures that are cost-effective. Customers will only be able to choose from those measures that are first deemed to be cost-effective. Second, as noted earlier, the rationale for offering customer financial incentives is to overcome market barriers, and the amount of the financial incentive should be set high enough to overcome those barriers. In some cases, for example, low-income customers or small businesses, the market barriers might be especially high. These market barriers might be so high as to prevent the customer from recognizing both the energy benefits and the non-energy benefits, in which case a higher customer incentive may be necessary to get the customer to adopt the measure.

This leaves the second question. If a program administrator offers a financial incentive that exceeds the energy benefits of the efficiency measure, will this result in inequity across customers? In other words, why should all utility customers provide funding to pay a program participant a financial incentive that exceeds the energy benefits? Does this approach result in paying too much ratepayer funds to achieve non-energy benefits?

We believe that this approach does not necessarily lead to customer inequity concerns. This issue is parallel to the issue raised in Section 2.4 about whether utility ratepayer funds in general should be used to pay for non-energy benefits. We believe that this issue is best addressed through the program screening practices, not through the practices for setting the customer financial incentives. The program screening practices account for all of the costs that need to be covered by the utility funding: the customer financial incentive, the technical support offered to customers, the delivery costs, the auditing costs, the administration and planning costs, and the monitoring and evaluation costs. The program screening practices thus allow for a more comprehensive assessment of the potential for customer inequities as a result of the energy efficiency programs. If the customer inequity issues are resolved through the program screening practice, then there is no need to address them in establishing the customer financial incentives.[29]

28 This will not be true if the customer financial incentive exceeds the full incremental cost of the energy efficiency measure.

29 Furthermore, customer equity concerns might actually be mitigated by enabling more customer types and a greater number of customers to participate in energy efficiency programs, as discussed in Section 3.2.

As discussed in Section 2.4, we believe that it is vitally important to ensure that utility ratepayer funds that are used to support energy efficiency programs will result in a net reduction in ratepayer utility costs, that is, that the energy benefits will exceed the efficiency program costs. This goal can be achieved by applying the PAC Test to the entire portfolio of energy efficiency programs offered by a program administrator. If the portfolio passes the PAC Test, then customers and consumer advocates can be confident that the energy efficiency programs as a whole will reduce utility costs to customers.

Nonetheless, there is an important perception issue here. At first glance, it appears as though paying financial incentives that exceed the energy benefits could lead to uneconomic decision-making or inequitable outcomes, or at least create the risk for such outcomes. We therefore recommend that program administrators should not offer customer financial incentives that exceed energy benefits as a general rule. This is consistent with the principle of setting the customer incentive as large as necessary to overcome market barriers, but no larger. However, in those cases in which the program administrator has evidence that it may be necessary to offer customer financial incentives that exceed the energy benefits in order to overcome market barriers, for example, for some low-income customers or for some small business customers, then they should have the flexibility to do so.

3.7 Regulatory Options to Address Other Program Impacts

There are several options available for including OPIs in energy efficiency cost-effectiveness screening. The ideal approach is to develop quantitative, monetary estimates for all relevant OPIs. These dollar values of the OPIs would be added to the energy benefits and the energy costs for each measure, as appropriate. This would allow for a comprehensive comparison of the energy efficiency costs and benefits, including OPIs.

There are, however, several challenges and uncertainties associated with developing quantitative monetary estimates of some OPIs. Consequently regulators have developed several approaches for incorporating OPIs into energy efficiency screening practices despite these challenges. These approaches are summarized below.

- **Include all relevant OPIs:** Develop quantitative estimates of all OPIs, with a focus on those OPIs that are expected to be most relevant and most significant. In theory this approach would produce the most accurate representation of OPIs. The challenges and uncertainties of quantifying OPIs are frequently cited as reasons for not including them in energy efficiency screening. We note that these challenges and uncertainties exist for many aspects of utility regulation and planning, including estimates of avoided costs that form the heart of energy efficiency screening. Some states have been able to develop quantitative estimates of OPIs that are sufficiently reliable for planning purposes.[30]

- **Readily measurable OPIs only:** Develop quantitative estimates of those OPIs that are readily measurable. This is a practical approach because several OPIs are readily measureable without significant time or financial commitments.[31] This approach will fail to capture the full range of OPIs, however, depending upon the resources and time dedicated to the effort.

- **Sensitivity analysis:** Consider cost-effectiveness results with varying ranges of OPIs included. For example, New York regulators are provided with benefit-cost ratios that include a range of NEIs, from zero NEIs, to half of the readily measurable NEIs, to all of the readily measurable NEIs. This approach assists regulators in understanding a range of effects that NEIs can have on benefit-cost ratios, and may help to address concerns about uncertainty in the NEI values. The New York approach is inherently conservative, however, in that it only assesses the impacts of NEIs of magnitudes that are lower than the readily measurable magnitudes. A better approach would be to include higher levels of NEI values in the sensitivity analyses as well.

- **Adder:** Develop and apply an adder to the efficiency program benefits to reflect the non-energy benefits.

30 See, for example, NMR, 2010.

31 For additional information on methodologies for quantifying OPIs, see SERA, 2010 and NMR, 2010.

For example, the adder could be a percentage increase or a $/MWh increase to the energy benefits. The rationale for using an adder is that it is meant to be a proxy for the difficult-to-measure non-energy benefits. It is an explicit acknowledgement that the non-energy benefits are higher than zero, and that the adder is the best approximation available at the time. Adders could be applied at the measure, program, sector, or portfolio levels. Adders applied at the measure or program levels could be tailored to the specific non-energy benefits associated with those measures or programs, while adders applied at the portfolio level should represent non-energy benefit levels across the portfolio on average. Overall this is a simplified approach that does not require extensive evaluation activities and lends certainty to the routine of program screening. On the other hand it may be seen as too much of an approximation, and determining an appropriate adder may be difficult, or may be very conservative owing to estimates and politics.

- **Reduced Benefit-Cost Ratio Threshold:** Apply a lower benefit-cost threshold than 1.0 to efficiency programs to reflect the non-energy benefits. This approach has an effect similar to applying an adder, that is, an adder can be directly converted into a lower threshold and vice-versa. However, we prefer using an adder relative to reducing the benefit-cost threshold. Using an adder has the benefit of being more transparent, because there is an explicit increase in the benefits to reflect the non-energy benefits, whereas reducing the benefit-cost threshold has implications for both the benefits and the cost. Also, it is more transparent and easier to understand the application of a different adder for different efficiency programs to reflect different non-energy benefits, relative to the application of a different cost-benefit threshold for different programs.

- **Hybrid:** A combination of the various options could be employed to create a hybrid approach. For example, a state could include all readily measurable NEIs, and use an adder for hard-to-measure NEIs. As discussed earlier, Vermont uses an adder for NEIs in addition to readily measurable NEIs, while Colorado requires an adder but also allows for readily measurable NEIs. Furthermore, a state could include readily measurable NEIs and conduct a sensitivity analysis for additional NEIs. This approach is most consistent with the nature of NEIs, whereby some NEIs are easily and readily monetized, while others require a more qualitative analysis on the potential range of impacts that accrue to customers from efficiency programs. Additionally, this method affords regulators flexibility in determining the most appropriate NEI policy for their state. Finally, it allows consideration of all NEIs believed to be most significant, with the choice of methodology used to determine each NEI being made on the basis of available resources.

The approach used may depend upon the particular OPI being evaluated. Other fuel savings and resource savings (e.g., water and sewer) are relatively easy to quantify and monetize, and thus they should always be monetized in cost-effectiveness analyses. Some of the non-energy benefits, such as improved health, safety, and comfort, can be more difficult to quantify and may be better suited for sensitivity analyses or adders if resources are not available to develop monetary values.

Ideally the approach used to account for OPIs should be applied at the measure level. If they cannot be applied at the measure level, then the next best approach would be to apply them at the program level. OPIs can vary significantly by efficiency measures, and many OPIs are only relevant for certain measures (e.g., water savings associated with water heater measures; other fuel savings associated with space heating measures; and health, safety, and comfort benefits associated with space heating measures). Applying OPIs at the measure level offers a more accurate depiction of the magnitude of their benefits.

3.8 Recommendations

The Best Tests to Use for Screening Energy Efficiency Programs

We recommend that the Societal Cost Test be used to screen energy efficiency programs. This test includes the broadest range of energy efficiency costs and benefits and provides the best measure of public policy benefits that are of great importance to legislators and regulators, such as other fuel savings, low-income benefits, and environmental benefits.

We recommend that all states that choose not to rely on the Societal Cost Test use the TRC Test to screen energy efficiency programs. This test includes many of the important energy efficiency costs and benefits and helps address many important public policy benefits, such as other fuel savings, low-income benefits, and customer equity.

There is an important concern, however, with applying either the Societal Cost Test or the TRC Test, because of the potential impact on costs to utility customers. Some stakeholders may be concerned that accounting for OPIs and the associated public policy benefits will unnecessarily increase energy efficiency program costs and burden utility customers with costs for achieving benefits that are not related to utility services. This is a critical consideration, particularly for states that are pursuing aggressive levels of energy efficiency savings or pursuing all cost-effective energy efficiency.

To address this concern, we recommend that the PAC Test be applied to the entire portfolio of efficiency programs. This will ensure that the entire set of programs will result in a net reduction in utility revenue requirements (i.e., a net reduction in costs to utility customers). This combined program/portfolio screening approach should be simple to apply, because it relies upon a single, primary test (either the Societal Cost Test or the TRC Test) for all of the detailed cost-effectiveness assessments, and a secondary test (the PAC Test) that would be applied as a check on behalf of utility customers. Applying the tests in this manner allows states to balance the goal of achieving key public policy objectives with the goal of ensuring a net reduction in costs to utility customers.

The Application of Other Program Impacts in Screening Energy Efficiency

When using the Societal Cost Test, it is important to account for the utility-perspective, participant-perspective, and societal-perspective OPIs to the greatest extent possible.

When using the TRC Test, it is important to account for the utility-perspective and participant-perspective OPIs to the greatest extent possible. It is particularly important to account for the participant-perspective OPIs, because otherwise the TRC Test will be internally inconsistent and will lead to cost-effectiveness results that are skewed against energy efficiency, will cause program administrators to underinvest in energy efficiency programs, and will impose higher costs on utility customers.

When using the PAC Test, it is important to account for utility-perspective OPIs. The utility-perspective OPIs are relatively certain and relatively easy to quantify. In addition, the utility-perspective OPIs will directly affect utility revenue requirements, and thus have a direct impact on utility customer costs.

We recommend that each state develop an approach for accounting for OPIs that best suits its needs and best accounts for values of the OPIs relevant to it. To this end, we recommend that each state should do the following:

- Identify all of the OPIs that are relevant for the energy efficiency programs offered and the screening test used in the state, regardless of whether reliable, monetized values are available for them. This should be based on a state-specific assessment of which OPIs are likely to be most significant, not simply on those that are readily measurable. This step is important to at least understand the type and breadth of the OPIs relevant to the state efficiency programs.
- Develop quantitative, monetary estimates for all OPIs that can be readily monetized. At a minimum, this should include the other fuel savings, because these savings can be relatively easily monetized using forecasts of the prices for those fuels.
- Develop some methodology for addressing those OPIs that are not monetized, for example, by conducting sensitivities or using an adder to the benefits as a proxy. Although there are limits to these approaches, and adders are sometimes criticized for being too conservative, these approaches may be necessary to ensure that some of the significant OPIs are not ignored simply because they are difficult to quantify.
- Address the non-energy benefits associated with low-income customers. Many studies have shown that these are among the most significant NEBs, and many analyses have indicated that these NEBs can have a substantial impact on the cost-effectiveness of low-income programs, frequently making the difference between programs that are cost-effective and those that are not. If the state does not develop quantitative estimates for the low-income non-energy benefits, then at a minimum these benefits should be addressed through some proxy approach.
- Hire independent contractors to develop the best

state-specific OPI estimates possible. The money required for this type of research could come from the program administrator's energy efficiency budgets, as a part of the evaluation, monitoring, and verification activities. The value of this research would likely be well worth the cost, given the magnitude of OPIs that could be identified and pursued through the energy efficiency programs.

- Identify those OPI assumptions, methodologies, and outcomes that can be transferred across utilities and across states, in order to increase awareness of the issues, promote consistency where appropriate, increase acceptance of hard-to-quantify values, and reduce costs.

Recommendations for Further Research

Also, as noted earlier, each state should hire independent consultants to develop state-specific OPI estimates. In addition, some national level research could help advance our understanding of some of the more important non-energy benefits (SERA, 2010, p. 46-47; 78-79). This research could also lend support to the analyses that are conducted at the state level. The following list includes those NEIs that we believe are likely to be significant and to benefit from further research.

- Indoor air quality and health effects at home and at work
- Reduced sick days off from school or work
- Increased productivity at businesses and at schools
- Family stability and fewer household moves
- Safety, fires, and insurance, and damage prevention

4. Environmental Compliance Costs

4.1 Environmental Compliance Costs Versus Externalities

In theory, the Societal Cost Test, the TRC Test, and the PAC Test should all explicitly account for the avoided costs of compliance with environmental regulations. It is now common practice to account for the cost of complying with certain environmental regulations, such as the costs of purchasing SO_2 and NO_X allowances. It is much less common, however, to fully account for the costs of complying with forthcoming or future environmental regulations. Failing to do so skews the cost-effectiveness evaluations against energy efficiency, can lead to significantly less energy efficiency than is cost-effective, and can result in customers paying for alternative environmental compliance options that are much more expensive than energy efficiency resources.

The costs of environmental compliance should not be confused with environmental externalities. These costs represent the anticipated costs that will be incurred by utilities in the future to comply with environmental requirements; costs that will eventually be passed on to ratepayers, and thus are clearly within the definitions of both the TRC Test and the PAC Test, as well as the Societal Cost Test. In contrast, environmental externalities represent costs of environmental damages to society in general, or the costs of abating those actions that lead to the damages.[32] These externalities would be included in the Societal Cost Test, but not the TRC or the PAC Tests.

Note also that environmental compliance costs are separate from environmental externalities, and it is important to ensure that they are not double counted. The environmental externalities represent all of the environmental damages that might happen after the environmental regulations are met, if there are any. Over time, if environmental regulations become increasingly stringent, the environmental compliance costs will tend to increase while the environmental externality costs will experience a corresponding decrease.

Estimates of the avoided costs of environmental compliance should be based on the environmental requirements pertinent to the relevant state, which might include federal regulations, state regulations, or both. These costs should include all current and reasonably anticipated future regulations that impact the electric sector, including those that regulate criteria pollutants (such as ozone, particulate matter, SO_2, and NO_X), water effluent and use, air and water toxics, solid waste management, and GHGs. In the sections that follow we focus on EPA regulations and GHG requirements, because these are expected to result in significant costs of compliance, in both the near term and long term.[33]

4.2 Current and Anticipated EPA Regulations

Summary of Current and Anticipated EPA Regulations

The EPA has proposed and promulgated a number of environmental rulemakings that affect the operation of existing and new power plants under the Clean Air Act (CAA), the Clean Water Act (CWA), and the Resource Conservation and Recovery Act (RCRA).

The CAA is a comprehensive federal law that regulates

32 A useful frame of reference is that environmental regulations are a mechanism by which regulators and policymakers can "internalize" otherwise external environmental costs. Harm from pollution is considered an environmental externality cost imposed on society in general; by compelling power plants to spend money to reduce pollution and hence harm, environmental regulations move the burden of pollution from society (an externality) to polluters (an internal cost realized in the cost of service).

33 We recognize that utility management will be making decisions based on a number of factors (e.g., low natural gas prices) in addition to pending environmental regulations. (Brattle Group, 2012).

air emissions from stationary sources, such as chemical plants, steel mills, and electrical generators, as well as mobile sources (US EPA, 2012a). Under the CAA, the EPA sets emission standards for both stationary and mobile sources, and air quality standards that must be obtained by regions, states, and municipalities.

Emission standards directly affecting stationary sources, including power plants, issued under the CAA include the following:

- **Mercury/Air Toxics Standards (MATS):** MATS is the first national emission standard to reduce mercury and other toxic materials such as arsenic and acid gas from power plants. MATS was proposed in 1990 and finalized in December 2011. It became effective in March 2012. Sources effectively have four years to comply with the rule (US EPA, 2012b).

- **Cross-State Air Pollution Rule (CSAPR):** The EPA's CSAPR was expected to replace the 2005 Clean Air Interstate Rule (CAIR) for the regulation of SO_2, NO_X, and particulates. A December 2008 court decision allowed the requirements of CAIR to remain in place temporarily, but directed the EPA to issue a new rule to implement the CAA requirements concerning the transport of air pollution across state boundaries. CSAPR was finalized in July 2011 but was stayed in December 2011 pending judicial review. On August 21, 2012, the US Court of Appeals for the District of Columbia vacated CSAPR, ordering that CAIR remain in effect (US EPA, 2012c; US Court of Appeals, 2012).[34]

- **New Source Performance Standards (NSPS):** In December 2010, the EPA announced it would propose an NSPS to regulate GHG emissions from new and modified electric power plants under section 111(b) of the CAA, and from existing electric power plants under section 111(d). On March 27, 2012, the EPA proposed the NSPS for new and modified power plants. This proposal essentially requires any new power plant to limit emissions to no more than 1,000 pounds of CO_2 per MWh, which is slightly more than the emissions from natural gas power plants and far below the average emissions from coal power plants (Washington Post, 2012). This issue is addressed in more detail in Section 4.3.

Although CSAPR was recently vacated, this rule should continue to be included in a review of EPA regulations. As stated earlier, it is important to consider regulations that are expected to result in significant costs of compliance in both the near term and the long term. Although CAIR remains in place as a backstop, the EPA must promulgate a replacement for both CAIR and CSAPR in order to meet the requirements of the CAA. This new rule may need to achieve emission reductions above and beyond those anticipated from CSAPR, as National Ambient Air Quality Standards (NAAQS) for NO_x, SO_2, ozone, and particulates are updated and become more stringent. The requirements for pollution abatement to meet these new standards could result in significant costs of compliance and should be accounted for in energy efficiency cost-effectiveness screening.

The EPA has established and periodically revised state-by-state NAAQS for criteria pollutants. The EPA maintains air quality monitoring stations across the nation, and air managers in each state are responsible for crafting plans to meet NAAQS at these monitors. States where monitors show that air quality is out of compliance are required to submit State Implementation Plans (SIPs) to the EPA detailing how the state will implement, attain, maintain, and enforce NAAQS (US EPA, 2011). The EPA regularly revisits the NAAQS, and has over time ratcheted down the acceptable level of pollution at these monitors. In 2010, the EPA strengthened standards for NO_2 and SO_2, and is currently considering more stringent standards for ozone (US EPA, 2012d).

The EPA has also proposed a few other environmental standards under the CWA and the RCRA, which will have direct impact on the operation of existing power plants and factories:

- **316(b) Cooling Water Rule:** The proposed 316(b) will establish requirements for power plants and factories to adopt certain control technologies or

34 In vacating CSAPR, the US Court of Appeals for the District of Columbia objected to two significant requirements: (1) the EPA's cost-based standards for determining how much pollution power plants could eliminate if they applied available controls at or below given cost-effectiveness thresholds; and (2) the EPA's failure to give states an opportunity to implement CSAPR's obligations first through State Implementation Plans rather than through Federal Implementation Plans, which were simultaneously promulgated with CSAPR.

practices to reduce injury and death of fish and other aquatic life caused by cooling water withdrawals. The proposed rule applies to all existing power generating, industrial, and manufacturing facilities that have the design capacity to withdraw more than two million gallons per day (GPD) and use at least 25 percent of that water exclusively for cooling (US EPA, 2011b).

- **Wastewater Rule:** The EPA found that the current regulations under the Wastewater Rule, which were last updated in 1982, do not adequately address the pollutants being discharged, mainly from steam electric power plants, and have not kept pace with changes that have occurred in the electric power industry over the last three decades. Coal ash ponds and flue gas desulfurization (FGD) systems used by such power plants are the source of much of these pollutants (US EPA, 2012e). No new rule has been proposed, but the EPA intends to issue proposed regulations in mid 2012 and a final rule in late 2013 (RAP, 2011).

Table 4-1

Major EPA Rulemakings Impacting Power Plants

Proposed Regulation	Targeted Pollutant	Control Options	Schedule
316(b) Cooling Water Rule	Cooling water intake design	Intake design upgrades: cooling water intake structures	• Proposed rule April 20, 2011 • Final rule July 2012 • Facility compliance due by 2020
Wastewater Rule	Wastewater toxic metals	Treatment or zero discharge	• Proposed rule July 2012 • Final rule January 2014
CSAPR	Reduced downwind contribution to ozone and PM2.5 non-attainment	NOx removal: SCR 70-95%; selective non-catalytic reduction 30-75%; SO2 removal: scrubber ≥95%; dry sorbent injection <70%	• Final rule July 2011, vacated August 21, 2012 • Schedule unknown (the EPA is considering whether to petition the US Court of Appeals for rehearing)
Mercury/Air Toxics Rule	Hazardous air pollutants (Hg, HCl, metals, organics)	Hg removal: fabric filter baghouse - activated carbon injection 80-90%; scrubber-SCR co-benefit >90%	• Proposed rule May 3, 2011 • Final rule due by November 2015 (3 years, case-by-case 1-year extension)
New Source Performance Standards for Greenhouse Gases	Greenhouse gases	CCS, market-based approaches	TBD
Coal Combustion Residuals Rule	Coal combustion waste disposal	Phase out wet surface impoundments (ash ponds); composite liners; other changes for disposal sites	• Proposed rule March 2010 • Final rule TBD • Ash pond closures 5-7 years after final rule (2016-2018)

Abbreviations: CSAPR, Cross-State Air Pollution Rule; CCS, carbon capture and sequestration; EPA, US Environmental Protection Agency; HCl, hydrochloric acid; NOx, nitrous oxide; SCR, selective catalytic reduction; SO2, sulfur dioxide

Source: RAP, October 2011

- **Coal Combustion Residuals Rule:** Coal combustion residuals (CCRs), also known as coal ash, are the materials that remain after burning coal for electricity. CCRs include fly ash, bottom ash, boiler slag, and FGD gypsum. These materials are currently exempt wastes under an amendment to the RCRA. The EPA, however, has proposed a new rule to regulate CCRs on June 21, 2010. This initiative was triggered by the massive coal ash spill at the Tennessee Valley Authority's Kingston facility in December 2008. Since then, the EPA has taken aggressive steps to gather information from and assess impoundments at facilities managing CCRs nationwide. No date has yet been set up for a final rule (US EPA, 2012f).

Table 4-1 presents a summary of the major EPA rulemakings that affect power plants. It includes the regulation, the pollutant targeted, the primary control options, and the schedule for compliance.

Figure 4-1 presents some estimated ranges of forward-going costs of these environmental controls.[35] These costs were estimated by Synapse Energy Economics for actual coal units (with the number of units indicated by "n"), using control cost methodologies developed by Sargent & Lundy, the US EPA, and EPRI. Data for current environmental controls, MW capacity, heat rate, and coal type were used to calculate $/kW costs for each of the control technologies for each unit.[36] The variable costs for O&M of the incremental controls were then added to the amortized capital cost to determine a unit's total forward-going cost in $/MWh. As indicated, FGDs are likely to be the most expensive controls.

The costs in Figure 4-1 do not necessarily represent the costs that would eventually be incurred to comply with EPA regulations. The regulations are often specific about the facilities impacted, by region, age, size, heat rate, capacity factor, pollution produced, or a combination thereof. Generally speaking, however, it is a reasonable starting assumption that coal-fired power plants that are currently uncontrolled for SO_2, NO_X, particulates, or mercury will likely require environmental controls.

Figure 4-2 provides an illustrative example of potential cumulative retrofit costs at an older 300-MW coal-fired power plant. This figure shows how various forthcoming EPA environmental regulations can contribute to total power plant costs in $/kWh terms relative to the current operating cost. The costs are illustrative, as both the

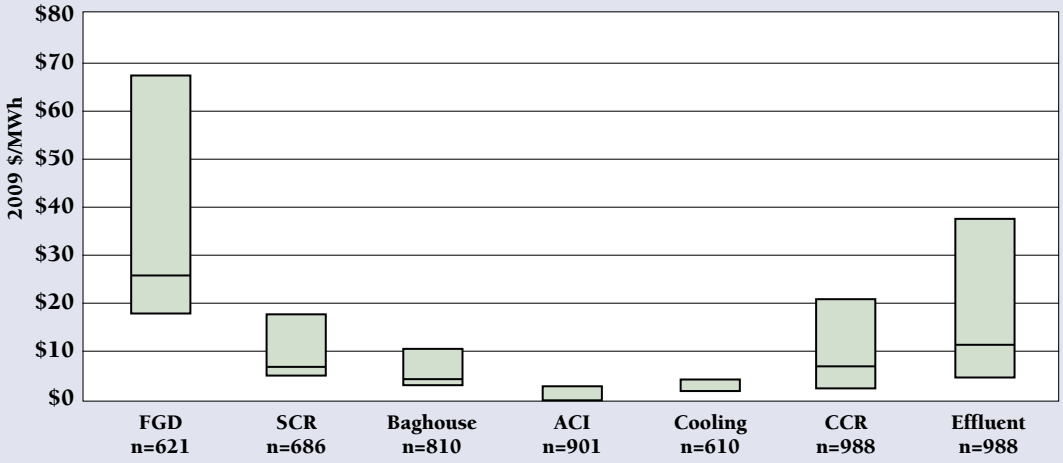
35 Forward-going costs are calculated for all coal units that do not currently have that control installed.

36 The capital costs were amortized based on a 12.7 percent capital recovery factor and were converted to $/MWh using an average of 2008-2010 annual capacity factors.

37 Cost estimates for FGD, SCR, Baghouse, and ACI controls are based on calculations developed by Sargent & Lundy for EPA Base Case IPM Model v.4.10 (US EPA, 2010). Cost estimates for cooling controls are based on estimates in the 2011 EPA document "Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule" (US EPA, 2011b). Cost estimates for CCR and effluent controls based on estimates from the 2010 EPRI document "Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act" (EPRI, 2010).

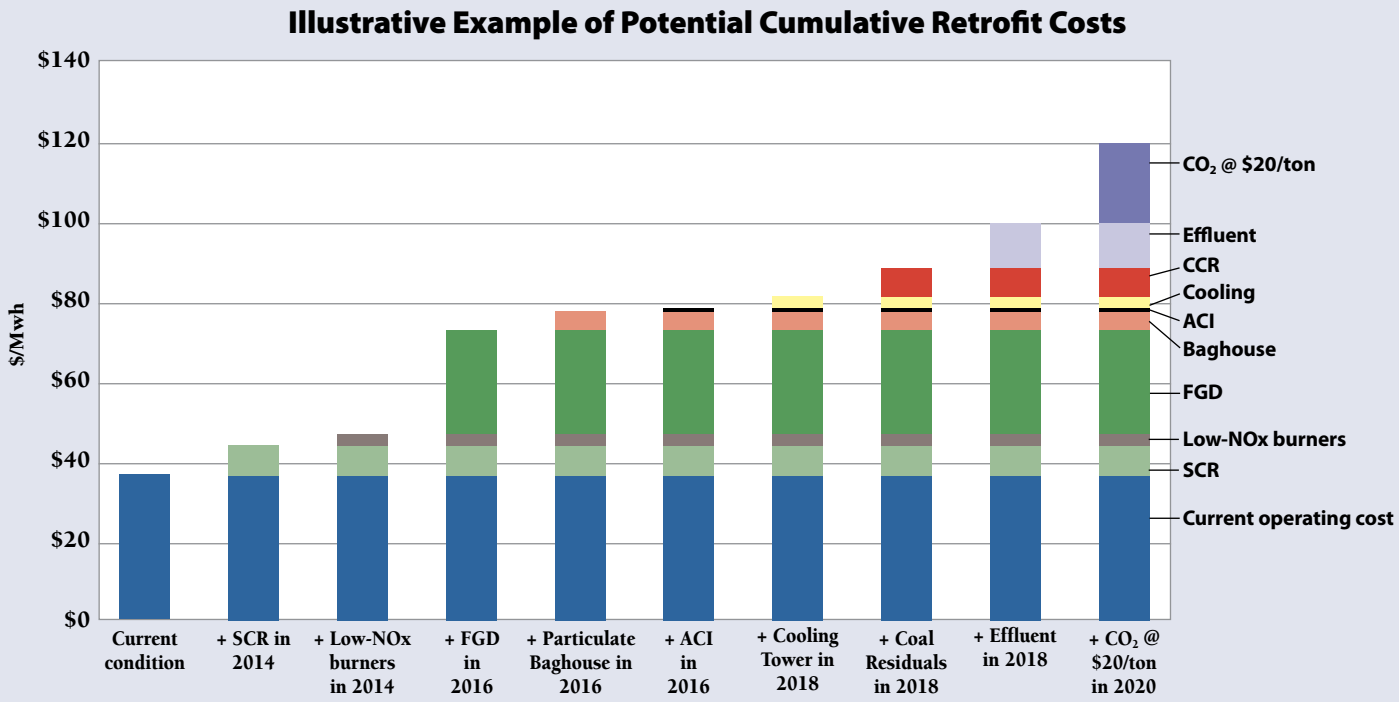
Figure 4-1

Estimated Forward-Going Cost of Environmental Controls [37]



Note: The upper bound of each box represents the 75th percentile of a given control's forward-going cost. The middle line of each box represents the median forward-going cost, and the bottom bound of the box represents the 25th percentile of the cost.

Figure 4-2



Source: Estimates for current operating cost and low-NOx burners are based on RAP 2011 estimates (RAP, 2011, p. 15). All other cost estimates are based on Synapse Energy Economics analysis of Sargent & Lundy research for EPA IPM Base Case v4.10 model (US EPA, 2010).

operating costs and retrofit costs can vary significantly and will be dependent on each particular coal unit. The right-most bar in the figure indicates the additional cost of CO_2 allowance price of $20/ton starting in 2020. (The cost of complying with CO_2 regulations is discussed in the following section.)

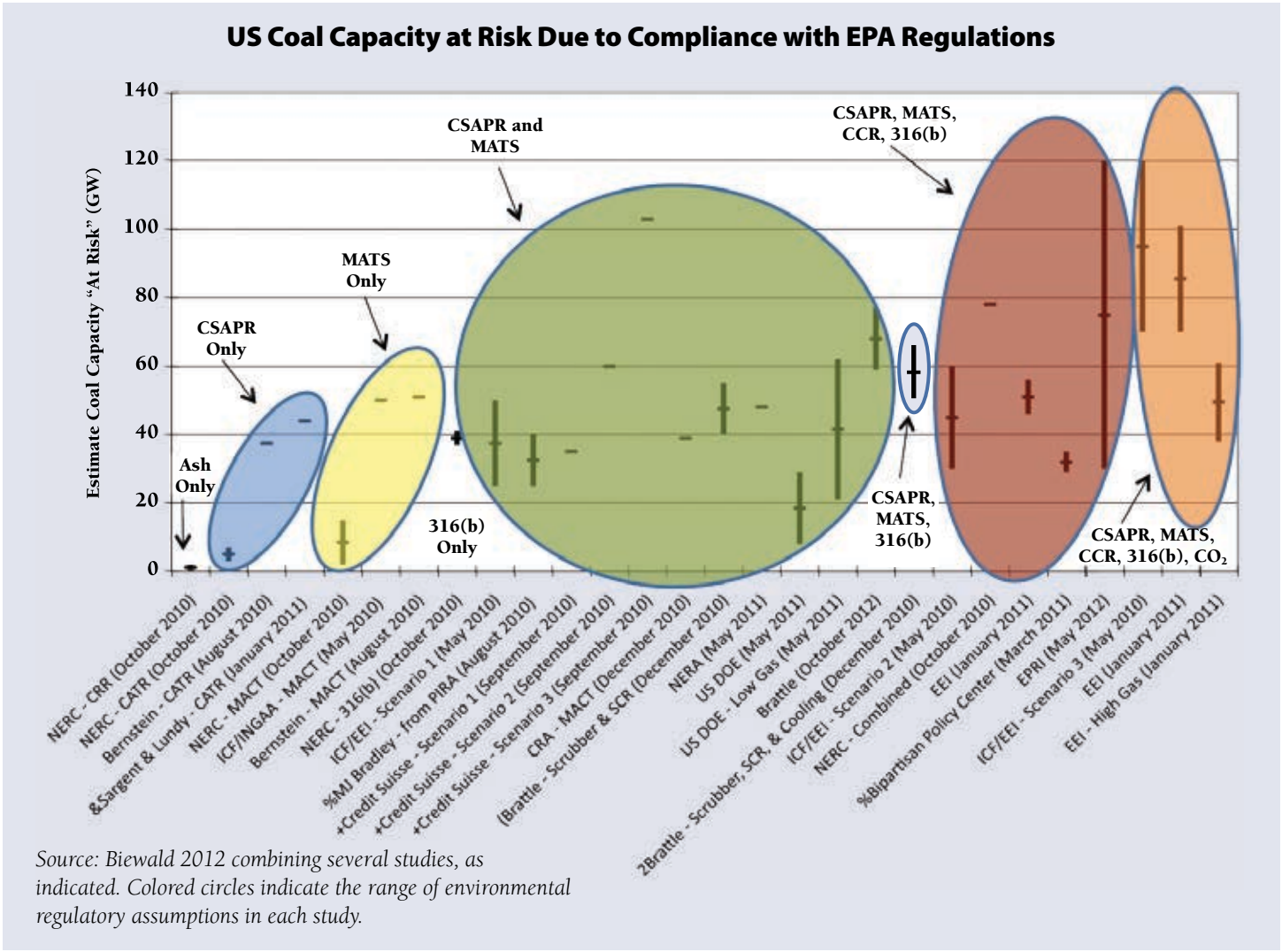
Responding to expected EPA rulings in 2009, the Edison Electric Institute (EEI) suggested that environmental control costs could result in a "train wreck" for the US coal fleet. In May 2010 ICF International prepared a report for EEI predicting that environmental regulations could result in significant coal retirements (ICF International, 2010). Other organizations followed. Studies from Bernstein Research, Credit Suisse, the North American Electric Reliability Council (NERC), Charles River Associates, and the Brattle Group, all suggested that between 20 and 60 GW of coal capacity (or 12-19 percent of coal nameplate capacity) could face retirement under the confluence of environmental regulations (Bernstein Research, 2010; Credit Suisse, 2010; NERC, 2010; Charles River Associates, 2010; Brattle Group, 2010; EEI, 2011; EPRI, 2012).

An updated study from EEI reviews this confluence of rules with the significantly lower gas prices of 2010 and estimates 50-73 GW of "unplanned coal retirements" by 2015 (EEI, 2011). Finally, a recent study from EPRI predicts 35-113 GW of retirements, or up to 36 percent of the US coal fleet, rendered non-economic by stringent capital requirements and dropping gas prices (EPRI, 2012).

Figure 4-3 summarizes the range of potential coal plant retirements estimated by these studies. The ranges indicate either uncertainty in a particular study or a sensitivity range of gas or carbon dioxide (CO_2) prices. The most recent studies examining the confluence of CSAPR, MATS, the CCR rule, the 316(b) regulation, and the possibility of CO_2 regulations estimate that up to a third of the US coal fleet may be non-economic.[38]

38 As discussed earlier, we maintain CSAPR in our analysis of EPA regulations even though the US Court of Appeals recently vacated this rule. The number of studies in Figure 4-3 that have considered the impact of CSAPR demonstrates the importance of the intent of that EPA rule.

Figure 4-3



Source: Biewald 2012 combining several studies, as indicated. Colored circles indicate the range of environmental regulatory assumptions in each study.

Note that none of the studies listed here consider the EPA's renewed interest in modifying effluent limitation guidelines to prevent the leakage of toxic wastes from air emissions controls. The proposed version of this guideline is expected to be released in 2012, and may put additional existing coal capacity at risk for retirement.

Also note that some of the recent EPA regulations will apply to more than just coal units. Some of the older, less efficient oil and gas units may face compliance requirements as well.

The Importance of Considering Potential Compliance Costs

It is clear that over the next four to eight years many coal units will become considerably more expensive to maintain and operate than they are now. Utilities have been, and will be, conducting analyses of the economics of either retrofitting their coal units to meet the new regulations or retiring the units and replacing them with alternative resources.

This has two important implications for the evaluation of energy efficiency resources. First, the avoided energy and capacity costs associated with energy efficiency could be higher in the future, under either a retrofit scenario or a retirement scenario. Some of the retrofit technologies can reduce the capacity factors and increase the O&M costs of the existing coal units. Under a retirement scenario, some of the replacement facilities might have higher fuel or operating costs than the existing coal unit. These future changes should be factored in to the energy efficiency cost-effectiveness analysis in order to properly capture the full value of the efficiency.

Second, and more important, energy efficiency can offer a low-cost alternative resource in a coal plant retirement analysis. In some cases, energy efficiency might be able to provide sufficient energy and capacity, possibly in conjunction with other resources, to enable a utility to retire a coal plant at a lower cost than retrofitting it.

In evaluating a coal unit retirement, it is critical that the evaluation be conducted as early as possible, and the energy efficiency resources be assessed as thoroughly as possible, to identify the full potential for energy efficiency. If efficiency resources are insufficient to replace the retired coal plant within the timeframe required, then they could be combined with other resources as needed to develop the lowest cost option to replace the coal unit.

If efficiency resources are not properly assessed in the analysis of EPA regulation compliance options, then customers could likely pay significantly higher electricity costs.[39] If a utility decides to install control technologies to comply with the regulations, when plant retirement in combination with efficiency resources would be a less expensive option, then customers will bear the increased costs of those control technologies. If, on the other hand, a utility decides to retire a coal plant and replace it with another supply-side resource (e.g., a natural gas combined cycle plant) without first considering lower cost efficiency options, then customers will bear the increased costs of the new supply-side resources, and associated environmental compliance costs for these resources.[40]

To make matters worse, if a new supply-side resource is constructed to replace a retired coal plant without first considering lower cost efficiency resources, then the future avoided energy and capacity costs would likely become much lower, making energy efficiency resources less cost-effective. It is thus essential that analyses of EPA regulation compliance options be conducted as early as possible, and that such analyses assess energy efficiency resources as thoroughly as possible, in order to ensure that the compliance plan will result in lowest costs to customers.

It is also important that utilities assess coal unit retrofit options as comprehensively as possible. Some utilities have taken a piecemeal approach, analyzing one regulation at a time or just the few regulations that would be effective in the short-term. This limited approach can lead to uneconomic decisions regarding plant upgrades versus retirements. Once one retrofit technology is installed at a plant then it is that much more cost-effective to retrofit it with the next technology, even if retirement would be most economic if all retrofit requirements were considered at once. Any assessment of retirement options must account for all of the potential control technologies that might be required by all of the EPA regulations that are anticipated over the relevant study period (as well as costs associated with the climate change initiatives discussed in the next section). This is the only way to ensure that the eventual compliance plan will result in the lowest costs to customers.

In addition, energy efficiency should be viewed as a tool for helping utilities and states comply with some of the EPA regulations. The EPA is currently considering mechanisms to be able to quantify emissions reductions resulting from energy efficiency and renewable energy. Synapse Energy Economics is currently working with the EPA to develop publicly available, transparent tools to help integrate efficiency into SIPs for NAAQS compliance.[41]

The implications of the EPA regulations on the economics of energy efficiency will vary around the country, depending upon the extent to which each utility relies upon older, uncontrolled coal plants. They will also depend upon the structure of the electricity industry. Those utilities operating in regions with organized wholesale markets could be affected by any of the coal plants in the region of the market, because the costs of complying with the EPA regulations could be passed on through wholesale energy and capacity prices throughout the region, either directly by increasing costs of plants that sometimes set clearing prices or indirectly by removing plants from the bottom of the bid stack. Those utilities that are vertically integrated will be primarily affected by the implications

39 There could be an argument made that customers should not bear environmental compliance costs that are higher than necessary due to inadequate or imprudent utility planning, including insufficient consideration of energy efficiency opportunities. This issue is beyond the scope of this report.

40 For example, while replacing coal capacity with natural gas-fired generation will avoid SO_2 and air toxics emissions, new natural gas will emit, among other things, CO_2 and NOX. There will be compliance costs associated with these pollutants.

41 For more information, see the EPA's website: http://www.epa.gov/airquality/eere/manual.html.

of the EPA regulations on their own coal units, but may also be affected by cost pressures on plants in the region supplying purchased power.

Recommendations: Accounting for Recent and Proposed EPA Regulations in Energy Efficiency Screening Practices

Evaluate Efficiency Resources on a Timely Basis. It is important to screen for energy efficiency opportunities on a frequent, periodic basis, because energy efficiency may take several years to ramp up to the levels needed to economically respond to evolving EPA regulations, or to replace or partially replace a retiring coal plant. If energy efficiency is considered as an alternative to a coal plant retrofit with only one or two years available before the retrofit is required, then it is likely to be too late to develop anywhere near the full amount of efficiency that is potentially available.

Consider All Likely Future EPA Regulations. Clearly the most important step for regulators is to ensure energy efficiency screening accounts for all current and anticipated future EPA regulations over time, because this is the most accurate reflection of the future and will lead to more efficient economic decisions than piecemeal analyses. Furthermore, as discussed in Section 4.3, it is important to account for the potential costs from climate change requirements along with all the current and anticipated EPA regulations to more accurately reflect the future and avoid piecemeal analyses that lead to uneconomic decisions.

Apply Comprehensive Planning Practices. Many states use some form of integrated resource planning (IRP) for evaluating energy efficiency resources. When screening energy efficiency resources as part of preparing an IRP, several steps should be taken to ensure a valid, unbiased result:

- Energy efficiency must be properly and comprehensively modeled in all coal plant retirement/refurbishment scenarios.
- Planning models must properly account for risk associated with EPA regulations, as well as coal plant retirements.
- Planning models must properly account for the interactive effect of plant retirements, (i.e., the retirement of one plant will have implications for the economics of other plants in the region).

Even in a more simplified avoided cost methodology for screening energy efficiency resources, it is important to ensure that:

- Avoided costs used in efficiency screening properly account for all potential power plant refurbishments and retirements. For states in regions with organized wholesale markets, this should include the best possible forecast of all of the coal units likely to be retired or refurbished within the market region. For states with vertically integrated utilities, this should include the best possible forecast of all the utility's coal units that are likely to be retired or refurbished, plus a similar forecast for neighboring utility systems that may affect purchases and sales of power.
- Avoided cost forecasts must properly account for increased fuel and O&M costs associated with compliance with EPA regulations, including outage and replacement power costs incurred during upgrades.

4.3 Current and Anticipated Climate Change Requirements

Although there is considerable uncertainty about federal requirements to address climate change, this does not mean that there will be no future costs associated with climate change requirements or that such costs should be ignored in evaluating energy efficiency cost-effectiveness. Evaluators should use the best information available and most pertinent to their state, and should determine the best estimate possible of the costs of complying with climate change requirements.

Many states have climate change requirements and objectives, and many utilities do incorporate projections of the costs of GHG requirements in evaluating energy efficiency cost-effectiveness. Below we provide an overview of current climate change initiatives that might affect electric and gas utility planning.

Current and Anticipated Climate Change Initiatives

Federal Initiatives

Climate Legislation

The 111th Congress from 2009 through the end of 2010 had a major focus on climate policy. Congress considered enacting legislation that would reduce GHG emissions

through a federal cap on GHG emissions and trading emissions allowances, or through other means. Legislative proposals and President Obama's initiatives aimed to reduce GHG emissions by approximately 80 percent from current levels by 2050. Despite passage of comprehensive climate legislation in the House in the 111th Congress, the Senate ultimately did not take up climate legislation in that session.

The 112th Congress from 2011 through 2012 has shown to be markedly different from the 111th Congress, with a Republican majority in the US House of Representatives and a diminished Democratic majority in the Senate. Rather than debating measures to reduce GHG emissions like the 111th Congress, the 112th Congress has focused on preventing the EPA from regulating GHG emissions under its existing authority. Much of this deliberation has taken place within the context of larger political battles over government spending levels (CCES, 2012a).

Congressional action, however, is only one avenue in an increasingly dynamic web of activities that will lead to internalizing a portion of the costs associated with GHG emissions. As Congress wrestles with the issue, the states, the federal courts, and federal agencies are undertaking initiatives to address climate change. Many efforts are proceeding simultaneously.

EPA Efforts

The EPA has been pursuing several approaches to address GHG emissions. The EPA's initiative was also in response to the Supreme Court mandate in *Massachusetts v. EPA* that determined that the harms associated with climate change are serious and well recognized, that GHGs fit within the CAA's definition of "air pollutant," and that the EPA has the authority to regulate GHGs.[42] As a first step, the EPA issued its 2009 Endangerment Finding, in which the "EPA formally found that six key GHGs emitted from motor vehicles contribute to climate change, resulting in a threat to the public health and welfare" (CCES, 2012b). This Endangerment Finding led the EPA to regulate GHG emissions under the CAA. Since then, a few rules associated with GHG regulation have been proposed or adopted as follows:

- On August 12, 2010, the EPA proposed two rules to ensure that businesses planning to build new, large facilities or make major expansions to existing ones obtain New Source Review Prevention of Significant Deterioration (PSD) permits that address GHGs. These rules became effective in early January 2011.

- December 2011, the EPA announced that it will issue the NSPS for new and modified electric power plants under section 111(b) of the CAA, and for existing electric power plants under section 111(d). On March 27, 2012, the EPA proposed the NSPS for new and modified power plants. This proposal essentially requires any new power plant to limit emissions to no more than 1000 pounds of CO_2 per MWh, which is slightly more than the emissions from typical natural gas combined cycle power plants and far below the average emissions from coal power plants (Washington Post, 2012). A recent study by the University of California Center for Energy and Environmental Economics revealed that about 84 percent of natural gas combined cycle gas turbine (CCGT) units that commenced operating between 2006 and 2010 would meet this emission standard, whereas the EPA reported 95 percent of such units would meet the standard (Kotchen & Mansur, 2012). The study also concluded that only 71 percent of the planned CCGT units would meet the target largely because of a trend toward smaller capacity (Kotchen & Mansur, 2012).

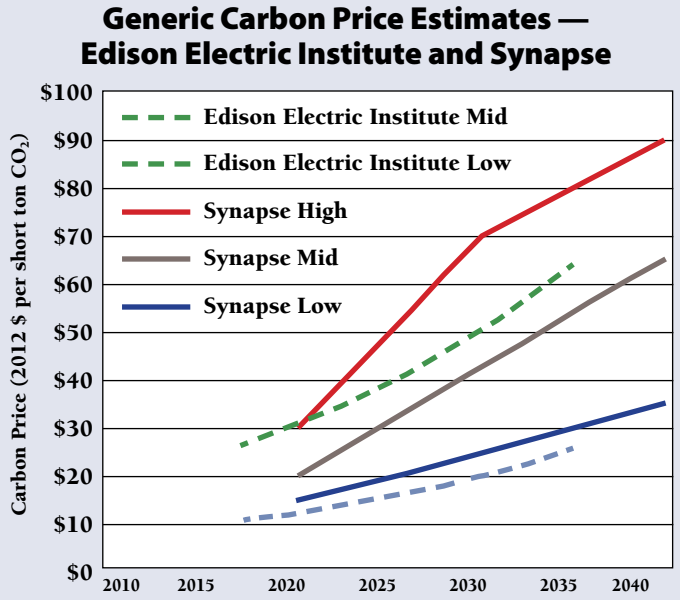
Forecasts of CO_2 Prices Resulting from Federal Initiatives

Figure 4-4 presents two forecasts of the potential CO_2 allowance prices resulting from federal climate change initiatives. One forecast was prepared by EEI and is meant to represent a proxy for regulatory action by the EPA and/or potential future legislation from Congress (EEI, 2011, p. 50). The EEI forecast includes a Mid Case and a Low Case.

The other CO_2 price forecast in Figure 4 4 was prepared by Synapse Energy Economics (Synapse, 2012b). The Synapse Energy Economics CO_2 price forecast is intended to represent a reasonable range of expectations regarding the timing and magnitude of costs for federal GHG emissions. The Synapse Energy Economics forecast is

42 Information on the EPA's plans and regulations are available from the EPA website on climate change regulatory initiatives at http://www.epa.gov/climatechange/initiatives/index.html.

Figure 4-4



Sources: Synapse, 2012b; EEI, 2011

based on regional and federal level policy developments in the near term, as well as various projections of legislative compliance costs from past proposed federal climate change bills in the long term. An earlier version of the Synapse Energy Economics Reference Case CO_2 price forecast is used for screening energy efficiency programs in California and in several New England states.

Regional Initiatives

Over the past several years, several states and provinces in North America have developed or have been developing multistate climate initiatives, including GHG caps and allowance trading to reduce GHG emissions.

- **North America 2050:** The most recent effort in this area is North America 2050: A Partnership for Progress (NA2050) launched in March 2012. NA2050 is the successor to the 3-Regions Initiative, which was a collaboration among members of the three North American regional cap-and-trade programs: The Midwestern Greenhouse Gas Reduction Accord, the Regional Greenhouse Gas Initiative, and the Western Climate Initiative. NA2050 is currently comprised of a group of US states and Canadian provinces (16 States and five Canadian provinces) committed to policies that move their jurisdictions toward a low-carbon economy while creating jobs, enhancing energy independence and security, and protecting public health and the environment (CCES, 2012c; NA2050, 2012).

- **Regional Greenhouse Gas Initiative:** The Regional Greenhouse Gas Initiative (RGGI) is an effort of nine northeast and mid-atlantic states to limit GHG emissions and is the first market-based CO_2 emissions reduction program in the United States. Participating states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten-percent reduction in these emissions from levels at the start of the program by 2018.[43] This is the first mandatory carbon trading program in the nation.

- **Western Climate Initiative:** In 2007, governors of five western states signed an agreement establishing the Western Climate Initiative (WCI), a joint effort to reduce GHG emissions and address climate change.[44] Subsequently two more states and four Canadian provinces also joined the effort.[45] Fourteen states and provinces also are official observers of the process.[46] WCI members signed a Memorandum of Understanding agreeing to jointly set a regional emissions target and establish a market-based system—such as a cap-and-trade program covering multiple economic sectors—to aid in meeting this target. The WCI regional, economy-wide GHG emissions target is 15 percent below 2005 levels by 2020, or approximately 33 percent below business-as-usual levels. The WCI Partners released the Design

43 The nine states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Information on the RGGI program, including history, important documents, and auction results, is available on the RGGI Inc. website at www.rggi.org.

44 The five states are Arizona, California, New Mexico, Oregon, and Washington.

45 Utah, Montana, British Columbia, Manitoba, Ontario, and Quebec.

46 Alaska, Colorado, Idaho, Kansas, Nevada, and Wyoming, as well as the provinces of Nova Scotia and Saskatchewan and the Mexican states of Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, and Tamaulipas.

for the WCI Regional Program in 2010. In November 2011, WCI, Inc., a nonprofit corporation, was established to provide administrative and technical services to support the implementation of GHG emission trading programs in the region (CCES, 2012c; WCI, 2012).

- **Midwest Greenhouse Gas Reduction Accord:** In 2007, six states and one Canadian province established the Midwest Greenhouse Gas Reduction Accord (MGGRA).[47] Three additional states are official observers.[48] The members agree to establish regional GHG reduction targets, including a long-term target of 60 to 80 percent below current emissions levels, and to develop a multisector cap-and-trade system to help meet the targets. The MGGRA Advisory Group presented final recommendations in May 2010 (CCES, 2012c).

State Initiatives

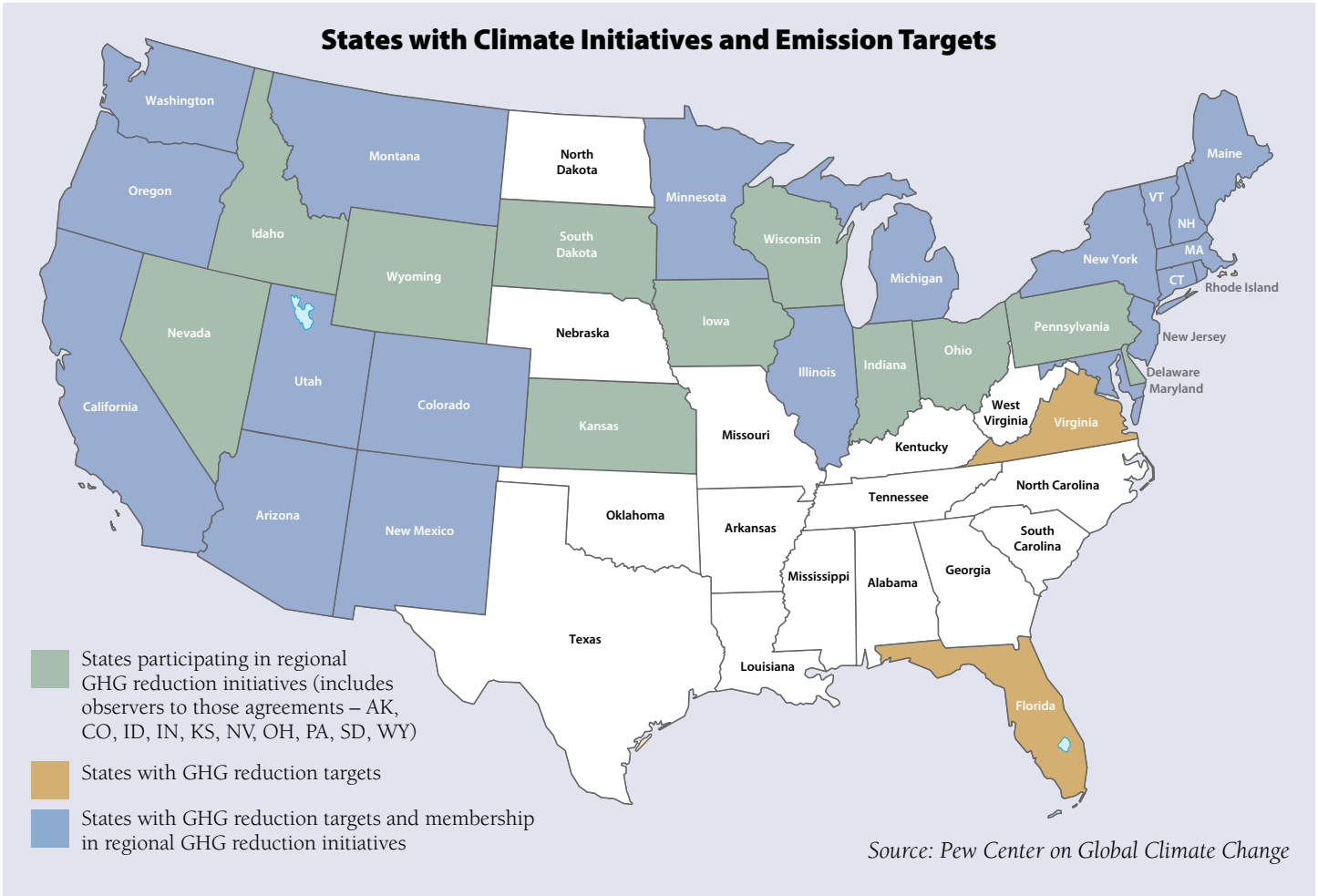
Many states are taking action to address climate change and reduce GHG emissions within their own borders. For several years states have been the innovative laboratories for climate change policies, and they are adopting a wide variety of policies across the nation. For example, 43 states have adopted a GHG inventory and/or registry; 36 states adopted and two states are currently developing a state climate change action plan; and 22 states have established GHG emissions targets.

Figure 4-5 shows states with emission targets and those participating in or observing regional climate initiatives as

47 The states are Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin, as well as the Premier of the Canadian Province of Manitoba.

48 Observers are Indiana, Ohio, and South Dakota.

Figure 4-5



of October 2011. States that have adopted emissions targets and/or that are participating actively in regional climate initiatives comprise 44 percent of US electrical generation, 48 percent of retail electricity sales, and 58 percent of US population. The observer states add an additional 17 percent of electrical generation, 16 percent of retail electricity sales, and 15 percent of the US population.

Regulatory Options to Account for Climate Change Requirements

Compliance with Federal Climate Change Initiatives

Many utilities and utility regulators recognize that the federal government will, in one way or another, impose carbon restrictions on energy resources in the near- to midterm future. There remains considerable uncertainty regarding exactly what those restrictions will be, when they will be in place, and what they will cost. Nonetheless, it is important to use the best forecasts possible of the cost of complying with federal climate change initiatives, particularly in the context of planning for energy resources that will operate for 20, 30, or even 40 years into the future.

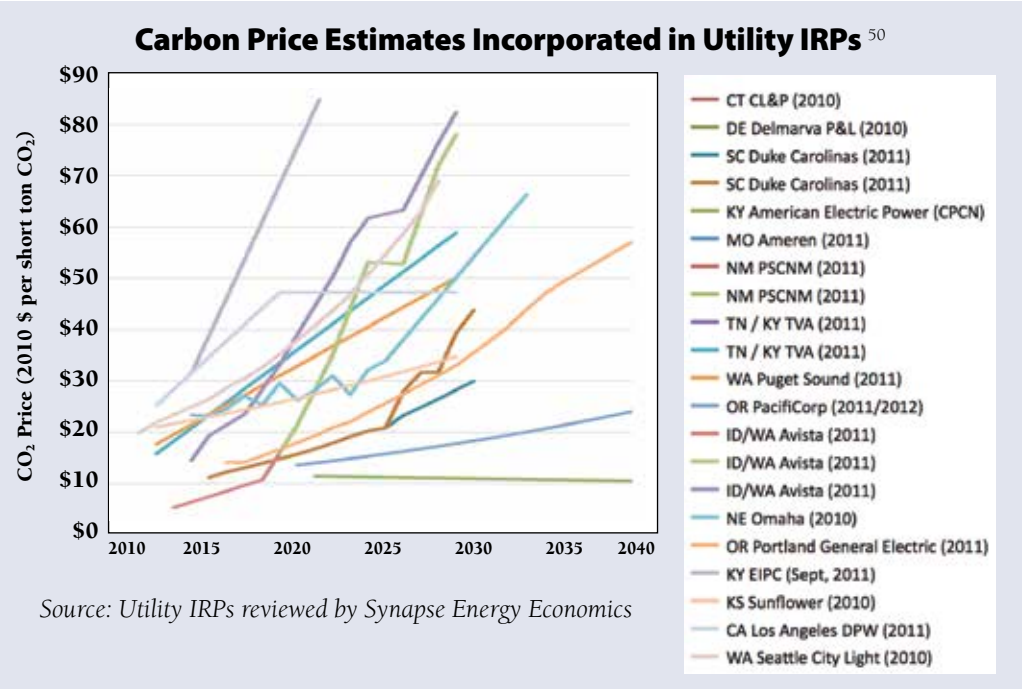
Utilities use two interrelated approaches to account for the cost of complying with climate change requirements when assessing energy efficiency resources: through integrated resource planning and through energy efficiency screening practices. The typical approach is to assume a CO_2 allowance price that would be in effect under the environmental requirement. (The requirement could be a cap-and-trade mechanism that literally required GHG emitters to purchase CO_2 allowances, or a different type of climate change requirement that is expected to lead to compliance costs that are comparable to the price of CO_2 allowances.)

If a CO_2 allowance price is used, then a forecast of such prices should be added to the dispatch costs of all generation resources that emit GHGs, either as part of IRP or as part of estimating avoided costs for screening energy efficiency resources. A CO_2 allowance price forecast should be used as a "base case" planning assumption, as opposed to simply being included in an "environmental case" or a "carbon constrained case," because the forecast should represent the most likely future cost of complying with federal climate change requirements.

Figure 4-6 provides a summary of the CO_2 allowance price forecasts used recently in several utility IRPs.[49] In general, the price forecasts range from $10 to $30 per ton of CO_2 in the early years, and increase to a range of $30 to $60 per ton in 2030. Most of these forecasts are based on analyses of potential future federal GHG legislation.

Those utilities that do not have the resources to develop

Figure 4-6



Source: Utility IRPs reviewed by Synapse Energy Economics

49 This graph is not intended to be a comprehensive presentation of all CO_2 price forecasts used in IRPs. Instead its purpose is to provide an indication of the magnitude and range of CO_2 price forecasts used by many utilities.

50 The CO_2 prices presented here are for the Reference Case, the Mid Case, or the case that is used to develop the preferred resource plan in each IRP. Note when IRP only provides a CO_2 price at the beginning and the end of an analysis period, we interpolated the values for the interim years. All CO_2 units are converted to short tons and constant dollars.

their own forecast of CO_2 allowance prices can adopt a forecast available from public sources. Figure 4-4 presents two examples of publically available forecasts of CO_2 prices; one from EEI and one from Synapse Energy Economics.

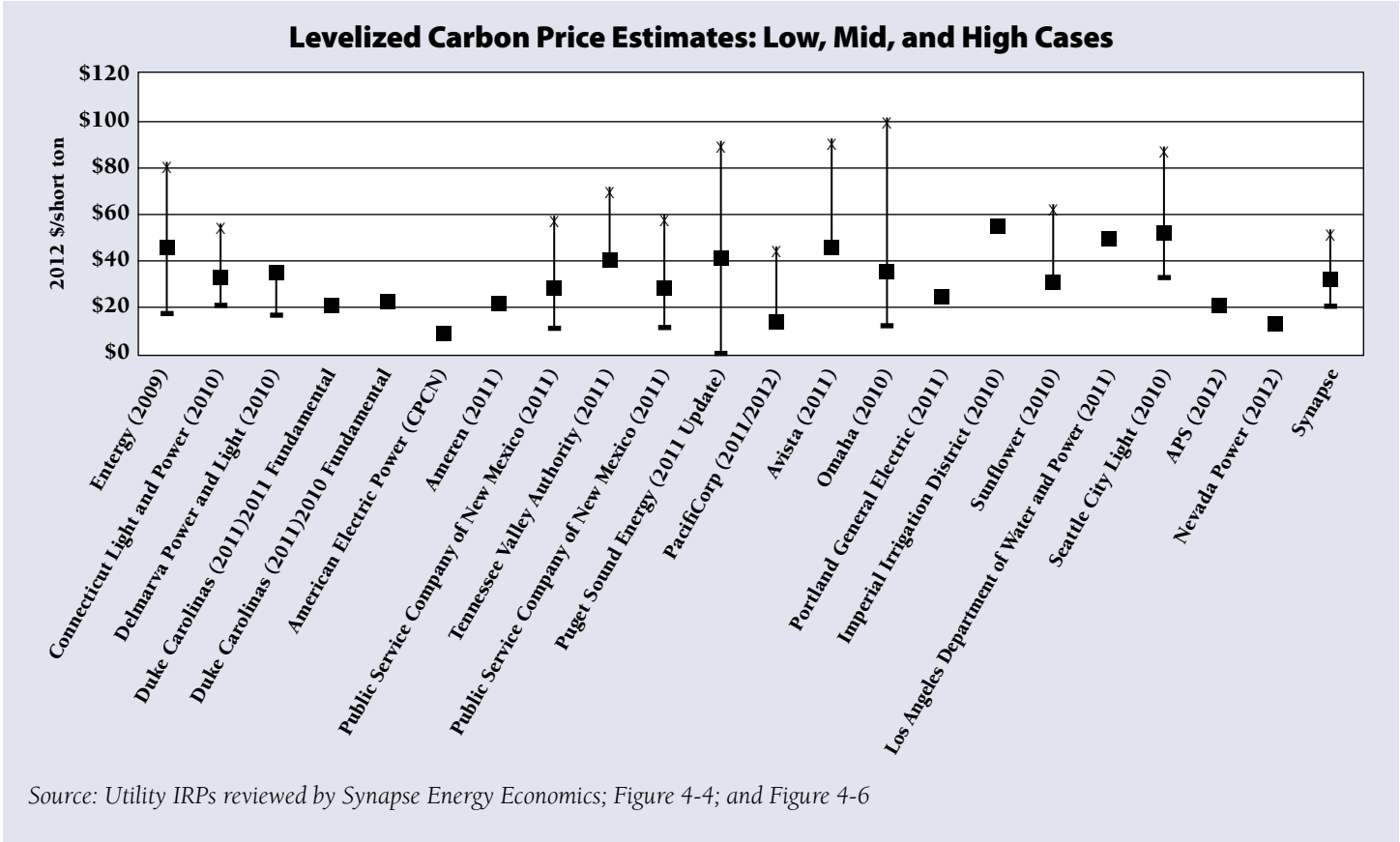
Figure 4-7 presents a summary of the range of recent CO_2 price forecasts in levelized terms. The low value for each forecast represents the levelized value of the Low Case; the middle value represents the levelized value of the Mid Case or Reference Case; and the high value represents the levelized value of the High Case. For those forecasts in Figure 4-7 that include only a single value, the value represents the Mid Case or Reference Case. As indicated, the levelized costs for the Mid Case forecasts tend to be in the range of $20 to $50/ton of CO_2.

Many state regulatory commissions require energy efficiency program administrators to account for the cost of complying with current and anticipated GHG regulations in screening energy efficiency programs. Below we list several examples of such regulatory policies.[51]

- **California.** California has been incorporating CO_2 prices in evaluating cost-effectiveness energy efficiency programs since 2004 when an E3 report examined a range of carbon values from $5 to $69 per ton of CO_2 and recommended the use of $8 per ton as a levelized cost in its analysis (based on a trend of $5 per ton in the near term, $12.50 per ton by 2008, and higher values thereafter [E3 and RMI, 2004]). In 2009, California adopted the CO_2 price forecasts prepared by Synapse Energy Economics (a previous Synapse Energy Economics forecast than the one presented above) for estimating the cost of

51 This list is not intended to be a comprehensive list of all states that require energy efficiency screening to account for the costs of compliance with environmental requirements, nor is it meant to be an exhaustive discussion of any one state. We present these summaries as illustrative examples.

Figure 4-7



Source: Utility IRPs reviewed by Synapse Energy Economics; Figure 4-4; and Figure 4-6

power plants used as a benchmark against renewable energy contracts under the State's renewable portfolio standard (RPS) (CPUC, 2009, p. 9). For evaluating energy efficiency programs, California Public Service Commission has recently proposed to adopt the same CO_2 price forecast adopted in the RPS case (CPUC, 2011, p. 2).

- **New England.** All New England states rely on avoided cost estimates from the Avoided Energy Supply Component (AESC) Study produced every two years for the region. The most recent version of the AESC was prepared by Synapse Energy Economics, and includes a forecast of future CO_2 compliance costs. The forecast is based on CO_2 allowance prices from RGGI in the early years, and then assumes that federal climate change requirements will begin to take effect in 2018 (Synapse, 2011). The CO_2 allowance prices for the federal requirements are the same prices presented in Figure 4 6. The most recent AESC study also includes an estimate of $80/ton for the long-term cost of CO_2 abatement sufficient to achieve climate stabilization. Each state decides whether to include the avoided costs of complying with environmental regulations in screening energy efficiency measures. Vermont, which uses the Societal Cost Test in screening energy efficiency, uses the $80/ton CO_2 abatement cost. Connecticut, Maine, Massachusetts, and New Hampshire use the CO_2 allowance price forecast. Rhode Island uses a forecast of the RGGI allowance prices.

- **New York.** In the Order Establishing Energy Efficiency Portfolio Standard and Approving Programs, the Commission found that implementation of energy efficiency programs will have a more favorable impact on air quality than the no action alternative (New York PSC, 2008, p. 67). At Appendix 3 of this order the TRC Test was amended to include a CO_2 adder of $15/ton ($2008) as an estimate of the benefit of carbon reductions. This CO_2 value is currently being used to screen efficiency programs implemented by NYSERDA and the investor-owned utilities (Tress & Kim, 2012; NYSERDA, 2012).

- **Oregon.** In the early 1990s the Oregon PUC required utilities to analyze a range of environmental cost adders in the utility IRP process. The CO_2 costs ranged from $10 to $40/ton (in 1990 $) (Oregon PUC, 1993). In 2008 the Commission adopted a new rule entitled "Guideline 8" on environmental costs (Oregon PUC, 2008). Guideline 8 does not provide any specific numbers, but instead establishes broad guidelines as to how utilities should assess environmental compliance costs as follows:

  The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxide, sulfur oxides, and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities…. The utility should identify at least one CO_2 compliance "turning point" scenario which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio (Oregon PUC, 2008, Order No. 08-339, Appendix C, "Adopted Guideline 8").

  The Energy Trust of Oregon, the state's third-party efficiency program administrator, incorporates the cost of carbon in their energy efficiency cost-effectiveness analysis based on the values used in PacifiCorp and PGE's IRPs (Gordon, 2012).

- **Wisconsin.** Wisconsin's state energy efficiency program administrator, Wisconsin Focus on Energy (FOE) categorizes externalities into economic and non-economic externalities. Economic externalities are assumed to be internalized, for example, through mitigation requirements or cap-and-trade markets (PA Consulting Group & KEMA, 2009, p. 3-9, 6-9). CO_2 is part of economic externalities and is included in their benefit cost called "simple benefit cost test," which combines elements of the TRC and Societal Cost Tests' approach (PA Consulting Group & KEMA, 2009, p. 2-3). Wisconsin FOE assumes $26/ton of CO_2 in 2020 and $28 in 2035. Mercury, which is currently considered a non-economic externality, is included in a test called "expanded benefit cost test." This test incorporates non-energy benefits as well as macroeconomic benefits.

Compliance with State Climate Change Initiatives

As indicated in Section 4.3, many states have established initiatives to address climate change, and several of them have established GHG emission targets. For these states, the environmental compliance costs may be more certain than those associated with federal initiatives, and may be experienced much sooner. In addition, some of these state climate change requirements could be significantly more stringent than the anticipated federal requirements.

For these states with climate change requirements, it is important that the cost of complying with the current and anticipated requirements is properly accounted for when screening energy efficiency programs. Ideally each state should assess the cost of complying with its own state-level climate change requirements. If the state requirements are expected to be less stringent than the federal requirements, then the federal requirements should be used as the basis for the cost of compliance (see earlier discussion). If the state requirements are expected to be more stringent than the federal requirements, then the state requirements should be used as the basis for the cost of compliance.

Ideally each state's cost of climate change compliance should be based on a statewide analysis of all GHG abatement options across all sectors of the state's economy. If possible, each state should develop a forecast of the marginal GHG abatement option that would be necessary for complying with that state's climate change requirements. This marginal climate change compliance cost should then be added to other avoided costs when screening energy efficiency resources. In this way, energy efficiency would be evaluated on an equivalent basis with other GHG abatement options.

In the absence of a statewide GHG abatement analysis, estimates could be based on an analysis of electricity sector GHG abatement options. Ideally this would include a supply curve of all the electric sector GHG abatement options, ranked from lowest cost to highest cost. The marginal GHG abatement option could then be used to indicate the avoided cost of complying with the state's GHG requirements. This approach is likely to be conservative relative to an estimate of economy-wide abatement options, because the electricity sector typically has some of the lowest-cost abatement options, and the electricity sector is expected to play a significant role in meeting economy-wide climate change requirements.

Massachusetts Example

In 1992 the Massachusetts Department of Public Utilities (DPU) required all utilities to consider the consequences of various environmental externalities when selecting new electric power generation sources (MA DPU, 1992). This decision was subsequently appealed to the state's supreme judicial court by the Massachusetts Electric Company. The court found that the DPU did not have the jurisdiction to require utilities to account for environmental costs in their resource planning and selection process. The court noted, however, that the DPU did have the jurisdiction to require utilities to account for all costs required to comply with current and reasonably anticipated future environmental regulations, because the costs of complying with these regulations will be included in utility rates, and thus are within the DPU's jurisdiction (MA SJC, 1994).

In 2009 the DPU required all energy efficiency program administrators to include the costs of complying with existing and reasonably anticipated future environmental regulations when screening energy efficiency programs (MA DPU, 2009, p. 17). The DPU noted that one of the most important such regulations was the Massachusetts Global Warming Solutions Act, which requires reductions of Massachusetts CO_2 emissions of 25 percent by 2020 and 80 percent by 2050. The DPU currently has a docket open to identify the best means of estimating the costs of compliance with environmental regulations (MA DPU, 2011).

In the absence of a supply curve of all the electric sector GHG abatement options, a state could develop estimates of the marginal cost of complying with GHG requirements using proxies. We discuss three examples below: forecasted renewable energy certificate (REC) prices, RPS alternative compliance payments, and estimates of marginal abatement costs. Although each of these examples should be considered as approximations of an uncertain cost, they may nonetheless be very valuable improvements to those planning processes that assume that compliance costs will be zero.

Forecasted REC Prices as a Proxy for Marginal Abatement Costs

RPSs are frequently established to address environmental concerns and climate change requirements, and the cost of renewable resources is very likely to be less than or equal to the marginal cost of complying with climate change requirements. Energy efficiency resources offer many of the same energy and non-energy benefits as renewable resources, and thus there is a sound economic and public policy rationale for paying as much for efficiency as is paid for renewables.

Under this approach, energy efficiency program administrators would develop a forecast of the REC prices for their state. These REC prices would then be assumed to be a proxy for the cost of compliance with that state's environmental requirements, including climate change requirements. This cost of compliance would then be included in the Societal Cost, the TRC, and the PAC Tests when screening energy efficiency resources.

There is a significant disadvantage to this approach, however, because REC prices can be volatile, depending upon the extent to which renewable supply matches the RPS demand. Furthermore, a state's RPS requirement might not be sufficient to develop enough renewables to meet that state's climate change goals, in which case the REC prices will be less than the marginal cost of complying with climate change regulations, and thus will understate the value of energy efficiency resources. For these reasons, we prefer using the RPS alternative compliance payment level as a proxy for marginal abatement costs.

RPS Alternative Compliance Payments as a Proxy for Marginal Abatement Costs

Most RPS mechanisms have an alternative compliance payment (ACP), that load-serving entities can pay if they are unable to purchase RECs at lower cost. The ACP is meant to serve as a cap on the amount that load-serving entities (and eventually customers) might have to pay to comply with the RPS. In effect, the ACP represents the maximum cost that legislators and regulators are willing to impose upon customers to acquire the benefits of renewable resources. Load-serving entities will typically pay the ACP when the demand for renewable resources exceeds the supply and the REC prices exceed the ACP.

For those states with relatively stringent climate change requirements, the ACP could be used as a proxy to represent the cost of compliance with environmental regulations, including climate change regulations. In such states, the renewable resources developed as a result of the RPS alone are unlikely to be sufficient to meet the stringent climate change requirements, thus more expensive GHG abatement options will be required in addition to the RPS renewables. Consequently the ACP is likely to be less than or equal to the marginal cost of complying with climate change requirements, and thus would represent a reasonable proxy for the cost of compliance.

This approach would result in applying the same cost cap for both renewable resources and energy efficiency. This can be justified on the grounds that energy efficiency offers essentially the same (and in some cases more) environmental compliance benefits and other non-energy benefits than renewable resources.

This approach would put energy efficiency on a level playing field with renewable resources and other GHG abatement options. It would allow efficiency program administrators and other planners to choose efficiency whenever it is a lower cost option for meeting climate change requirements. Consequently this approach would ultimately lead to lower costs for customers.

Note that the costs to customers for efficiency resources will not necessarily include the full ACP. The ACP would represent a cap, in which the maximum amount that would be paid for efficiency resources would be equal to the avoided supply-side costs plus the ACP. The ultimate costs to customers will be the average cost of saved energy across the efficiency portfolio, which is certain to be much less than this cap due to the many low-cost efficiency measures and programs offered by program administrators.

Literature Available on Marginal Abatement Costs

There is a large amount of literature available on marginal GHG abatement costs. Program administrators and utility regulators can draw upon this literature to develop costs that are relevant to the climate change requirements in their state.

In recent years there has been a lot of research on the marginal abatement costs required to achieve climate stabilization, by reducing global carbon emissions to 80 percent below 1990 levels by 2050. For those states with climate change mandates that are comparable to these climate stabilization targets, this literature may prove useful in developing a marginal abatement cost for the state.

For example, the recent study by Synapse Energy Economics to estimate the avoided costs of energy efficiency in New England reviewed the international literature containing estimates of the abatement costs to reduce global carbon emissions to 80 percent below 1990 levels by 2050 (Synapse, 2011). The study indicated that there is a wide range of GHG abatement cost estimates available, but concluded that a CO_2 price of $80/ton represents a conservative estimate in the middle to lower end of that range, and that such a price could be appropriate for screening energy efficiency resources in New England.

Recommendations to Account for Climate Change Requirements

Include GHG Compliance Costs in the Societal Cost, TRC, and PAC Tests. It is important to recognize that including the cost of complying with climate change regulations is not the same as including externalities (future environmental regulation costs are internal to the utility, not external). The costs of compliance with such future climate change requirements thus should be included in the Societal Cost, TRC, and PAC Tests.

Recognize the Importance of Accounting for GHG Compliance Costs Now. Federal action on climate change is likely within the mid- to long-term future, and many states have already established climate change requirements. Uncertainty regarding the timing and magnitude of compliance costs is not an excuse for inaction. Not accounting for compliance costs now is equivalent to assuming that the costs will be zero, even though it is clear that they will be significantly greater than that within the mid- to long-term future. Failure to account for climate change compliance costs in power plant comparisons and in determining avoided costs for energy efficiency screening will lead to suboptimal outcomes for ratepayers. Many energy efficiency resources have measure lives of 15 years, 20 years, or more. Supply-side resources have operating lives that are even longer. Resource decisions made in the near term should be based on the best assumptions available about the conditions that will exist over these long periods of time.

Account for Federal Climate Change Initiatives. All states should establish energy efficiency screening methodologies that account for the cost of complying with federal climate change initiatives. If a state does not have its own forecast of federal CO_2 allowance prices, then it should rely upon publicly available forecasts, such as the EEI and Synapse Energy Economics forecasts presented in Figure 4-4.

Account for State Climate Change Initiatives. As indicated earlier, there are 22 states that have set state emission targets, while 36 states have state climate change action plans. All states that have such climate change requirements should account for the costs of complying with those requirements in screening energy efficiency programs. Ideally they should use state-specific marginal GHG abatement costs. In the absence of these they should use reasonable proxies for the marginal GHG abatement costs.

Include All Types of Environmental Compliance Costs. It is important to account for all likely environmental compliance costs, for example, climate change and EPA regulations (e.g., air, water, solid waste), as they can have cumulative effects. Furthermore, because energy efficiency may take several years to ramp up to desired levels it is important to screen for energy efficiency opportunities on a frequent, periodic basis.

Recognize the Limits of Cap-And-Trade Mechanisms. If a state, region, or the federal government were to eventually establish some form of CO_2 cap-and-trade system as a method for imposing climate change requirements, it will still be important for utilities to implement all cost-effective energy efficiency on an ongoing basis. A cap-and-trade system alone will not bring forth much energy efficiency, let alone all cost-effective energy efficiency, due to the many barriers to energy efficiency. Ratepayer-funded energy efficiency programs are necessary to overcome these market barriers; and in the absence of such energy efficiency programs, society will underinvest in efficiency and pay too much to comply with cap-and-trade programs. In sum, energy efficiency programs, with comprehensive screening practices, are an important complement to CO_2 cap-and-trade programs.

Ensure That Efficiency Resources Are Treated Comparably With Other Resources Built to Address Climate Change. If a utility proposes to construct new supply-side resources specifically to address climate change requirements (e.g., new wind facilities, a new nuclear plant, or a new coal plant with carbon sequestration), then it should (1) use these proposed resources as the marginal cost of compliance with climate change requirements when screening energy efficiency resources, and (2) implement all energy efficiency resources that cost less than these proposed resources. Failure to do so would lead to uneconomic outcomes and potentially significantly higher costs to electric customers for complying with the climate change requirements.

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Appendix A: Principles Underlying the Tests

The Purpose of this Appendix

The purpose of this appendix is to review some of the theoretical underpinnings of the cost-benefit tests. First we define a few key terms that are critical to understanding the difference between the tests, such as "external costs" and "non-energy impacts" (NEIs). Then we describe each test and provide some detail on exactly which types of costs and benefits it should, and should not, include.

We focus on the distinctions between the Program Administrator Cost (PAC) Test, the Total Resource Cost (TRC) Test, and the Societal Cost Test. These tests have not been well defined in practice, and this has led to some deviations from the theoretical underpinnings of the tests.

The Cost-Benefit Tests in Theory

As discussed in more detail in Section 2 of this report, five cost-effectiveness tests have been developed to consider efficiency costs and benefits. Each of these tests combines the various costs and benefits of energy efficiency programs in different ways, depending upon which costs and benefits pertain to the different parties.

To understand the definitions of the cost-benefit tests, it is important to recognize three important principles. First, each test is meant to indicate the cost-effectiveness of the efficiency resources from a particular perspective (program participants, all utility customers, society, and so on). Once the perspective is clarified, then it becomes clear which cost and benefit is appropriate to include in which test.

Second, each test must be internally consistent, that is, it must include all the costs and benefits associated with the perspective being evaluated. For example, if all the costs of a particular perspective are included in the test, then it is important to include all of the benefits from that same perspective. Otherwise the results of the test will be skewed and misleading.

Third, each test must properly account for "transfer payments" between different parties. Transfer payments occur when a benefit to one party is caused by a cost to another party. According to economic theory, these payments should not be considered either a cost or a benefit because they cancel each other out. Whether a particular cost impact is considered a transfer payment depends upon the perspective that is used for the economic analysis. For example, in the Participant Test, the participating customer's bill savings are considered a benefit, whereas in all the other tests they are not considered a benefit because they are a transfer payment from other customers (or from utility shareholders in the cases in which lost revenues are not recovered by the utility).

Below we summarize the five cost-effectiveness tests, with an emphasis on the perspective that each is meant to represent.

- **Societal Cost Test.** This test includes the costs and benefits experienced by all members of society.
- **Total Resource Cost (TRC) Test.** This test includes the costs and benefits experienced by all utility customers, including energy efficiency program participants and non-participants.[52]
- **Program Administrator Cost (PAC) Test.** This test includes the energy costs and benefits that are experienced by the program administrator of the energy efficiency program. In other words, these costs and benefits are limited to the impacts on revenue requirements from the energy efficiency program; the costs equal the increase in revenue requirements necessary to implement the programs, and the benefits equal the savings in revenue requirements as a result of implementing the programs.[53]

52 The name for this test is misleading, because it does not include the total cost of the resources. A more accurate name for this test would be the All Customers Test.

53 The name for this test is misleading, because these costs and benefits are not all from the perspective of the utility or other agency administering the efficiency programs. A more descriptive name for this test would be the Revenue Requirements test.

- **Participant Test.** This test includes the costs and benefits that are experienced by the customer who participates in the efficiency program.
- **Ratepayer Impact Measure (RIM) Test.** This test provides an indication of the impact of energy efficiency programs on utility rates.

Some of the most important differences between these tests are in whether they include NEIs and externalities. We discuss this issue in more detail below. First we provide some definitions of NEIs and externalities, to be clear on what is meant by each term.

Definitions of Terms

Internal Versus External Costs and Benefits

Utilities and customers make resource decisions that take into account the costs and benefits they, themselves, incur. Those costs and benefits are said to be "internal" or "internalized," because the utility or customer bears them directly and takes them into account in its internal decision-making. For instance, in choosing between a natural gas generator and a coal generator to install at a given location, a utility would consider the capital and operating costs of each technology, as well as the benefits provided (energy, capacity, ancillary services, and so on) and other non-monetary values, such as availability, black start capability, and the various risks each entailed. In choosing between a natural gas furnace and an electric heat pump for a new home, a customer would also consider her capital and operating costs and non-monetary values affecting the quality of service provided by the appliance, such as ability to provide cooling, noise levels, and so forth. The key point in each case is that all of the costs and benefits listed accrue to the decision maker, which in general is the buyer or seller of a good; for our purposes it is the utility or the utility customer.

Some costs and benefits accrue to a party other than the decision makers. In the example of a utility choosing between two generating technologies, the usual example of an externality is the emission of air pollutants. In this instance, it might be that the coal technology would emit more air pollution per kWh of generation than the natural gas technology. (Assume for purposes of this discussion that we are discussing a form of air pollution that is not subject to a tax or fee.) Other examples could include noise levels or traffic congestion from transportation of fuel. The cost of the air pollution might include health effects on the population downwind of the plant, damage to crops and buildings, or global climate change. The cost of noise pollution could be lowered property values in the neighborhood and lost sleep. The cost of traffic congestion could be time lost and extra fuel consumed by local traffic. The point is that the utility does not bear those costs; members of the public bear them. That makes those costs externalities.

When regulators establish pollution abatement requirements (e.g., the EPA cap-and-trade program for SO_2 emissions), the costs of complying with those requirements will be borne by the polluting entity and will thus become internalized. There may still be external costs associated with SO_2 emissions, if there continues to be some environmental and health damages after the requirements are met. In this case these incremental environmental and health damages would be external costs.

Whether a cost or benefit is an externality does not depend on whether there is a monetary value associated with it. In our examples, there is a monetary cost when air pollution causes increased medical bills and crop damage or when traffic congestion causes increased fuel consumption by vehicles in local traffic (the dollar per gallon price of the fuel), but there might not be one for lost time of the travelers. Either way there is a cost, and that cost is an externality.

Monetized Versus Non-Monetized Costs and Benefits

The party to whom a cost or benefit accrues, whether internal or external, may experience that cost or benefit as a cash income or expense item, or as a change in its assets and liabilities on its balance sheet. In the utility generator case above, the capital costs for the technology show up as both a cash outlay and (usually) a change on the balance sheet reflecting the asset and its financing. The operating costs show up as expense items. The power supply benefit shows up as revenue from sale of the energy and capacity. These all happen to be internal costs and benefits, and they are also directly experienced by the company as monetary values, so they are said to be "monetized." The monetary values typically arise directly from market prices of the various goods and services consumed or produced.

The utility also experiences internal but non-monetary costs and benefits. One technology might provide black start capability (the ability to restart a generator without a supply of power from the grid), a vital need but not one for which there typically is a market price. This is an example of an internal cost but one that either has no monetized value or for which one needs to be estimated, say by determining the market cost of installing a diesel generator

solely for black start service.

The cost of medical care in the community due to increased air pollution is an example of an external cost that can be monetized. It is an externality because those medical costs are borne by individuals, insurance companies, or society as a whole, not the utility. It has a monetary value because the market price for the various medical services (emergency room visits, medical appointments, asthma drugs, and so forth) can be determined.

Economists and social scientists have developed methods of estimating dollar values for costs that do not have market prices. For example, lost productivity and shortened life expectancy for the population due to air pollution can be treated as if it had a dollar value by estimating a person's lost earning potential (as is often done in setting the damages in a civil liability case). Other examples include regulators' revealed preference, contingent valuation surveys, and willingness-to-pay or willingness-to-accept surveys.

Non-Energy Impacts

Most readers will be familiar with the range of energy costs and savings considered in energy efficiency cost-benefit tests. These include savings in capital and operating costs of generators or natural gas supply, avoided line losses, and avoided costs for market purchases of power, gas, or ancillary services. Energy efficiency cost-benefit tests also include the relevant efficiency program costs.

Non-energy impacts are those costs and benefits that are not part of the cost or avoided cost of energy. NEIs are described in detail in Section 3 of this report. NEIs might be internal or external, depending on whom they affect, and might be monetized or not.

Taking a residential efficiency program for low-income customers as an example, we can identify a number of illustrative NEIs and categorize them. (This discussion does not seek to do so exhaustively.) Certain costs and benefits would accrue to the low-income customer, some to the utility, and some to society as a whole. Table A-1 presents a sample of key NEIs from a low-income home retrofit program, and indicates whether they are market-priced, and whether they are internal costs from the perspective of the program participant, the utility, or to society.

Utility-perspective NEIs, such as reduced arrearages and reduced bad debt, can be priced by markets, because these are direct operating costs borne by the utility. These costs are internal to the utility and internal to society.

Some participant-perspective NEIs, such as increased property values and reduced consumption of other fuels, can be priced by markets, whereas others, such as increased comfort and increased safety, cannot be priced so easily using markets. All participant NEIs are internal costs from the participant and the societal perspectives, but are external costs from the utility perspective.

Some societal-perspective NEIs, such as reduced health care costs, can be priced by markets, whereas others, such as reduced environmental impacts, cannot be priced so easily using markets. All societal-perspective NEIs are internal costs from the societal perspective, but are external costs from the participant and utility perspectives.

Table A-1 demonstrates that NEIs will be experienced in different ways by different parties, can be priced using markets in some cases but not others, and will represent internal costs from some perspectives but external costs from other perspectives.

Table A-1

Sample NEIs for a Low-Income Program: Internal vs. External Costs

NEI	Market Priced	Internal to Participant	Internal to Utility	Internal to Society
Utility-Perspective NEIs				
Reduced arrearages	Yes	–	Yes	Yes
Reduced bad debt	Yes	–	Yes	Yes
Reduced terminations and reconnections	Yes	–	Yes	Yes
Participant-Perspective NEIs				
Increased comfort	–	Yes	–	Yes
Increased property value (for homeowners)	Yes	Yes	–	Yes
Increased safety	–	Yes	–	Yes
Reduced water consumption	Yes	Yes	–	Yes
Reduced consumption of other fuels	Yes	Yes	–	Yes
Reduced lost pay from sick days	Yes	Yes	–	Yes
Societal-Perspective NEIs				
Reduced environmental impacts	–	–	–	Yes
Reduced health care costs	Yes	–	–	Yes
Increased productivity due to fewer sick days	Yes	–	–	Yes

Appendix B: Choice of Discount Rate

The choice of discount rate to use for calculating present values of costs and benefits has significant implications for the cost-effectiveness of energy efficiency programs, because program costs are typically incurred in the first years, while program benefits are enjoyed for the life of the energy efficiency measure. This section describes the rationale for which discount rate should be applied when screening energy efficiency programs, for each of the standard cost-effectiveness tests.

The Goal of Discounting

Financial analysis of investments in energy efficiency should account for the fact that an energy efficiency initiative typically consists of an upfront investment in a structure or an end-use piece of equipment, which is expected to provide returns in the form of energy savings over a number of years. In order to compare costs and benefits that occur over a number of years, the various cash flows (i.e., the initial investment and the annual savings over the measure life) must be compared in a consistent way, usually as a present value expressed in the dollars of a common reference year.

There is nothing special about energy efficiency in this regard; this challenge exists for analyzing any long-lived investment. Economic and financial theory generally acknowledge that a monetary benefit provided in a given year is more valuable than the same monetary value delivered in a later year.

There are three commonly accepted reasons for this. One is inflation, which almost always causes a dollar in a future year to have less purchasing power than a dollar in an earlier year. The second reason is time preference; economic theory holds that people simply value benefits in the present more than the same benefit in the future, at least with respect to monetary benefits. The farther out in the future an expected benefit, the more such a person would prefer a present benefit. The third reason is risk; future monetary benefits from an investment are rarely guaranteed. The promise of a monetary benefit in a future year has less value than an actual monetary benefit in the current year due to the risk that the future benefit may not occur or may be less than expected.

Accounting for Inflation

This part of the discounting is relatively straightforward and requires a forecast of inflation rates for the term of the project life. One option is to use an econometric forecast (e.g., from an economic forecasting firm). Another common approach is to use the historical long-term inflation rate or the average inflation rate for a period of recent years. Either way, the assumed inflation rate can be used to turn each year's costs and savings into so-called "real dollars" or "constant dollars." Typically a project's start year or a base year for a utility's other forecasting efforts would be chosen.

The choice of whether to use a "real" discount rate or a "nominal" discount rate depends upon the inflation assumptions that are used in the annual costs and benefits of the efficiency cost-effectiveness analysis. It is important that consistent assumptions are used throughout. If the annual costs and benefits include the effects of inflation (i.e., are in nominal dollars), then the discount rate should be in nominal terms. If the annual costs and benefits are net of inflation (i.e., are in real dollars), then the discount rate should be in real terms.

Accounting for the Time Value of Money

This is the time preference issue mentioned previously. Suppose that an investor is offered a guaranteed return for investing funds. What would that return have to be to attract investments? Certainly it would have to cover the anticipated rate of inflation, but that will usually not be sufficient. Most people would rather have something today than the same thing in a year. Some extra return will be required.

This extra return is usually called a "risk free discount rate," because it assumes there is no risk associated with future benefits. (Risk will be discussed next.) In principle, such a risk free discount rate measures how much the

decision maker on a given project values money this year versus next year. Note that the time value of money will be very different for different decision makers. This point will also be discussed below.

Accounting for Risk

Adjusting for risk is the most difficult part of discounting. Again, the risk adjustment depends on the perspective of the decision maker. Perhaps the simplest case is that in which the decision maker is a utility's management. The source of an investor-owned utility's investment funds is a combination of bond investors and equity investors, possibly including some preferred stockholders. Utility investments are typically discounted at the weighted average cost of capital (WACC), that is, the weighted average yield of the company's bonds and preferred stock along with its allowed return on equity. When applying WACC for discounting, it is important to keep in mind that these values come from markets that factor in all three issues: estimated inflation rates, time value of money, and perceived riskiness of investing in the utility.

Application to the Cost Benefit Tests

Although it is important to understand the economic theory underlying the application of discount rates, it is also important to recognize that the choice of discount rate is ultimately a policy call by the utility regulators. The choice of discount rates should be informed by considering which party is being affected and what is the time value of money for that party, but it should also be informed by considering how much weight the regulators want to give to the future costs and benefits associated with energy efficiency programs (especially benefits, because these occur well into the future).

Discount Rate for the Societal Cost Test

The Societal Cost Test, as its name implies, should use a discount rate based on society's preferences. Compared to individuals and firms, society should have a broader tolerance for receiving benefits in the future, and also be better able to access funds at a lower borrowing cost. In this case, the discount rate should be relatively low.

Energy efficiency investments for special groups of customers, particularly low-income and at-risk populations, could also be viewed with a societal discount rate for several reasons. These customers are generally receiving some degree of support from society at large, so the investment can appropriately be viewed in a societal context. It is society investing in society, and should be analyzed using a discount rate appropriate to society as a whole.

The social discount rate should reflect the benefit to society as a whole, and should also take into account both the reduced risk of energy efficiency investments, as well as society's reduced time preference for a societal payback. This social discount rate is typically the lowest discount rate that reflects increased value in future savings. The Societal Cost Test also includes environmental externality costs, which should arguably be discounted at a very low discount rate, if at all.

Discount Rate for the PAC and TRC Tests

The purpose of the TRC and PAC Tests is to compare energy efficiency investments with the decision maker's other investment options. Historically the discounting challenge was relatively straightforward for these tests: the primary decision maker was the utility, and its WACC was used. (See, for example, NAPEE, 2008, p. 4-8.) This was seen as treating energy efficiency investments comparable to investments in supply-side resources, assuming that costs were recovered in a comparable fashion and that consumers would be paying the same cost of capital on both supply-side and demand-side investments.

More recently it has become clear that there are significant differences in the financial risks associated with supply- and demand-side resource investments. Energy efficiency investments are typically funded by a system benefit charge or a balancing account in utility rates. In either case, there is little risk to the utility associated with these investments, because they are passed directly on to customers independent of utility operations, utility performance, or other risk factors. Consequently an energy efficiency investment is less risky than a supply-side investment on a purely financial basis, in addition to being less risky with regard to planning, construction, and operation. A lower discount rate than the WACC (i.e., a risk-adjusted discount rate) should therefore be used in applying the PAC Test or the TRC Test.

This lower risk also exists in those instances in which a third party administers the energy efficiency programs (e.g., Cape Cod, Delaware, Hawaii, Maine, New York,

Oregon, Vermont). In these cases, the utility WACC would clearly not be an appropriate discount rate, because that rate does not represent the time value of money to the third-party administrator. The discount rate for third-party administrator programs should be low for the same reason that discount rates for utility-administered programs funded by system benefits charges should be low: there is very little financial risk associated with the funding source, as there is no long-term financing involved.

One option for developing a lower, risk-adjusted discount rate is to remove some, or all, of the risk premium and time preference embedded in the utility's WACC. This could be achieved by comparing the utility's financial risk profile to that of other companies with lower risks or with other market indicators of low-risk investment rates.

Another option is to use a more generic market indicator of a low-risk investment. For example, the interest rates on US Treasury bills are widely regarded as a good indication of low-risk investments. We are aware of at least three states that use the interest rates on US Treasury bills as a low-risk discount rate for assessing the cost-effectiveness of energy efficiency programs (ODC, 2012; MADPU, 2010; Efficiency ME, 2009).

We recommend that states use the interest rates on long-term (e.g., 10-year) US Treasury bills as the discount rate for the PAC and the TRC Tests. This indicator is widely accepted as representing low-risk investments and is straightforward, transparent, and readily available. It also means that different utilities in a single state will use the same discount rates across the state, as it eliminates the need to develop utility-specific risk-adjusted discount rates.

Discount Rate for the Participant Test

The Participant Test considers whether an energy efficiency investment is cost-effective from the program participant's point of view. This test should be used principally to set an incentive level that would be sufficient to make consumers implement efficiency measures. A consumer's discount rate should be used to discount the costs and benefits in this test.

Choosing a consumer's discount rate is administratively and theoretically complicated, however, as different customers have different discount rates. There is considerable uncertainty over what the reference point should be, as some consumers have home equity credit available, but some only have access to credit card-type debt with a much higher cost.

For residential customers, energy efficiency programs are generally of lower risk than almost any investment the household can make, but immediate needs tend to put pressure on household capital, making borrowing rates also a factor. These points suggest that home equity loan or home mortgage rates might be appropriate, especially in new construction and remodeling programs, with higher credit card rates being more applicable to participants in low-income programs.

For commercial and industrial customers, a reasonable cost of borrowing proxy could be local commercial lending rates or a prime rate plus an adder for non-prime businesses (e.g., a prime rate plus three percent). For large entities with internal capital rationing, it would be appropriate to use the firm's internal rate of return hurdle rate or its internal payback requirement.

Discount Rate for the RIM Test

Discounting is a side issue for the RIM Test, because the key goal of this test is to indicate the effect of energy efficiency programs on retail rates. The utility WACC may be appropriate for this purpose, because this is the borrowing cost that ultimately determines utility rates.



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Best Practices in Energy Efficiency Program Screening:

How to Ensure that the Value of Energy Efficiency is Properly Accounted For



Prepared for:

National Home Performance Council

Synapse Energy Economics, Inc.

Synapse Energy Economics

Tim Woolf, Erin Malone,
Kenji Takahashi, William Steinhurst

Preface

In 2011, a group of energy efficiency industry stakeholders convened to address concerns that the current practice of cost-effectiveness testing is inhibiting the development of effective, high-quality energy efficiency programs. Convened by the National Home Performance Council this stakeholder coalition includes representatives from state and local governments, utilities, program administrators and implementers, professional evaluators and researchers, contractors, and labor.

NHPC's white paper, *Measure it Right*, was released for comment in November 2011 and again June 2012 to recommend a framework of best practices for implementation of cost-effectiveness tests. While the paper outlined stakeholder positions, concrete research was identified to further the understanding of the complex interaction between cost effectiveness tests and energy efficiency programs.

This paper by Synapse Energy Economics was commissioned by NHPC to address this need. The paper provides a comprehensive review of a wide range of problems and inconsistencies in current cost-effectiveness test practices, and recommends a range of best practices to address them. These best practices (a) align test implementation with the underlying objectives of the tests as originally designed;(b) ensure that energy resources are developed at the lowest cost; and (c) support public policy goals such as promoting customer equity, serving a broad range of customers, encouraging comprehensive whole-house improvements, and avoiding lost opportunities.

We anticipate that these recommendations will provide guidance to commissions, commission staff and program evaluators well into the future. However, we also expect and hope that this report will launch a robust conversation about best practices for cost-effectiveness testing, and we invite comments and critique of the paper and its recommendations. NHPC welcomes these comments and aims to address these issues with further studies, stakeholder convening, and policymaker communication.

NHPC is grateful to the Energy Foundation and Energy Federation Incorporated (EFI) for the financial support for the on-going stakeholder process, the white paper, and this research paper. NHPC also thanks both its board of directors for making this tricky issue an organization priority and the diverse group of stakeholders who shared their knowledge and expertise on cost-effectiveness testing to advance solutions. Finally, NHPC thanks the team at Synapse that authored this excellent and path-breaking paper.

The National Home Performance Council is a national non-profit organization created to support whole-house energy efficiency programs through research and stakeholder engagement. NHPC's board of directors includes a wide range of energy efficiency stakeholders including: state energy offices, non-profit organizations, contractors, program implementers, real estate representatives, utilities, and manufacturers. NHPC's mission is to address challenges that prevent the growth and expansion of the whole-house energy efficiency sector and communicate these solutions.

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Executive Summary

Accounting for the Full Value of Energy Efficiency

Energy efficiency is widely recognized as a low-cost, readily-available resource that offers a variety of benefits to utility customers and to society as a whole. Many states have established efficiency savings targets, some states require that energy efficiency be the first choice among resource options, and an increasing number of states require energy efficiency program administrators to pursue all cost-effective energy efficiency. As states continue to advance energy efficiency initiatives and establish increasingly aggressive savings goals, it is vitally important that best practices be used in screening energy efficiency resources for cost-effectiveness.

There is a great amount of variation across the states in the ways that energy efficiency programs are screened for cost-effectiveness. Many states are applying methodologies and assumptions that do not capture the full value of efficiency resources, leading to under-investment in this low-cost resource, and thus higher costs to utility customers and society.

Many states are applying methodologies and assumptions that do not capture the full value of energy efficiency, leading to underinvestment in this low-cost resource…It is vitally important that states properly apply the cost-effectiveness tests.

The purpose of this report is to identify the best practices available for screening energy efficiency resources, in order to capture and assess the full value of those resources. Many of these best practices are based on economic theory, while others are a matter of public policy and should be based on thoughtful decisions by legislators and regulators. Our goal is to help inform those decisions.

As discussed below, five standard tests are used to determine the cost-effectiveness of energy efficiency programs. Of these, the Program Administrator Cost (PAC) test, the Total Resource Cost (TRC) test, and the Societal Cost test are predominately used by states as the primary test for screening efficiency programs. Ever since ratepayer-funded energy efficiency programs have been in place, there has been considerable debate about which test is best to use for screening energy efficiency. That debate continues to this day. We address this issue below and in Section 2.

However, we note that – while the choice of test is important – it is even more important to ensure that states are *properly applying* the cost-effectiveness tests. That is, to ensure that each test is being applied in a way that achieves its underlying objectives, is internally consistent, accounts for the full value of energy efficiency resources, and uses appropriate planning methodologies and assumptions. Many states are not properly applying the cost-effectiveness tests, and thus are understating the value of energy efficiency resources.

In the following sub-sections we provide an overview of the best practices to use in applying the cost-effectiveness tests when screening energy efficiency resources.

These include: fully accounting for other program impacts (OPIs)[1] where appropriate; properly estimating avoided costs; using the most appropriate discount rate; capturing spillover effects; fully accounting for the risk benefits of energy efficiency; and more. All of the best practices we recommend are being applied today in at least one state, and sometimes in many states. However, there are few states, if any, that apply all of the best practices recommended here. In the final section of this Executive Summary we discuss the key issues to consider in deciding which test to use in screening energy efficiency programs.

We note at the outset that one of the chief considerations in screening energy efficiency programs is to ensure that the programs will reduce energy costs to customers. Energy efficiency offers a variety of benefits to customers and to society as a whole, some of which have important public policy implications. However, in screening energy efficiency resources it is critical to acknowledge that for many key stakeholders – e.g., legislators, regulators, and consumer advocates – the benefit of reducing energy costs and reducing customers' bills is paramount.

Treatment of Other Program Impacts

Other program impacts are those costs and benefits that are not part of the cost, or the avoided cost, of energy. OPIs fall into three categories:

- *Utility-perspective* OPIs include, for example, reduced customer arrearages and reduced bad debt write-offs.
- *Participant-perspective* OPIs include, for example, improved health, increased safety, other fuel savings, reduced maintenance costs, and increased comfort. Many of these participant-perspective OPIs are especially significant for low-income customers.
- *Societal-perspective* OPIs include, for example, reduced environmental impacts and reduced costs of providing health care.

These OPIs should be included in cost-effectiveness tests for which the relevant costs and benefits are applicable. The primary rationale for including OPIs is to ensure that the tests are internally consistent. This is especially important in the application of the TRC test. By definition, this test includes the participant cost of the energy efficiency measures, which can be quite large in many cases. In order for the TRC test to be internally consistent, it must also include the participant benefits from the energy efficiency measures, including OPIs. Excluding the participant-perspective OPIs from the TRC test results in cost-effectiveness outcomes that are skewed against energy efficiency, under-investment in energy efficiency programs, and higher costs for utility customers on average.

The primary rationale for including other program impacts is to ensure that the tests are internally consistent. Since the TRC test includes the program participants' costs, it must also include the program participants' benefits.

[1] We use the term "other program impacts" to describe what are commonly referred to as non-energy impacts (NEIs) or non-energy benefits (NEBs). OPIs are those costs and benefits that are not part of the costs, or the avoided cost, of the energy provided by the utility that funds the efficiency program. In addition to non-energy impacts, OPIs also include "other fuel savings," which are the savings of fuels that are not provided by the utility that funds the efficiency program.

Unfortunately, OPIs are often not accounted for in a comprehensive manner and are frequently ignored altogether. A recent survey found that most states use the TRC test as the primary test for screening energy efficiency programs; however, only 12 states quantify participant OPIs, and not all OPIs are accounted for among those 12 states. As a result, many states are applying the TRC test in a way that is skewed and understates the true value of energy efficiency. This may be the most significant problem with energy efficiency program screening methods in the US today.

The PAC test can be applied at the portfolio level to give regulators and other stakeholders confidence that utility customer funds spent on energy efficiency will reduce costs for those utility customers.

There are two types of participant-perspective OPIs that deserve particular attention: low-income benefits, and other fuel savings. These impacts tend to be of significant magnitude and will help justify low-income programs, residential retrofit programs, and new construction programs. All of these programs offer significant public policy benefits by serving a broad range of customer types; achieving comprehensive, whole-house savings; promoting customer equity; and reducing lost opportunities.

It is important to recognize that including OPIs in the TRC test may require utility customers to pay higher energy efficiency costs than otherwise. These higher costs can be justified because (a) accounting for OPIs is necessary in order to maintain internal consistency in the TRC test; and (b) accounting for OPIs helps to achieve important public policy benefits. Nonetheless, regulators and other stakeholders need to have confidence that utility-customer funds spent on energy efficiency programs will reduce energy costs for those utility customers. This concern can be addressed by applying the Program Administrator Cost test to the entire portfolio of energy efficiency programs. (This recommendation is described in more detail below under the subheading “The Best Test(s) to Use for Screening Energy Efficiency Programs.”)

Choice of Discount Rate

The choice of discount rate to use for calculating the present values of costs and benefits has significant implications for the cost-effectiveness of energy efficiency programs. This is because program costs are typically incurred in the early years, while program benefits are enjoyed over the life of the energy efficiency measure. States use a variety of discount rates when screening energy efficiency programs, indicating a diversity of views on this important issue.

The different cost-effectiveness tests require the use of different discount rates because they represent the perspectives of different decision-makers. The Societal Cost test requires the use of a societal discount rate, which is typically very low due to society’s (i.e., government’s) tolerance for waiting for future benefits, and its ability to access funds at relatively low borrowing costs.

The discount rate applied to the PAC and TRC tests should reflect the lower financial risk of energy efficiency investments.

Many states use the utility’s weighted average cost of capital (WACC) when applying the TRC and PAC tests, based on the notion that energy efficiency investments are comparable to investments in supply-side resources that are financed at the WACC. However, investments in energy efficiency resources are different from investments in supply-side resources, especially in the way that costs are recovered by the utility.

Utilities typically have to raise capital (mostly with debt and equity) to invest in supply-side resources, and then they are later allowed to recover the investment plus the cost of capital through rates over the life of the asset. For energy efficiency investments, utilities are typically allowed to recover the investment immediately through system benefit charges, or in a very short amount of time through balancing accounts in rates. Because of this different approach to cost recovery, efficiency investments are a much lower financial risk to utilities than supply-side resources.

The discount rate applied to the TRC test and the PAC test should reflect this lower financial risk of energy efficiency investments. We recommend that states use a generic market indicator of a low-risk investment, such as the interest rate on long-term US Treasury bills, when applying the TRC or the PAC test. This rate is widely accepted as representing low-risk investments, and is straightforward, transparent, and readily available.

Calculation of Avoided Costs

All of the relevant avoided costs should be accounted for, and each of them should be calculated correctly.

Energy efficiency programs result in several types of avoided costs, and each of them should be included in the screening analysis and calculated correctly. First and foremost, avoided energy and capacity costs should be based on long-term forecasts that properly capture the energy and capacity impacts of energy efficiency resources, account for the structure of the market in which the relevant utility operates, and capture differences between peak and off-peak periods.

It is also important to account for the cost of transmission and distribution that is avoided by energy efficiency. In estimating these costs, program administrators should distinguish between those transmission and distribution costs that can be deferred or avoided through energy efficiency and those that cannot. Avoided distribution costs tend to be higher than avoided transmission costs, but avoided transmission costs are increasing, particularly in regions of the country that are expecting significant growth in new transmission investments.

The avoided costs of compliance with environmental regulations should be explicitly accounted for in the Societal Cost test, the TRC test and the PAC test. The costs of environmental compliance will eventually be passed on to ratepayers, and those that can be avoided should be included as part of the avoided costs of energy efficiency. Recent environmental regulations from the US Environmental Protection Agency are likely to increase the costs of environmental compliance, and may require the retirement of many fossil-fired generation units, which will have significant implications for energy efficiency avoided costs.

In those states and regions with climate change requirements, energy efficiency should be evaluated on an equivalent basis with other options for mitigating greenhouse gases.

Similarly, there are several existing and anticipated initiatives at the federal, regional and state levels to curtail the emissions of greenhouse gases (GHG). Energy efficiency is by far the lowest-cost and most plentiful option for meeting these initiatives. In order to meet climate change regulations at the lowest cost, the full avoided cost of complying with current and future GHG initiatives should be accounted for in screening energy efficiency programs. In sum, energy efficiency should be evaluated on an equivalent basis with other options for

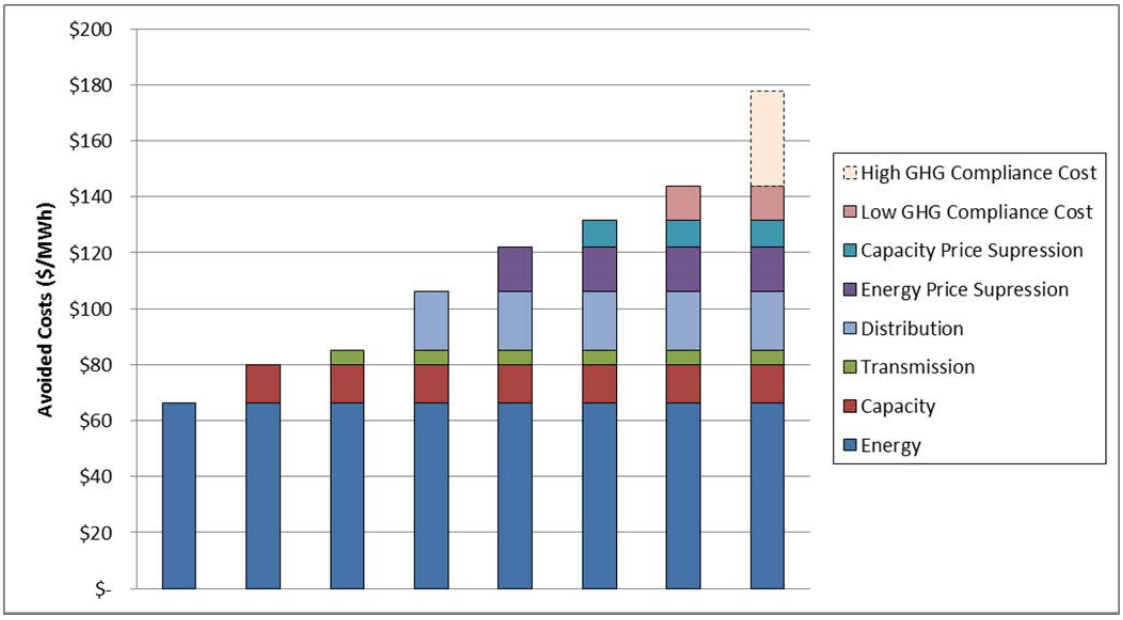
mitigating GHG emissions.

In regions of the country with organized wholesale energy and capacity markets, energy efficiency resources will reduce energy and capacity demands, which can lead to reduced wholesale energy and capacity prices. Because wholesale energy and capacity markets provide a single clearing price to all wholesale customers, the reductions in wholesale energy and capacity clearing prices are experienced by all customers of those markets. This price suppression effect should be included as one of the benefits of energy efficiency in those regions with competitive wholesale electric markets.

Analyses of energy efficiency cost-effectiveness should take account of the transmission and distribution losses that are avoided by transmitting less power from the generator to the end-use customer. In doing so, program administrators should account for the marginal losses, as opposed to the average losses, because these are the losses that are avoided by energy efficiency measures. Marginal losses tend to be significantly higher than average.

These components of avoided costs, especially when combined, will have a significant impact in determining the cost-effectiveness of energy efficiency resources. Figure ES.1 presents a summary of the avoided costs mentioned above, with the different components broken out separately. The avoided costs presented in Figure ES.1 are used by an actual electric utility in New England that we reference throughout this study as an example, as further discussed below. The details behind each of these avoided costs are presented in Appendix A.

Figure ES.1. Example of Avoided Costs, Broken Out by Component ($/MWh)



Source: Synapse 2011, as discussed in Appendix A.

Additional Screening and Methodological Issues

In order to fully capture the actual effect of energy efficiency programs, it is important to properly account for free-riders, spillover effects, and market transformation. These effects should be estimated and accounted for in a manner that is timely, consistent, and

Energy efficiency screening practices should properly account for spillover effects, market transformation, risk benefits, the full useful life of efficiency measures, and be screened at the program level.

comprehensive. Programs that are expected to have significant market transformation impacts should be provided with greater flexibility in the screening process, for example by allowing market transformation programs to be implemented even if they do not pass the TRC test, but including their costs and benefits in the PAC test applied at the portfolio level.

It is also important to recognize that energy efficiency can mitigate various risks associated with energy planning and the construction and operation of large, conventional power plants. These risks include fuel price risk, construction cost risk, planning risk, reliability risk, and risks associated with new regulations. These risk benefits should be accounted for when screening energy efficiency programs, either through system modeling or through risk adjustments to the energy efficiency benefits.

Energy efficiency measures produce savings over the course of their useful lives. Depending on the measure, the useful life can be as long as 20 years or more. Energy efficiency screening practices should use study periods that include the full life of the measures. Artificial caps on study periods or useful measure lives will skew the cost-effectiveness analysis, and result in an under-investment in energy efficiency.

Cost-effectiveness tests should be applied at the appropriate level in the planning process. Some states require that each energy efficiency measure be screened for cost-effectiveness, while others require screening at the program level, and others require screening at the portfolio level. We recommend that states do not require energy efficiency to be screened at the measure level, because this is overly restrictive and ignores the important interactions between measures. In particular, it ignores the fact that some measures have benefits in terms of encouraging customers to adopt other efficiency measures. As noted below, we recommend that energy efficiency programs be screened at the program level using the Societal Cost test or the TRC test, and that the entire portfolio of programs be screened using the PAC test.

Furthermore, when energy efficiency measures are screened in the field (i.e., at the customer's premises), they should be screened using the Participant's Cost test, to provide the customer with relevant information regarding which measures to adopt. The TRC test should not be used for field screening energy efficiency measures, because it is overly restrictive, can exclude measures that are cost-effective to customers, increases the transaction costs of contractors and customers, creates lost opportunities, and hinders the goal of achieving comprehensive, whole-house efficiency savings.

The Best Test(s) to Use for Screening Energy Efficiency Programs

Five standard tests are used to evaluate energy efficiency programs, three of which are predominately used by states as the primary test for screening efficiency programs: the PAC test, the TRC test, and the Societal Cost test. The choice of which test to use will have a significant impact on the amount of energy efficiency resources that are identified as being cost-effective.

Choosing the most appropriate test requires consideration of several factors. One key factor is the question of scope. If a state wishes to limit the scope of the cost-effectiveness analysis to utility revenue requirements, then the PAC test is most appropriate. If a state wishes the scope of the analysis to include the total incremental impacts of the efficiency measure on all utility customers, then the TRC test is most appropriate. If a state wishes the scope of the analysis to include all impacts to society, then the Societal Cost test is most appropriate.

We recommend that the Societal Cost test to be used to screen energy efficiency programs…. States that choose not to rely upon the Societal Cost test should use the TRC test….States that choose to use the TRC test must account for the participants' other program impacts.

We recommend that all states that choose not to rely on the Societal Cost test use the TRC test to screen energy efficiency programs. If a state chooses the TRC test, the test should account for OPIs to the greatest extent possible, as further discussed in this report. If regulators are unwilling to account for OPIs, the TRC test should not be used for screening energy efficiency programs, because this approach will provide misleading results that are skewed against energy efficiency.

If regulators choose to not account for OPIs, the PAC test is the best test to use in screening energy efficiency programs. This test is relatively transparent, is limited to the impacts on revenue requirements, and ensures that utility customers on average will experience lower utility costs as a result of the efficiency programs. If the PAC test is used, regulators must recognize that important benefits are being ignored, particularly low-income benefits and other fuel savings.

We recommend that the PAC test be applied at the portfolio level, regardless of which test is used at the program level, to ensure that the entire set of programs will result in a net reduction of utility revenue requirements.

However, there is an important concern with applying either the Societal Cost test or the TRC test, because of the potential impact on costs to utility customers. Some stakeholders may be concerned that accounting for OPIs and the associated public policy benefits will unnecessarily increase energy efficiency program costs, and burden utility customers with costs for achieving benefits that are not related to utility services. This is a critical consideration, particularly for states that are pursuing aggressive levels of energy efficiency savings or pursuing all cost-effective energy efficiency.

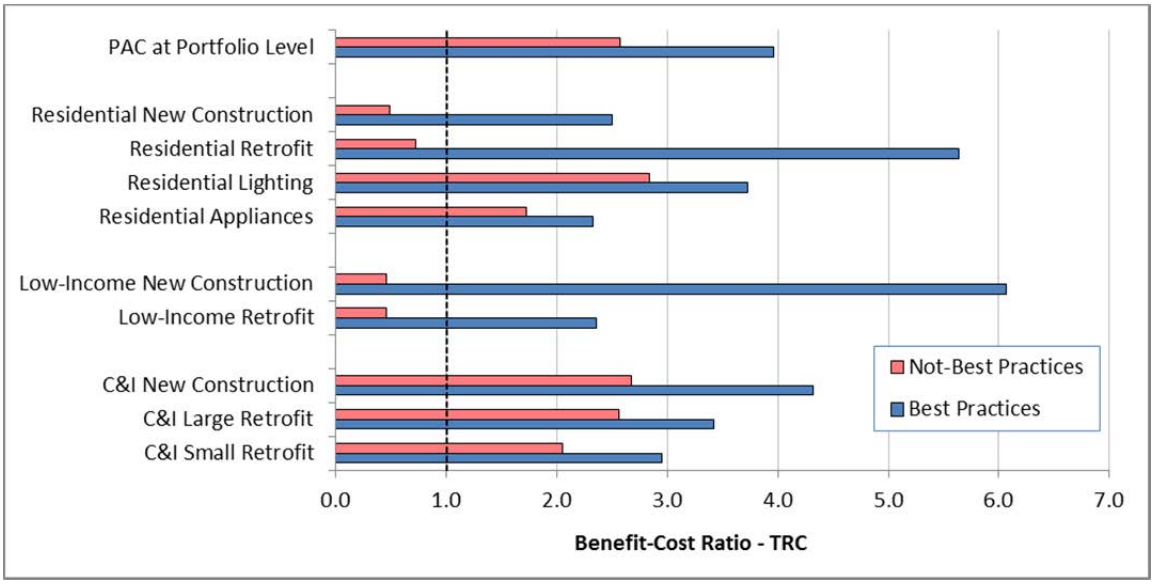
To address this concern, we recommend that the PAC test be applied to the entire portfolio of efficiency programs. This will ensure that the entire set of programs will result in a net reduction in utility revenue requirements, i.e., a net reduction in costs to utility customers. This combined program/portfolio screening approach should be simple to apply because it relies upon a single, primary test (either the Societal Cost test or the TRC test) for all of the detailed cost-effectiveness assessments, and a secondary test (the PAC test) that would be applied only once at the end of the assessment as a check on behalf of utility customers. Applying the tests in this manner allows states to balance

the goal of achieving key public policy objectives with the goal of ensuring a net reduction in costs to utility customers.

Illustrative Example of the Impacts of Best Practices

Figure ES.2 provides an illustration of how different methodologies and assumptions can affect the cost-effectiveness of energy efficiency programs. The screening results presented below for the best practices are for an actual utility in New England that we use throughout this study to illustrate the potential impact of different screening approaches and assumptions. The data presented in Figure ES.2 result from applying the TRC test.

Figure ES.2. Cost-Effectiveness Under Best Practices and Not-Best Practices



The best practices case (blue bars) includes all the avoided costs described above, the OPIs that are currently used in Massachusetts, a risk-adjusted discount rate of 3.2 percent, and a study period of 30 years to capture all or most of the efficiency measure lives. In contrast, the not-best practices case (red bars) includes all the same assumptions except that the discount rate is based on a utility weighted average cost of capital (8.5 percent), the study period is limited to 15 years, and all OPIs are excluded.

As the figure illustrates, cost-effectiveness is reduced significantly when the not-best screening practices are applied. The low-income programs are most affected, primarily because the OPIs are excluded. The residential new construction and retrofit programs are also heavily affected, primarily because the other fuel savings are not accounted for in the not-best practices case. The impacts on the commercial and industrial sector are primarily due to the change in discount rate.

In the sections below we provide similar illustrative examples, wherein we indicate the separate effects of different approaches and assumptions.

1. Introduction

Background

Despite many years of experience with screening energy efficiency programs in the US, states use a wide variety of practices when screening energy efficiency programs. Different methodologies for identifying and modeling the costs and benefits of energy efficiency programs significantly influence which programs are considered cost-effective.

The purpose of this report is to provide energy efficiency program administrators, regulators, and other efficiency stakeholders with a reference document containing best practices for screening energy efficiency programs.[2] The report is focused on several topics that are currently posing challenges for energy efficiency program administrators in today's planning climate.

One of the premises underlying our analysis is that energy efficiency program administrators should be implementing all cost-effective energy efficiency, and therefore it is critical that the cost-effectiveness tests be properly designed and implemented. Another premise underlying our analysis is that consumer advocates and regulatory commissioners are key stakeholders in the review and approval of energy efficiency plans and therefore need to have confidence that the design and application of the energy efficiency cost-effectiveness screening is in the best interest of utility customers.

Issues with Current Screening Practices

The variety of practices around the states for energy efficiency screening has not only led to inconsistency, but also to many cases where the cost-effectiveness tests are not being applied properly. Some of the topics that are currently posing challenges for energy efficiency program administrators include the following:

Other Program Impacts: Other program impacts should be included in the appropriate energy efficiency cost-effectiveness tests, in order to ensure that the tests are internally consistent. However, in practice these important impacts are rarely accounted for in a comprehensive manner and are frequently ignored altogether. This leads to energy efficiency screening results that are incomplete, misleading, inconsistent with the underlying rationale of the cost-effectiveness tests, and typically skewed against energy efficiency.

Application of Avoided Costs: Avoided costs are a significant component of efficiency program benefits. Therefore, all avoided costs should be included in program screening and calculated correctly. Unfortunately this is not the case in every state. For example, some states undervalue avoided capacity costs, some do not account for avoided T&D costs, some in regions with competitive wholesale markets do not account for the price suppression effect, and some do not fully account for avoided environmental compliance costs.

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[2] For our purposes here we define "best practices" as those policies and practices that: (a) are most likely to support key goals of utility regulators, such as ensuring low-cost, reliable, safe energy services; and (b) are most likely to support additional public policy goals of legislatures and regulators.

Discount Rate: The discount rate used to calculate present values of costs and benefits has significant implications for the cost-effectiveness of energy efficiency programs. Many states use the utility weighted average cost of capital for a discount rate. However, the energy efficiency activities are a low-risk investment for most energy efficiency program administrators, and thus a lower discount rate would be appropriate.

Cost-Effectiveness Screening Level: Cost effectiveness can be determined at either the measure level, program level, or at the portfolio or plan-wide level. Of these options, measure level screening is the strictest application for determining cost-effectiveness, and often leads to limited programs and savings. We are aware of at least one state that screens for cost effectiveness at the measure level and is experiencing difficulty justifying certain measures, including insulation in home energy retrofits. While such measures provide significant levels of savings, especially when combined with other measures or efficiency efforts, the program administrators cannot include uneconomic measures in their efficiency plans, and are therefore compelled to reduce their program offerings and overall savings.

Measure Life: Implementing energy efficiency programs requires upfront spending, while the measures installed through the programs produce savings over the course of their useful lives. Depending on the measure, the useful life can be as long as 20 years or more. Some states artificially truncate the years of benefits that can be included in cost-effectiveness screening (e.g., only 15 years of savings can be accounted for). Such an approach skews the cost-benefit analysis because it limits the full amount of benefits resulting from efficiency efforts.

This report addresses these and other issues, and recommends best practices that regulators, program administrators, and other efficiency stakeholders can adopt for appropriate efficiency program screening.

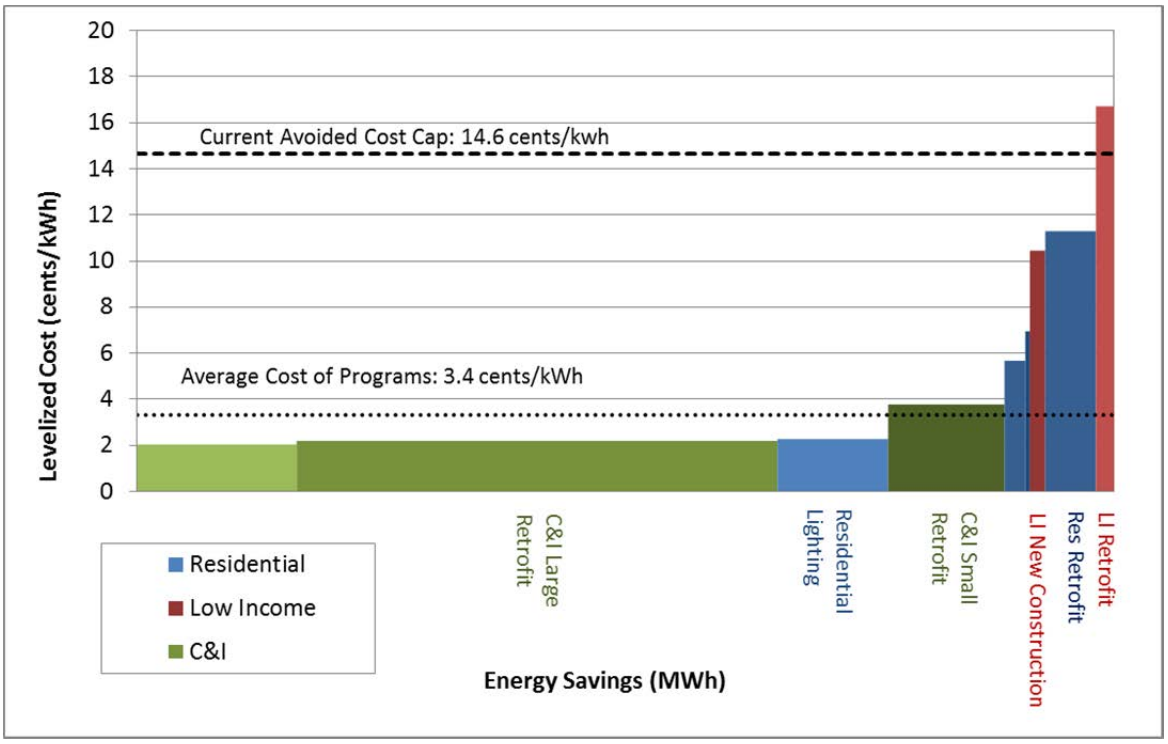
Illustrative Examples

For many of the topics discussed below, we provide an illustrative example that demonstrates the issue and highlights the effect of applying the recommended best practice. The illustrative examples are based on an actual efficiency portfolio provided by an electric utility in New England, including the utility's efficiency budget, savings, measure life, avoided costs, and other factors. We reference the same utility in each example for consistency.

Appendix A includes a description of the programs that are offered by this example utility. Figure 1.1 below provides a summary of the actual levelized cost of saved energy for each of these programs, relative to the avoided cost cap that is currently being used by this utility. Each program's energy savings are presented in the width of the program's bar, and each program's levelized cost is demonstrated by the bar's height. (The costs and avoided costs presented in this figure are limited to those that are included in the Program Administrator Cost test, i.e., just the electricity-related costs and benefits.)

As indicated in Figure 1.1, these programs are all well below the avoided cost of electricity, with the exception of one of the low-income programs. (This low-income program is cost-effective under the Total Resource Cost test, because of the low-income other program benefits. We will address this issue in Section 4.1.) The average cost of the energy efficiency portfolio as a whole is well below the avoided costs, with an average levelized cost of 3.4 cents per kWh.

Figure 1.1. Levelized Costs by Program Energy Savings (cents/kWh)



Source: The program costs are the actual 2010 program costs of our example New England utility.

In the following sections we will return to this example utility, and provide illustrative calculations for how different energy efficiency screening assumptions will affect the cost-effectiveness results.

2. Tests for Screening Energy Efficiency Programs

2.1 Description of the Cost-Effectiveness Tests

The costs and benefits of energy efficiency are qualitatively different from those of supply-side resources in that they can have different implications for different parties. As a result, five cost-effectiveness tests have been developed to consider efficiency costs and benefits from different perspectives.[3] Each of these tests combines the various costs and benefits of energy efficiency programs in different ways, depending upon which costs and which benefits pertain to the different parties. These tests are described below and summarized in Table 2.1.[4]

- The Societal Cost Test.[5] This test includes the costs and benefits experienced by all members of society. The costs include all of the costs incurred by any member of society: the program administrator, the customer, and anyone else. Similarly, the benefits include all of the benefits experienced by any member of society. The costs and benefits are the same as for the TRC Test, except that they also include externalities, such as environmental costs and reduced costs for government services.
- The Total Resource Cost (TRC) Test. This test includes the costs and benefits experienced by all utility customers, including both program participants and non-participants. The costs include all the costs incurred by the program administrator and participating customer, including the full incremental cost of the efficiency measure, regardless of whether it was incurred by the program administrator or the participating customers.[6] The benefits include all the avoided utility costs, plus any other program benefits experienced by the customers, such as avoided water costs, reduced operations and maintenance costs, improved comfort levels, health and safety benefits, and more.
- The Program Administrator Cost (PAC) Test.[7] This test includes the energy costs and benefits that are experienced by the energy efficiency program administrator. This test is most consistent with the way that supply-side resources are evaluated by vertically integrated utilities. The costs include all expenditures by the program administrator to design, plan, administer, deliver, monitor and evaluate efficiency programs offset by any revenue from the sale of freed up energy supply. The benefits include all the avoided utility costs, including avoided energy costs, avoided capacity costs, avoided transmission and distribution costs, and any other costs incurred by the utility to provide electric services (or gas services in the case of gas energy efficiency programs).

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3 For additional information on these tests, see CA PUC 2001 and NAPEE 2008.

4 These tests are sometimes defined slightly differently by different Public Utilities Commissions. Some states have created additional tests (e.g., ODC 2012; MEA 2011).

5 The California Standard Practice Manual (SPM) considers the Societal Cost Test a variant on the TRC test (CA PUC 2001, p 18). Many states and studies depart from the SPM by drawing a more complete distinction between these two tests.

6 The incremental measure cost is the difference between the cost of the efficiency measure and the cost of the most relevant baseline equipment that would have been installed in the absence of the program.

7 This is sometimes referred to as the Utility Cost test or the Energy System test.

- The Participant Test. This test includes the costs and benefits experienced by the customer who participates in the efficiency program. The costs include all the direct expenses incurred by the customer to purchase, install, and operate an efficiency measure. The benefits include the reduction in the customer's electricity bills, as well as any financial incentive paid by the program administrator.[8]
- The Ratepayer Impact Measure (RIM) Test.[9] This test provides an indication of the impact of energy efficiency programs on utility rates. The results of this test provide an indication of the impact of energy efficiency on those customers that do not participate in the energy efficiency programs. The costs include all the expenditures by the program administrator, plus the "lost revenues" to the utility as a result of the inability to recover fixed costs over fewer sales. The benefits include the avoided utility costs.

Table 2.1. Components of the Energy Efficiency Cost-Effectiveness Tests

	Participant Test	RIM Test	PAC Test	TRC Test	Societal Cost Test
Energy Efficiency Program Benefits:					
Customer Bill Savings	Yes	---	---	---	---
Avoided Generation Costs	---	Yes	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	---	Yes	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	---	Yes	Yes	Yes	Yes
Other Program Benefits (utility perspective)	---	---	Yes	Yes	Yes
Other Program Benefits (participant perspective)	Yes	---	---	Yes	Yes
Other Program Benefits (societal perspective)	---	---	---	---	Yes
Energy Efficiency Program Costs:					
Program Administrator Costs	---	Yes	Yes	Yes	Yes
EE Measure Cost: Rebate to Participant	---	Yes	Yes	Yes	Yes
EE Measure Cost: Participant Contribution	Yes	---	---	Yes	Yes
Other Program Costs	Yes	---	Yes	Yes	Yes
Lost Revenues to the Utility	---	Yes	---	---	---

How the Cost-Effectiveness Tests Are Being Used Today

A recent survey by ACEEE provides a useful summary of how the cost-effectiveness tests are used across the states.[10] Nationwide, a total of 45 jurisdictions have some level of formally approved ratepayer-funded energy efficiency programs in operation. All of these jurisdictions use some type of benefit-cost test in connection with their ratepayer-

[8] Throughout this analysis we use the term program administrator to refer to the entity that implements energy efficiency programs, whether it be a vertically integrated utility, a distribution utility or a third party administrator.

[9] This has previously been referred to as the Non-Participant test and the No-Losers test.

[10] The ACEEE report provides the results of a comprehensive survey and assessment of the current "state of the practice" of utility-sector energy efficiency program evaluations across the 50 states and the District of Columbia. The study examined many aspects relating to how states conduct their evaluations and the key assumptions employed, including the use of cost-effectiveness tests (ACEEE 2012).

funded energy efficiency programs. Most states have some type of legal requirement for the use of such tests, either by legislation or regulatory order (ACEEE 2012, p.30).

Many states examine more than one benefit-cost test. The ACEEE survey found that 36 states (85 percent) apply the TRC test; 28 states (63 percent) apply the PAC test; 23 states (53 percent) apply the Participant Test; 22 states (51 percent) apply the RIM test, and 17 states (40 percent) apply the Societal Cost Test (ACEEE 2012, p.12).

However, regulators tend to adopt one of these tests as the primary guideline for screening energy efficiency programs. The ACEEE survey found that 95 percent of states rely on a single, primary screening test:

- The TRC is used by 29 states (71 percent) as the primary methodology for defining energy efficiency cost-effectiveness.
- The Societal Cost test is used by six states (15 percent) as the primary methodology for defining energy efficiency cost-effectiveness.
- The PAC test is used by five states (12 percent), as the primary methodology for defining energy efficiency cost-effectiveness
- The RIM test is used by one state (2 percent), as the primary methodology for defining energy efficiency cost-effectiveness (ACEEE 2012, p.13).

2.2 Implications of the Cost-Effectiveness Tests

In theory, all of the above cost-effectiveness tests should be considered in the evaluation of ratepayer-funded energy efficiency resources, to provide the most complete picture of the impacts on different parties. However, most states rely upon one or two tests as the *primary* standard for screening energy efficiency programs, due to the challenges of working with multiple tests that provide different results.

Also, it is important to recognize that the different tests provide different types of information and should be used for different purposes. The RIM test and the Participant test provide "distributional" information, i.e., information regarding how the impacts of energy efficiency are distributed across customers. In particular, the RIM test provides an indication of the primary impacts of energy efficiency on those customers who do not participate in the energy efficiency programs, because the main impacts on these customers are the adjustments in rates resulting from energy efficiency. The Participant test, on the other hand provides an indication of the primary impact of energy efficiency on the program participants. These two tests together provide a rough indication of how the benefits are distributed between program participants and non-participants.

In the paragraphs below we summarize some of the key implications of each of the five cost-effectiveness tests. Table 2.2 summarizes some of the key points.

The Societal Cost test is the most comprehensive standard for evaluating the cost-effectiveness of efficiency, because this is the only test that includes all benefits and costs to all members of society. Ideally, the Societal Cost test should include all costs and benefits, including externalities, regardless of who experiences them.

The TRC test is the next most comprehensive standard for evaluating the cost-effectiveness of energy efficiency, by including all the impacts to the program administrator and its customers.[11] It offers the advantage of including the full incremental cost of the efficiency measure, regardless of which portion of that cost is paid for by the utility and which portion is paid for by the customer. In practice, however, the TRC is frequently misapplied. Many states that use the TRC test do not include all of the costs and benefits to customers, in particular the other program costs and benefits. Applying the TRC test in this way skews cost-effectiveness results, typically skewed against energy efficiency. This issue is discussed in detail in Section 4.1.

Table 2.2. The Five Principal Cost-Effectiveness Tests[12]

Test	Key Question Answered	Summary Approach	Implications
Societal Cost	Will total costs to society decrease?	Includes the costs and benefits experienced by all members of society.	Most comprehensive comparison, including the impact to all of society.
Total Resource Cost	Will utility costs and program participants' costs decrease?	Includes the costs and benefits experienced by all utility customers, including energy efficiency program participants and non-participants	Includes the full incremental cost of the efficiency measure, including participant cost and utility cost.
Program Administrator Cost	Will utility costs decrease?	Includes the costs and benefits that are experienced by the energy efficiency program administrator.	Limited to impacts on utility revenue requirements. Most consistent with supply-side cost-effectiveness methodologies.
Participant Cost	Will program participants' costs decrease?	Includes the costs and benefits that are experienced by the customer who participates in the efficiency program	Provides distributional information. Useful in program design to improve participation. Of limited use for cost-effectiveness screening.
Rate Impact Measure	Will utility rates decrease?	Includes the costs and benefits that will affect utility rates, including program administrator costs and benefits and lost revenues.	Provides distributional information. Useful in program design to find opportunities for broadening programs Should not be used for cost-effectiveness screening.

The PAC test is more restrictive than the TRC test, in that it only compares the program administrator costs to the costs of avoided supply-side resources. One way to think of this test is that it is limited to the impacts that would eventually be charged to all customers through the revenue requirements; the costs being those costs passed on to ratepayers for implementing the efficiency programs, and the benefits being the supply-side costs that are avoided and not passed on to ratepayers as a result of the efficiency programs.[13] This test is most consistent with the way that utilities typically evaluate the cost-effectiveness of supply-side resources. However, the PAC does not include several

[11] The name of this test is misleading, because it does not include "total" costs of an energy efficiency resource. A more accurate and descriptive name for this test would be the All Customers test, because it includes the total costs and benefits to all utility customers.

[12] Adapted from NAPEE 2008, p.2-2, with modifications.

[13] The name of this test is a little misleading, because it does not include the costs and benefits to the program administrator itself (e.g., utility profits). A more descriptive name for this test would be the Revenue Requirements test.

significant impacts that have important public policy implications, and are important in planning energy efficiency programs, most notably the benefits to low-income customers and the savings associated with alternative fuels.

The Participants test is fundamentally different from the other tests, in that it limits benefits to customer bill savings as the primary benefit of the programs. Customer rates are typically higher than the marginal avoided costs of the energy system, leading to higher energy efficiency benefits per unit of energy saved. Also, the only costs in this test are the customer costs, which in many cases are lower than the costs incurred by the program administrator to plan, design, and deliver the energy efficiency programs. Consequently, this test is typically the least restrictive of all the other cost-effectiveness tests. As noted above, it provides an indication of the distributional effects of the energy efficiency program, along with the RIM test, and may useful in optimizing program design for participation.

The Rate Impact Measure test tends to be the most restrictive of all the efficiency tests, because the utility lost revenues can make very large contributions to the energy efficiency program costs. Most, if not all, states have ruled that the RIM test should not be used as the primary test for evaluating energy efficiency cost-effectiveness. There are several reasons for this.

- Applying the RIM test to screen efficiency programs will not result in the lowest cost to society or the lowest cost to customers on average. Instead, it will lead to the lowest rates (all else being equal). However, achieving the lowest rates is not the primary goal of utility planning and regulation, especially if lower rates lead to higher costs to customers on average.
- The RIM test is heavily influenced by the lost revenues to the utility. However, lost revenues are not a true cost to society. Lost revenues represent a "transfer payment" between efficiency program participants and non-participants; the bill savings to the program participants result in the lost revenues that are collected from all customers, including non-participants.14 In this way, lost revenues are not a new or an incremental cost in the same way that the program administration costs are a new and incremental cost of implementing energy efficiency programs, and they should not be applied as such in screening a new energy efficiency resource.
- A strict application of the RIM test can result in the rejection of large amounts of energy savings and the opportunity for large reductions in many customers' bills in order to avoid what are often small impacts on non-participants' bills. From a public policy perspective, such a trade-off is illogical and inappropriate.
- The RIM test does not provide useful information about what happens to rates as a result of program implementation. A RIM test benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact. And it says nothing at all about the amount of cost savings associated with the energy efficiency.

[14] Note that in those jurisdictions where utilities are not allowed to collect lost revenues and do not have decoupling, for those years in between rate cases this transfer payment is actually between the utility shareholders and program participants.

- Screening efficiency programs with the RIM test is inconsistent with the way that supply-side resources are screened, and creates an uneven playing field for the consideration of supply- and demand-side resources. There are many instances where utilities invest in new power plants or transmission and distribution facilities in order to meet the needs of a subset of customers, (e.g., new residential divisions, an expanding industrial base, geographically-based upgrades). These supply-side resources are not evaluated on the basis of their equity effects, nor are the "non-participants" seen as cross-subsidizing the "participants."

Nonetheless, efficiency programs can lead to increased rates, and rate impacts are an important consideration for regulators and other efficiency stakeholders. However, it is important to recognize that the rate impacts of energy efficiency programs are not a matter of cost-effectiveness. (As noted above, the lost revenues are simply a transfer payment and do not represent an incremental cost.) Instead, they are a matter of customer equity between program participants that experience reduced bills and non-participants that experience increased rates and therefore increased bills.[15]

Therefore, the RIM test should not be used in screening energy efficiency programs for cost-effectiveness. Instead, efficiency program administrators should take steps to (a) analyze rate and bill impacts in a fashion that provides much more information than what is available from the RIM test; (b) design programs in a way that mitigates rate impacts without sacrificing energy efficiency savings; and (c) work to increase the number of program participants so as to mitigate the equity concerns between participants and non-participants.[16]

2.3 Deciding Whether to Apply the PAC, TRC or Societal Test

The decision of which cost-effectiveness test to use for screening efficiency programs has been a matter of debate since the introduction of energy efficiency programs, and continues to be a subject of debate today (Neme and Kushler 2010; CA PUC 2012b). This decision requires consideration of several factors, including economic factors and public policy issues. Below we describe the key issues to consider in making this decision.

First is the question of scope. While the cost-effectiveness tests are frequently described as pertaining to different perspectives, another way to distinguish them is that they vary by the scope of the impacts to be accounted for. If the scope of the test is to be limited to revenue requirements, then the PAC test is most appropriate. If the scope of the test is to include the total incremental impacts of the efficiency measure on all customers, then the TRC test is most appropriate. If the scope of the test is to include all impacts to society, then the Societal Cost test is most appropriate. The decision of which scope to use is a policy decision, which will need to balance several public policy considerations, discussed below.

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[15] It is important to note that all customers benefit from energy efficiency programs in certain ways, regardless of whether they participate in the programs. For example, all customers will experience reduced risk, improved reliability, reduced transmission and distribution costs, reduced costs of environmental compliance, reduced environmental impacts, and the benefits of price suppression effects in wholesale electric markets.

[16] For additional information regarding the management of rate and bill impacts, see US DOE 2011.

The Societal Cost test is the most comprehensive test, and is most appropriate for those states that wish to give consideration to the societal benefits of energy efficiency programs, particularly the environmental and health benefits. The disadvantages of this test are that some stakeholders may view the scope as outside the interests and jurisdiction of regulatory commissions; some of the societal impacts are uncertain and difficult to forecast; and this test might lead to undesirable cost impacts on utility customers.

The TRC test is the next most comprehensive test, and is the most widely used test. Regulators and legislators are apparently drawn to this test because it includes the total incremental impacts of efficiency measures. However, the TRC test creates a dilemma for policymakers. In order to be internally consistent the test must include other program impacts on the program participants, but regulators are often wary of doing so because some of the costs are uncertain and difficult to quantify. In addition, some stakeholders are concerned that including OPIs in the assessment of energy efficiency could lead to utility customers paying higher costs for efficiency programs in order to pay for other program benefits that are not in their interest and should not be paid for through utility rates.

The PAC test is most appropriate for those states that want to limit the energy efficiency cost-effectiveness analysis to the impacts on revenue requirements. There are many advantages to this test: it is consistent with the way that supply-side investments are evaluated; it includes costs that are relatively easy to identify and quantify; and it includes the energy costs and energy benefits that are most important to utility regulators. Probably the most important benefit of the PAC test is that it provides legislators, regulators, consumer advocates and others with confidence that the energy efficiency programs will result in lower costs to utility customers. This is an extremely important consideration, particularly for those states that seek to implement all cost-effectiveness energy efficiency resources.

However, relying on the PAC test has one significant disadvantage in that the costs and benefits to energy efficiency program participants are not taken into consideration. There are two implications of this. First, by not including the participant's cost the PAC test does not include the full incremental cost of efficiency measures, which may be important to policymakers. Second, the PAC test does not include the other program benefits of efficiency measure, some of which are clearly important to policy makers. The other program benefits that are typically most important to regulators are (a) those benefits that pertain to low-income customers, because of the significant public policy implications of this sector; and (b) the other fuel savings, because these savings are important to promote comprehensive, whole-house, one-stop-shopping residential retrofit programs as well as new construction programs where customers tend to use multiple fuels. In Section 4.1 we provide an illustration of how these two types of benefits can have a significant impact on program cost-effectiveness.

Once the scope is established, it is important to ensure that the test being applied includes all the appropriate costs and benefits in a way that is internally consistent. For example, when applying the PAC test it is important to include all the costs and all the benefits that are expected to affect utility revenue requirements. Similarly, when applying the TRC test it is important to include all the participant benefits as well as the participant costs in order to maintain internal consistency. Otherwise, the test results will be skewed and misleading. These issues are discussed in more detail in Section 4.1. In addition, it is important to ensure that there is no double-counting of costs or benefits in the test

being applied. Finally, it is important to ensure that transfer payments are properly accounted for when deciding which costs and benefits to include in each test.

To summarize, in choosing the appropriate test to use, policymakers must consider and balance several key questions. How important is it to include all societal impacts, including environmental and health impacts? How important is it to include the full incremental cost of the efficiency measures? How important is it to include other program impacts and the associated public policy benefits (e.g., low-income benefits, other fuel savings)? How important is it to ensure that utility revenue requirements are minimized?

2.4 Recommendations for Which Tests to Apply

With all of these considerations in mind, we offer the following recommendations. First, we note that ideally the three key tests – the PAC, TRC and Societal tests – should all be considered when assessing energy efficiency cost-effectiveness. However, we recognize that this still leaves the ultimate question of which program to implement, and that in practice it is more common and straightforward to use a single, primary test to answer this ultimate question. Our recommendations below include a primary test applied at the program level, but a secondary test applied at the portfolio level. This approach offers the benefits of both breadth and simplicity.

We recommend that the Societal Cost test be used to screen energy efficiency programs, for all those states that have the authority to account for the societal impacts of efficiency program. This test includes the broadest range of energy efficiency costs and benefits, and provides the best measure of the public policy benefits that are of great importance to legislators and regulators, such as low-income benefits, other fuel savings, and environmental benefits. Many of the concerns about quantifying the societal impacts can be addressed through rigorous analysis or sound public policy decision-making. Concerns about excessive increases to utility costs can be addressed by applying the PAC test at the portfolio level, as described below.

We recommend that all states that do not use the Societal Cost test use the TRC test to screen energy efficiency programs at the program level, and that this test should include OPIs to the greatest extent possible. At a minimum, the TRC test should include the OPIs associated with low-income programs and with other fuel savings. If regulators choose not to account for OPIs, then the TRC test should not be used for screening energy efficiency programs.

If regulators choose to not account for OPIs, the PAC test is the best test to use in screening energy efficiency programs. This test is relatively transparent, is limited to the impacts on revenue requirements, and ensures that utility customers on average will experience lower utility costs as a result of the efficiency programs. If the PAC test is used, regulators must recognize that important benefits are being ignored, particularly the low-income benefits and the other fuel savings.

The remaining concern with applying either the Societal Cost test or the TRC test relates to the potential impact on revenue requirements and costs to utility customers. This is a critical consideration, particularly for those states that are implementing aggressive levels of energy efficiency savings or pursuing all cost-effective energy efficiency.

To address this concern, we recommend that the PAC test be applied to the portfolio of efficiency programs, to ensure that the entire package of programs will result in a net reduction in revenue requirements and a net reduction in costs to utility customers. Under this approach, either the Societal Cost test or the TRC test would be the primary test for screening each energy efficiency program. Programs that do not pass the primary test would not be considered cost-effective. Then the PAC test would be applied to the portfolio of programs that do pass the primary test. If the portfolio of programs does not pass the PAC test, then one or more of the programs would need to be modified in such a way that the entire portfolio eventually passes the PAC test.

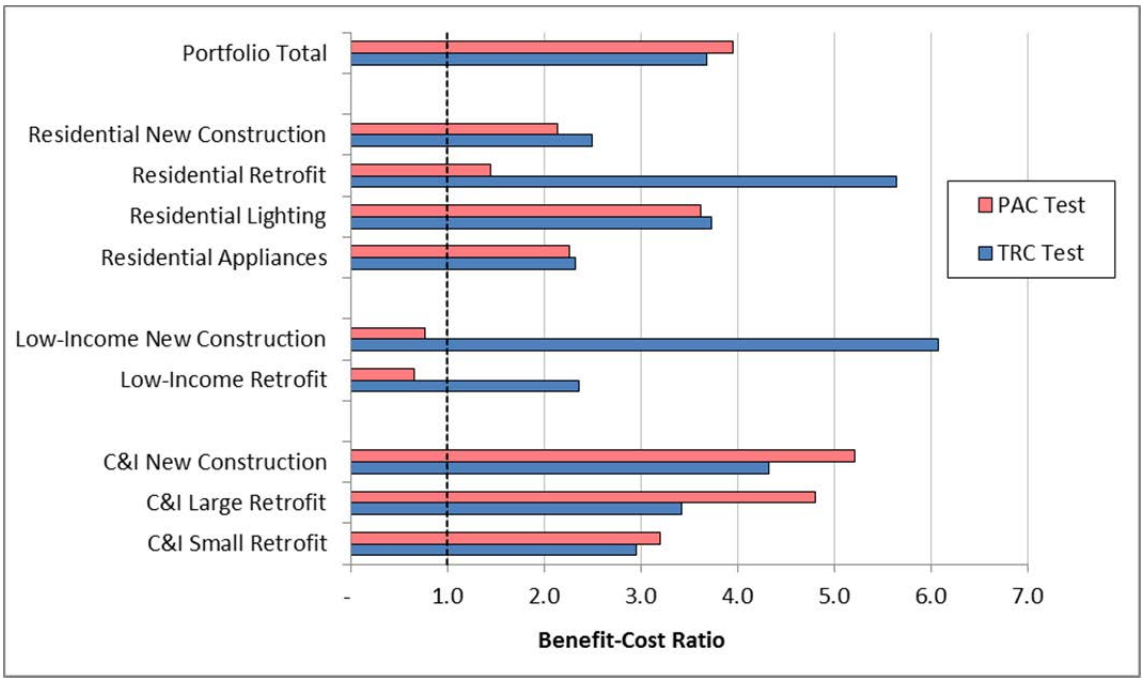
This combined program/portfolio screening approach should be simple to apply because it relies upon a single, primary test (either the TRC test or the Societal test) for all of the detailed cost-effectiveness assessments, and the secondary test (the PAC test) is applied only once at the end of the assessment as a check on behalf of utility customers. Applying the tests this way allows for a balancing of the goal of achieving key public policy objectives, such as accounting for the full incremental cost of the efficiency measure, accounting for other program impacts, and accounting for societal benefits, with the goal of ensuring a net reduction in costs to customers. The application of the PAC test at the portfolio level also provides a clear indication of the overall benefits to utility customers in terms of millions of dollars in net benefits.

Illustrative Example

Figure 2.1 illustrates program cost-effectiveness under the TRC the PAC tests, at the program and portfolio levels for our example New England utility. The TRC results below include the effect of OPIs.

While the programs and portfolio exhibits strong cost-effectiveness, the figure demonstrates the principles described above. Specifically, the TRC can be applied at the program level to ensure that public policy goals are achieved, while the PAC can be applied at the portfolio to provide confidence that the overall energy efficiency initiative will result in lower revenue requirements and lower bills on average for utility customers.

Figure 2.1. Cost-Effectiveness Results; TRC and PAC; Portfolio and Program Level



Source: The 2012 energy efficiency plan for our example utility.

3. Calculation of Avoided Costs

Energy efficiency programs result in several types of avoided costs, and it is important that all of them are included in the screening analysis and that each of them is calculated correctly. This section provides an overview of the proper techniques for estimating avoided costs. Proper estimation of avoided costs requires many important analytical techniques that are beyond the scope of this study. Readers are encouraged to refer to the reference documents for more details.

3.1 Introduction

The typical approach for quantifying the benefits of energy efficiency is to forecast long-term avoided costs, defined as costs that would have been spent if the energy efficiency savings measure had not been put in place. In addition, the utility may not have to purchase as much system capacity, make as many upgrades to distribution or transmission systems, buy as many emissions offsets, or incur as many other costs. All such cost savings resulting from efficiency are directly counted as avoided cost benefits. (NAPEE 2007, Section 3).

There are two main categories of avoided costs: energy-related and capacity-related avoided costs. Energy-related avoided costs involve market prices of energy, losses, natural gas commodity prices, and other benefits associated with energy production such as reduced air emissions and water usage. Capacity-related avoided costs involve infrastructure investments such as power plants, transmission and distribution lines, pipelines, and liquefied natural gas (LNG) terminals (NAPEE 2007, Section 3).

Nationwide, states use different methodological approaches as the basis for their avoided costs. Twelve states use essentially fixed values based on an assumed “next power plan,” eleven states based them on a more sophisticated modeling of average or marginal system costs, twelve states used some market price based methodology, and three states used some other methodology (ACEEE 2012, p.32).

3.2 Avoided Energy Costs

When estimating avoided energy costs it is important to consider the relevant market structure. For those utilities that participate in competitive wholesale markets, a forecast of market prices should be used to estimate avoided costs. For vertically integrated utilities that do not participate in competitive wholesale markets, integrated resource planning approaches should be used to estimate avoided costs.

If energy market prices are used to estimate avoided energy costs, then these market prices must be forecast for as many years into the future as necessary to cover the entire study period. (See Section 5.2 for a discussion of the appropriate study period to use.) In a wholesale electricity market context, the market price is equal to the marginal cost of operating enough generation units to meet demand in each hour of the year. This marginal energy cost can vary significantly between peak and off-peak hours and seasons, and is likely to change over time in response to changing demands, changing fuel prices, plant retirements and plant additions.

Integrated resource planning approaches typically require developing two long-term, optimized electricity scenarios, one without energy efficiency programs and one with,

and compare the difference in present value revenue requirements between the two scenarios. It is important that each of the scenarios modeled include an optimized set of resources; otherwise the avoided costs could be artificially inflated. Ideally, the costs of each scenario would be estimated using an hourly production cost model in order to get an accurate indication of the hourly operational costs of the electricity system.

Regardless of whether a market price forecast is used or IRP practices are used, it is important to reflect the different avoided energy costs that occur at different times of the day and different times of the year. This is because different types of energy efficiency resources can reduce demand at different times when prices may be significantly different. Those resources that reduce demand during primarily peak periods will result in higher avoided energy costs than those that reduce demand primarily during off-peak periods.

3.3 Avoided Capacity Costs

As with avoided energy costs, those utilities that participate in competitive wholesale capacity markets should use a capacity market price forecast, while those that do not should use integrated resource planning approaches.

Forecasts of avoided capacity costs typically include both a short-run and a long-run component. The transition point between the two occurs in the resource balance year, i.e., the first year in which new capacity resources may be needed to meet reliability requirements and the growth of peak loads.

Over the short-run, while there is sufficient existing capacity resources on the system, wholesale capacity market prices would be driven by the mix of existing capacity resources needed to meet the capacity requirement in each year. Over the long run, when new capacity is needed to meet demand, the capacity market prices would be driven by new entrants to the wholesale capacity market.

While the new entrant to the capacity market could be any type of generator (baseload, cycling, peaking), with any type of fuel (gas, coal, oil, wind, solar, nuclear), the new entrant's capacity-only cost is likely to be consistent with the cost of a new gas-fired combustion turbine facility, which is built primarily for the purpose of providing peaking capacity. For this reason, forecasts of wholesale market capacity prices typically assume that those prices will trend toward the cost of a new gas-fired combustion turbine by the resource balance year (Synapse 2011c). The long-run capacity value would be equal to the combustion turbine's annualized fixed cost less the net revenues it would earn through participation in the energy and ancillary services markets, i.e., the residual capacity value.

When using integrated resource planning methods to estimate avoided capacity costs it is important to properly identify the year in which new capacity is needed, both in the scenario with energy efficiency and the scenario without. It is also important to recognize that there are avoided capacity benefits from energy efficiency resources prior to the resource balance year.

Regardless of whether a market price forecast is used or IRP practices are used, it is important to estimate the avoided capacity costs separately from the avoided energy costs to ensure that there is no double-counting or under-counting of one or the other.

Some program administrators use the costs associated with a new power plant, e.g., a new peaking combustion turbine, to forecast avoided capacity costs. If this approach is used it is important to separate the capacity costs associated with the peaking unit from the energy costs.

3.4 Avoided Transmission and Distribution Costs

Introduction

The US utility sector has invested on the order of $35 to $40 billion per year in the T&D system over the past decade and is forecast to invest nearly $50 billion per year over the next two decades (RAP 2012). Energy efficiency has the potential to defer forecasted T&D investments. While not all forecast T&D investments will be deferrable due to time-related deterioration of equipment or other factors, a significant portion of T&D investment is likely to be associated with load growth. The potential benefits of deferring even a modest portion of such investments could be substantial. Most states include some value for avoided T&D in their calculation of avoided costs (ACEEE 2012, p.32).

There are two types of categories of avoided T&D costs, based on whether energy efficiency programs target at specific areas to alleviate congestions of specific T&D facilities. One type of avoided cost is called "passive deferral," which occurs from typical energy efficiency programs when the growth in load or stress on of the T&D system is reduced as a result of broad-based (e.g., statewide or utility service territory-wide) efficiency programs. Another type of deferral is called "active deferral," which occurs when a conscious decision is made to invest in energy efficiency measures or programs in targeted geographic locations for the specific purpose of lowering loads on local T&D system elements. (RAP 2012, pp. 3 – 4).[17]

T&D Avoided Cost Methodologies

T&D avoided cost values can be constructed by estimating historical annual marginal T&D investment, or by evaluating planned, future T&D investment at specific sites. One common method for estimating avoided T&D costs is called "projected embedded analysis." In this method, utilities use long-term historical trends (more than 10 years) and sometimes planned T&D costs to estimate future avoided T&D costs. (NARUC 1992) This approach often looks at load-related investment (as opposed to customer-related) and estimates system-wide (e.g., utility service territory) average avoided T&D costs. It has been mainly applied to the evaluation of the benefits of energy efficiency programs (as opposed to other resources such as distributed generation and demand response).

This approach is relatively inexpensive and less time consuming than the system planning approach as it does not require an engineering study of the electric system, nor does it require obtaining site specific load and investment data. As a weak point, it does

[17] In recent years, aggressive geographically targeted energy efficiency programs have been implemented in several jurisdictions in an attempt to defer specific T&D projects. Examples include Pacific Gas and Electric's Delta Project, Portland General Electric's Downtown Portland Pilot, Consolidated Edison programs, Efficiency Vermont Geo-Targeted DSM, and National Grid projects in Rhode Island (RAP 2012).

not provide an accurate picture of avoided costs for specific T&D projects. It fails to capture the highest value projects that energy efficiency might defer. However, an average value estimated using the projected embedded analysis does provide an indicator of T&D avoided costs sufficient for evaluating energy efficiency for an energy future scenario that assumes significant amount of energy efficiency deployment statewide. The value would provide a rough estimate of long-term T&D avoided cost values for efficiency projects that could reliably operate to support the grid system.

The "system planning approach" examines relevant components of specific planned T&D projects. This approach is suitable for evaluating the benefits of "active deferral" of targeted energy efficiency programs and other demand side resources. This analysis incorporates projected investment costs, system performance data, forecasted area load growth and on this basis estimates avoided T&D costs for specific locations (NARUC1992). This approach could provide price or value signals that might induce locating cost-effective energy efficiency projects in the area of need.

Recently this approach has been taken to evaluate the value of distributed generation and energy efficiency by a number of entities including ConEdision in New York, Efficiency Vermont, Detroit Edison, Southern California Edison, Bonneville Power Authority and the DG Collaborative in Massachusetts that included pilot projects by National Grid and NSTAR. (Pace and Synapse 2006; Jakubiak 2003; Kingston 2005; E3 and BPA 2004; RMI et al, 2008; RAP 2012). While this approach provides a detailed local area view of T&D avoided costs, it is more costly and time consuming to conduct than the alternative that uses historical annual marginal T&D investment. The site-specific method requires a rigorous engineering study of the electric system to identify local system upgrade needs and incorporates small area investment and load data.

In some regions of the country future transmission costs are expected to increase significantly relative to historic transmission costs. In these cases, it is important that the estimate of avoided transmission costs account for this trend and not rely entirely upon historic transmission costs.

We recommend that all energy efficiency program administrators develop reasonable estimates of avoided T&D costs, using methodologies that are best able to capture the expected future costs of transmission and distribution in their system and their region. These avoided costs can be significant and will have important implications for energy efficiency cost-effectiveness screening.

Illustrative Estimates of Avoided Transmission and Distribution Costs

Below we present a summary of several T&D avoided cost estimates being used for evaluating energy efficiency programs mainly from Western and Northeastern states. (Synapse 2011c; NWPCC 2010). As indicated, the avoided distribution costs tend to be higher than the estimated avoided transmission costs, in those cases where they are both estimated. Avoided T&D costs of this magnitude can have a significant impact on the cost-effectiveness of energy efficiency programs, particularly those that have relatively high capacity savings.

Table 3.1. Select T&D Avoided Cost Estimates (2011$/kW-year)

Utility	Avoided Transmission	Avoided Distribution	Total
SDG&E, CA	20.5	n/a	n/a
SCE, CA	56.4	n/a	n/a
PG&E, CA	14.7	23.7	38.4
PacifiCorp	31.9	83.2	115.1
PGE, OR	10.8	22.4	33.2
NSTAR, MA	15.0	89.0	104.1
WMECo, MA	20.7	62.2	82.9
National Grid, MA	20.4	111.6	132.0
National Grid, RI	20.4	89.0	109.4
CL&P, CT	1.3	29.7	31.0
UI, CT	2.5	46.0	48.5

3.5 Avoided Environmental Compliance Costs

Introduction

In theory, the Societal Cost test, the TRC test and the PAC test should all explicitly account for the avoided costs of compliance with environmental regulations. It is now common practice to account for the cost of complying with *current* environmental regulations, such as the costs of purchasing SO2 and NOX allowances. However, it is much less common to fully account for the costs of complying with *forthcoming or future* environmental regulations. Failing to do so skews the cost-effectiveness evaluations against energy efficiency, can lead to significantly less energy efficiency than is cost-effective, and can result in customers paying for alternative environmental compliance options that are much more expensive than energy efficiency resources.

These avoided costs of environmental compliance should not be confused with avoided environmental externalities. Instead, these costs represent the anticipated costs that will be incurred by utilities in the future to comply with environmental requirements; costs that will eventually be passed on to ratepayers, and thus are clearly within the definitions of the TRC test and the PAC test, as well as the Societal Cost test.

Summary of Current and Anticipated EPA Regulations

The US Environmental Protection Agency (US EPA) has proposed and promulgated a number of environmental rulemakings that affect the operation of existing and new power plants under the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act.

The Clean Air Act is a comprehensive federal law that regulates air emissions from stationary sources such as chemical plants, steel mills, and electrical generators as well as mobile sources. Under this act, EPA sets emission standards for both stationary and

mobile sources, and air quality standards that must be obtained by regions, states, and municipalities.

Emission standards directly affecting stationary sources, including power plants, issued under the CAA include: the mercury/air toxics standards; the cross-state air pollution rule; and new source performance standards.

At the state level, EPA has established and periodically revised National Ambient Air Quality Standards for criteria pollutants. In 2010, the EPA strengthened standards for NO_2 and SO_2, and is currently considering more stringent standards for ozone.

EPA has also proposed a few other environmental standards under the Clean Water Act and the Resource Conservator and Recovery Act that will have direct impact on the operation of existing power plants and factories, including the 316(b) cooling water rule; the waste water rule; and the coal combustion residuals rule.

The combined effect of these EPA regulations has led to some utilities announcing the retirement of several older, less-efficient fossil-fired power plants, and many more plant retirements are expected over the next five to seven years. Many fossil plants that do not retire will have to install expensive pollution abatement equipment and are likely to experience higher operating costs and reduced heat rates (RAP 2011c). These changes are likely to have significant effects on the avoided costs of energy efficiency programs (Synapse 2012).

Current and Anticipated Climate Change Initiatives

There are a variety of initiatives to curtail the emissions of greenhouse gas gases, at the federal, regional, state and local levels. These initiatives have important implications for the avoided cost of electricity, in the short-term and mid-term as well as the long-term.

At the federal level, despite a lack of action from the US Congress, the US EPA has been pursuing several approaches to address greenhouse gas emissions. On August 12, 2010, EPA proposed two rules to ensure that businesses planning to build new, large facilities or make major expansions to existing ones obtain New Source Review Prevention of Significant Deterioration (PSD) permits that address greenhouse gases. These rules became effective in early January 2011. On December 2011, US EPA announced that it will issue the New Source Performance Standards (NSPS) for new and modified electric power plants under section 111(b) of the Clean Air Act, and for existing electric power plants under section 111(d). On March 27, 2012, US EPA proposed the NSPS for new and modified power plants. This proposal essentially requires any new power plant to limit emissions to no more than 1,000 pounds of CO_2 per MWh, which is slightly more than the emissions from typical natural gas combined cycle power plants and far below the average emissions from coal power plants (Synapse 2012).

At the regional level, several states and provinces in North America have developed or have been developing multi-state climate initiatives including greenhouse gas caps and allowance trading to reduce greenhouse gas emissions. These regional efforts include North America 2050, which is a collaboration among several regional initiatives; the Regional Greenhouse Gas Initiative, which includes ten Northeast states; the Western Climate Initiative, which includes seven Western states and four Canadian provinces; and the Midwest Greenhouse Gas Reduction Accord, which includes six Midwest states and one Canadian province (Synapse 2012).

At the state level, many states are taking action to address climate change and reduce greenhouse gas emissions within their own borders. For several years states have been the innovative laboratories for climate change policies, and they are adopting a wide variety of policies across the nation. To date 43 states have adopted a greenhouse gas inventory and/or registry; 36 states adopted and two states are currently developing a state climate change action plan; and 22 states have established greenhouse gas emissions targets. Some states have adopted policies with significant limits on greenhouse gases, e.g., requiring reduction of CO_2 emissions to 80 percent of 1990 levels by 2050 (Synapse 2012).

Recommendations

Accounting for EPA Regulations

All states should recognize that the costs of compliance with current and anticipated EPA regulations must be included in the PAC, TRC, and Societal Tests in order for them to include all relevant impacts. These are costs that will be incurred by utilities and passed on to ratepayers, and therefore should be included in all of these tests.

Energy efficiency opportunities should be screened on a frequent, periodic basis, because energy efficiency resources may take several years to ramp up to the levels needed to economically respond to evolving EPA regulations or to replace or partially replace a retiring coal plant.

Program administrators should properly account for all current and anticipated future EPA regulations over time on a comprehensive manner, because this is likely to provide the most accurate reflection of the future and will lead to more efficient economic decisions than piecemeal analyses (RAP 2011c).

Those states that use some form of integrated resource planning for evaluating energy efficiency resources should properly address the issues related to the EPA regulations, including (a) fully accounting for energy efficiency in all coal plant retirement and refurbishment analyses; (b) properly accounting for the risk associated with EPA regulations, as well as coal plant retirements; and (c) properly accounting for the interactive effect of plant retirements.

Those states that use a more simplified avoided cost methodology for screening energy efficiency resources should properly address the issues related to the EPA regulations, including (a) ensuring that avoided costs properly consider the cost implications of all potential coal plant refurbishments and retirements; and (b) ensuring that avoided costs properly consider increased fuel, operation and maintenance costs associated with compliance with EPA regulations.

Accounting for Climate Change Requirements

All states should recognize that the costs of compliance with current and anticipated climate change regulations should be included in the PAC, TRC, and Societal Cost tests. These are costs that will be incurred by utilities and passed on to ratepayers through utility rates.

All states should recognize the importance of accounting for climate change compliance costs now. Uncertainty regarding the timing and size of those costs is not a good reason for inaction. Many energy efficiency resources have measure lives of 15 years, 20 years,

or more. Supply-side resources have operating lives that are even longer. Resource decisions made in the near-term should be based on the best assumptions available about the conditions that will exist over these long time periods.

All states should establish energy efficiency screening methodologies that account for the cost of complying with federal climate change initiatives. If a state does not have its own forecast of federal CO_2 allowance prices, then it should rely upon publicly available forecasts.[18]

All states that have state-specific climate change requirements should account for the costs of complying with those requirements in screening energy efficiency programs. Ideally, states should use state-specific marginal greenhouse gas (GHG) abatement costs. In the absence of these, they should use reasonable proxies for the marginal GHG abatement costs.

Energy efficiency program administrators should account for all likely environmental compliance costs (e.g., climate change, EPA regulations, and others), as they can have significant cumulative effects. Furthermore, because energy efficiency may take several years to ramp up to desired levels, it is important to screen for energy efficiency opportunities on a frequent, periodic basis.

3.6 Price Suppression Effects in Wholesale Electricity Markets

In regions of the country with organized wholesale energy and capacity markets, energy efficiency resources will reduce energy and capacity demands, which then can lead to reduced wholesale energy and capacity prices. Because wholesale energy and capacity markets provide a single clearing price to all wholesale customers purchasing power in the relevant time period, the reductions in wholesale energy and capacity clearing prices are experienced by all customers of those markets. Thus, even a small reduction in a market clearing price can result in significant cost reductions across the entire market. This effect is referred to as the market price suppression effect (Synapse 2011c).

The market price suppression effect is expected to primarily occur over the short-term period after the demand response resource is called to operate. Over the long-term, when new physical capacity is needed to maintain the reliability of the system, the capacity price is likely to be set by the long-run marginal cost of new capacity and will hence be less sensitive to small reductions in demand. Even then, capacity prices could be lower with demand response than without because the long-run capacity supply curve is likely to have a lower slope. One of the challenges in estimating the impact of demand response on market prices is distinguishing between the short- and long-term market price impacts.

Note that the market price suppression effect should be considered a benefit in the RIM, PAC and TRC tests because it represents a reduction in costs to wholesale electric customers, which are passed on to retail electric customers. However, this effect should not be considered a benefit in the Societal Cost test because it represents a transfer payment from the generators that are displaced to the wholesale market customers.

[18] See, for example, forecasts prepared by the Edison Electric Institute and by Synapse Energy Economics (Synapse 2012).

3.7 Line Losses

Generating facilities are often located at great distances from customers and require step-up transformers to get the power onto the transmission system, long transmission lines, transmission substations, step-down transformers to distribution voltages, distribution lines, and distribution line transformers. Losses occur at each of these steps of the transmission and distribution system. Typical utility-wide average annual losses from generating plants to meters ranges from 6 percent to 11 percent, depending on the transmission distances, system density, distribution voltages, and the characteristics of the transmission and distribution system components (RAP 2011b, p.3).

Energy efficiency reduces loads at the customer premises, which removes the utility's requirement to supply these avoided demands with generating facilities, thereby reducing line losses. When regulators and utilities value efficiency investments in cost-effectiveness analyses, they often credit energy efficiency with avoiding the *average* losses, usually because they are a measured and published figure (RAP 2011b, pp. 1-3).

However, losses on utility transmission and distribution systems are not uniform throughout the day or the year. Additionally, efficiency measures generally contribute more to the reduction of peak demands than they do on average. Consequently, using average line losses understates the line losses avoided by energy efficiency (RAP 2011b, pp. 1 – 3).

Marginal line losses are the losses actually avoided when energy efficiency measures are installed, and are usually significantly larger than average line losses. Depending on the load shape of the utility, the percentage of generation that is lost before it reaches loads are typically at least twice as high as the average annual losses on the system. Further, line losses increase significantly during periods of peak demand on the electricity system; the time when energy efficiency measures typically provide significant levels of savings. During the highest critical peak hours (perhaps 5 to 25 hours per year) when the system is under stress, the losses may be four to six times as high as the average (RAP 2011b, pp. 1 – 4).

Marginal line losses require more information and more detailed calculations to measure than average losses, and few utilities or regulators have studied the marginal losses that can be avoided with incremental investments in efficiency measures that provide savings at the time of extreme peak demands. However, very significant benefits can result from measures that reduce peak demand, including energy efficiency, demand response, and use of emergency generators located at customer premises (RAP 2011b, pp. 1-5).

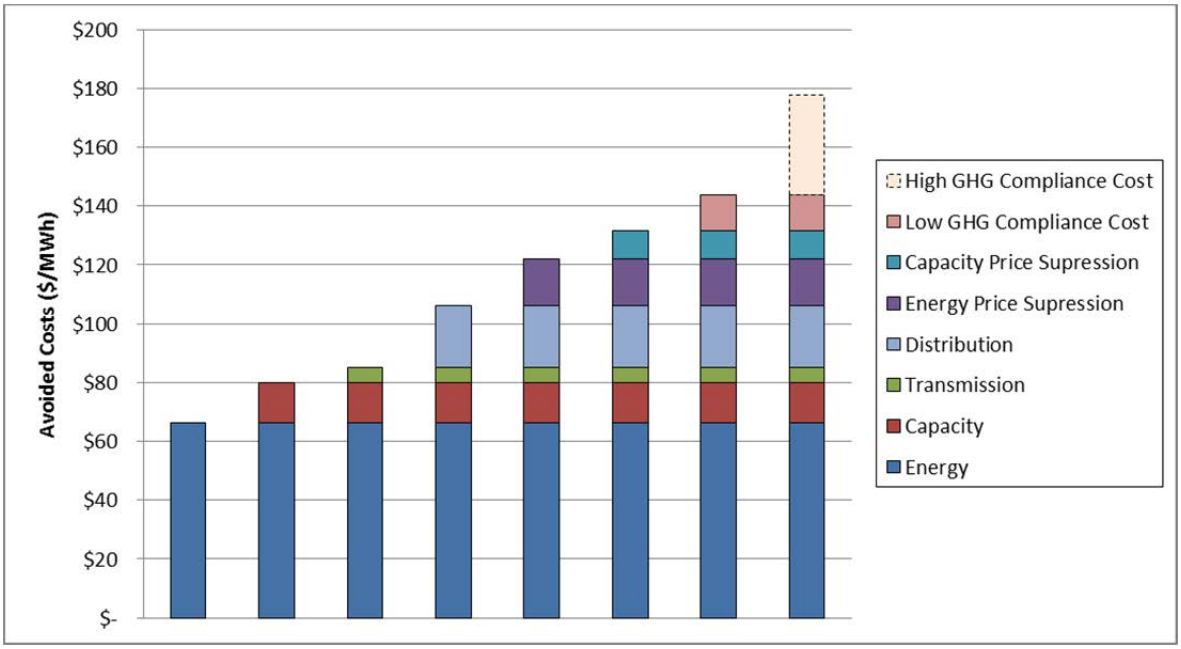
The bottom line is that energy efficiency measures typically provide significant savings at the time of the system peak demand, and that time occurs when the line losses are highest. Therefore, program administrators should use marginal line losses in efficiency cost-effectiveness screenings instead of average line losses. As a rule of thumb, utilities and regulators can assume that marginal losses are about 1.5 times average losses (RAP 2011b, p.5).

3.8 Illustrative Example

Figure 3.1 below provides an example of the cumulative effect of avoided costs, by presenting the costs broken out by type. These costs are levelized over 20 year for

consistent comparison purposes. The right-most bar provides the total impact of avoided costs. These are the actual avoided costs that are used by our example electric utility (with the exception of the high GHG compliance cost). Additional information on these costs is presented in Appendix A.

Figure 3.1. Example of Avoided Costs, Broken Out by Component ($/MWh)



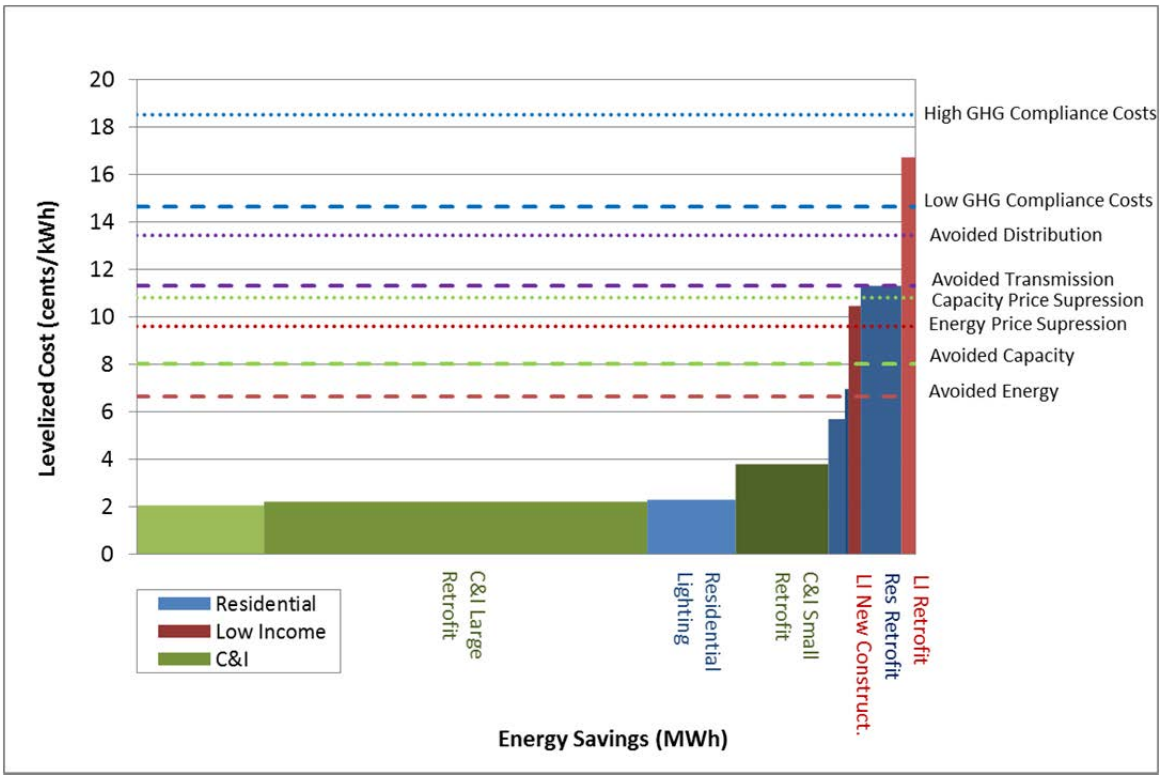
Source: Synapse 2011, as discussed in Appendix A.

For our purposes here, we present two versions of GHG compliance costs. The low GHG compliance cost is based on a forecast of CO_2 allowance prices under the current Regional Greenhouse Gas Initiative (in the short-term), as well as a forecast of CO_2 allowance prices under a future federal cap-and-trade requirement (over the long-term). This is the GHG compliance cost that is actually used by our example electric utility.

The high GHG compliance cost would be applicable to a state that has climate change regulations that are stricter than what is currently expected from current regional and future federal regulations. In particular, if a state has a requirement to reduce CO_2 emissions to 80 percent of 1990 levels by 2050, then it could expect to incur costs similar to those presented in Figure 3.1 for the high GHG compliance cost case. These estimates of GHG compliance costs are discussed in more detail in Appendix A.

Figure 3.2 provides the breakout of avoided costs superimposed over the 20-year levelized cost of saved energy for each program. (Refer to Figure 1.1.) The low GHG compliance cost line indicates the avoided cost cap that is currently being used by our example utility. As indicated, the programs are all well below this avoided cost cap, except for the low-income retrofit program which is cost-effective once the OPIs are factored in. Indeed, most programs are cost-effective relative to just the avoided energy and capacity costs. However, the additional avoided costs are necessary to support the economics of the residential retrofit and the low-income programs; two program types with important public policy implications.

Figure 3.2. Avoided Costs Relative to the Levelized Cost of Saved Energy (cents/kWh)



Sources: The avoided costs are discussed in Appendix A. The levelized program costs are actual 2010 program costs from our example New England electric utility.

4. Capturing All the Impacts of Energy Efficiency

4.1 Other Program Impacts

Description of Other Program Impacts

Other program impacts are those costs and benefits that are not part of the cost, or the avoided cost, of energy.[19] There is a wide range of other program impacts associated with energy efficiency programs. OPIs are categorized by the perspective of the party that experiences the OPI: the utility, the participant, or society at large.

Below we present a summary of the OPIs that have been identified for inclusion in cost-effectiveness tests. This list is not intended to be all-inclusive; instead it presents those OPIs that are most frequently cited in the literature and are expected to have a significant impact on energy efficiency program cost-effectiveness.

Utility-Perspective OPIs

Utility-perspective OPIs are indirect costs or savings to the utility and its ratepayers. These OPIs can be further divided into the following subcategories.

- Financial and accounting OPIs: From the utility perspective, a number of OPIs are realized from efficiency program implementation in the form of financial savings, nearly all of which arise from programs targeted to low-income customers. Energy-efficient technologies often result in reduced energy bills for participants, which can decrease the likelihood that customers experience difficulties with paying their utility bills. In turn, utilities realize financial savings through reduced costs associated with events such as arrearages and late payments (NMR 2011, p.4-1). These OPIs are often separately identified as the following: reduced arrearages, reduced carrying costs on arrearages (interest), reduced bad debt written off, and rate discounts (NMR 2011; Hall 2002).
- Customer service OPIs: Timely customer bill payments can result in fewer customer calls, late payment notices, shut-off notices, terminations, reconnections, and other collection activities. The utility realizes savings in staff time and material (NMR 2011, p.4-11).
- Safety Related OPIs: Utilities may realize savings from their efficiency programs due to a reduction in safety-related emergency calls and insurance costs due to reduced fires and other emergencies (NMR 2011, pp. 4-1, 4-15).

[19] We use the term “other program impacts” to describe what are commonly referred to as non-energy impacts (NEIs) or non-energy benefits (NEBs). OPIs are those costs and benefits that are not part of the costs, or the avoided cost, of energy provided by the utility funding the efficiency program. In addition to non-energy impacts, OPIs also include “other fuel savings,” which are the savings of fuels that are not provided by the utility that funds the efficiency program. For efficiency programs that are funded by electric utilities, the other fuels would primarily include gas, oil, propane and wood. For efficiency programs that are funded by gas utilities, the other fuels would primarily include electricity, oil, propane and wood. These other fuel savings are typically considered part of non-energy impacts, even though they actually involve energy savings. We have retitled NEBs and NEIs to OPIs to better represent the full range of impacts from efficiency programs.

Participant-Perspective OPIs

Participants in both low-income and non-low-income programs can realize a variety of OPIs from energy efficiency programs (NMR 2011, pp. 2-6, 5-1). These OPIs can be further divided into the following subcategories.

- Resource OPIs: energy efficiency can result in reduced water and/or sewage costs. Resource OPIs can also include heat (or lack thereof) generated by efficient equipment, as well as other fuel savings or costs (NMR 2011; SERA 2010).
- Equipment OPIs: participants often experience efficient equipment performing better than previous or inefficient equipment, resulting in reduced (or increased) maintenance costs, improved lighting quality, etc. (NMR 2011, pp. 5-13 – 5-15; SERA 2010).
- Property value: increased property value is frequently recognized as an OPI associated with program participation. The benefit of increased property value has been estimated through the value of anticipated ease of selling or renting, or in some cases, increased resale or rental value. The improved durability and reduced maintenance for the home is also taken into consideration (NMR 2011, p.5-16; SERA 2010).[20]
- Comfort: participants in energy efficiency programs commonly experience greater perceived comfort, either due to fewer drafts and more steady temperatures with HVAC equipment, or reduced noise from better equipment. Improved (or worsened) aesthetics can also be considered comfort OPI (NMR 2011, p.5-9; SERA 2010).
- Health and safety: energy efficiency programs may have direct impacts on health through improved home environments, reduced exposure to hypothermia or hyperthermia – particularly during heat waves and cold spells – improved indoor air quality, and potential reductions in moisture and mold, leading to amelioration of asthma triggers and other respiratory ailments. Reduced incidence of fire and carbon monoxide exposure are also commonly identified as safety-related benefits resulting from weatherization. Safety is also improved from better, more durable lighting equipment (NMR 2011, pp.5-30 – 5-34; SERA 2010; NZ EEAC 2012).
- OPIs for owners of low-income rental housing:[21] OPIs can accrue to owners of low-income rental properties, including marketability/ease of finding renters, reduced tenant turnover, increase in property value, equipment maintenance for heating and cooling systems, reduced maintenance for lighting, durability of property, and reduced tenant complaints (NMR 2011, pp.1-8, 7-1).

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[20] While increased property value is frequently cited as a significant benefit of home energy retrofit programs, some parties argue that the increased property value is primarily a function of the reduced utility bills and that to include both would be double-counting. We include this item in our list in order to be comprehensive, but caution that the property value NEI should only include those changes in property value that are not accounted for in the other categories of energy efficiency benefits.

[21] It is important to ensure that any impacts included in this category are not double-counting the impacts in other categories listed here (e.g., reduced maintenance, increased property value).

- Utility related OPIs: just as the utilities incur costs associated with making bill-related calls to payment-troubled participants or service terminations and reconnections, participants also incur opportunity costs of time spent addressing utility billing issues. Participants are impacted through reduced bill-related calls to utilities, greater control over their utility bills, reduced termination and reconnections, reduced transaction costs, and buffers against energy price increases (NMR 2011, p.5-45; SERA 2010; Hall 2002).
- Economic stability: low-income households spend a disproportionate amount of their income on energy costs, when compared to the population at large. Reducing energy costs decreases rates of mobility among low-income households, and allows income to be made available for other uses, such as healthcare (NMR 2011, p.5-19; SERA 2010).

Societal-Perspective OPIs

Societal-Perspective OPIs are indirect program effects beyond those realized by utilities, their ratepayers, or program participants, but accrue to society at large (SERA 2010, p.2). These OPIs can be further divided into the following subcategories.

- Environmental impacts: Electricity generation can have a variety of environmental impacts, including emissions of greenhouse gases, SO2, NOX, particulates, and air toxics; emissions of solid wastes; consumption of water; land use; mining impacts; aesthetic impacts and more. By reducing the need to generate, transmit and distribute electricity, energy efficiency can result in a variety of significant environmental benefits that will accrue to society as a whole (NMR 2011, p.6-1; SERA 2010).
- Economic development: efficiency programs can impact economic conditions such as employment, tax revenues, earnings, and economic output (NMR 2011, pp.6-1 – 6-4; SERA 2010).
- National security: a benefit of efficiency comes from reducing the need for energy imports, thereby enhancing national security (NMR 2011, p.6-6; SERA 2010).
- Healthcare: to the extent that energy efficiency programs can improve health and reduce health care costs, they provide a benefit to society. Examples include reduced hospitalization and visits to doctors due to reduced incidences of illness or reduced incidence rates of chronic conditions (NMR 2011, pp.6-3, 6-4; SERA 2010; NZ EEAC 2012).
- Recycling benefits: efficiency programs that include the recycling of old appliances can create benefits from waste reduction and reduced use of landfills (NMR 2011).

It is important to note that some OPIs can have benefits to more than one perspective. For example, reduced bill related calls save time and money for the utility and the participant, or improved health can affect a participant and reduce the societal costs of healthcare.

The Rationale for Accounting for Other Program Impacts

The decision of whether and how to include OPIs has significant implications for the cost-effectiveness of energy efficiency programs. As indicated in our example below, the

inclusion of OPIs can sometimes make the difference between a program being cost-effective or not.

In theory, the different categories of OPIs should be included in those tests where the relevant costs and benefits are applicable. In other words, the Societal Cost test should include the utility-, participant- and societal-perspective OPIs because this test accounts for the impacts from all these perspectives; the TRC test should include the utility- and participant-perspective OPIs because this test accounts for the impacts on utilities and participants; and the PAC test should include the utility-perspective OPIs because this test accounts for the impacts on utilities and customer revenue requirements.

The primary rationale for including OPIs in the cost-effectiveness tests is to ensure that the tests are internally consistent. The whole premise of the tests is to assess the costs and benefits from different perspectives so that regulators and other stakeholders can consider the implications of the programs from those perspectives. If any one test includes some of the costs (or benefits) from one perspective, but excludes some of the costs (or benefits) from that same perspective, then the test results will be skewed, i.e., they will not provide an accurate indication of cost-effectiveness from that perspective. Test results that are skewed are misleading at best, and could lead program administrators to significantly under-invest or over-invest in energy efficiency. In some cases, the test results could be skewed so much as to render them meaningless.

This is especially important in the application of the TRC test.[22] By definition, the TRC test includes the participant's cost of the energy efficiency measure. In some cases, this cost can be quite large. In order for this test to be internally consistent, it must also include the participant benefits associated with the energy efficiency measure, including other program benefits. Excluding the participant-perspective OPIs from the TRC test will provide cost-effectiveness results that are skewed against energy efficiency, will result in under-investment in energy efficiency programs, and will result in higher costs for all customers on average.

Many regulators and other stakeholders are understandably concerned that including OPIs when screening energy efficiency programs is too comprehensive in that it includes costs and benefits that are outside of the regulators' primary objectives. More specifically, many stakeholders are concerned that including other program benefits will require utility customers to pay increased rates in order to achieve certain benefits (e.g., improved health, safety and comfort for participants) that should not be supported with ratepayer funding. This concern is understandable and is a critical consideration that should be made when deciding which cost-effectiveness test to apply and how to apply it. We address this issue in Section 2.4.

It is important to recognize that this issue of scope (i.e., whether to include impacts on participants) arises at the point when a commission (or legislature) decides on which test to use as the primary screening test. If the TRC test is chosen as the primary test, then the commission (or legislature) is making an explicit or implicit decision to include costs to participants, which are typically outside the scope of regulators' primary objectives in the same way that other program benefits are outside that scope. Once this decision is made, the scope is established (i.e., impacts on both non-participants and participants); then it is necessary to determine how to maintain internal consistency within this scope.

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[22] This is also important for the Societal Cost test. Here we focus on the TRC test because of its widespread use.

Among the participant-perspective OPIs that should be included in the TRC test, there are two types that deserve mention at this point: low-income other program benefits, and other fuel savings. First, these two types of OPIs tend to have the biggest impact on the cost-effectiveness of certain programs. This is demonstrated in our illustrative example below.

Second, these two types of OPIs tend to support important public policy goals of regulators and other stakeholders. Low-income other program benefits are vital because they help justify programs that serve an important, hard-to-reach, disadvantaged set of customers. Other fuel savings are important because they help justify comprehensive residential retrofit and residential new construction programs that are designed to treat multiple fuels in customers' homes. Combined, these OPIs help to support much more comprehensive residential programs and to serve a more diverse set of residential customers, which promotes greater customer equity, both within the residential sector and between the residential and other sectors. Promoting customer equity is clearly an important public policy goal of regulators. Consequently, we recommend that regulators place priority on finding ways to account for at least these two participant-perspective OPIs.

The Application of Other Program Impacts in Practice Today

As described in Section 2.1, a recent survey by ACEEE provides a summary of how the cost-effectiveness tests are used across the states. The study finds that, while 36 states use the TRC test (which includes participant costs) as their primary test, only 12 of those states treat any type of participant non-energy benefits as a benefit (ACEEE 2012, p.31).

Of those states that do include non-energy benefits, most of them were limited to water and other fuel savings. Only two states quantify a benefit for participant operation and maintenance savings, and no state quantifies benefits for things like comfort, health, safety, or improved productivity in their primary benefit-cost test (ACEEE 2012, p.32).

This survey clearly documents the fundamental imbalance in how the TRC test is often applied today; where many states account for the participant costs of efficiency measures, but few of them account for the full participant benefits. In sum, the majority of states currently conduct cost-effectiveness tests that are inherently skewed against energy efficiency.

Regulatory Options for Addressing Other Program Impacts

There are several options available for including OPIs in energy efficiency cost-effectiveness screening. The states that account for OPIs, as discussed above, typically quantify those OPIs that are readily measureable. This is especially true of low-income programs. A few states take the analysis further by allowing for an adder, allowing for BCRs less than 1.0, or conducting a scenario analysis.[23] Using the current approaches as a starting point, below we identify the possible methods to account for OPIs in cost-effectiveness screening.

- Include all relevant OPIs: Develop quantitative estimates of all OPIs, with a focus on those OPIs that are expected to be most relevant and most significant. In

[23] See Synapse 2012 for additional details on how some states address OPIs in efficiency screening.

theory this approach would produce the most accurate representation of OPIs. The challenges and uncertainties of quantifying OPIs are frequently cited as reasons for not including them in energy efficiency screening. We note that these challenges and uncertainties exist for many aspects of utility regulation and planning, including estimates of avoided costs that form the heart of energy efficiency screening. Some states have been able to develop quantitative estimates of OPIs that are sufficiently reliable for planning purposes.[24]

- Readily measurable OPIs only: Develop quantitative estimates of those OPIs that are readily measurable. This is a practical approach because several OPIs are readily measureable without significant time or financial commitments.[25] However, it may fail to capture the full range of OPIs, depending upon the resources and time dedicated to the effort.

- Sensitivity analysis: Consider cost-effectiveness results with varying ranges of OPIs included. For example, New York regulators are provided with benefit-cost ratios that include a range of OPIs; from zero OPIs, to half of the readily measurable OPIs, to all of the readily measurable OPIs. This approach assists regulators in understanding the range of effects that OPIs can have on benefit-cost ratios, and may help to address concerns about uncertainty in the OPI values. However, this method could require a more qualitative analysis, thus removing the benefit of a "bright line" metric afforded by the use of a cost-effectiveness test.

- Adder: Apply an adder to the efficiency program benefits to reflect all the OPIs. The adder would be used to represent the full range of other program benefits that accrue to customers. Higher adders could be applied to low-income programs to reflect the higher level of OPIs that are likely to accrue to low-income customers. Adders could be applied at the measure, program, sector, or portfolio levels. Overall, this is a simplified approach that does not require extensive evaluation activities. On the other hand it may be seen as too much of an approximation, and determining an appropriate adder may be difficult.

- Reduced Benefit-Cost Ratio Threshold. Apply a lower benefit-cost threshold than 1.0 to efficiency programs, especially for programs that are expected to have significant OPIs. This approach has a similar effect as applying an adder to account for OPIs; an adder can be converted into a lower threshold and vice-versa. Using an adder has the benefit of being more transparent and avoiding the need to change energy efficiency screening thresholds or apply different thresholds for different programs.

- Hybrid: A combination of the various options could be employed to create a hybrid approach. For example, a state could include all readily measurable OPIs, and use an adder for hard to measure OPIs. As discussed above, Vermont uses an adder for OPIs in addition to readily measurable OPIs, while Colorado requires an adder but also allows for readily measurable OPIs. Further, a state could include readily measurable OPIs, and conduct a sensitivity analysis for additional OPIs. This approach is most consistent with the nature of OPIs, whereby some OPIs are easily and readily quantified, while others require

[24] See, for example, NMR 2010.
[25] For additional information on methodologies for quantifying OPIs, see SERA 2010 and NMR 2010.

a more qualitative analysis on the potential range of impacts that accrue to customers from efficiency programs. Additionally, this method affords regulators flexibility in determining the most appropriate OPI policy for their state. Finally, it allows consideration of all NEIs believed to be most significant, with the choice of methodology used to determine each NEI being made on the basis of available resources.

There is one other option that is sometimes proposed to address this issue. The participant cost could be broken into two portions: one portion that is related to energy savings, and one portion that is related to participant other program benefits. Under this approach, the TRC test would include only that portion of participant cost that relates to energy savings (CAPUC Staff 2012; CAPUC 2012b). In this way, the scope of the TRC would include only energy-related costs and benefits: those of the program administrator and those of the participating customers.

Recommendations

All states that use the PAC test for screening energy efficiency should properly account for the utility-perspective OPIs in their cost-effectiveness analyses.

All states that use the TRC test for screening energy efficiency should properly account for utility-perspective and participant-perspective OPIs in their cost-effectiveness analyses. If a state is unwilling to account for participant-perspective OPIs, then the TRC test should not be used for energy efficiency screening purposes because this will lead to misleading results that are skewed against energy efficiency. In the absence of participant-perspective OPIs, the PAC test is the best test to use in screening energy efficiency.

Similarly, all states that use the Societal Cost test should properly account for utility-, participant- and societal-perspective OPIs in their cost-effectiveness analyses.

The TRC or Societal Cost test (including OPIs) should be applied at the program level, while the PAC test should be applied at the portfolio level to ensure that utility customers will experience lower utility costs as a result of the energy efficiency programs. This concept is discussed in more detail in Section 2.4.

Each state should develop an approach for accounting for OPIs that best suits their needs. We recommend that each state should do the following:

- Identify all of the OPIs that are relevant for the energy efficiency programs offered, and the screening test used, in the state.
- Develop quantitative estimates for all OPIs that can be readily quantified. At a minimum, this should include the other fuel savings, because these savings can be relatively easily quantified using forecasts of the prices for those fuels.
- Develop some methodology for addressing those OPIs that are not quantified, e.g., by using an adder to the benefits as a proxy. If the state does not develop quantitative estimates for the low-income other program benefits, then at a minimum these benefits should be addressed through some proxy approach.
- Hire independent contractors to develop the best state-specific OPI estimates possible. The money required for this type of research could come from program administrator's evaluation, monitoring and verification budgets.

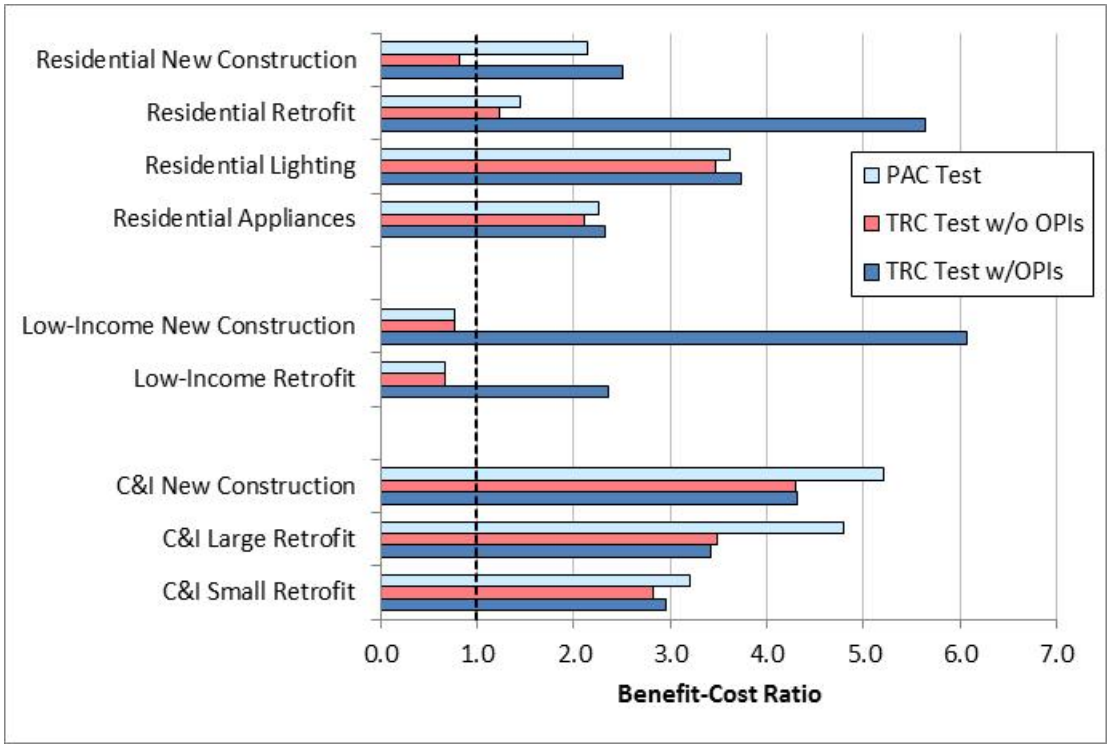
Illustrative Example

Figure 4.1, provides the benefit-cost ratios under the PAC test, the TRC test with OPIs included, and the TRC test without OPIs included for our example utility. The OPIs that we use here are the ones that are currently in use by Massachusetts energy efficiency program administrators (NMR 2010).

First, it is interesting to note the difference between the results under the PAC test relative to the TRC test without OPIs. The low-income programs are identical under these two tests because the customers are not required to make any contribution toward the incremental cost of efficiency measures. The C&I programs are more cost-effective under the PAC test than the TRC test, because customers contribute towards the incremental efficiency measure cost, and the OPIs for C&I programs are assumed to be relatively small.

Second, it is interesting to note the difference between the results under the TRC test with and without OPIs. The low-income programs are much more cost-effective with the OPIs included because of the low-income other program benefits and the other fuel savings. The residential new construction and retrofit programs are much more cost-effective with the OPIs included because of the other fuel savings. These two OPIs (low-income other program benefits and other fuel savings) account for the vast majority of the differences between the cases with and without OPIs.

Figure 4.1. Cost-Effectiveness Analysis for OPIs



Source: The 2012 energy efficiency plan for our example utility, with modified assumptions as noted.

With regard to C&I programs, there are very few OPIs applied to the C&I sector. This may be primarily due to the fact that this sector has not been studied as much as the

residential and low-income sector, since C&I programs tend to be highly cost-effective without OPIs.

4.2 Free-Riders, Spillover and Market Transformation

Background

In assessing the cost-effectiveness of energy efficiency programs, program administrators and regulators have sought to identify "net" impacts of the efficiency programs on energy savings. This is so called "net savings", which is the savings net of what would have occurred in the absence of the program.

This approach attempts to isolate savings impacts not directly or indirectly caused by the program. Net savings theoretically include free-riders and spillover, the estimation of which has been historically challenging and controversial especially because it requires identifying the counter-factual as a baseline (i.e., what would have happened in the absence of the program). Nevertheless, many states use a net savings approach because utility regulators wish to know the net impacts of efficiency programs when assessing their cost-effectiveness.

Recently, there has been lively debate on net savings of energy efficiency programs because the audiences for energy savings estimates have grown to include new stakeholders and regulators, especially air regulators with the expectation that energy efficiency efforts may contribute to significant greenhouse gas emissions reduction, while long-standing audiences have increased their scrutiny of net savings estimates, largely in response to increased funding and expanded regional goals for energy savings and reduced emissions (NMR 2010, page 9).

Definitions

There are various parameters that adjust gross energy savings such as realization rates, measure persistence, installation rates, hours of use, free-rider, spillover, and rebound effects. The two key factors that influence the calculation of net savings are free-rider and spillover effects. Market transformation effects can be considered a type of spillover effect.

Free-rider: "A program participant who would have implemented the program measure or practice in the absence of the program. Free riders can be 1) total, in which the participant's activity would have completely replicated the program measure; 2) partial, in which the participant's activity would have partially replicated the program measure; or 3) deferred, in which the participant's activity would have completely replicated the program measure, but at a future time than the program's timeframe." (NMR 2010, page 6)

Spillover: "Reductions in energy consumption and/or demand caused by the presence of an energy efficiency program, beyond the program-related gross savings of the participants and without financial or technical assistance from the program. There can be participant and/or nonparticipant spillover. Participant spillover is the additional energy savings that occur when a program participant independently installs energy efficiency measures or applies energy saving practices after having participated in the efficiency program as a result of the program's influence. Non-participant spillover refers

to energy savings that occur when a program nonparticipant installs energy efficiency measures or applies energy savings practices as a result as a result of a program's influence. Additional distinctions may also be made to spillover such as "like" or "unlike" spillover (the former refers to the same measure as the program, while the latter refers to other actions taken as a result of program participation) and "inside" and "outside" of the project (the former referring to non-incented measures taken within the same project that had received an incentive while the latter is adoption of non-incented measures in an unrelated project)."(NMR 2010, page 7)

Market Transformation Program: "An energy efficiency program strategy that leads to a reduction in market barriers resulting from a market intervention, as evidenced by market effects that last after the intervention has been withdrawn, reduced or changed." (NEEP 2009, p.22)

There is also another factor called "rebound" effect that influences the net energy savings. The rebound effect describes an effect where consumers increase the level of energy service due to lower cost of energy usage resulting from more energy efficient measures. Our study will focus on free-rider and spillover and will not discuss the rebound effect in our study for two reasons. First, the literature on this topic indicates that the rebound effect from energy efficiency programs is minimal (Synapse 2011a; Nadel 2011; Ehrhardt-Martinez and Latiner 2010). Second, historically free-rider and spillover effects have been the major focus on net savings.

Current Practice

Recent surveys by NMR (2010), ACEEE (2012), and LBNL (2010) revealed the "operational" definitions and methods for measuring net savings are different by jurisdiction. In general, the surveys found that some states only include free-ridership, some states include both free-ridership and spillover, and some states do not include either (See Table 4.2). Many states adjust for free ridership, but a fewer states adjust for spillover. Even where spillover is used, it is limited to a few cases in some states.

ACEEE makes the following points:

> In current practice, substantial differences exist among states in things like the treatment and measurement of free riders, spillover, net savings, deemed savings, and non-energy benefits. These differences make it difficult to interpret comparisons among states in reported energy efficiency results, and preclude the ability to make true "apples to apples" comparisons. - We explored the net savings issue in a little more detail, and asked whether states made specific adjustments for "free riders" and "free-drivers/spillover." Interestingly, while 28 states (67%) indicated they make an adjustment for free-riders, only 17 states (44%) make an adjustment for free-drivers/spillover. (ACEEE 2012, p.33).

Aside from what factors are included in net savings measurements, we note that there are various methods to measure the effect of free-rider and spillover effects or net to gross savings or ratios, including, but not limited to (a) self-reporting surveys, (b) enhanced self-reporting surveys, (c) market sales data analysis, (d) historical tracing (case study method), (d) structured expert judgment, (d) econometric modeling, and (e) deemed or stipulated estimates (NMR 2010, page 27 – 32; NAPEE 2007, 5-4 – 5-7). Finding the most appropriate method depends on (1) the structure of the energy efficiency program; (2) the availability of market sales data and meaningful comparison

groups; and (3) the likelihood of substantial upstream effects (e.g., effects at the manufacture and distributor level (MA DPU 2011, page 10).

Table 4.2. Market Influences and Program Effects Included in Estimates of Net Savings

State	Free-ridership	Spillover/ Market Effects
CA	Yes	Yes in few cases
CT	Yes	Yes in some cases
FL	Yes	Yes
IA	No	No
ID	No	No
IL	Yes	Yes
MA	Yes	Yes
ME	Yes	No
MN	Yes	No
NEEA	No	No
NY	Yes	Yes
OR	Yes	Yes
PA	No	NA
TX	No	No
WI	Yes	Yes in few cases
Total Yes	10	8

Source: NMR 2010, Table 2-2.

Major Issues

NMR recently conducted an extensive survey of net energy savings through a literature review and stakeholder interviews. This study found that the accurate measurement of free ridership and spillover remains challenging despite continual improvement in methods (NMR 2010, page 12). In fact, because there are now numerous programs offered by multiple entities to promote energy efficiency programs (e.g., utility programs, federal tax credits, ARRA funding), it is becoming more complex and difficult to isolate the impact of one program from others, which, some argue, reduces the accuracy of the recent net savings estimates (NMR 2010, p.49).

NMR (2010) summarizes the current practice of measuring net savings as follows:

- Focuses too heavily on narrowly defined metrics of individual program success or failure—especially free ridership—while deemphasizing other important impacts, such as non-energy benefits and behavioral effects, as well as portfolio and policy-level impacts. (NMR 2010, page 18)
- Creates the impression that the estimates accurately represent the savings attributable to the program when, in reality, the methods available often yield results that may not accurately represent actual program-induced savings due to shortcomings related to bias, reliability, and validity because estimating net savings requires "measuring" the counterfactual as a baseline. (NMR 2010, page 18 and 33) This issue includes the difficulty in measuring cumulative spillover effects over time from the programs implemented in the previous years as well as the potential failure to account for any synergistic impacts of the portfolio of programs (NMR 2010, page 35-36). To make matters worse,

spillover from program activity in previous years may be identified as free ridership in the current program year. (NMR 2010, page 34)

- Requires large expenditures of resources that are not in keeping with the importance of the estimates and their reliability and validity, thereby diverting resources from other planning, evaluation, and implementation activities that could yield greater benefits. (NMR 2010, page 18)
- Some parties argue that "the focus on minimizing free ridership is counterproductive and greater savings could be achieved if the focus were on maximizing outreach and not on avoiding outreach to the "wrong people" (i.e., free riders)" (NMR 2010, page 44).

However, NMR (2010) also found that many stakeholders still emphasize the importance of the use of net savings because net savings allow us to assess the effectiveness of various program designs and whether the designs should be replicated, expanded, revised, or discontinued. It also allows us to ensure that ratepayer or taxpayer funds are being spent responsibly and in a manner that ensures that efficiency is the lowest-cost resource (NMR 2010, 18).

Finally, market transformation programs present a distinct challenge with regard to cost-effectiveness screening. These programs are explicitly designed to achieve savings beyond the direct program impacts (i.e., spillover effects); savings that might not occur for several years, might last for many years beyond that, and might be very difficult to quantify. Screening these programs without accounting for their spillover effects would clearly understate their true value and would preclude many valuable programs from proceeding. The options for addressing this issue include: (a) allowing these programs to be implemented even if they do not have a benefit cost ratio of one or greater; (b) including the costs and benefits of these programs within the evaluation of other related programs, and requiring that the combined program be cost-effective; or (c) developing an adder to the estimated benefits to best represent the likely spillover effects of the market transformation program.

Recommendations

We recommend that program administrators and other stakeholder place less emphasis on free-ridership and greater emphasis on spillover and market transformation effects, in order to achieve more balance between these effects. In addition, all of these effects should be accounted for in a more timely and effective manner as part of program process evaluation, in order to inform whether a program should be redesigned or replaced as a result of these effects. [26]

We recommend that free-riders be treated consistently in estimating both the costs and benefits of energy efficiency programs. If the impacts of free-riders are subtracted from the efficiency savings, then the impacts of free-riders should be subtracted from the cost estimates as well.

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[26] In Massachusetts, the state regulator, utilities, and other stakeholders are currently investigating this issue, and trying to develop ways to estimate net savings that achieve three core benefits (1) increased reliability and accuracy in reporting program-delivered savings (which also capture multi-year impacts from program efforts in the multi-year planning cycle); (2) better planning assumptions for program strategies; and (3) increased administrative efficiency (MA Joint Comments 2012)

We recommend that program administrators and other efficiency stakeholders explore options to better capture the cumulative, long-term effects of energy efficiency programs. Programs that are highly successful in educating customers about the advantages of energy efficiency will naturally encourage those customers to adopt additional efficiency measures in the future. Expected savings from such customers should be estimated to the extent possible, and accounted for in screening efficiency programs.

We recommend that market transformation programs be evaluated in a way that accounts for the fact that they will have significant spillover effects by design. One way to achieve this goal is to allow market transformation programs to be implemented even if they do not pass the TRC test, but to include their costs and benefits in the PAC test applied at the portfolio level.

Finally, we recommend regional coordination on the definition and calculation of net savings. As we pointed out above, the operational definitions and methods for measuring net savings are very different by jurisdiction. More consistency on the net savings definition and calculation may be needed to address current policies and/or future policies such aggressive state-wide energy efficiency programs, an ISO capacity market, and regional GHG emissions reduction requirements. The Northeast Energy Efficiency Partnership's Forum on regional energy efficiency measurement and verification is a good example of using a regional approach to address these issues.

4.3 The Risk Benefits of Energy Efficiency

Energy Efficiency Offers Several Important Risk Benefits

Energy efficiency can mitigate the various risks associated with large, conventional power plants. A recent study evaluated the costs and risks of various energy resources, and found out that energy efficiency is the least cost and least risky electricity resource (Ceres 2012). Figure 4.2 provides a summary of how the Ceres study characterizes the costs and risks associated with various electricity resources. Some of these key risks are described below.

Fuel price risk. Increases in fuel price volatility underscore the significant benefits associated with reducing this risk. Historically, varying demand for and supplies of natural gas and the highly volatile nature of natural gas prices have been primary drivers of more volatile electricity rates.

Construction Cost Risk. The longer development timelines associated with conventional generation as compared to energy efficiency solutions exposes these resources to longer-term increases in the cost of labor and materials – unanticipated cost increases which increase the risk of disallowance and stranded costs. For example, the construction schedule of the proposed Levy nuclear power plant in Florida has been delayed five years due to financial and design problems and its cost estimates has increased from $5 billion to $22.5 billion.[27] In contrast, energy efficiency can be deployed quickly and is one of the least risky resources, both financially and environmentally.

[27] http://www.businessweek.com/ap/financialnews/D9HQ2TN80.htm

Figure 4.2. Projected Utility Generation Resources in 2015 – Relative Cost and Risk



Source: Ceres 2012, p.9.

Planning risk. When it turns out electric demand growth is lower than expected, there is a risk that a portion of the capacity of new power plants may be unused for a long time. In January 2012, lower-than-expected electricity demand along with unexpectedly low natural gas prices, led Minnesota-based wholesale cooperative Great River Energy to mothball its brand-new coal-fired power plant immediately after the plant's completion. The utility expects to pay an estimated $30 million next year just for maintenance and debt service for this plant (Ceres 2012, page 33). Energy efficiency resources that reduce load incrementally never face this type of problem.

Reliability risk**.** Energy efficiency can improve the overall reliability of the electricity system. First, efficiency programs can substantially reduce peak demand, during those times when reliability is most at risk. Second, by slowing the rate of growth of electricity peak and energy demands, energy efficiency can provide utilities and generation companies more time and flexibility to respond to changing market conditions, while moderating the "boom-and-bust" effect of competitive market forces on generation supply (RAP 2001). Lastly the operating risk of a large power plant (i.e., forced outage) can be catastrophic while the operating risk of energy efficiency is minimal because a large power plant could lose the entire energy supply while energy efficiency could lose only a small portion of its expected energy savings.

New regulation risk. Fossil fuel and nuclear power plants have a risk of facing new regulation that makes them more costly or uneconomic. For example, the nuclear safety regulation is likely to become stricter due to the recent accident at Fukushima in Japan, which could increase the operating or construction cost of nuclear power plants (Ceres 2012). The new and proposed US EPA air regulations have already revealed numerous coal-fired power plants that are likely to become uneconomic and retire. AEP recently

announced the retirement of its coal-fueled power generation totaling nearly 6,000 megawatts.[28] Further there is a high likelihood that some form of carbon regulations will be enacted at the federal level, which will increase the cost of fossil fuel power plants. In contrast, energy efficiency is not subject to any of these expected regulations and laws, and in fact reduces the level of such risks associated with such power plants to the extent of the energy displaced by efficiency.

Water constraint risk. Electric power plants use about 40 percent of all US freshwater withdrawals, especially for cooling the power plants.[29] In recent years we are experiencing more severe droughts in regions like the Southeast and Southwest. In 2008, Tennessee Valley Authority's nuclear reactor Brown Ferry in Alabama had to shut down its operation because of water shortage as well as the restrictions on the temperature of the discharged coolant.[30] The US electric system is facing a significant risk that a large number of power plants relying on water cooling may need to shut down due to water shortage during the summer peak when energy is most needed. This risk increases with global warming. Energy efficiency is not subject to water constraint risk, and can eliminate or reduce this risk to the extent it can avoid the use of conventional power plants.

Accounting for Risk Benefits in Integrated Resource Planning

The Northwest Power and Conservation Council (NWPCC) has been assessing and developing plans for the future of energy resources in the Northwest region every five years. Risk assessment and management has always been one of the most important elements of the NWPCC's Power Plans. Since the first Power Plan, it has analyzed the value of shorter lead times and rapid implementation of energy efficiency and renewable. Starting in the Fifth Power Plan in 2005, the NWPCC extended its risk assessment and incorporated other risks such as electricity risk uncertainty, aluminum price uncertainty, emission control cost uncertainty, and climate change (NWPCC 2005).

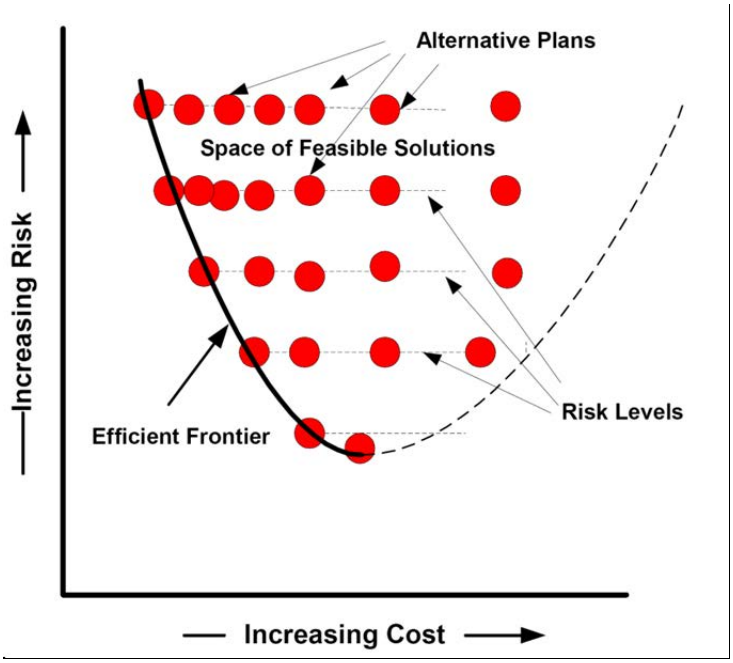
The NWPCC addressed risk by evaluating numerous energy resource portfolios against 750 futures. Risk of one portfolio is measured using a metric called TailVaR90, which is essentially the average value for the worse 10 percent of outcomes. The average value of a portfolio is the most likely cost outcome for the portfolio.

Using these two statistics, the NWPCC develops a chart that compares the risk and the average cost of each portfolio. Figure 4.3 provides an illustrative example of this analysis. The set of points corresponding to all portfolios is called a feasibility space, and the left-most portfolio in the feasibility space is the least-cost portfolio for a given level of risk. The line connecting the least cost portfolios is called the *efficient frontier*, which allows the NWPCC to narrow their focus, typically to a fraction of one percent of these portfolios. NWPCC calls this entire approach to resource planning "risk-constrained, least-cost planning." (NWPCC 2010, pp. 9-5 to 9-6)

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28 http://www.aep.com/newsroom/newsreleases/?id=1697
29 http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf
30 http://www.msnbc.msn.com/id/22804065/ns/weather/t/drought-could-shut-down-nuclear-power-plants/#.T-N_8hdYuM8

Figure 4.3. Efficient Frontier of Feasibility Space



Source: NWPCC 2005, p.6-13.

The NWPCC's Power Plans have historically found that energy efficiency is the most valuable resource for the region in its risk-constrained, least-cost planning. The NWPCC states this point as follows:

> The Council's power plan addresses the risks these uncertainties pose for the region's electricity future and seeks an electrical resource strategy that minimizes the expected cost of, and risks to, the regional power system over the next 20 years. Across multiple scenarios considered in the development of the plan, one conclusion was constant: the most cost-effective and least risky resource for the region is improved efficiency of electricity use … In each of its power plans, the Council has found substantial amounts of conservation to be cheaper and more sustainable than most other types of generation. In this Sixth Power Plan, because of the higher costs of alternative generation sources, rapidly developing technology, and heightened concerns about global climate change, conservation holds an even larger potential for the region … The plan finds enough conservation to be available and cost-effective to meet 85 percent of the region's load growth for the next 20 years. (NWPCC 2010, page 3)

Other Options to Account for Risk Benefits

Options for accounting for risk benefits when using avoided costs for screening include: using a cost adjustment factor, an additional risk hedge value, adjusting the discount rates, and applying a qualitative approach.

Some states account for this benefit of energy efficiency directly in their screening criteria. For example, Vermont applies a 10 percent cost adjustment factor to its energy efficiency program screening to account for the risk benefits. In this process, costs of efficiency measures are decreased by 10 percent.

Oregon also applies a 10 percent cost adjustment factor, which is applied differently into the efficiency program cost screening. The 10 percent adjustment factor is added to the cost of avoided electricity supply to provide advantages for efficiency and conservation measures. This adder represents the various benefits (such as risk mitigation, environmental benefits, and job creation) of energy efficiency in general that are not reflected in the market. The NWPCC advocated the use of the adder and the Oregon PUC has mandated it in its order UM551.

In addition to this type of cost adjustment factor, the Energy Trust of Oregon, and the statewide energy efficiency provider in the state, has applied some risk hedge values developed by the NPWCC to the benefit of energy efficiency. The NPWCC in its Fifth Power Plan conducted an analysis of energy efficiency programs as a hedge against risks associated with high power prices or marked exposure. The Power Plan found that additional conservation measure above the cost-effectiveness threshold lower system cost without adding risk. Specifically, the Council identified $5/MWh of risk avoidance for discretionary programs (i.e., retrofit) and $10/MWh of risk avoidance for lost opportunity programs (i.e., new construction program) to be the optimal additional values above the cost-effectiveness threshold to screen out cost effective DSM measures because such thresholds resulted in the reduction in the total cost and risk for each plan (ETO 2005; Braman 2009).[31] The Energy Trust of Oregon is currently revisiting this issue and planning to use the hedge values developed by two local investor owned utilities, PacifiCorp and Portland General Electric in their most recent IRPs (Gordon 2012).

Recommendations

Efficiency screening practices should properly account for the risk benefits of energy efficiency, either through system modeling or through risk adjustments to the energy efficiency benefits.

[31] Energy Trust of Oregon 2005. Risk Avoidance Value for Energy Efficiency, a summary of Risk Avoidance Value in the 5th Power Plan prepared for the Energy Trust of Oregon staff, November 2005; Personal communication with Matt Braman at the ETO on January 15, 2009

5. Efficiency Screening Methodological Issues

5.1 Discount Rate

The choice of discount rate to use for calculating present values of costs and benefits has significant implications for the cost-effectiveness of energy efficiency programs, because program costs are typically incurred in the first years while program benefits are enjoyed for the life of the energy efficiency measure. This section describes the rationale for which discount rate should be applied when screening energy efficiency programs, for each of the standard cost-effectiveness tests.

The Goal of Discounting

Financial analysis of investments in energy efficiency should account for the fact that an energy efficiency initiative typically consists of an upfront investment in a structure or an end-use piece of equipment, which is expected to provide returns, in the form of energy savings, over a number of years. In order to compare costs and benefits that occur over a number of years, the various cash flows (i.e., the initial investment and the annual savings over the measure life) must be compared in a consistent way, usually as a present value expressed in the dollars of a common reference year.

There is nothing special about energy efficiency in this regard; this challenge exists for analyzing any long-lived investment. Economic and financial theory generally acknowledge that a monetary benefit provided in a given year is more valuable than the same monetary value delivered in a later year.

There are three commonly accepted reasons for this. One is inflation, which almost always causes a dollar in a future year to have less purchasing power than a dollar in an earlier year. The second reason is time preference; economic theory holds that people simply value benefits in the present more than the same benefit in the future, at least with respect to monetary benefits. The farther out in the future an expected benefit, the more such a person would prefer a present benefit. The third reason is risk; future monetary benefits from an investment are rarely guaranteed. The promise of a monetary benefit in a future year has less value than an actual monetary benefit in the current year due to the risk that the future benefit may not occur or may be less than expected.

Accounting for Inflation

This part of the discounting is relatively straightforward, and requires a forecast of inflation rates for the term of the project life. One option is to use an econometric forecast, e.g., from an economic forecasting firm. Another common approach is to use the historical long-term inflation rate or the average inflation rate for a period of recent years. Either way, the assumed inflation rate can be used to turn each year's costs and savings into so-called "real dollars" or "constant dollars." Typically, a project's start year or a base year for a utility's other forecasting efforts would be chosen.

The choice of whether to use a "real" discount rate or a "nominal" discount rate depends upon the inflation assumptions that are used in the annual costs and benefits of the efficiency cost-effectiveness analysis. It is important that consistent assumptions are

used throughout. If the annual costs and benefits include the effects of inflation (i.e., are in nominal dollars), then the discount rate should be in nominal terms. If the annual costs and benefits are net of inflation (i.e., are in real dollars), then the discount rate should be in real terms.

Accounting for the Time Value of Money

This is the time preference issue mentioned above. Suppose that an investor is offered a guaranteed return for investing funds. What would that return have to be to attract investments? Certainly it would have to cover the anticipated rate of inflation, but that will usually not be sufficient. Most people would rather have something today than the same thing in a year. Some extra return will be required.

This extra return is usually called a "risk free discount rate," because it assumes there is no risk associated with future benefits. (Risk will be discussed next.) In principle, such a risk free discount rate measures how much the decision maker on a given project values money this year versus next year. Note that the time value of money will be very different for different decision makers. This point will also be discussed below.

Accounting for Risk

Adjusting for risk is the most difficult part of discounting. Again, the risk adjustment depends on the perspective of the decision maker. Perhaps the simplest case is that where the decision maker is a utility's management. The source of an investor-owned utility's investment funds is a combination of bond investors and equity investors, possibly including some preferred stockholders. Utility investments are typically discounted at the weighted average cost of capital (WACC), i.e., the weighted average yield of the company's bonds and preferred stock along with its allowed return on equity. When applying WACC for discounting, it is important to keep in mind that these values come from markets that factor in all three issues: estimated inflation rates, time value of money, and perceived riskiness of investing in the utility.

Application to the Cost Benefit Tests

While it is important to understand the economic theory underlying the application of discount rates, it is also important to recognize that the choice of discount rate is ultimately a policy call by the utility regulators. The choice of discount rates should be informed by considering which party is being affected and what is the time value of money for that party, but it should also be informed by considering how much weight the regulators want to give to the future costs and benefits associated with energy efficiency programs (especially benefits, because these occur well into the future).

Discount Rate for the Societal Cost Test

The Societal Test, as its name implies, should use a discount rate based on society's preferences. Compared to individuals and firms, society should have a broader tolerance for receiving benefits in the future, and also be better able to access funds at a lower borrowing cost. In this case, the discount rate should be relatively low.

Energy efficiency investments for special groups of customers, particularly low income and at-risk populations could also be viewed with a societal discount rate for several reasons. These customers are generally receiving some degree of support from society at large, so the investment can appropriately be viewed in a societal context. It is society

investing in society, and should be analyzed using a discount rate appropriate to society as a whole.

The social discount rate should reflect the benefit to society as a whole, and should also take into account both the reduced risk of energy efficiency investments, as well as society's reduced time preference for a societal payback. This social discount rate is typically the lowest discount rate that reflects increased value in future savings. The Societal Cost test also includes environmental externality costs, which should arguably be discounted at a very low discount rate, if at all.

Discount Rate for the PAC and TRC Tests

The purpose of the TRC and PAC tests is to compare energy efficiency investments with the decision-maker's other investment options. Historically, the discounting challenge was relatively straightforward for these tests: the primary decision maker was the utility, and its WACC was used. (See, for example, NAPEE 2008, p.4-8.) This was seen as treating energy efficiency investments comparable to investments in supply-side resources, assuming that consumers would be paying the same cost of capital on any utility investment.

More recently, it has become clear that there are significant differences in the financial risks associated with supply- and demand-side resource investments. Energy efficiency investments are typically funded by a system benefit charge or a balancing account in utility rates. In either case, there is little risk to the utility associated with these investments because they are passed directly on to customers independent of utility operations, utility performance or other risk factors. Consequently, an energy efficiency investment is less risky than a supply-side investment on a purely financial basis, in addition to being less risky with regard to planning, construction and operation. Therefore, a lower discount rate than the WACC (i.e., a risk-adjusted discount rate) should be used in applying the PAC test or the TRC test.

This lower risk also exists in those instances where a third party administers the energy efficiency programs (e.g., Delaware, Hawaii, Maine, New York, Oregon, Vermont). In these cases, the utility WACC would clearly not be an appropriate discount rate, because that rate does not represent the time value of money to the third-party administrator. The discount rate for third-party administrator programs should be low for the same reason that discount rates for utility-administered programs funded by system benefits charges should be low: there is very little financial risk associated with the funding source, since there is no long-term financing involved.

One option for developing a lower, risk-adjusted discount rate is to remove some, or all, of the risk premium and time preference embedded in the utility's WACC. This could be achieved by comparing the utility's financial risk profile to that of other companies with lower risks or with other market indicators of low-risk investment rates.

Another option is to use a more generic, market indicator of a low-risk investment. For example the interest rates on US Treasury Bills are widely regarded as a good indication of low-risk investments. We are aware of at least three states that use the interest rates on US Treasury bills as a low-risk discount rate for assessing the cost-effectiveness of energy efficiency programs (ODC 2012; MADPU 2010; Efficiency ME 2009).

We recommend that states use the interest rates on long-term (e.g., 10-year) US Treasury Bills as the discount rate for the PAC and the TRC tests. This indicator is

widely accepted as representing low-risk investments, is straightforward, is transparent and is readily available. It also means that different utilities in a single state will use the same discount rates across the state, as it eliminates the need to develop utility-specific risk-adjusted discount rates.

Discount Rate for the Participant Test

The Participant Test considers whether an energy efficiency investment is cost effective from the program participant's point of view. This test should be used principally to set an incentive level that would be sufficient to make consumers implement efficiency measures. A consumer's discount rate should be used to discount the costs and benefits in this test.

However, choosing a consumer's discount rate is administratively and theoretically complicated as different customers have different discount rates. There is considerable uncertainty over what the reference point should be, as some consumers have home equity credit available, but some only have access to credit card type debt with a much higher cost.

For residential customers, energy efficiency programs are generally of lower risk than almost any investment the household can make, but immediate needs tend to put pressure on household capital, making borrowing rates also a factor. These points suggest that home equity loan or home mortgage rates might be appropriate, especially in new construction and remodeling programs, with higher credit card rates being more applicable to participants in low income programs.

For commercial and industrial customers, a reasonable cost of borrowing proxy could be local commercial lending rates or a prime rate plus an adder for non-prime businesses, e.g., a prime rate plus three percent. For large entities with internal capital rationing, it would be appropriate to use the firm's internal rate of return hurdle rate or its internal payback requirement.

Discount Rate for the RIM Test

Discounting is a side issue for the RIM test because the key goal of this test is to indicate the effect of energy efficiency programs on retail rates. The utility WACC may be appropriate for this purpose because this is the borrowing cost that ultimately determines utility rates.

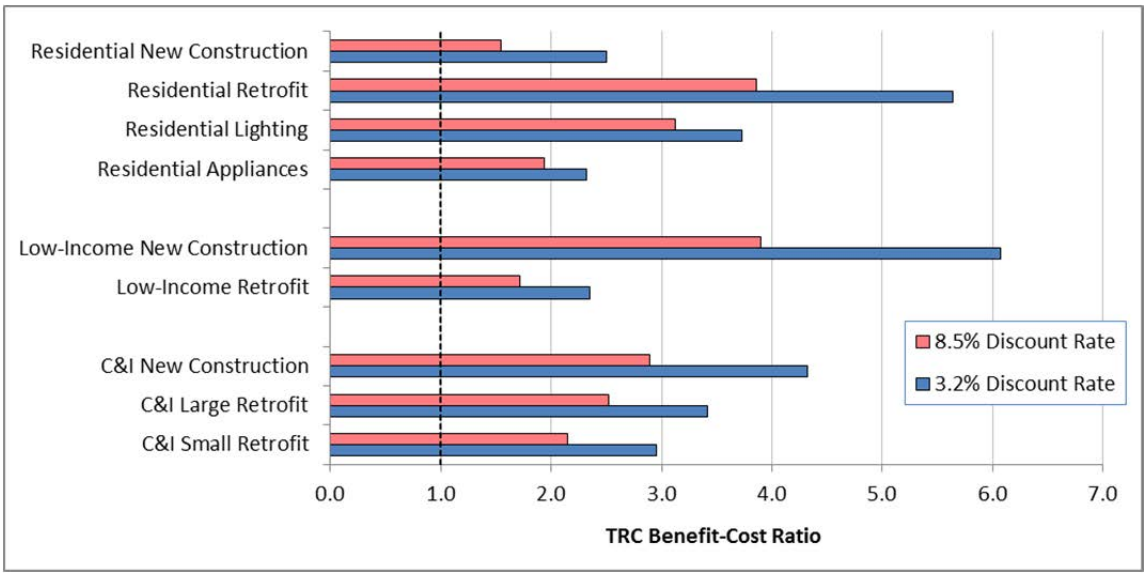
Illustrative Example

Figure 5.1 summarizes the impact on program cost-effectiveness when using different discount rates. The blue bars present program cost-effectiveness using a nominal discount rate of 3.2 percent, which is our example utility's actual discount rate for energy efficiency screening, based on 10-year US Treasury Bills. The red bars represent program cost-effectiveness using a high discount rate of 8.5 percent, roughly equal to a utility's after-tax WACC.

This figure illustrates that a higher discount rate will reduce program cost-effectiveness, especially for programs with longer measure lives. As discussed above, the new construction programs typically have longer measure lives than other energy efficiency programs, and so discounting the savings from such programs at a higher rate will have

a greater negative impact on program cost-effectiveness than for measures with shorter lives.

Figure 5.1. Cost-Effectiveness with Different Discount Rates



Source: The 2012 energy efficiency plan for our example utility, with modified assumptions as noted.

5.2 Study Period

Energy efficiency measures produce savings over the full course of their useful lives. Depending on the measure, the useful life can be as long as 20 years or more. Energy efficiency screening practices should include the savings available over the full life of the energy efficiency measure. This requires using a study period that is long enough to capture savings over their full useful lives. Shorter study periods will skew the cost-effectiveness results against energy efficiency.

Ideally, a study period of at least 25 years should be used to evaluate the cost-effectiveness of energy efficiency resources, given that some energy efficiency measures affect existing and new buildings and thus can last at least 30 years. After 30 years the effect of discounting significantly reduces energy efficiency benefits, even in cases where relatively low discount rates are used, and thus there is little advantage to using a study period beyond 25 years.

If, for some reason, program administrators do not have the inputs or the models to account for 25 years, then other methodologies should be used to capture the benefits in the years that are not included in the study period. For example, “end effects” calculations can be made to adjust the benefits that are derived using a shortened study period.

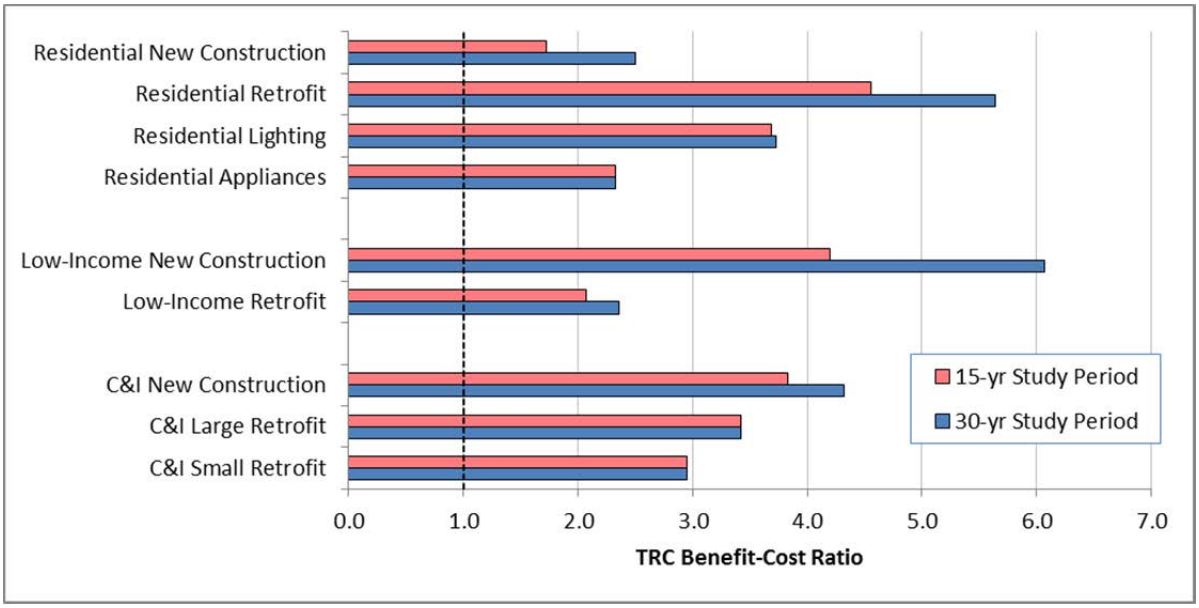
If there is reasonable data regarding the degradation of measure performance, or about early failure of energy efficiency measures, then these factors should be accounted for separately in the program screening process by adjusting the savings or the lifetime assumptions for the measure.

Illustrative Example

Figure 5.1 below provides an example of program cost-effectiveness using two different study periods. The blue bars represent the results for the base case, where the study period is 30 years. This is the actual study period used by our example New England utility. (However, the measure lives used in this example only extend to 25 years, so the effective study period is 25 years.) The red bars represent the resulting benefit-cost ratios if the study period is limited to 15 years.

The low-income new construction program's cost-effectiveness is most affected by this adjustment, moving from a benefit-cost ratio greater than 6.0, to a benefit cost ratio closer to 4.0. The majority of savings in this program, and in the residential and C&I new construction programs, result from measures with lives between 19 and 25 years. Ignoring the savings that accrue in the later years of a measure's life negatively impacts the program's cost-effectiveness, especially for new construction and retrofit programs.

Figure 5.2. Program Cost-Effectiveness Using Different Study Periods



Source: The 2012 energy efficiency plan for our example utility, with modified assumptions.

5.3 Screening Level

Cost-effectiveness tests can be applied at different levels in the energy efficiency portfolio of activities. In general, there are three levels to evaluate cost-effectiveness when planning energy efficiency programs: the "measure" level, the "program" level, and the "portfolio" level. Evaluating cost-effectiveness at the measure level means that each individual component (i.e., measure, equipment, or other action) of an efficiency program must be cost-effective. Screening at the measure level is the most restrictive application of the cost-effectiveness tests, and can create a barrier to greater savings levels. (NAPEE 2008, pp.3-9, 3-10).

Evaluation at the program level means that collectively the measures under a program must be cost-effective, but some measures can be uneconomical if there are other measures that more than make up for them. While non-cost-effective measures may

reduce a program's overall cost-effectiveness, the program administrator may be able to achieve greater overall savings through the combination of measures. Additionally, a measure may not be cost-effective on its own, but may become cost-effective when combined with other efforts.[32] (NAPEE 2008, pp.3-9, 3-10).

Evaluating cost-effectiveness at the portfolio level means that all of the programs taken together must be cost-effective, but individual programs can be positive or negative. This is the most flexible application of cost-effectiveness testing, as program administrators have the ability to experiment with different strategies and technologies that may not be immediately cost-effective or require further testing, such as pilot programs, market transformation programs, or emerging technologies. (NAPEE 2008, pp. 3-9, 3-10).

A recent ACEEE report surveyed states on the level at which program administrators screen for cost-effectiveness. The most prevalent responses to the question of "what level" the benefit-cost tests are applied were: the "portfolio" level (30 states, 70%) and the "program" level (30 states, 70%), although nearly half of those states noted that they had some expectations at the program level (e.g., low-income programs, pilot programs, etc.) where the benefit-cost test was not required or waivers were granted. Thirteen states (30%) applied their benefit-cost test requirements at the measure level, and a majority of those states provide exceptions for things like low-income programs and/or situations where measures can be bundled together into a cost-effective package of measures (e.g., certain "whole house" type programs). (ACEEE 2012, p.31).

Finally, it is important to note that in addition to screening energy efficiency programs for planning purposes, it is also possible to screen energy efficiency programs at the point of implementation, i.e., "field screening." Field screening can be applied during the process of auditing homes and businesses for retrofits, and may be important to provide customers with assurance that certain efficiency measures will be appropriate to the unique conditions of their building. The best test to use in field screening is the Participant Cost test, because this test indicates which efficiency measures the customer should adopt and what the customer benefits of those measures will be.

The TRC test should not be used for field screening energy efficiency measures, for several reasons. First, it is especially difficult to properly account for other program impacts at the measure level for each building; and without the OPIs the TRC test will be skewed against the energy efficiency measures. Second, measure level field screening does not account for the interactions between measures, particularly the benefits that one measure might have in encouraging customers to adopt other measures. Third, experience has demonstrated that measure-level field screening is overly restrictive, can exclude measures that are cost-effective to customers, increases the transaction costs of contractors and customers, creates lost opportunities, and hinders the goal of achieving comprehensive, whole-house efficiency savings.

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[32] Summing up the benefits of multiple measures at the program level may require some adjustment for what are known as "interactive effects" between related measures. Interactive effects occur when multiple measures installed together affect each other's impacts. When measures affect the same end use, their combined effect when implemented together may be less than (or more than) the sum of each measure's individually estimated impact. (ACEEE 2008, p.3-10).

Recommendation

Energy efficiency programs should not be screened at the measure level, because this is overly restrictive and ignores the important interactions between measures, especially the fact that some measures that might not be cost-effective on their own but might nonetheless have important benefits in terms of encouraging customers to participate in programs or adopt other measures.

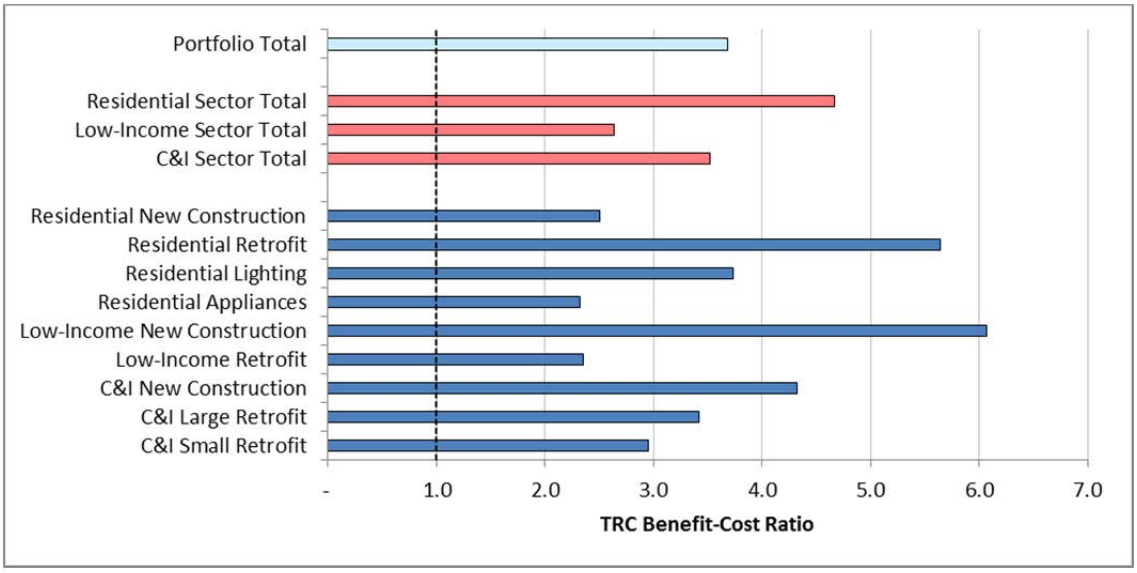
As noted above, we recommend that energy efficiency programs be screened at the program level using the TRC test or the Societal Cost test, and that the entire portfolio of programs be screened using the PAC test. This allows regulators to balance the goal of achieving key public policy objectives (through the use of the TRC test or the Societal test), with the goal of ensuring a net reduction in costs to customers (through the PAC test).

When energy efficiency contractors screen efficiency measures in the field, the Participant Cost test should be used, to provide the customer with relevant information regarding which measures to adopt. The TRC test should not be used for field screening energy efficiency measures.

Illustrative Example

Figure 5.3 presents cost-effectiveness at the program level, sector level, and portfolio level for our example New England utility. While each screening level indicates that the energy efficiency activities are robustly cost-effective, the figure demonstrates that programs or sectors with lower cost-effectiveness can be absorbed by programs or sectors that are more cost-effective. For example, the low-income sector has a benefit-cost ratio of about 2.6, while the residential sector has a benefit-cost ratio of about 4.7, and the C&I sector has a benefit-cost ratio of about 3.5. On average, at the portfolio level of screening, the sectors produce a benefit-cost ratio of about 3.7.

Figure 5.3. Cost-Effectiveness at Different Screening Levels



Source: The 2012 energy efficiency plan for our example utility, with modified assumptions.

6. Summary of Recommendations

Here we provide a summary of the recommendations made above. We recognize that most states have an established set of practices that have been developed with considerable effort and stakeholder input over time, and that some states might have good reasons for adopting an approach that is different than what makes sense for other states. Nonetheless, we urge regulators and other stakeholders to consider these recommendations as opportunities to improve upon current practices where appropriate.

Tests for Screening Energy Efficiency Programs

We recommend that the Societal Cost test be used to screen energy efficiency programs. If a state chooses to use the Societal Cost test, the test should account for utility- participant- and societal-perspective OPIs to the greatest extent possible.

We recommend that all states that choose not to rely on the Societal Cost test use the TRC test to screen energy efficiency programs. If a state chooses the TRC test, the test should account for OPIs to the greatest extent possible.

If regulators are unwilling to account for OPIs, the TRC test should not be used for screening energy efficiency programs. In the absence of participant OPIs, the PAC test is the best test to use in screening energy efficiency.

We recommend that the PAC test be applied to the entire portfolio of efficiency programs, to ensure that the entire portfolio of programs will result in a net reduction in revenue requirements and a net reduction in costs to utility customers.

The RIM test should not be used in screening energy efficiency programs for cost-effectiveness. Instead, efficiency program administrators should take steps to (a) analyze rate and bill impacts in a fashion that provides much more information than what is available from the RIM test; (b) design programs in a way that mitigates rate impacts without sacrificing energy efficiency savings; and (c) work to increase the number of program participants so as to mitigate the equity concerns between participants and non-participants.

Best Practices

Regardless of which test is used, it is crucial that states apply the cost-effectiveness tests appropriately. Accordingly, we recommend the following best practices designed to ensure that tests are implemented in a way that achieves the underlying objective of the test, is internally consistent, accounts for the full value of energy efficiency resources, and uses appropriate planning methodologies and assumptions. These practices include the following.

Calculation of Avoided Costs

Avoided energy and capacity costs should be based on long-term forecasts that properly capture the energy and capacity impacts of energy efficiency resources, account for the structure of the market in which the relevant utility operates, and captures differences in hourly and seasonal peak periods.

Efficiency program screening should account for avoided transmission and distribution costs, distinguishing between those costs that can be deferred or avoided through energy efficiency and those that cannot. Avoided transmission costs should be based on forecasts of future transmission activity, as opposed to historical activity, especially in regions of the country that anticipate significant increases in transmission investments.

The avoided costs of compliance with environmental regulations should be explicitly accounted for in the Societal Cost test, the TRC test and the PAC test. This should include costs associated with compliance with current and anticipated environmental regulations from the US Environmental Protection Agency. This should also include costs associated with compliance with current and anticipated federal, regional and state initiatives to curtail the emissions of greenhouse gases.

Efficiency program screening should also account for the price suppression effects, in those regions of the country that participate in competitive wholesale electric markets. Even a small reduction in a market clearing price can result in significant cost reductions across the entire market.

Efficiency program screening should also properly account for electricity transmission and distribution losses. The estimate of losses should be based on marginal losses.

Capturing All the Impacts of Energy Efficiency

Each state that uses the TRC test or the Societal test should (a) identify all of the OPIs that are relevant for the energy efficiency programs offered in the state; (b) develop quantitative estimates for all OPIs that can be readily quantified; (c) develop some methodology for addressing those OPIs that are not quantified; and (d) pay particular attention to the OPIs that are unique to low-income customers. States should hire independent contractors to develop the best state-specific OPI estimates possible.

Efficiency screening practices should properly account for free-riders, spillover effects and market transformation. These effects should be estimated and accounted for in a manner that is timely, consistent and comprehensive. Programs that are expected to have significant market transformation impacts should be provided with greater flexibility in the screening process.

Efficiency screening practices should properly account for the risk benefits of energy efficiency, either through system modeling or through risk adjustments to the energy efficiency benefits.

Efficiency Screening Methodological Issues

The discount rates that are applied to the TRC test and the PAC test should reflect the fact that energy efficiency investments pose lower risks to the utilities relative to supply-side investments. We recommend the use of a generic market indicator of a low-risk investment such as the interest rate on long-term US Treasury Bills.

Energy efficiency screening practices should account for the savings available over the full life of the energy efficiency measure.

Energy efficiency programs should not be screened at the measure level. We recommend that energy efficiency programs be screened at the program level using the

TRC test or the Societal Cost test, and that the entire portfolio of programs be screened using the PAC test.

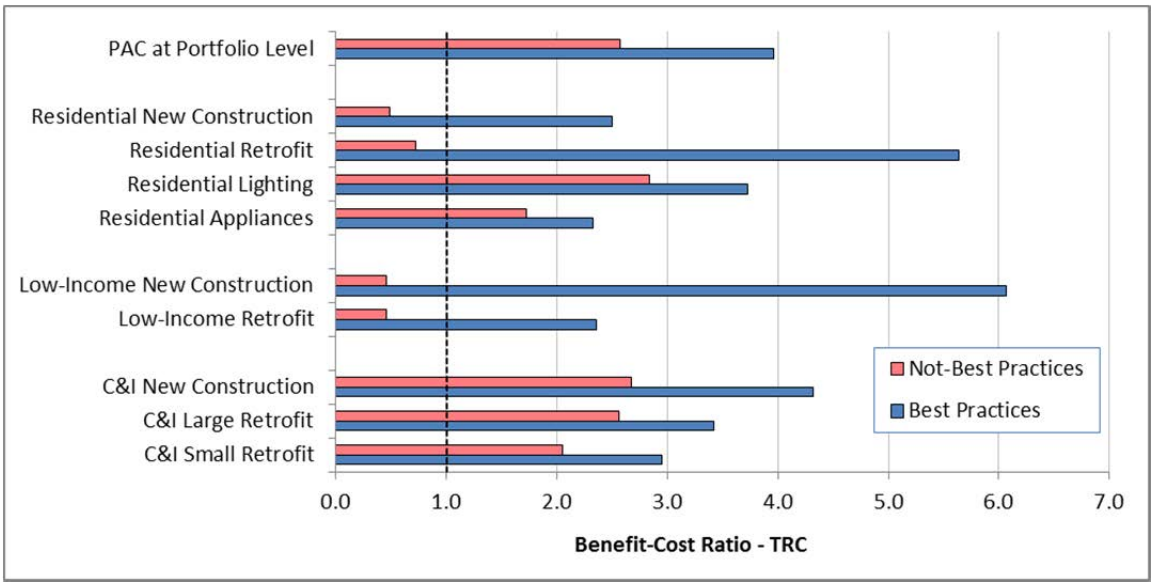
When energy efficiency measures that are screened in the field, they should be screened using the Participant's Cost test, to provide the customer with relevant information regarding which measures to adopt. The TRC test should not be used for field screening energy efficiency measures.

Illustrative Example

Figure 6.1 provides an illustration of how different methodologies and assumptions can affect the cost-effectiveness of energy efficiency programs. We return to the screening results for the programs that we have presented above, using the benefit-cost ratios of the TRC test.

In Figure 6.1 the best practices case (blue bars) includes all the avoided costs described above in Section 3 (except for the high environmental compliance costs), the other program impacts that are used in Massachusetts as described in Section 4.2, a risk-adjusted discount rate of 3.2 percent, and a study period of 30 years to capture all or most of the efficiency measure lives. In contrast, the not-best practices case (red bars) includes all the same assumptions except that an 8.5 percent discount rate is applied, measure lives are capped at 15 years, and all other program impacts are excluded.

Figure 6.1. Cost-Effectiveness Under Best Practices and Not-Best Practices



Source: The 2012 energy efficiency plan for our example utility, with modified assumptions.

As the figure illustrates, cost-effectiveness is reduced significantly when poor screening practices are applied. The low-income programs are most affected by poor efficiency practices primarily because the OPIs are excluded. The residential new construction and retrofit programs are also heavily affected, primarily because the other fuel savings are not accounted for. While this illustration may seem like an extreme example, there are states that use the TRC test without including OPIs, states that use a discount rate based on WACC, and states that limit the study period to less than 30 years.

Checklist of Best Practices

Here we present a checklist for regulators and other stakeholders to use to determine how comprehensively they are accounting for the value of energy efficiency resources.

Do the energy efficiency screening policies and practices in your state:

- Use a screening test that includes the desired scope?
- Apply the screening test in a way that is internally consistent?
- Include the utility-perspective other program impacts in the PAC test?
- Include the participant-perspective other program impacts in the TRC test?
- Include the societal-perspective other program impacts in the societal cost test?
- Properly account for avoided energy costs?
- Properly account for avoided capacity costs?
- Properly account for avoided T&D costs?
- Properly account for price suppression effects?
- Properly account for avoided environmental compliance costs from current and anticipated future regulations?
- Properly account for marginal line losses?
- Include a societal discount rate for the societal cost test?
- Include a low-risk discount rate for the PAC and TRC tests?
- Properly account for spillover effects, as well as free-riders?
- Screen market transformation programs in a way that accounts for their spillover effects?
- Include considerations for the risk benefits of energy efficiency?
- Include a study period that is as long as the longest lived energy efficiency measure?
- Screen programs at the program level?
- Use the Participant's Cost test for field-level screening?

If you answered no to any of these questions, then your state may be understating the value of energy efficiency, and customers in your state may be paying more than necessary for electricity and gas.

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Appendix A – Illustrative Example and Avoided Costs

Introduction

Throughout this paper we have referenced an actual New England utility's energy efficiency programs and screening results, in order to demonstrate the implications of the different screening practices. We have relied on the same utility in each of the examples discussed in the body of the report, and have based each example on the utility's actual efficiency programs, including its projected (or actual where pertinent) budget, savings, benefits, and other assumptions.

This Appendix provides a more complete background on that utility's efficiency programs, as well as the avoided cost assumptions included in its cost-effectiveness analysis. Each of these topics is discussed in more detail below.

Program Descriptions

The report focuses on nine of the utility's programs that are common to efficiency programs in many states. This New England utility actually administers more programs than those discussed in the report, such as a behavioral-based program. By restricting the analysis to these nine programs, our intention is to focus on a core set of programs that are typically offered in states, rather than provide a comprehensive analysis of program portfolios. The identified programs and a brief description of each program's purpose are provided below.

- Residential Retrofit: the purpose of this program is to provide residential customers with energy efficiency recommendations that enable them to identify and initiate the process of installing cost-effective energy efficiency upgrades. The program provides information through outreach mechanisms, incentives, and multiple financing options.
- Residential New Construction: the purpose of this program is to capture lost opportunities, encourage the construction of energy-efficient homes, and drive the market to one in which new home are moving towards net-zero energy.
- Residential Appliances: the purpose of this program is to raise consumer awareness of the benefits of energy-efficient ENERGY STAR-qualified consumer products, encourage consumers to purchase qualified appliances and consumer electronics, promote higher efficiency standards for products, and to help customers reduce energy bills by replacing or recycling inefficient products.
- Residential Lighting: the purpose of this program is to increase consumer awareness of the importance and benefits of purchasing ENERGY STAR-qualified lighting products and expand the availability, consumer acceptance, and use of high-quality energy-efficient lighting technologies and controls.
- Low-Income Retrofit: the purpose of this program is to deliver energy efficient products and services directly to the homes of income eligible customers to help them lower their energy bills to achieve deeper and broader energy savings.

- Low-Income New Construction: the purpose of this program is to capture lost opportunities, encourage the construction of energy-efficient homes, and drive the market to one in which new homes are moving towards net-zero energy.
- Small Commercial and Industrial (C&I) Retrofit: this program focuses on comprehensive gas and electric energy efficiency opportunities associated with mechanical, electrical, and thermal systems in existing commercial, industrial, governmental and institutional buildings. It provides technical assistance and incentives to encourage retrofitting of equipment that continues to function, but is outdated and inefficient, and can be replaced with a premium efficient product.
- Large C&I Retrofit: this program focuses on comprehensive gas and electric energy efficiency opportunities associated with mechanical, electrical, and thermal systems in existing commercial, industrial, governmental and institutional buildings. It provides technical assistance and incentives to encourage retrofitting of equipment that continues to function, but is outdated and inefficient, and can be replaced with a premium efficient product.
- C&I New Construction: this program is designed to optimize the efficiency of equipment, building design and systems in new construction and renovation of commercial, industrial, institutional and government facilities. The focus is on offering a comprehensive set of electric and gas efficiency options that are specific to the needs of each unique facility. The program also targets the brief window of opportunity to install premium grade replacements when equipment fails or is near the end of its useful life.

Avoided Costs Assumptions

Introduction

The avoided cost assumptions used by the New England utility are based on Synapse's Avoided Energy Supply Costs in New England: 2011 Report (AESC Study). The AESC Study provides projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers throughout New England (Synapse 2011).

The AESC Study provides estimates of avoided costs for program administrators throughout New England to support their internal decision-making and regulatory filings for energy efficiency program cost-effectiveness analyses. Ultimately, the relevant regulatory agencies in each state specify the categories of avoided costs that program administrators in their states are expected to use in their regulatory filings, and approve the values used for each category of avoided cost.

Avoided Energy Costs

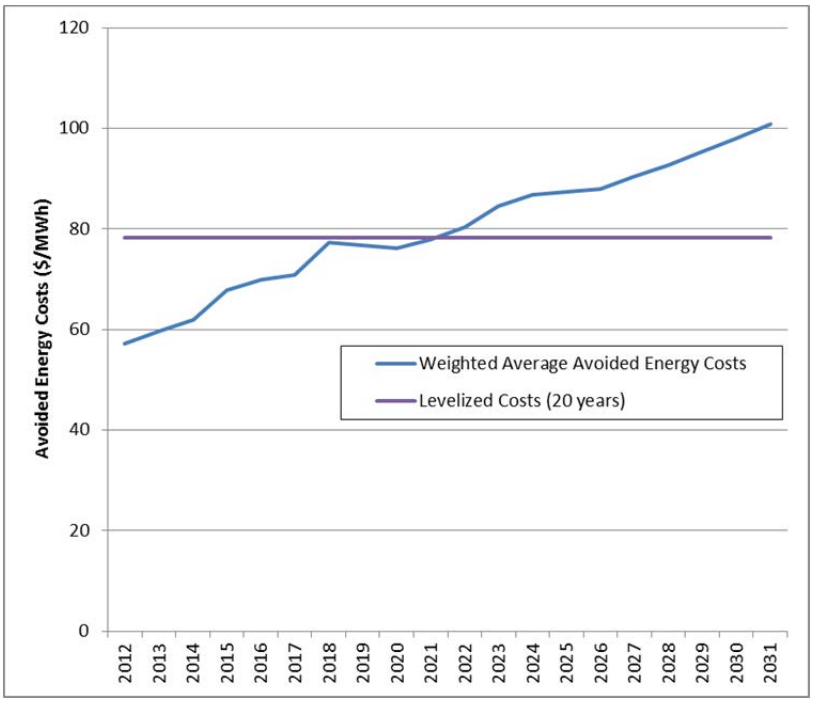
Electric energy costs are avoided by efficiency programs due to a reduction in the annual quantity of electric energy that utilities and competitive suppliers are obligated to acquire for their customers. Therefore, avoided electric energy costs are an estimate of the value of a reduction in annual electric energy use by retail customers. In New England, the competitive, wholesale market determines the value of avoided energy costs.

In general, the fundamental assumption of behavior in competitive energy markets is that generators will bid their marginal cost of producing electric energy into the energy market. Their marginal cost is based on the unit's opportunity cost of fuel, variable operating and maintenance costs, and opportunity cost of tradable permits for air emissions (Synapse 2011, p.2-21).

In New England, natural gas fired units are the dominant marginal source of generation, i.e., they set the market price in most hours of most years (Synapse 2011, p.1-10). Annual gas use for electric generation in New England has been forecasted to grow by an average of 0.6% between 2011 and 2025, and by an average of 1.3% thereafter (Synapse 2011, p.3-2). Therefore, when combined with additional assumptions about the New England market and natural gas prices, the AESC study projects that avoided energy costs will increase over time.

The annual avoided energy costs developed by the AESC Study, as well as a single 20-year levelized avoided cost, are summarized in Figure A.1 (see Synapse 2011, App. B). As presented in Figure A.1, avoided energy costs start at approximately $54 per MWh in 2012, and increase to approximately $100 per MWh by 2031, with a levelized cost of $78 per MWh. The avoided energy costs are weighted by the four energy costing periods: summer on-peak, summer off-peak, winter on-peak, and summer off-peak (Synapse 2011, p.2-1).

Figure A.1. Avoided Energy Costs



Avoided Capacity Costs

Similar to energy costs, capacity costs are avoided by efficiency programs due to a reduction in the annual quantity of electric capacity that utilities and competitive suppliers are obligated to acquire to ensure an adequate quantity of generation during hours of

peak demand. In New England, utilities and competitive suppliers acquire capacity from the Forward Capacity Market (FCM) (Synapse 2011, p.1-3).

Under the FCM, ISO-NE acquires sufficient capacity to satisfy the installed capacity requirement it has set for a given power year through a forward capacity auction (FCA) for that power year. The price for capacity in that power year is based upon the results of the FCA for that year. The FCA for each power year is conducted roughly three years in advance of the start of that year. (Synapse 2011, pp.2-4, 2-5).

The 2011 AESC Study's projection of capacity prices is based on the fourth FCA (FCA 4) observed supply curve and extrapolations of that curve. This was considered the best approach for the AESC Study based on the information available and a fair representation of the impacts of projected capacity retirements and additions. (Synapse 2011, p.6-1).

Under the 2011 FCM rules, each FCA will have a ceiling price and a floor price through the sixth FCA (FCA 6). The status of floor prices for auctions after FCA 6 is at this time uncertain. For the first four FCAs, the floors averaged $3.50/kW-month. Each of these auctions concluded when it reached the floor price (Synapse 2011, pp.2-4, 2-5).

Figure A.2. Avoided Capacity Costs

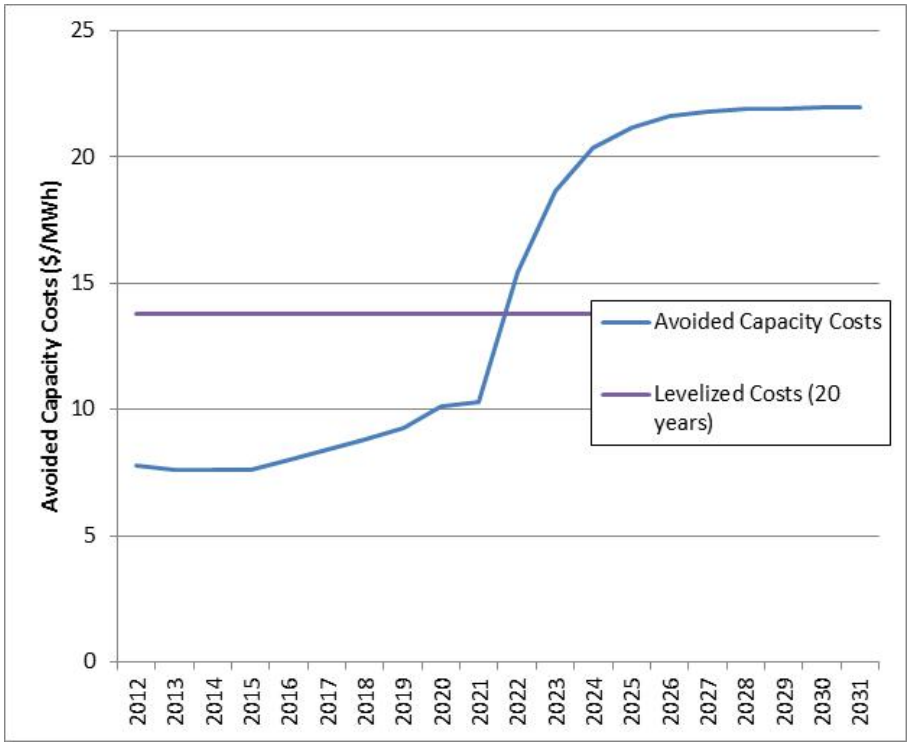


Figure A.2 presents the annual avoided capacity costs developed by the AESC Study, as well as the 20 year levelized avoided costs (see Synapse 2011, App. B).[33] As

[33] The avoided capacity costs in $/kW-month were converted to $/MWh in order to make them comparable with the other avoided costs presented in this appendix.

indicated in Figure A.2, avoided capacity costs start at approximately $7 per MWh in 2012, and increase to approximately $22 per MWh in 2031, with a levelized cost of about $14 per MWh.

The costs in the first few years are based on the FCA floor prices. The costs then gradually increase as the supply of capacity becomes tighter. Finally, the costs increase to the capacity costs associated with a peaking unit in the years 2024 - 2026 when new capacity is needed on the system.

(Note that we made some minor modifications to the avoided capacity costs shown in Figure A.2 for the years 2016 through 2019. We removed the floor prices in the FCM for these years because they are now outdated and removing them provides a clearer, more generally applicable indication of likely changes in capacity market prices over time. Specifically, we increased the 2015 avoided capacity cost by five percent each year for 2016 through 2019, instead of using the projected avoided costs for those years. This modification was not applied in the illustrative examples throughout the report; it was only applied to simplify this chart.)

Avoided Transmission and Distribution Costs

Local transmission and distribution (T&D) infrastructure costs are avoided by efficiency programs due to a reduction in the timing and/or size of new T&D projects that have to be built, resulting from the reduction in electric energy that has to be delivered (Synapse 2011, p.1-4). The basic method in most avoided-T&D estimates is to divide actual or expected investment by actual or expected load growth.

Not all types of future T&D investments will be deferrable or avoidable as a result of reduced load growth from energy efficiency. A significant portion of T&D investments might be needed regardless of load growth as a result of deterioration of T&D equipment, on-going maintenance and upgrades, or other factors.

Each utility in New England uses utility-specific estimates of avoided T&D, although a consistent method is utilized by each utility. In New England, avoided transmission estimates range from $1.25 per kW-year (or $0.26 per MWh) to $20.30 per kW-year (or $4.21 per MWh). Avoided distribution estimates range from $29.74 per kW-year (or $6.17 per MWh) to $109.25 per kW-year (or $22.68 per MWh) (Synapse 2011, p.6-70).

The methods used by each utility to forecast avoided T&D costs are based on the relationship between historic T&D costs and historic loads. The future T&D costs in New England, especially transmission costs, are expected to be significantly higher than those in recent years. Therefore, it is quite likely that the forecast of avoided T&D costs listed above turn out to be significantly lower than the actual avoided T&D costs.

Price Suppression Effects

In regions of the country with organized wholesale energy and capacity markets, energy efficiency programs can reduce demand, which then can lead to reduced wholesale energy and capacity prices. Because wholesale energy and capacity markets provide a single clearing price to all wholesale customers purchasing power in the relevant time period, the reductions in wholesale energy and capacity clearing prices are experienced by all customers of those markets. Thus, even a small reduction in a market clearing price can result in significant cost reductions across the entire market. This effect is

referred to as the market price suppression effect. (Synapse 2011, pp. 1-17-18, 2-49-50, 6-30-37.)

The market price suppression effect is expected to primarily occur over the short-term period after the energy efficiency measure is implemented. Over the long-term, when new physical capacity is needed to maintain the reliability of the system, the capacity price is likely to be set by the long-run marginal cost of new capacity and will hence be less sensitive to reductions in demand. Even then, capacity prices could be lower with energy efficiency than without because the long-run capacity supply curve is likely to have a lower slope. One of the challenges in estimating the impact of energy efficiency on market prices is distinguishing between the short- and long-term market price impacts (Synapse 2011, pp. 1-17-18, 2-49-50, 6-30-37).

In determining the price suppression effect in New England, the AESC Study followed a two-step approach. The first step is to estimate the impact a reduction in load will have upon the market price, assuming no other changes occur. The second step is to estimate the pace at which suppliers participating in that market will respond to that reduction with actions that offset the reduction and eventually cause the market price to move toward the level it would have been under the Reference Case. In other words, responses taken by market participants will eventually offset, or dissipate, the price suppression impact.

Figures A.3 and A.4 summarize both the annual energy and capacity price suppression effects in New England from the AESC Study. The AESC Study projects an 11 year phase-out for energy-related price suppression effects and a 12 year phase-out for capacity-related price suppression effects (Synapse 2011, p.6-2). This phase out is depicted in Figures A.3 and A.4 by the tail at zero that begins in 2025 for energy price suppression and 2027 for capacity price suppression. The longer projected dissipation of the capacity price suppression effect is based upon a detailed analysis of the various factors that tend to offset the reduction in capacity prices. Those factors include: (1) timing of new capacity additions, (2) timing of retirements of existing capacity, (3) elasticity of customer demand, and (4) the portion of capacity that LSEs acquire from the FCM. (Synapse 2011, p.6-2). Also note that the impact on capacity prices is not experienced until 2016; three years after efficiency measures have been installed.

Figure A.3. Energy Price Suppression

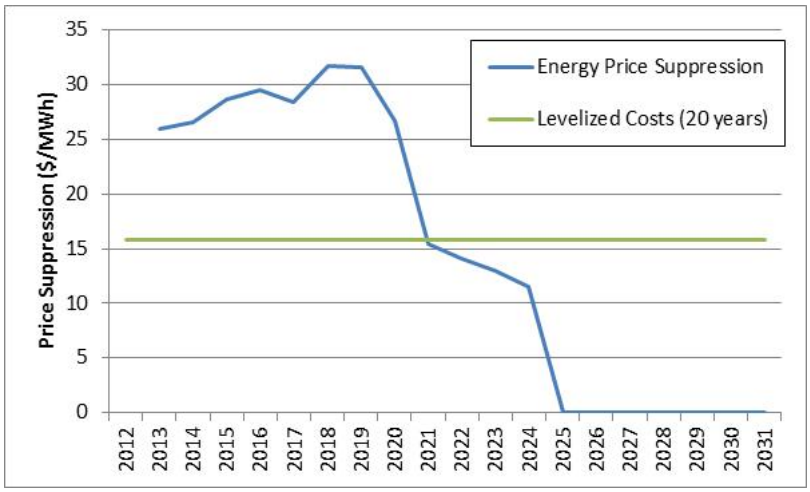
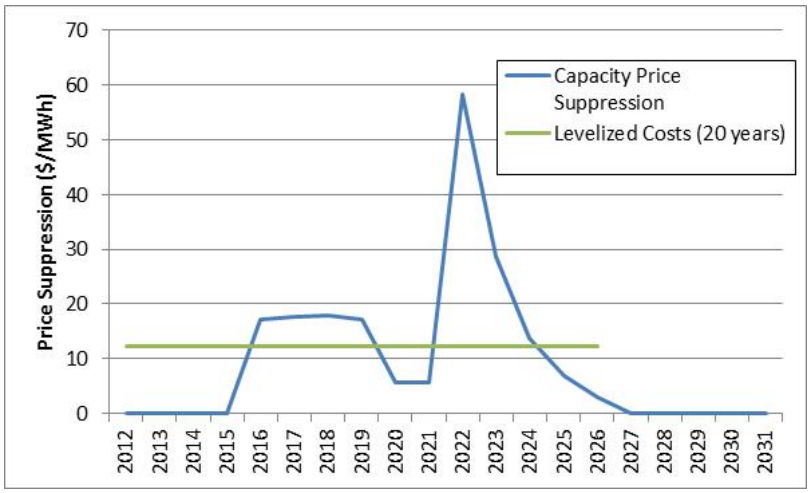


Figure A.4. Capacity Price Suppression



Avoided Environmental Compliance Costs

The AESC Study estimates the cost of complying with regulations governing the emissions of SO_2, NOx, and CO_2. Each of these pollutants is currently limited by a cap-and-trade mechanism, which results in market prices for pollution allowances. These market prices are then included in the operating costs of the power plants that produce these emissions. The AESC Study projects the market prices for each of these emissions, and includes these costs as one of the components of avoided costs. (Synapse 2011, p.2-14). These costs are not environmental externalities; they are the cost of complying with current and future environmental regulations.

The AESC Study's forecast of CO_2 allowance prices is worthy of some discussion here. The projected allowance prices associated with CO_2 are presented in Figures A.5 and A.6, in $/short ton and $/MWh, respectively. These figures also present the 20 year levelized cost of each price forecast. The AESC Study assumes that Regional Greenhouse Gas Initiative (RGGI) allowances prices will persist in the short-term, based on recent auction results which have been at the reserve price and are likely to remain so in the future. After 2017, the AESC Study uses prices estimated for expected federal regulations, in which a national cap-and-trade program for greenhouse gas emissions is enacted. From 2026 onward, the AESC Study assumes allowance prices will rise at the rate of inflation. (Synapse 2011, pp. 2-15, 2-19).

Figure A.5. Forecasted Allowance Price of Carbon Dioxide ($/Short Ton)

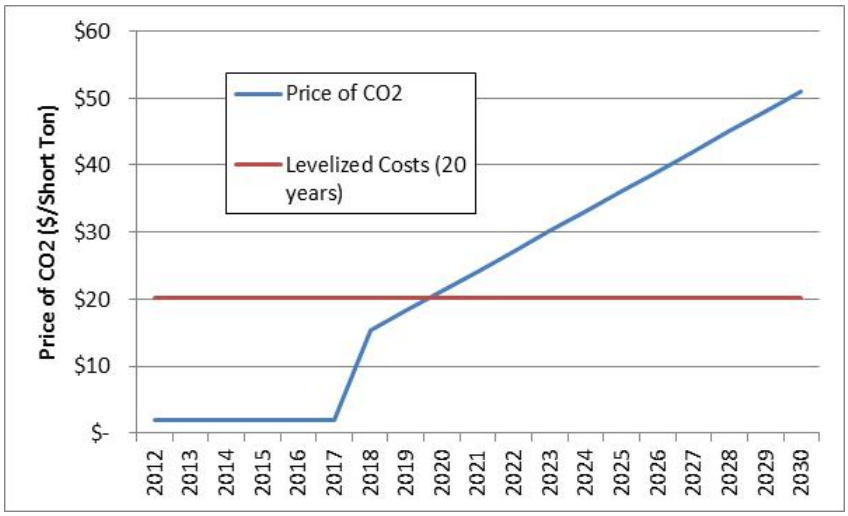
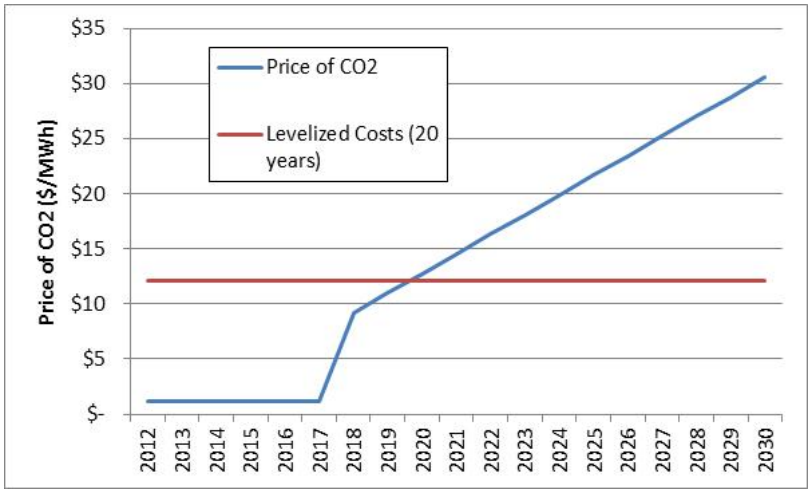


Figure A.6. Forecasted Allowance Price of Carbon Dioxide ($/MWh)



However, the RGGI requirements and the forecasted federal cap-and-trade requirements that result in the CO_2 prices presented above will not eliminate the environmental impacts of greenhouse gas emissions. Additional regulations are already in place in some states to limit greenhouse gas emissions to more stringent levels. States that adopt more stringent GHG standards than the RGGI requirements or the forecasted federal requirements will experience higher environmental compliance costs than those presented above.

The AESC Study estimates that the long-term cost of reducing CO_2 emissions to a sustainability target of 80 percent below 1990 levels by 2050 can be approximated at $80/ton of carbon, based on a review of several studies of global carbon mitigation options (Synapse 2011, pp.1-18, 1-19). States that establish comparable targets for climate mitigation could view the $80/ton long-term abatement cost as a reasonable

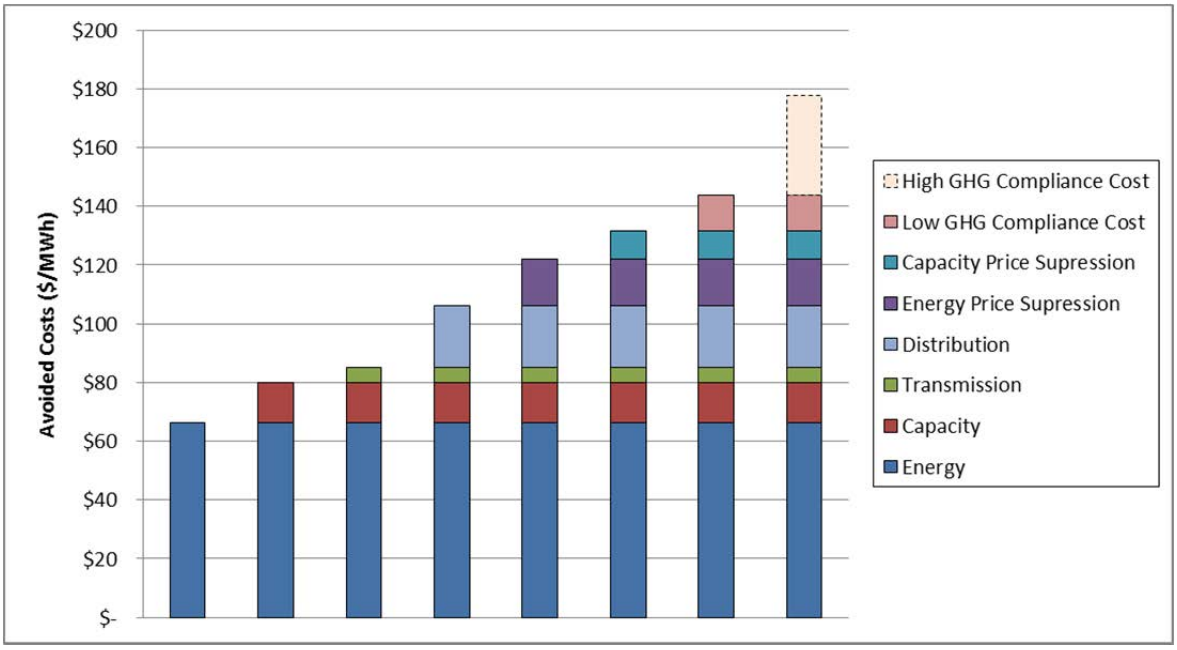
estimate of the cost to achieve these sustainability targets.[34] (Synapse 2011, p.4-40). We refer to these costs as the high GHG compliance costs.

Total Avoided Costs

Combining the different avoided costs discussed above demonstrates the total effect that efficiency programs can have in terms of reducing electricity costs. Figure A.7 accumulates the 20 year levelized costs for each avoided cost, with the right-most bar providing the total impact of avoided costs.

The High GHG compliance cost is indicated with dashed lines because these costs would only be considered environmental compliance costs in those states that have GHG requirements comparable to a sustainability target of reducing CO_2 emissions to 80 percent below 1990 levels by 2050. In other states these high GHG compliance costs would be considered environmental externalities, and thus would only be relevant for the Societal Cost test.

Figure A.7. Example of Avoided Costs, Broken Out by Component ($/MWh)



[34] Massachusetts is one example of a state that has adopted such targets.

FLORIDA SOLAR ENERGY CENTER®
Creating Energy Independence

ZEH: Lakeland, Florida

Original Conceptual Study (1994)	Project Report (November 1998)	Original Project Progress Report	Performance Data - Zero Energy Homes

Examining the Limits of Building Energy Efficiency Through Side-by-Side Testing

In 1998 the Florida Solar Energy Center began its Zero Energy Homes research program in collaboration with the City of Lakeland municipal utility and builder Rick Strawbridge. Two homes, one the builder's standard model (the Control) and the other a super-energy-efficient photovoltaic residence (PVRES), were constructed and tested on a side-by-side basis for more than a year. The goal was to determine the extent to which contemporary energy efficiency technologies can reduce the demand for electricity in Florida homes. The measured results from this project were very encouraging and have since formed the basis for a national Zero Energy Homes program.

More information about the Zero Energy Home in Lakeland, Florida:

- Aerial View 1
- Aerial View 2
- Air Conditioning
- Building Envelope
- Construction
- Ducts
- Economics
- Floor Plan
- HVAC
- Infrared Thermography
- Lighting
- Monitoring
- Overhangs
- PV System
- Refrigerator
- Roof
- Solar Thermal
- Wall Insulation
- Water Heater
- Windows

Below is an aerial photograph showing the two homes used in the Lakeland Zero Energy Homes project. As the photo indicates, the homes are identical in floor plan and orientations. However, they differ greatly in energy-efficiency with the Control Home being the builder's "standard" model that meets Florida's relativley stringent energy code and the PVRES home including the most energy-efficient provisions the FSEC project team could devise.



In one year, the PVRES home used 6960 kWh of electricity and had a PV system production of 5180 kWh. For the same year, the Control used 22,600 kWh. This gives a yearly energy savings due to the differences in the energy efficiency of the two homes of 70%. Putting the PV system production into the numbers shows that the PVRES house's net energy use (electricity from the utility) for the entire year was only 1780 kWh. Note in Figure 1 below that comparing the PVRES house energy, including the energy it produced, against the standard house shows that the PVRES house had a 92% utility energy savings compared to the standard house.

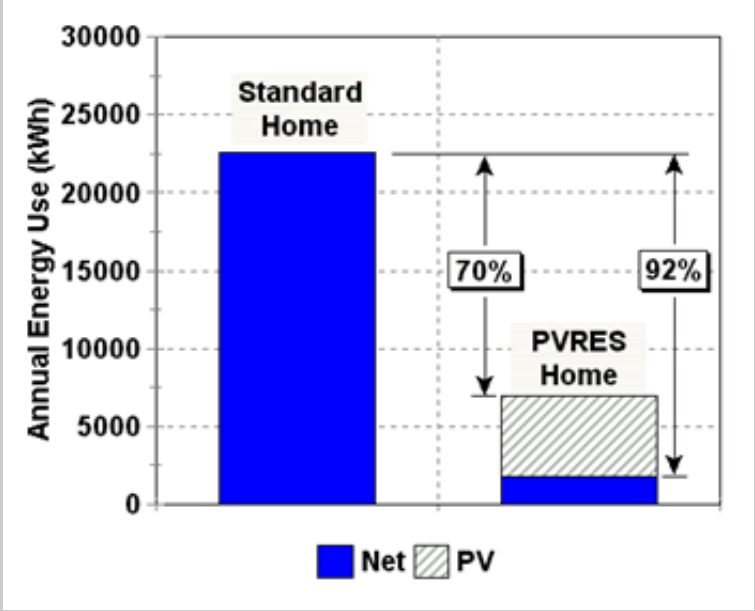


Figure 1. *Bar chart of annual energy use in standard home and PVRES home showing 92% reduction in net annual energy use by PVRES home.*

Perhaps even more important than annual energy use is the fact that during periods of peak electric demand, the PVRES home, due to the PV system, placed nearly zero net demand on the utility system! This fact is clearly shown below in Figure 2, which plots the July 18, 1998, peak day energy demand, PV power production and net utility power data for the PVRES home. Note the green line, which shows the net utility energy used by the PVRES house on the hottest day in recorded history for Lakeland!

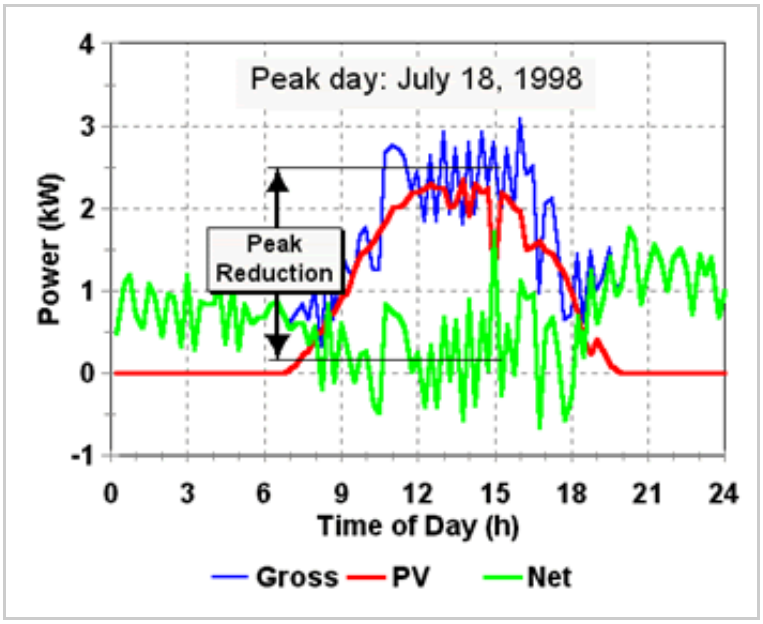


Figure 2. *Plot of peak day energy flows in PVRES home showing how PV power production reduces net energy demand during the day to near zero.*

A similar energy use and production plot for the annual average day shows even more impressive results for the PVRES home with net power flowing from the home to the utility for almost the entire period of daylight. Figure 3 below illustrates this fact, showing the annual average PV output and the utility peak load reduction (shaded). Again, note the green line showing power going from the home to the utility during daylight hours.

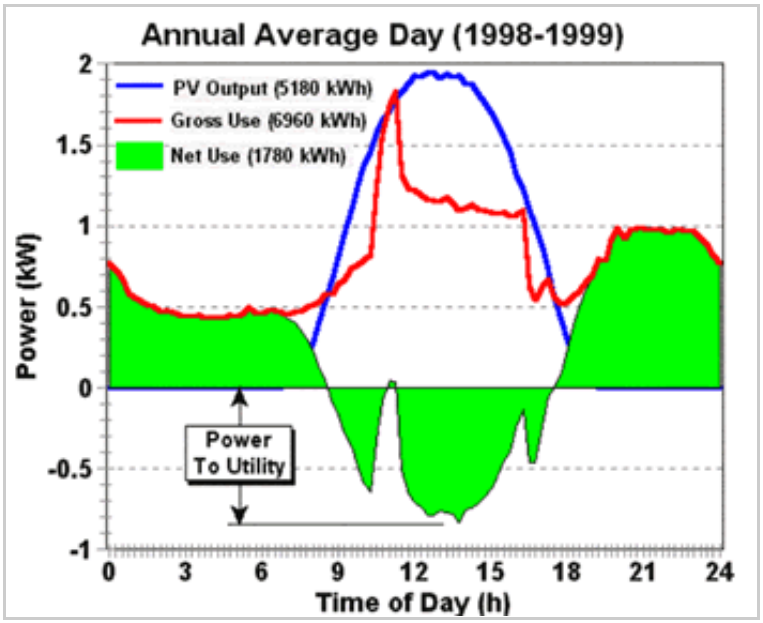


Figure 3. *Plot showing measured annual average PV production, total home energy use and net home energy use for PVRES home during 1998-1999 monitoring period.*

Small Business Energy Efficiency: Roadmap to Program Design

Kristen Funk, Center for Energy and Environment

ABSTRACT

The small business sector represents a largely untapped market for energy efficiency (EE) programs. Small businesses account for 29% of Xcel Energy's electric energy sales in Minnesota. However, traditional prescriptive rebate programs have failed to achieve high participation rates by small businesses. Free audits and generous rebates are not sufficient to overcome the burden on the business to initiate action and do not address the unique market barriers faced by small businesses.

Designing a successful small business retrofit program requires a paradigm shift from traditional EE programs. EE must be treated as a product to be sold. High volumes of opportunities must be generated and every aspect of the delivery process integrated with software that has the capacity to organize thousands of audits, while allowing customization to the unique needs of each business. Program staff must be technically proficient, but ultimately be selected because of sales experience. Extensive efforts must be made to develop, maintain and train an extensive network of contractors. While not sufficient by themselves, generous rebates are critical to initiation of the sales process. Neutral cash flow financing makes projects even more attractive.

The combination of these program elements has proven to be a successful approach for the One-Stop Efficiency Shop^{SM} lighting retrofit program. This is a full-service program for small businesses with demand below 400 kW. Almost 57% of program participants have a demand smaller than 50 kW. Between 2000-2012 the program will have served 8,600 small businesses resulting in 86 MW of savings.

Introduction

The One-Stop Efficiency Shop^{SM} (One-Stop) is a full-service rebate program available to small businesses in Xcel Energy's Minnesota service territory with an electric demand of 400 kW or less. The program is designed to save business owners energy and money through the installation of energy efficient lighting by specifically targeting barriers that prevent small businesses from investing in energy efficiency (EE) products: limited financial resources and time, limited knowledge of lighting products and lack of access to quality contractors. To address these issues the program offers:

- A simple, one-stop service that holds customer time requirements to a minimum
- Intensive marketing to bring the service to the customer, rather than relying on the customer to seek it out
- Substantial incentives

- Convenient and attractive financing
- A computerized audit/data communication and reporting system that generates and tracks all site-specific paperwork

Since 2000 the program has saved 74 MW and has disbursed $32 million in rebates to 7,100 program participants. Participating business owners will save $250 million over the life of the new lighting equipment they have installed.[1]

Now in its 13th year, the program has become very successful saving nearly 12 MW in 2011 alone. However, this was not always the case. Even with a full suite of services and benefits available from its initial launch, One-Stop only saved 55 kW in 2000 and was in danger of not being renewed beyond 2001. This paper is an effort to break down some of Center for Energy and Environment's (CEE) early misconceptions about implementing lighting efficiency projects, and how individual elements of the program have evolved through lessons learned over the last decade. Although CEE's experience is specific to lighting, we believe these lessons can be applied more broadly to small business programs across EE technologies.

Full Service is Essential but not Enough

Small business owners are notoriously short of time and resources. They face barriers such as lack of information, lack of capital, high financing costs and split incentives (Quantum Consulting Inc. 2004). In most cases EE is not even a consideration. If the lights work when they turn them on that is all that matters. As part of a 2010 One-Stop program evaluation 39 program participants were surveyed concerning the amount of time they spent researching EE. The average response was ten hours annually (the highest response was 100 hours) and 13 respondents reported that they spent no time researching EE, the most common answer (Frontier 2010).

Traditional rebate programs historically have not been able to penetrate the small business sector (Quantum Consulting Inc. 2004). CEE believed the most effective way to overcome the barriers unique to small businesses was to create a full-service program that brought all of the necessary resources directly to a business, thus eliminating the need for a business owner to assemble and manage their own retrofit project. The original design of the program accomplished this by offering:

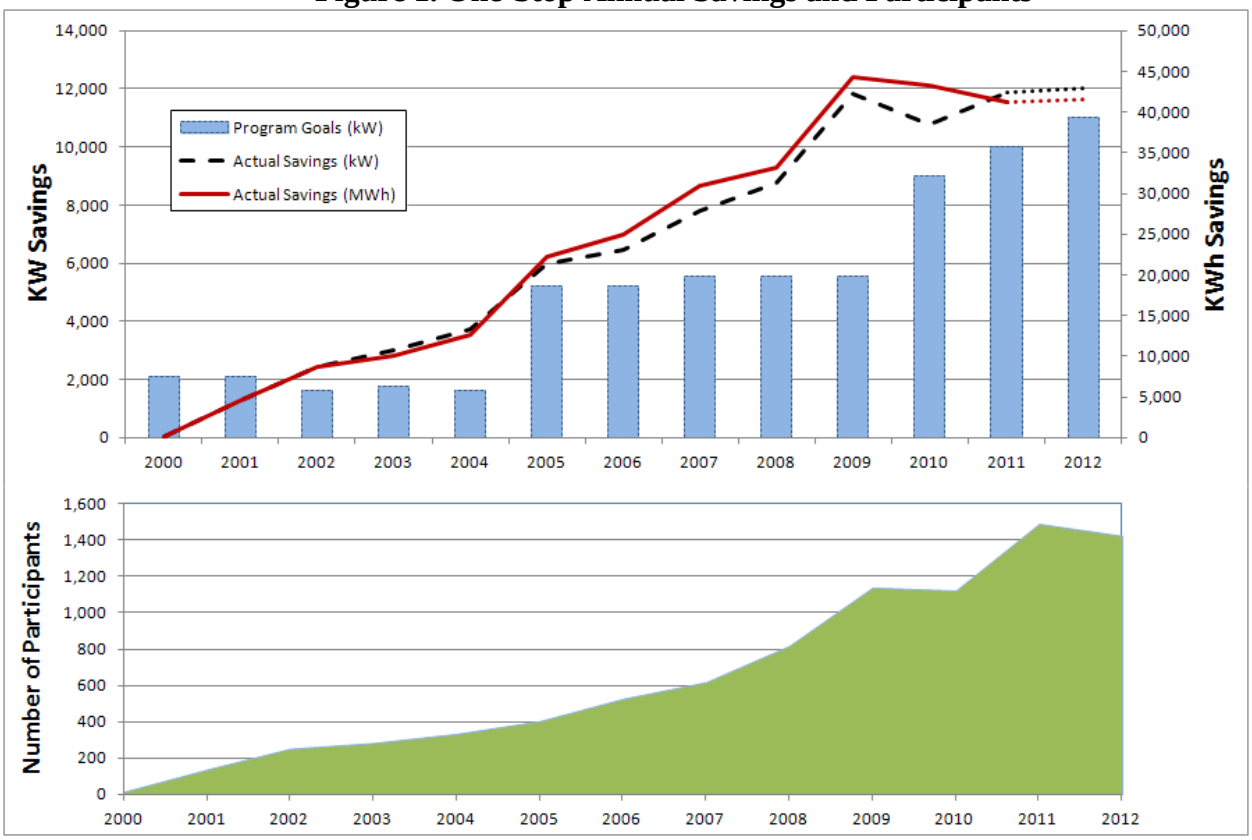
- A free, no-obligation lighting assessment with cost savings recommendations
- Below market rate, neutral cash flow financing
- Rebates up to 60% of the total installed cost of the project
- Qualified contractors to install the new lighting
- Start-to-finish oversight of the lighting upgrade
- Completion and submission of all rebate paperwork

The 2010 program evaluation validated the design finding that "The full services of the One-Stop Shop are essential for the characteristics faced by the small business market. Without services to overcome these barriers, many small firms would likely not engage in lighting

[1] Equipment lifetime based on a conservative estimate of 12.5 years by CEE.

retrofits" (Frontier 2010, 4). Yet in the early stages of the program, this did not guarantee participation. Figure 1 shows annual program goals, actual savings and total participants.[2]

Figure 1. One-Stop Annual Savings and Participants



CEE quickly learned that although fundamental to the success of the program, offering a full suite of services was only one part of the equation. Assuming that the program would sell itself, too much emphasis was placed on completing audits with less priority placed on follow-up and implementation. CEE realized that this approach was not productive and that the potential energy savings were not being achieved. CEE reorganized the program in 2001 and placed more emphasis on promoting implementation rather than making audits the primary focus.

This shift in philosophy was a key component to the future success of the program. Although it is critical to have all the necessary resources available to deliver an EE program, success is not a given unless the program administrator can sell the program in a way that meets each potential participant's unique needs. It is the idea of selling EE that has ultimately led to the program's continued success.

Not All Leads are Created Equal

A lot of money is squandered every day because companies lack a clear understanding of what a "sales lead" really means. Consequently, they fail to make lead definition a credible facet of their business. [M]ost of the leads that sales receive aren't qualified leads or

[2] Numbers for 2012 are estimated based on the year's progress to date.

appropriate buyers for what is being sold. – Lead Generation for the Complex Sale (Carroll 2006, 6)

This type of sales saturated language may seem irrelevant to EE because those of us administering EE programs often do not view EE as a product that we are selling. In fact, we are selling a product. We are asking someone to choose EE over other items in which they might invest their finite resources. Since implementation is the ultimate goal and program administrators also have finite resources, it makes sense that we should spend those resources on businesses most likely to participate in our programs.

Like many programs, One-Stop offers a free lighting audit to entice people to participate. This is an effective way to attract the attention of business owners who are bombarded by requests for their time on a daily basis (Environment Northeast 2012). When the program launched, the One-Stop scheduler was asked to emphasize the free audit, potential rebates and money savings opportunities offered by the program. Promoting the program in this way was effective at getting business owners to complete an audit, but not very successful at achieving implementation. Not surprisingly, auditors found many business owners who were interested in the free information about their building, but little else. EE program administrators are ultimately looking for people who want to implement EE projects, not just complete an audit. The more time auditors spend with business owners who are not serious about EE, the less time they have to spend with those who are.

After learning this lesson, CEE took some time to define a good lead in the context of One-Stop and then worked with the scheduling company to create a new script for their callers. Table 1 is a matrix of questions the caller asks each potential participant.

Table 1. One-Stop Questions for Filtering Potential Program Participants

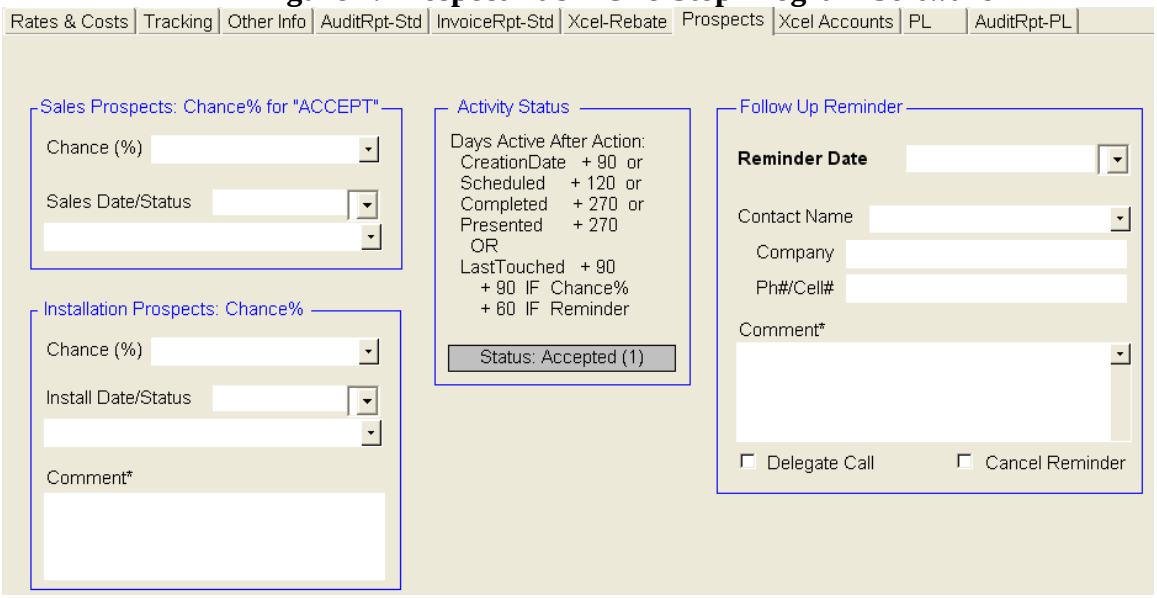
Questions	List of Potential Responses
What type of lighting are you currently using (if already retrofitted skip the remainder of the questions)?	Fluorescent Incandescent Exit Signs High Intensity Discharge (HID) Multiple Technologies
What is your building type?	Office Manufacturing Church Multi Family Multi Tenant Service Multiple Use Other
Can you help us identify some of your building's characteristics?	Square footage Number of buildings Number of fixtures
Do you have a lease situation that would restrict your payback criteria?	Yes No
Is a high energy bill a concern for your business or have you been looking for ways to reduce your energy use?	Yes No
Are you or your employees concerned about light levels or lighting quality – frequently burned out lights, color, brightness, high maintenance costs?	Yes No

With this reworked script, the caller lets the business owner know that One-Stop is a full-service, lighting rebate program, but a free audit is not even mentioned until the caller determines the business is a good candidate. This approach allows the caller to filter out businesses that are obviously not a good fit for the program such as those who have already retrofitted or do not have the budget to pay for a retrofit. If warranted, the caller has the ability to schedule a call-back for a later date. It should be noted that CEE also works with other organizations that might make referrals to make sure they understand how One-Stop defines a good candidate for the program. This allows everyone involved to make the best use of their time.

Once an audit is scheduled and completed the auditor begins the work of prioritizing those businesses that seem most likely to implement. At this point the auditor has a fairly clear idea of the business owner's interest level. Persistence and follow-up are crucial to the success of the program, but only effective if targeted at the right audience. CEE has incorporated a tracking page into its program software to help auditors identify prospects with the most potential for moving forward. The tab shown in Figure 2 gives auditors the ability to rank their projects as well as set up follow-up calls.

Even good leads do not always result in a decision to implement immediately, if ever. It is part of the auditor's responsibility to cultivate each lead appropriately and set up a level of communication that coincides with a business owner's needs and interests. This may mean a high level of contact over a short time span or setting up a follow-up call for several months in the future.

Figure 2. Prospect Tab – One-Stop Program Software



Creating a culture of prioritization and follow up is critical for maintaining a consistent flow of jobs through the program. Even with targeted marketing, the average job takes almost one year to complete from initial audit to installation. Approximately 17% take two years or more to complete a retrofit. Even when business owners with a high level of interest and good savings potential are identified, auditors need to be proactive in addressing any concerns that

might arise. Until the retrofit is actually completed there is any number of reasons a business owner may decide not to move forward.

Good leads, not audits, should be the basis of any EE program. Program administrators should take the time to define what an ideal lead is and then anyone who is a potential point of contact for the program should be taught the definition and trained on how to apply it to their interactions with potential program participants. This includes program staff, outside personnel who may be contracted to work with the program or other organizations that are providing referrals. Once good leads are generated they can be fostered as needed to obtain the best result. Ultimately this will lead to the best use of program and participant resources and produce a higher rate of implementation.

Education is not Sales

Lighting auditors are the frontline of the One-Stop program. They are the face of the program for potential participants and their role is crucial in generating project implementation. Their priorities in engaging potential participants will have a significant impact on the ultimate success of the program.

One-Stop was originally designed under the misconception that the program would sell itself. It is often difficult for those of us who administer EE programs to internalize the idea that others do not always perceive the benefits of EE the way we do. In the context of lighting, EE projects are relatively inexpensive and the payback can be quick. With significant rebates added to the mix there does not seem to be a reason for businesses not to participate. Due to this misperception, completing audits was the initial focus and lighting auditors were selected primarily for their technical expertise.

It soon became clear that this approach was not working. One-Stop auditors completed 215 audits in 2000, but only six businesses participated for a total savings of 55 kW (compared to a savings goal of 2100 kW). Because the auditors were recruited for their technical aptitude, they were able to educate business owners about, but not sell them on, EE. The difference may seem subtle but the impacts are substantial. Table 2 provides a summary of the differences between people who are “tellers” and people who are “sellers” (Ruth & Wysocki 2002).

Table 2. Tellers vs. Sellers

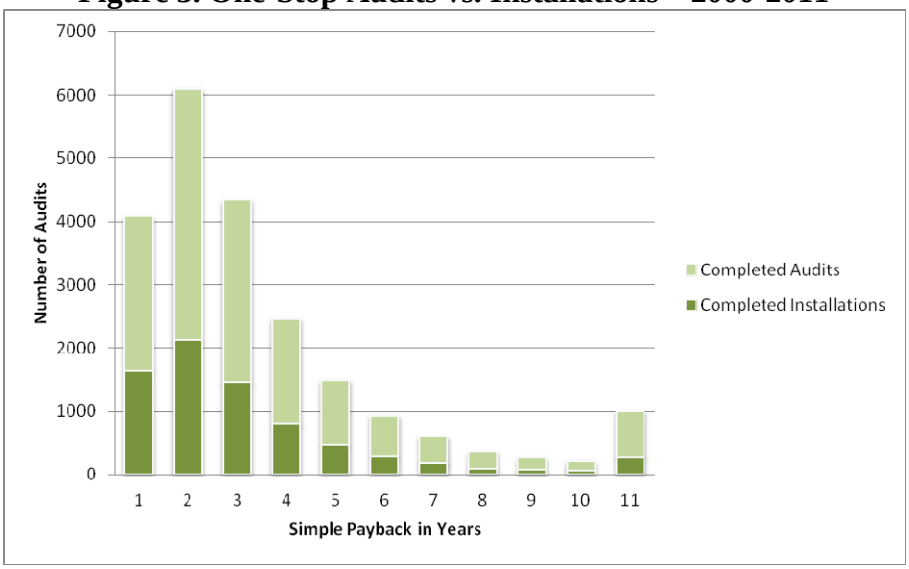
Tellers	Sellers
Give information	Solve Problems
Leave decision to the prospect	Gain conviction
Present features	Translate features into benefits
Avoid rejection	Risk rejection
Try to win by showing knowledge	Win by closing sales
Use rational level	Use emotional and rational levels
Reactive	Proactive
Want structure and stability	Accept uncertainty as the norm
Identify needs	Intensify needs and wants
Everyone comes to your door	You go to everyone’s door

The low level of participation caused CEE to reprioritize. Implementation became the primary focus and sales experience became the main requirement for new auditors. In fact, CEE hired three new auditors that had no experience in lighting, but had years of sales experience in other industries or the right personality to become a successful sales person. Their potential to

learn the technical aspects of lighting retrofits was also gauged, but was considered secondary to their ability to sell.

The results of this refocused effort were almost immediate. During the first half of 2001, the sales rate increased 50% and the average kW saved per week almost doubled. Figure 3 illustrates why the new emphasis on a sales mentality was so important.

Figure 3. One-Stop Audits vs. Installations – 2000-2011



CEE's experience indicates that a payback of three years or less is usually the most enticing to business owners. However, out of 74MW of total savings One-Stop has generated 20MW of savings from projects with a payback of four years or more. It is also clear that a quick payback is not an automatic deal closer. Business owners obviously have many reasons for choosing or not choosing to implement EE projects. As Chart 1 indicates by the number of short payback jobs that have not gone forward, saving money is not the only factor in their decision making process. Business owners choose to retrofit their lighting because: it's good for the environment, their maintenance costs are too high, it's a tax write-off, they want to increase the value of their building, they need better light and the list goes on. Saving money is often a secondary concern.

That is why it is so important to have an auditing staff that is capable of uncovering the unique needs and concerns of each individual business owner. The auditor then works to convince them that the program can meet those needs and is persistent in follow up after the initial audit. Education does not get to this point, but selling will.

Vendors are also Participants

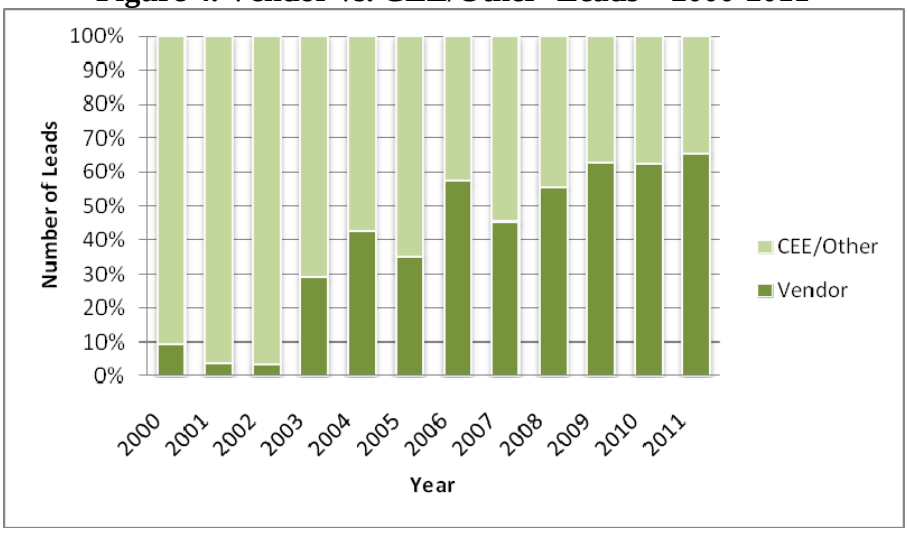
Vendors are often considered allies in the EE arena (U.S. Department of Energy 2006). This categorization of vendors can result in a passive relationship with EE program administrators. We understand each other's utility in the field we both work in, but the relationship will not automatically move beyond that point. This does not bode well for the small business sector because contractors often do not find rebate offerings attractive enough to shift their focus to this market segment.

When designing One-Stop, CEE hoped to promote vendor interest in small businesses by offering enhanced rebates, financing tools and completion of all project paperwork. The learning curve for a rebate program, specifically a full-service rebate program, can be quite steep. Vendors are not used to the additional benefits that are available and are often wary of the increased oversight required by the program manager in the context of audits, project management and post-installation inspections.

CEE found that over the first couple years of the program there was a minimal level of vendor interest outside of those vendors initially recruited to work with the program. In the interest of generating better leads CEE wanted to cultivate this resource because vendors already have established relationships with thousands of businesses that need lighting upgrades. As with business owners the program was not selling itself to vendors, so CEE decided to use the skills of its sales staff and make a concerted effort to market the program to vendors.

The foundation of this marketing effort was, and still is, one-on-one communication with vendors to explain the program process and how its various services can benefit them and their customers. Although an understanding of the program is important, One-Stop staff's interaction with vendors goes well beyond a simple explanation of the process. One-Stop auditors have spent countless hours educating vendors on lead generation, lighting technologies and selling techniques. One-Stop auditors often serve as advisers for new staff hired by vendors who work with the program, as well as to vendors who are just getting into lighting, or have always retrofitted a certain way and have not kept up with the changes in technology. These relationships require time to build, as well as consistent attention to maintain a level of trust and service so that vendors know they can rely on the program to serve their customers effectively and efficiently. Figure 4 shows the results of One-Stop's effort to reach out to vendors.

Figure 4. Vendor vs. CEE/Other[3] Leads – 2000-2011



Since the beginning of the program, CEE has worked with over 350 vendors to provide audit services and rebates to their customers. Since 2003, vendor referrals have increased significantly and for the past four years have represented over 50% of the audits scheduled by the program. A vendor referral does not automatically lead to implementation. One-Stop staff still

[3] CEE/Other includes leads generated by CEE as well as other non-vendor organizations such as local non-governmental organizations (NGO), utility customer service representatives, etc.

has to work with the vendor to convince the business owner to participate in the program. However, vendor referrals are usually much better leads than cold calling. The vendor has a pre-established relationship with the business owner and has already done some preliminary filtering like identifying opportunity for energy savings and determining the business owner's level of interest. One-Stop auditors can then help vendors with the sales process and bring oversight from a neutral, third-party that ensures contractor credibility and customer confidence through the retrofit and finalization of the rebate.

Vendors are an important resource for any EE program. They are integral to the implementation phase of any project, but more importantly they are a gateway to potential program participants. Vendors have already established relationships and a level of trust with their customers that makes their referrals much more valuable than any other source. When designing EE programs administrators should consider how vendors will work within them and try to incorporate elements that will make the program attractive and accessible. Once the program is launched administrators should proactively seek out relationships with appropriate vendors and their industry membership organizations. These relationships will take time to build and require consistent attention, but the rewards to the program will be well worth the effort.[4]

Software as Sales Support

Even with a full-service program, a philosophy of good lead generation, a sales mentality and outreach to vendors, not all audits will result in implementation. To be successful a program, One-Stop must generate thousands of leads per year. Thousands of reports must be delivered that provide potential participants with a simple, meaningful summary of the benefits of EE upgrades. One-Stop staff must be able to organize, track and modify their leads so they can effectively prioritize and follow-up. To accomplish these tasks a robust software package is a necessity (Quantum Consulting Inc. 2004).

CEE uses a software package called the Facility Assessment and Evaluation Tool (FACET) for One-Stop. The software is a database-driven auditing tool that was developed in-house specifically for One-Stop and has the ability to: a) complete all energy savings, financing and rebate calculations; b) provide a platform for program staff to modify audits as necessary to meet the unique needs of each participant; c) generate all necessary reporting from initial audit to completion paperwork; d) track construction progress; and f) retain all audits scheduled since the beginning of the program. Because it was programmed in Microsoft Access, program administrators have the ability to query against a live database and compile data on every piece of information that is collected during an audit. This is an extremely powerful tracking tool for identifying technology trends, best sales opportunities and market penetration.

[4] EE program administrators should also make a purposeful commitment to building relationships with like-minded organizations or organizations that could benefit from leading an EE campaign for their constituents. These might include NGO's that also have an interest in EE, business associations, utility customer service centers, chambers of commerce, neighborhood associations and local governments. The leverage these groups have in their communities can be used to help sell EE programs to potential participants. As an example, CEE recently worked with the City of Slayton in southeastern Minnesota. Small towns are often a difficult market to serve because they can be very skeptical of outside influences. CEE initially introduced One-Stop to city officials and convinced them to retrofit the city's buildings. They were so pleased with the results that CEE was able to partner with them to market One-Stop to local business owners and to date a total of 33 businesses have participated in the program. CEE recently finished a documentary on these projects which will be used in other marketing efforts for the program.

FACET is currently used to track over 19,000 audits. Maintaining a historical record of audits is critical to the program. The average installation for One-Stop takes approximately one year from the initial audit through finalization of the rebate paperwork. This means that many businesses that ultimately choose to retrofit their lighting take two, three or even more years to make the decision and complete the work. Business interests, financial viability and personnel change over time. What may not be a good investment one year can become a good investment two or three years later. By retaining historical data in a data-base format, CEE is able to identify those businesses with the greatest opportunity for savings and follow up as needed to keep One-Stop's services a part of the decision making process as the business evolves.

FACET also gives program staff the flexibility to easily modify properties to meet the unique budget and bidding requirements of each business. At the macro level, One-Stop staff can easily make copies of whole audits if they want to retain the original data. This is useful if a business owner can only afford to retrofit a portion of the building, but may consider retrofitting the rest at a later date. The auditor can easily create multiple phases for the property and provide the owner with cost, rebate and savings information for each phase. Auditors also often use this function to create multiple versions of a property to modify pricing or recommendations in a multiple bid situation. This allows auditors to provide an accurate rebate calculation for each bidder and keep each bid independent and confidential. The business can then compare bids and make an informed decision. Currently, 12% of audits in FACET have at least two phases or versions.

At the micro level, program staff can easily customize pricing and recommendations to tailor each audit to the business owner's needs. Individual recommendations or entire areas of the building can be deselected if they do not make sense to implement. Since they are not deleted from the audit, they can easily be selected again based on the business owner's circumstances.

Figure 5. FACET Lighting Analysis - Summary Page

Lighting Upgrades

		Estimated Costs	Estimated Annual Savings	Payback
Total Installed Cost	*Before rebate*	$19,708.95		
One-Stop Efficiency Shop Rebate*		$8,924.19		
Your Final Cost	*After rebate*	$10,784.76	$4,356.10 (a)	2.5 years
⇨ *Rebate equals 45% of installed cost.*		***(Including special orders)***		

****This offer is only valid for a period of 45 days. The project costs are based on current equipment pricing, utility rebate levels and customer eligibility requirements. After this offer's expiration date of 10/23/2010 you must request pre-approval and an updated rebate offer from the One-Stop program before starting the job.***

Xcel Energy Financing Option

Estimated monthly savings	$363.01 (a)	
Monthly loan payments at 3.9% for 31 month term	$375.95 (b)	2.7 years (Including Xcel Loan Financing Charges)

(b) Estimate based on a loan amount of $10,984.76, including a $200 loan processing fee. The loan term has a maximum of 5 years, with monthly payments not less than the estimated monthly savings. Final terms and conditions set by bank upon loan approval.

As Figure 5 illustrates, reporting generated by FACET immediately provides the business owner with a straightforward summary of the project that includes estimated project costs, rebates, payback and monthly loan payments if financing is being considered.

Detailed recommendations follow, each with their own savings and cost factors so the business owner can review each part of the project. Figure 6 is an example of a typical recommendation for existing T12 fixtures. After the installation is completed FACET also generates all final rebate paperwork so neither the business owner nor vendor have to take on that responsibility.

Figure 6. FACET Lighting Analysis – Detailed Recommendations

Recommended Lighting System Upgrades			Schedule Name & Hours/year of Operation		Installed Cost (Without Rebate)	Estimated Annual Savings	Selected
Area A: Offices							
Project: #1			A: Offices & Classrooms 2,477 hrs/yr		$523.39 Incl Special Order	$83.49	☑
Qty	**Watts**	**EXISTING Luminaire**	**Qty**	**Watts**	**NEW Luminaire**		
9	84.20	T12 4' 34W, STD-2, 2L	9	48	T8 4' 28W ELC2 2L *		

Software is a necessary tool for EE programs, but it should not only serve as a respository for program information, it should also help program administrators and staff organize and interact with projects in a manner that results in greater implementation. FACET was developed by CEE, but there are other auditing and sales tools that can give EE program adminstrators the power to anaylze data, track and follow up on quality leads and tailor audits to individual participant needs. The more functionality the software has, the easier it is for program adminstrators to use it to help market the program and sell jobs.

Conclusion

Small businesses are difficult to serve with EE programs. Small business owners have limited resources and EE is often the last thing on their minds. To serve this market effectively EE program administrators need to design aggressive programs that bring a wide range of services directly to potential participants, which are founded on a sales, not an educational mentality. Administrators should foster a culture of sales from lead generation through issuing a rebate check. Key aspects in developing a sales-oriented program include:

- Offering a full-service program – significant rebates, technical guidance, financing and contractors to complete the work
- Defining what a good lead is and creating a process for lead development and follow-up – is there good savings potential, can the potential participant pay for the project, are they really interested?
- Hiring staff with sales experience – when staff interacts with potential participants their goal should be to close a sale, not just provide information.

- Aggressively building relationships with vendors and other relevant organizations that can generate leads.
- Employing robust supporting software – program software should not only be a repository for audit information, but have the functionality to allow staff to organize and track projects to promote implemetation.

None of these elements is sufficent by itself to create a successful EE program, but as One-Stop administrators have learned over the years their combination can lead to significant implementation of EE projects in the small business market.

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Synapse
Energy Economics, Inc.

Big Risks, Better Alternatives

An Examination of Two Nuclear Energy Projects in the U.S.

October 6, 2011

AUTHORS

Max Chang, David White, Ezra Hausman, Nicole Hughes, and Bruce Biewald



485 Massachusetts Ave.
Suite 2
Cambridge, MA 02139

617.661.3248
www.synapse-energy.com

Acknowledgements

This study was prepared by Synapse Energy Economics, Inc. for the Union of Concerned Scientists (UCS). We are grateful to the following people for reviewing this paper: Steve Clemmer and Ellen Vancko of UCS, Sara Barczak and John Wilson of the Southern Alliance for Clean Energy, and Susan Glickman and Jamie Whitlock. Melissa Schultz provided editorial support. This report has benefited from their insights. However, any error or omission in this report is the responsibility of the authors.

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1. Executive Summary

Background

In 2011, nearly three decades after the last nuclear power plant came online in the United States, developers are pushing forward with a new generation of nuclear energy resources. There are now more than 20 applications before the Nuclear Regulatory Commission to build new nuclear plants or expand existing U.S. plants.[1] This reawakening of the nation's nuclear power industry is generating considerable debate—in part due to the costly bailouts asked of American tax- and ratepayers to cover hundreds of billions in cost overruns and plant abandonments in the past, coupled with soaring price tags for many proposed reactors.

Proponents of the nuclear resurgence argue that the latest generation of reactors, which are more standardized in design than their predecessors, will not be exposed to the same cost and performance uncertainty as prior nuclear projects in the United States. Nuclear energy is also touted as a necessary part of the equation to reduce carbon emissions and address climate change.

Recent experience in the nuclear energy industry world-wide is calling these assumptions into question. Nuclear projects in Finland and France are experiencing significant delays and cost overruns. The Fukushima Dai-Ichi plant disaster is raising even broader questions about nuclear safety and associated costs and risks; following the crisis in Japan, Germany announced that it will shut down all 17 of its nuclear reactors by 2022, while Switzerland and Italy have abandoned plans to build new reactors.

At the same time, forecasts for energy demand growth in the U.S. are much lower than they were just five years ago: demand for electricity declined during the economic recession, post-recession growth has been sluggish, and demand-side load reduction initiatives have helped to temper growth still further. On the supply side, renewable portfolio standards in numerous states have further reduced the need for additional thermal resources. Thus the argument that new baseload generation is urgently needed for supply reliability is not as credible as it might have been when many of the new-generation nuclear energy projects were first proposed.

The Purpose of this Report

In light of these trends, this report takes a close look at two modern-day nuclear energy projects in the U.S. The first project consists of two units, Levy 1 and 2, which have been proposed by Progress Energy Florida for a new site in Levy County, Florida. The second project also consists of a pair of units, Vogtle 3 and 4, which would be constructed at the site of the existing two-unit Vogtle nuclear power facility in Burke County, Georgia.[2] Site preparation work has already begun for the Vogtle units by a consortium consisting of Georgia Power (a subsidiary of Southern Company) and several municipal and cooperative electric utilities. Both of these projects were proposed in 2006, before the recession, to meet then-anticipated growth in demand.

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[1] http://nrc.gov/reactors/new-reactors/new-licensing-files/expected-new-rx-applications.pdf
[2] Georgia Power, a subsidiary of Southern Company, owns 45.7 percent of the proposed plant. Other owners include Oglethorpe Power (30 percent), MEAG Power (22.7 percent), and the City of Dalton, GA (1.6 percent).

The Levy project in Florida and the Vogtle project in Georgia provide illuminating case studies for the next phase of nuclear power generation in the United States for a number of reasons:

- They both propose to use the same "modular" reactor design: the Westinghouse AP1000 reactor, which is the same technology proposed by approximately one-half of the applications for new reactors filed with the U.S. Nuclear Regulatory Commission (NRC).
- They are both proposed in states where legislation allows utilities to recover project costs from ratepayers years before the reactors will actually come online.
- They represent different construction scenarios: a new "greenfield" power plant versus an expansion of an existing plant.
- They have different financing situations: the Vogtle project enjoys two subsidies that are not factored in the Levy project—a federal loan guarantee and production tax credits.
- The Vogtle project has a lower degree of transparency than Levy: Georgia Power has classified almost all cost and schedule information as "trade secret," while much of the information regarding Levy projections is publicly available.
- Construction progress varies: excavation and site preparation work has commenced for Vogtle 3 and 4, while site work for Levy 1 and 2 has been suspended.[3]

This report evaluates both nuclear energy projects, and then compares them to potential alternatives that are capable of meeting projected consumer demand in their respective states with low- or no-carbon resources at lower cost and risk.

Key Findings

Our analysis finds that there are major risks associated with the construction of both the Levy and Vogtle projects. While the AP1000 reactor represents a more standardized design than existing U.S. reactors, it has never been built in this country nor completed in any country. Nuclear power construction is still a very complicated process with numerous unknowns that can negatively impact plant economics. Risks for these projects include cost escalation, construction and regulatory delays, and lack of transparency (for the Vogtle project), all of which could lead to much higher costs to ratepayers. Using the companies' current cost estimates:

- By 2021, the Levy project will add at least $718 per year to the bill of a typical Progress Energy residential customer using 1,100 kWh per month; and
- By 2018, the Vogtle project will add at least $120 per year to the bill of a Georgia Power residential customer using 1,000 kWh per month.

If history is our guide, these cost estimates are likely to increase dramatically over time. The anticipated cost and rate impact for the Vogtle project, in particular, could increase significantly; the redaction of all cost and schedule data for this project has hindered independent analysis of the underlying assumptions that have allowed Georgia Power to maintain old cost estimates

[3] Progress notes in its November 8, 2010 Form 10-Q that "excavation and foundation preparation work anticipated in the initial schedule cannot begin until the COL is issued, resulting in a project shift of at least 20 months. Since then, regulatory and economic conditions identified in the 2010 nuclear cost-recovery filing have changed such that major construction activities on the Levy project are being postponed until after the NRC issues the COL, expected in late 2012 if the current licensing schedule remains on track" (p. 24).

despite major changes in economic and regulatory conditions over the past five years. This lack of transparency puts Georgia Power's ratepayers at significant risk for major price hikes in the coming years.

By comparison, based on publically available data, there are alternative options readily available to Progress Energy and Georgia Power that could meet consumers' energy needs and be implemented at a lower cost, with far less risk to ratepayers. Energy sales growth for both of these companies has slowed considerably compared to earlier projections, making it is possible to meet their future retail energy sales growth through smaller increments of alternative demand- and supply-side resources. These options include increased energy efficiency and renewable energy development.

Our analysis shows that both Florida and Georgia have significant room for improvement when it comes to energy efficiency investment. According to the American Council for an Energy-Efficient Economy (ACEEE), in 2010, Georgia ranked 37th overall and Florida ranked 30th overall among U.S. states as benchmarked against six energy efficiency categories.[4]

- **In Florida:** The Florida Public Service Commission (PSC) recently approved scaled-back demand-side management plans for Progress that are projected to capture a maximum of 2 percent energy savings over a 10-year period.[5] If Progress were to pursue an EE target of 15 percent cumulative load reduction over the same timeframe, it could maintain its energy load below peak 2006 levels based on its 2010 10-Year Site Plan retail sales forecast.
- **In Georgia:** The state currently has no energy efficiency targets. Recent reports support the fact that the state has large, untapped energy efficiency potential.

Both states also have significant potential for increased development of renewable energy resources. No meaningful renewable energy standards currently exist in Florida or Georgia.[6]

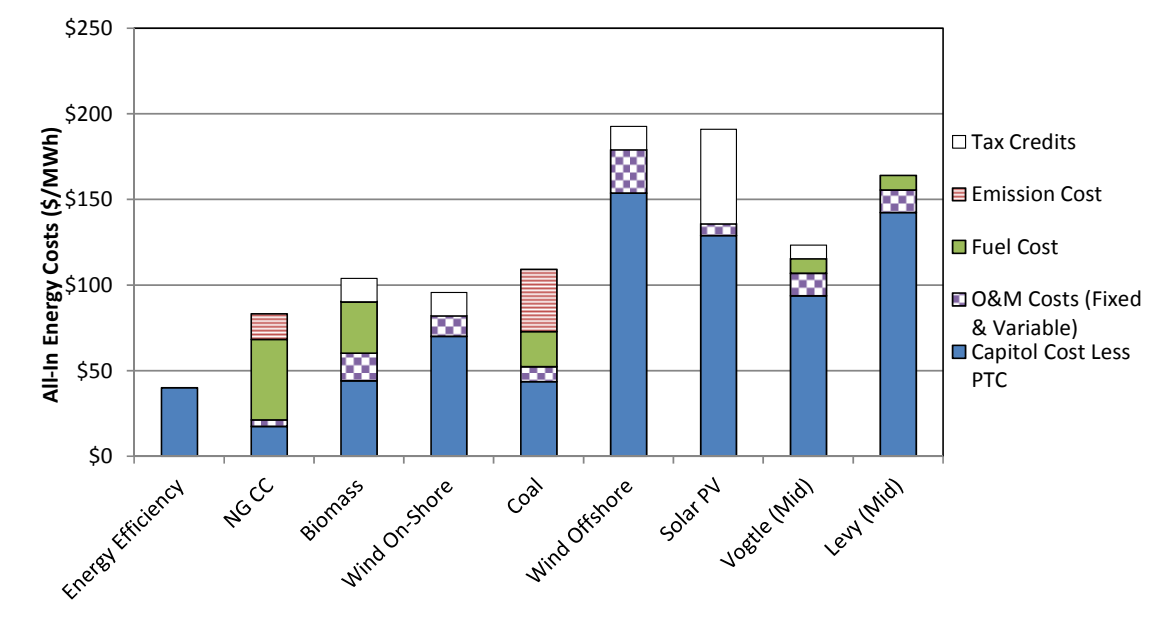
- **In Florida:** A 2008 Navigant Consulting report prepared for the Florida Public Service Commission found that, even without the benefit of Renewable Energy Certificates, the achievable installed renewable capacity in the state could account for 4 to 16 percent of electricity sales in 2020.[7]
- **In Georgia:** Available studies indicate that the renewable energy potential in the state could meet much of the state's future energy needs. A 2009 Southern Alliance for Clean Energy (SACE) report identified statewide renewable energy potential equal to approximately 27 percent of 2008 retail electricity sales.[8]

[4] These benchmark categories include 1) program funding and policy, 2) transportation, 3) building energy, 4) combined heat and power, 5) state government initiatives, and 6) appliance efficiency. The full report is available at www.aceee.org/sector/state-policy/scorecard.
[5] Southern Alliance for Clean Energy's projection of the state energy savings impact over a 10-year period of the scaled-back demand-side management plans for Progress Energy Florida and Florida Power and Light. The Florida PSC had set a higher energy savings goal in 2009 of 3.5 percent over a 10-year period, but the recently scaled-back demand-side management plans for the state's two largest investor-owned utilities has significantly reduced the energy savings goal.
[6] http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm
[7] http://www.psc.state.fl.us/utilities/electricgas/RenewableEnergy/FL_Final_Report_2008_12_29.pdf
[8] Southern Alliance for Clean Energy. *Yes We Can: Southern Solutions for a National Renewable Energy Standard.* Revised February 23, 2009. Report available at www.cleanenergy.org/images/files/SERenewables022309rev.pdf.

Available EE and RE alternatives are not only capable of meeting the projected growth in demand for each state at a lower cost than adding new nuclear capacity, but they also provide the benefit of reducing each state's greenhouse gas emissions. While neither Florida nor Georgia currently has established carbon reduction goals, the ability of the studied alternatives to reduce greenhouse gas emissions is important to note in comparing the overall impact of these options to the proposed nuclear projects.

In terms of reducing the greenhouse gas footprint of each state's electric sector while meeting projected energy demand, our analysis shows that CO_2 abatement through energy efficiency, natural gas, and some renewable energy options represent less expensive (and much less risky) solutions than expanding either state's reliance on nuclear energy. Exhibit 1 (below) shows projected mid-range levelized costs by component for the Levy and Vogtle projects compared to the mid-range levelized costs other alternatives evaluated in this report.[9]

Exhibit 1. Levy and Vogtle Levelized Cost Components Compared to Other Resources



The white segments in the above chart show the impact of the production or investment tax credits, both of which reduce the levelized cost of qualifying resources.

Policy Implications

While we cannot know with certainty the final cost of any of the options evaluated in this report, we do know that the overall trend for nuclear projects (and other large-scale construction projects) is one of *increasing* costs, while the overall trend for energy efficiency and renewable energy projects is one of *decreasing* costs.

[9] Exhibit based on data presented in Exhibit 13 and Exhibit B-1.

Moreover, there is considerable reason to believe that the Levy and Vogtle projects will present much greater risks and added costs for consumers than those anticipated by the projects' sponsors. The question is "to what degree?" And, why should ratepayers bear these sizable risks, when viable alternatives can meet energy needs and achieve environmental goals at lower cost?

Our analysis strongly suggests that both Florida and Georgia should reexamine their decision to place the risk of new nuclear construction on the states' ratepayers, and instead pursue options that are more cost-effective and environmentally sustainable to meet their energy needs. Specifically:

- Florida should take steps to increase energy efficiency targets to levels more consistent with leading states. Achieving an EE target of 15 percent over ten years would allow Progress Energy to meet its projected energy sales growth without the Levy units. With additional investment in renewable energy resources, Progress could retire some older, less-efficient, and more expensive generating plants—in addition to the coal-fired Crystal River plant, which is already slated for retirement.
- Georgia should commission new energy efficiency and renewable energy studies for the entire state, and take steps to set statewide energy efficiency and renewable energy targets. Existing studies suggest that Georgia Power could viably and economically meet its projected energy sales growth through a reasonable mix of energy efficiency and renewable energy resources—without the Vogtle units.

Pursuing these alternatives would enable Florida and Georgia to reliably meet demand growth and reduce carbon emissions at lower cost and with less risk than through the proposed Levy and Vogtle projects.

2. Introduction

A nuclear power plant has not been built in the United States since the early 1980s. Now, after 30 years of inactivity, the nuclear industry is seeking approval for a new generation of nuclear resources in the U.S.; nearly two dozen proposed projects are currently filed with the Nuclear Regulatory Commission.

This report takes a close look at two of these proposed projects: Levy 1 and 2 in Florida, and Vogtle 3 and 4 in Georgia. Costs and risks associated with these projects are evaluated, and then compared to alternative options capable of meeting the sought-after energy and carbon reduction goals.

The following table illustrates key similarities and differences between the Levy and Vogtle projects. Note that Georgia Power's pro rata share of Vogtle's $14 billion estimated cost is approximately $6.1 billion.

Exhibit 2. Similarities and Differences between the Levy and Vogtle Projects

Factor	Levy	Vogtle
Ownership (Percentage)	Progress Energy (100%)	Georgia Power (45.7%)
Boilers	Westinghouse AP1000	Westinghouse AP1000
Number of Units	Two	Two
Estimated Capacity (MW)	2,200	2,200
Greenfield Site	Yes	No
Expansion of Existing Site	No	Yes
Expected First Unit Delivery Year	2021	2016
Expected Second Unit Delivery Year	2023	2017
Federal Loan Guarantee	No	Yes
Early Financing Cost Recovery	Yes	Yes
Ongoing Reporting to State Commission	Yes	Yes
Current Total Cost Estimate	$22.5 billion	$14 billion

Cost Assumptions

In our analysis of Levy, Vogtle, and potential alternatives to each, we calculate the levelized costs for each option.

Levelization is a helpful way to compare the cost of different supply- and demand-side alternatives since it takes into account both investment and operating costs over time. It is the standard method for taking fixed and variable costs and converting them into a single total cost of energy, typically expressed as dollars per megawatt hour (MWh).

It is reasonable to think of levelized costs as a range rather than single point values since uncertainties exist in both investment and operating costs for different resources and technologies; differences in site-specific factors also influence costs for individual projects.

In this report, we have detailed our estimation of specific cost ranges for the Levy and Vogtle projects. We discuss qualitatively the drivers of cost uncertainty for other resources in Appendix D.

The levelized costs of these alternative resources are provided as points of comparison to the proposed nuclear projects.

To identify a cost range for the Levy and Vogtle projects, we first determined the low end of the range by converting the project costs currently reported by the two companies to levelized costs.

High-end cost estimates for the two projects were determined based on historical precedent for the two companies. Historical information provides a reasonable, if uncertain, proxy for future nuclear construction costs associated with a new, unproven design.[10]

The intention of the levelized cost analysis is to provide ratepayers and policymakers with a useful and plausible range of costs to reference in considering these two projects. However, our costs for these projects do not include nuclear waste disposal and decommissioning costs, which are another, albeit uncertain, cost component of nuclear power. These cost ranges, expressed in dollars per megawatt hour, are discussed in Sections 3 and 4 of this report.

The range in our cost estimates reflects the uncertainty associated with developing complex projects with the newly designed AP1000 reactor in this country. More detail about our levelized cost inputs is provided in Appendix B.

Subsidies

An important factor influencing the levelized cost of electricity for the Vogtle project is the availability of a Production Tax Credit (PTC) of $0.018 per kWh for the first 6,000 MW of capacity (nationwide) for the first eight years of operation. This PTC is capped at $125 million per year per 1,000 MW of capacity.

The PTC was included as part of the Energy Policy Act of 2005, and currently requires a unit to have an in-service date before January 1, 2021. In our calculations of the levelized cost for Vogtle 3 and 4, which are currently scheduled to come online in 2016 and 2017, we have assumed that both units will receive the full amount of the PTC. On the other hand, in our analysis of the Levy project, we have assumed that Levy 1, slated for delivery in 2021, will not meet the PTC cut-off date. Levy 2, which is projected to come online in 2023, does not receive the PTC either.

While the PTC reduces the cost of the Vogtle project for developers and, ultimately, ratepayers, it is not free money. The project costs covered by the PTC are paid by taxpayers.

Capital costs for Vogtle 3 and 4 also include the impact of a federal loan guarantee that is discussed later in this report. In addition to reducing the borrowing costs, a major impact of the loan guarantee will be an increase in the debt fraction and a significant decrease in the equity costs. Similar to the PTC, the federal loan guarantee serves to shift risks associated with the Vogtle project onto taxpayers.

Structure of This Report

This report discusses the Levy project in Section 3 and the Vogtle project in Section 4. Findings and recommendations specific to each project are included in these sections.

[10] Kessides, I. Nuclear power: Understanding the economic risks and uncertainties. Energy Policy. 38(2010) 3849-3864. As noted by the author, “There is widespread agreement that the best predictors for the future costs of nuclear plants are based on actual experience rather than detailed engineering cost models and estimates.”

The appendices that follow provide information relevant to both projects, including nuclear costs and risks, input assumptions, and other important data.

3. Florida: Levy 1 and 2

Progress Energy is proposing to build two new reactors, Levy 1 and 2, with a combined generating capacity of approximately 2,200 megawatts (MW). This greenfield project was originally proposed in 2006; at the time, Progress was proposing one 1,100 MW unit for the Levy site, at a projected cost of $2.5 to $3.5 billion.[11] In 2008, when Progress filed a petition for an affirmative Determination of Need, the company changed its proposal to include two reactor units for the Levy site, with an estimated cost (including Transmission) of approximately $17 billion, and an expectation that the reactors would come online in 2016.

Cost Escalation & Delays

During the first half of 2010, Progress announced another increase in the expected cost of the project, from $17 to $22.5 billion.[12] The projected cost for the Levy project has already increased nearly four-fold (per 1,100-MW unit) from Progress Energy's original estimate in 2006—before construction work has even begun. Based on an analysis of recent testimony from the company, we calculate the current projected cost of the two units to be even higher.[13]

As with prior-generation nuclear projects, Levy's cost escalation is being driven largely by regulatory and construction delays. In Progress Energy's 10-Q filing on November 8, 2010 ("Nov. 8 10-Q"), the company noted that:

> In 2009, the NRC Staff determined that certain schedule-critical work that PEF [Progress Energy Florida] had proposed to perform within the scope of the Limited Work Authorization will not be authorized until the NRC issues the COL [Combined Operating License]. Consequently, excavation and foundation preparation work will be shifted until after COL issuance. This factor alone resulted in a minimum 20-month schedule shift later than the originally anticipated timeframe. Since then, regulatory and economic conditions have changed, resulting in additional schedule shifts. These conditions include the permitting and licensing process, national and state economic conditions, recent FPSC DSM goals and the resulting impact on ratepayers, and other FPSC decisions. Uncertainty regarding PEF's access to capital on reasonable terms and increasing uncertainty surrounding carbon regulation and its costs could be other factors to affect the Levy schedule.

With the anticipated delays, Levy 1 is now scheduled for delivery in 2021 and Levy 2 is scheduled for 2023. If industry experience is a guide, further delays are likely. The company's 2011 Ten-Year

[11] *Gainesville Sun*. "Utility Eyes Site for Nuclear Plant." December 13, 2006. Available at http://tinyurl.com/6jm8qmn.
[12] Reuters. "Progress ups Levy nuclear costs, delays start." May 6, 2010. Available at http://www.reuters.com/article/idUSN0611303620100506.
[13] Synapse estimates the current cost of the project at $23.9 billion. This is based upon data from John Elnitsky testimony dated May 2, 2011, Exhibit RE-4, and carrying cost allocation from Progress Energy's 2010 Ten-Year Site Plan dated April 1, 2010.

Site Plan, dated March 31, 2011, does not include the proposed Levy project, since it is outside of the current ten-year planning horizon.[14]

The following exhibit outlines some of the major benchmarks associated with the project to date.

Exhibit 3. Chronology of Events for Progress Energy: Levy 1 and 2

Year	Month	Event	Completion Date	Cost Estimate	Note
2006	Dec.	Progress selects Levy site for single unit	2016 Unit 1	$2.5 to $3.5 billion	1
2008	March	Progress triples cost estimates for Levy Units 1 and 2 to $17 billion	2016 Unit 1 2018 Unit 2	$17 billion	2
2008	July	Florida PSC approves need for two units			3
2008	Aug.	Construction and operating license filed with NRC			4, 5
2008	Aug.	Approval given to project from governor and his cabinet			6
2009	Jan.	Progress signs contract for reactor design			7
2009	May	Progress files 2010 cost recovery plan to PSC			8
2009	May	Progress announces at least a 20-month delay on planned reactors			9
2010	Jan.	Progress announces unspecified delays to Levy project based on Florida PSC decision that denied $500 million rate hike request			10
2010	Feb.	Progress extends delay on Levy project to at least 36 months	2019 Unit 1 2021 Unit 2		11
2010	May	Cost estimate for project increases from $17.2 billion to $22.5 billion		$22.5 billion	12
2010	May	The timeline for the Levy project is delayed to 2021 for Unit 1 and 2023 for Unit 2	2021 Unit 1 2023 Unit 2		13

Notes:
1. http://news.google.com/newspapers?id=jrQpAAAAIBAJ&sjid=U-wDAAAAIBAJ&pg=2316,2730406&dq=progress+energy+levy&hl=en
2. http://www.sptimes.com/2008/03/11/Business/Price_triples_for_Pro.shtml
3. http://www.psc.state.fl.us/home/news/index.aspx?id=418
4. http://www.nrc.gov/reactors/new-reactors/col/levy.html
5. http://www.reuters.com/article/idUSN0147884920080801
6. http://www.world-nuclear-news.org/NN-Florida_cabinet_approves_Levy_plant-1208094.html
7. https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Florida+signs+contract+for+new%2C+advanced-design+nuclear+plant&pubdate=01-05-2009
8. https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+shifts+Levy+nuclear+project+schedule+&pubdate=05-01-2009
9. http://uk.reuters.com/article/2009/05/01/utilities-nuclear-progress-idUKN0134187020090501
10. http://articles.orlandosentinel.com/2010-01-14/business/os-progress-energy-nuclear-power-20100114_1_nuclear-power-rate-hike-plant
11. http://www.istockanalyst.com/article/viewiStockNews/articleid/3880743
12. http://www.businessweek.com/ap/financialnews/D9HQ2TN80.htm
13. http://www.cleanenergy.org/index.php?/Press-Update.html?form_id=8&item_id=184
    http://flaglerlive.com/25200/progress-energy-nuclear-costs

[14] Progress Energy. "Progress Energy Florida, Inc. Ten-Year Site Plan dated April 2011, 2010-2020." Available at http://www.floridapsc.com/utilities/electricgas/10yrsiteplans.aspx.

This exhibit shows that the project has already experienced significant cost escalation and multiple delays. Levy is not alone in this trend. Other modern-day nuclear projects are experiencing similar escalations in cost, as well as delays due to unforeseen regulatory, construction, and economic challenges. The Fukushima disaster in Japan is raising nuclear safety questions that could cause additional delays. See Appendix A for more information.

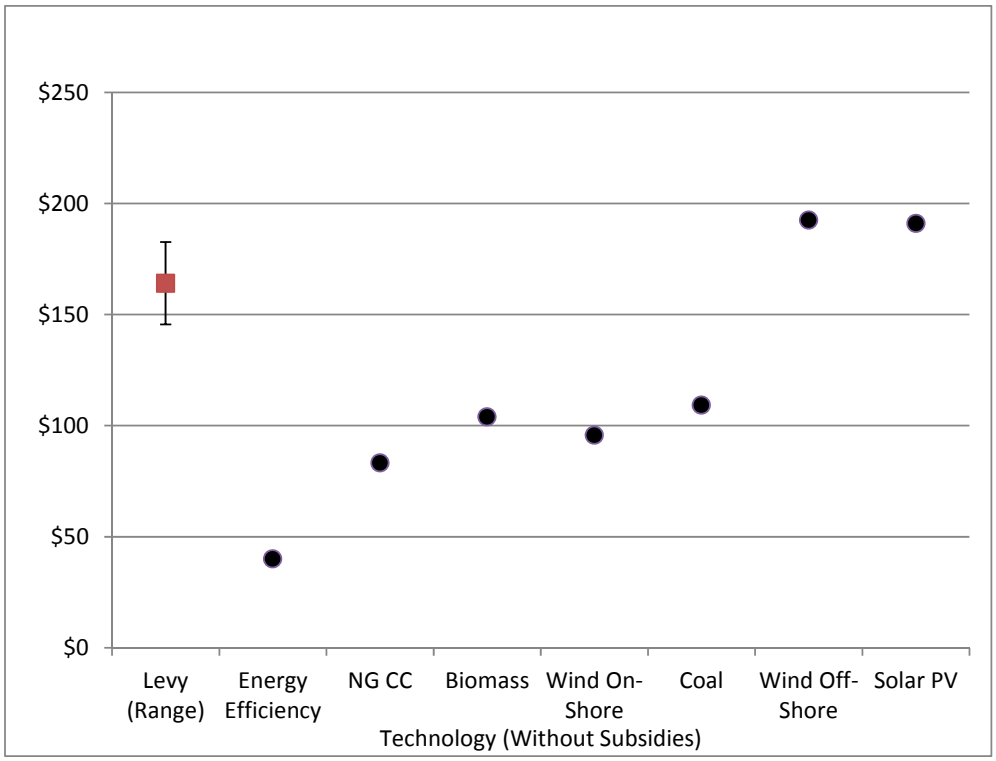
Given Progress Energy's announcements and the delay in *starting* the project, we anticipate that the company's most recent estimate of $22.5 billion is unlikely to be the final cost for the Levy project. Progress's Nov. 8 10-Q indicates that additional cost and schedule changes are expected: "…once PEF receives the COL, it will further refine the project timeline and budget."

In this report, we estimate the levelized cost range for Levy 1 and 2 to be $146 – $183 per MWh (see Exhibit 4, below).

- **Low estimate:** In the study, we use the current $22.5 billion project cost as the starting point, resulting in a low-end levelized cost estimate of $146 per MWh.
- **High estimate:** Given that the project cost for Levy has already increased several times, our high-end estimate assumes that costs will continue to rise. In the study, the high-end cost estimate is based on a 30-percent increase in the current cost of the Levy project. While this number is an estimate (based on Progress Energy's 30-percent increase in Levy construction costs between 2008 and 2010), it is certainly a plausible, potential outcome given Levy's observed trend of cost increases. The result is a high cost estimate of $183 per MWh, or $29.3 billion dollars (nominal) for the project when Unit 2 is currently scheduled for completion in 2023.
- **Mid-range estimate:** The mid-range cost estimate is based on a 15-percent increase in the current project cost, resulting in an estimate of $164 per MWh, or $25.9 billion dollars (nominal) for the project when Unit 2 is currently scheduled for completion in 2023.

For the other technology alternatives, we present our mid-range estimates for project installation in 2016, recognizing that there are cost uncertainties for any project.

Exhibit 4. Levelized Cost Range for Levy Compared to Mid-Range Estimates of Alternatives Excluding Tax Credits (2010$/MWh)



As shown in Exhibit 4 (above), on a levelized basis, energy-efficiency, combined-cycle natural gas, biomass, on-shore wind, and coal are all less expensive options than the $164/MWh mid-range estimate for the Levy project.[15] If we were to include the impact of tax credits ($55/MWh), the cost of solar PV would also be lower than the Levy mid-range estimate.

Adding to the risk for Florida ratepayers, state law allows Progress to collect money from its customers to pay for this costly project through a rate recovery mechanism—referred to as "early cost recovery"—long before the plant comes online and produces any benefits for electricity customers.

High Costs & Risks to Ratepayers

The nuclear construction cost recovery (NCCR) rule in Florida allows utilities to recover certain preconstruction and construction costs for a nuclear power plant prior to its commercial operation.[16] In addition, the NCCR rule allows for utilities to recover costs should they elect not to complete, or are precluded from completing, construction of a nuclear power project or uprates to existing reactors.

[15] Utility scale solar PV, which is a peaking resource with different economics, and off-shore wind show up higher in this comparative analysis.
[16] The NCCR rule is available at https://www.flrules.org/gateway/ruleno.asp?id=25-6.0423.

Progress has already begun collecting money from its customers for the Levy project. In 2010, an average Progress Energy residential customer using 1,100 kWh a month paid approximately $7.46 per month, or $89.52 for the year, to fund the Levy project. In 2011, that monthly charge went down to $6.08 per month ($72.99 for the year) due to schedule changes that delayed anticipated site work and associated expenses. In recent hearings, Progress Energy has asked to reduce the monthly charge further, to approximately $5.14 per month, for the Levy project.[17]

Progress has argued that customers will benefit in the long-run from the NCCR rule through reduced interest payments associated with financing the construction costs of the project. However, in reality this policy serves to shift the financing costs of this expensive project from Progress shareholders to its ratepayers during the construction period. In effect, ratepayers are forced to provide Progress with an interest-free loan, while the company shifts all the risk to consumers.

In a 2009 filing with the Florida PSC, Progress provided a cost recovery impact for the Levy project, which is summarized in Exhibit 5 below. While Progress's cost recovery impact was presented based on 1,000 kWh per month usage, the bill impacts shown in Exhibit 5 are calculated on 1,100 kWh per month usage. This is consistent with the 2009 EIA Form 826, which indicates that the average Progress Energy residential customer currently consumes 1,100 kWh per month.

Exhibit 5 shows that, based on the company's current cost estimate of $22.5 billion, the additional *monthly* charge from the Levy project for a customer using 1,100 kWh per month increases from $8.78 in 2013 to $59.83 in 2021. It is uncertain how the cost estimate will actually fluctuate year to year based on the current delay in the project's schedule and the amounts approved by the Florida PSC. Should the project come in at a higher cost than $22.5 billion, ratepayers will pay a correspondingly larger amount.

[17] Amounts from Progress Energy (2011). Progress Energy Florida makes annual fuel and environmental filings with the Florida Public Service Commission. Press Release: https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Florida+makes+annual+fuel+and+environmental+filings+with+Florida+Public+Service+Commission+&pubdate=09-01-2011

Exhibit 5. Proposed Cost Recovery for Levy[18]

Year	Monthly Impact	Annual Impact
2013	$8.78	$105.34
2014	$26.16	$313.90
2015	$10.62	$127.38
2016	$18.52	$222.29
2017	$28.66	$343.86
2018	$37.90	$454.74
2019	$48.26	$579.08
2020	$54.22	$650.63
2021	$59.83	$717.95

Based on monthly consumption of 1,100 kWh from EIA Form 826 2009 data for Progress Energy, and Progress Energy response to Office of Public Counsel's Third Interrogatories (No. 47) dated July 7, 2010 in Docket 100009-EI.

Better Alternatives Available in Florida

Given the high cost of the Levy project, the likelihood of continued cost escalation, the projected impact on ratepayers, and other associated risks, it is well worth considering alternative options in Florida that could meet the anticipated demand growth at a lower cost. This is especially true in light of Progress Energy's dwindling demand forecast, which has made the need for new supply-side resources far less urgent than it might have been when the Levy project was first proposed.

Time on Our Side

Growth in electricity usage is one of the determinants utilities use to assess the need for new supply resources. Accelerating electricity usage helps to justify new supply resources, such as Levy 1 and 2, in order to meet increased electricity sales.

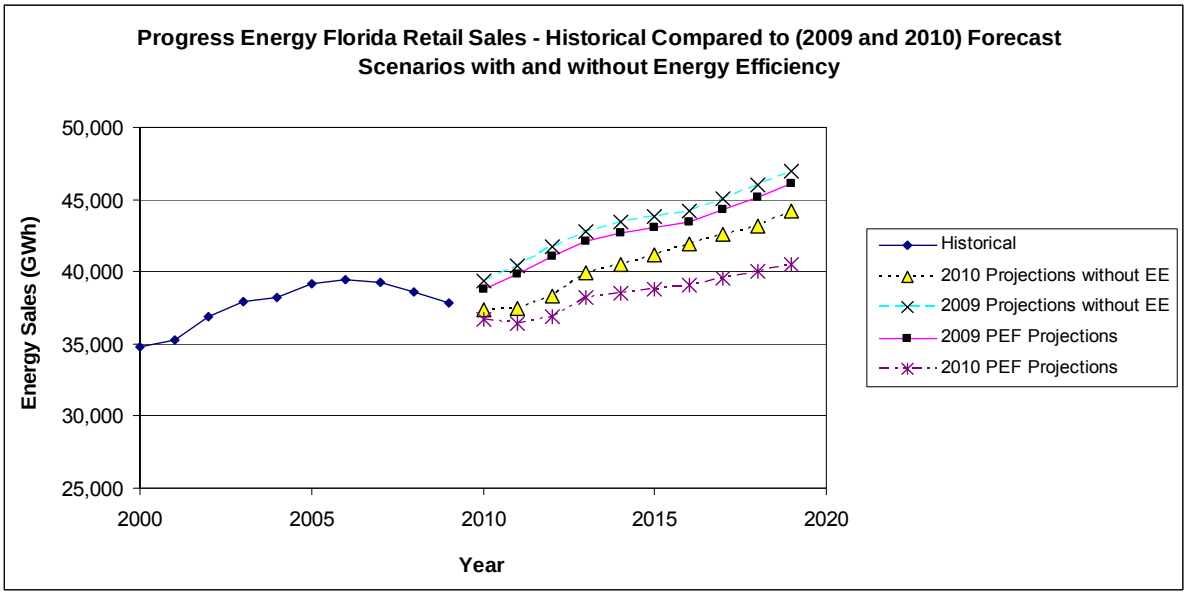
However, the recession that began in 2008 has slowed economic growth and corresponding electricity demand growth in Florida. Exhibit 6 shows that Progress saw a *decline* in annual retail sales between 2006 and 2009. As a result of changing economic conditions, Progress has lowered its summer peak load forecast by 14.4 percent for 2016, the year the project was originally scheduled for completion.[19]

[18] Progress Energy Florida. Supplemental Response to Office of Public Counsel's Third Set of Interrogatories (No.47) dated July 7, 2010 in Docket 100009-EI.

[19] Progress Energy's 2007 Ten-Year Site Plan projected a 2016 summer peak load of 12,906 MW. The 2011 Ten-Year Site Plan projects a summer peak load of 12,044 MW in 2020, or a decrease of 6.6 percent over the ten-year planning horizon.

The company's historical load growth from 2000 through 2007 was 1.7 percent. In 2009, Progress forecasted that its annual compound load growth of retail sales for 2010 – 2018 would be 1.4 percent.[20] In 2010, Progress's 10-year growth projection fell to 0.8 percent.

Exhibit 6. Electricity Sales Growth Scenarios



Based on Progress Energy's 2010 Ten-Year Site Plan forecast, energy sales will not reach the level last seen in 2006 until 2017. Slowing energy sales growth—either by design (as detailed more fully below) through energy efficiency, or due to sluggish economic conditions—has provided ample time to consider alternatives less costly than the Levy project to meet forecasted customer demand.

In fact, our analysis shows that viable alternatives to the proposed Levy project already exist; investments in energy efficiency can reduce energy demand immediately, while the incorporation of renewable energy can meet the remaining demand needs as they arise.

Energy Efficiency

A review of recent data shows that Florida has significant room to grow its investment in energy efficiency:

- The Florida PSC recently approved demand-side management plans for Progress that are projected to capture a maximum of 2 percent energy savings over a 10-year period.[21] This is even lower than an earlier goal set by the PSC in 2009, which called for energy savings

[20] Analysis includes only Progress Energy Florida retail sales. Wholesale sales, utility consumption, and line losses not included in the analysis. Together these components would increase load by approximately 14 percent, or on average by 7,327 GWh. Progress now forecasts that the compound annual growth in these components will be 0.14 percent between 2010 and 2019.
[21] http://www.aceee.org/sector/state-policy/florida

of 3.5 percent over a 10-year period, and is only a fraction of the goal recommended by the Commission staff's own expert.[22]

- Seventeen other states have set energy efficiency targets between 1.0 and 2.3 percent annually, with six states setting targets of at least 2.0 percent per year.[23]
- According to data from the American Council for an Energy-Efficient Economy (ACEEE) and the Energy Information Administration (EIA),[24] Florida saved 348,360 MWh in 2008 due to energy efficiency. Florida's per capita spending on energy efficiency was $7.15 across the state, well below the national average per capita spending of $11.08.[25] Leading states are investing even more in energy efficiency; the top five states per capita spending on energy efficiency range from $27.01 to $49.38.[26]
- According to the Southern Alliance for Clean Energy (SACE), Florida's largest utilities currently achieve energy efficiency of less than 0.2 percent of electricity sales. SACE estimates that energy efficiency investments would cost 2 – 4¢/kWh, while the average cost for electricity in the state is 12¢/kWh.[27] In comparison, the cost of energy from Levy, using our analysis, would be 17¢/kWh.
- In 2007, ACEEE conducted a study on the potential for energy efficiency and renewable energy to meet Florida's growing energy demands.[28] The study found that Florida could reduce its projected future electricity use by about 19 percent through energy efficiency programs.

Our analysis shows that, if Progress Energy Florida pursued an aggressive but achievable energy efficiency target of 1.5 percent of annual retail sales, it would result in virtually flat load growth from 2012 onward, using the 2010 ten-year forecast. This level of EE would place Progress above what many utilities have historically achieved, but still well below the savings and commitments of the most aggressive utilities, and well below ACEEE's identified potential of 19 percent of end-use sales by 2023.

This higher energy efficiency target (leading to a cumulative savings of 14 percent of retail sales by 2019) would enable Progress to maintain annual sales below its 2006 peak level. It would also negate the need to invest $22.5 billion in new nuclear units.

However, if Progress reduces its energy efficiency target to 880 GWh by 2019, as suggested in continuing with the company's current energy efficiency targets, load growth will rise through 2019, thus providing the company with additional justification to build Levy 1 and 2.

[22] Direct Testimony of PSC Staff Expert Richard Spellman, Docket No. 080407-13, July 17, 2009.
[23] ACEEE. The 2010 State Energy Efficiency Scorecard. Report Number E097.E107. October 2010. Available at http://www.aceee.org/research-report/e107.
[24] http://www.aceee.org/sector/state-policy/florida.
[25] Data from Appendix E. ACEEE 2010 Scorecard.
[26] ACEEE (2010). Per capita spending on energy efficiency for the top five states: 1) Vermont ($49.38), Rhode Island ($28.01), 3) Massachusetts ($27.88), 4) Hawaii ($27.41), and 5) California ($27.01).
[27] Southern Alliance for Clean Energy, "Removing Barriers to Energy Efficiency Investment is Key to Slashing Customer Electricity Bills and Creation of Clean Energy Jobs" February 2010. Available at http://www.cleanenergy.org/images/factsheets/Fla%20EE%20Recom%20Brief-SACE-Feb%202010.pdf.
[28] ACEEE, "Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demands." February 2007. Available at http://www.aceee.org/sites/default/files/publications/researchreports/e072.pdf.

While increasing funding for an aggressive energy efficiency program would require an initial investment that would result in a slight increase in electricity prices (compared to what ratepayers pay today), overall electricity bills would be lowered as customer electricity consumption is reduced. This investment in EE would defer or even prevent the need for investments in more expensive generation and associated transmission and distribution facilities, and further insulate consumers from potential increases in fuel costs.[29]

Finally, if we take Progress's 2010 Ten-Year Site Plan savings of 3,200 GWh and multiply that by an assumed cost of energy efficiency of $0.027/kWh, the result is a rough approximated cost of $0.086 billion—a tiny fraction of the current price tag of $22.5 billion for Levy 1 and 2. Importantly, the cost of EE could be even less: research by Synapse in 2008 has shown that utilities are achieving economies of scale as efficiency programs increase.[30] More detail on the costs of carbon abatement options is provided in Appendix F.

Renewable Energy

While increased energy efficiency could flatten load growth for Progress Energy, a concurrent increase in renewable energy could actually *reduce* system load and allow for the retirement of older, polluting, more expensive fossil-fired generation.

No renewable energy mandates currently exist in Florida, and the potential for renewable energy development is significant. According to a 2008 Navigant Consulting report prepared for the Florida PSC, the technical potential for renewable energy in Florida by 2020 ranges from 136,393 to 142,862 MW (see Exhibit 7 below).[31]

The report found that Florida currently has about 1,500 MW of renewable energy capacity, most of which is biomass. Photovoltaic accounts for 1.8 MW, and hydroelectric accounts for another 64 MW. The current generation mix for Progress Energy Florida is presented in Appendix C.

[29] A more detailed description of associated benefits resulting from aggressive energy efficiency may be found in the Synapse report, "Cost and Benefits of Electric Utility Energy Efficiency in Massachusetts." Available at http://www.synapse-energy.com/cgi-bin/synapsePublications.pl.

[30] Takahashi, Kenji., Nichols, David. The Sustainability and Costs of increasing Energy Efficiency Impacts: Evidence from Experience to Date. 2008 ACEEE Summer Study on Energy Efficiency in Buildings, August 20, 2008. Available at http://www.synapse-energy.com/Downloads/SynapsePresentation.2008-08.0.Sustainability-and-Costs-of-Efficiency-Impacts.S0051.pdf

[31] While the results of other renewable potential studies and installed projects may suggest changes to the exact aggregate numbers in the Navigant report, these modifications do not change the fact, as demonstrated in Exhibit 7, that there is a large, untapped potential for renewable resources in Florida.

Exhibit 7. Navigant Florida Renewable Energy Technical Potential

Resource	Technical Potential (MW)
Photovoltaic on rooftops	52,000
Photovoltaic in ground arrays	37,000
Concentrated solar power	380
Solar water heating	1,136
Onshore wind	186
Offshore wind	40,311
Biomass (available but not collected)	400 - 1,359
Biomass (potentially available)	3,945 - 9,555
Landfill gas (new sites)	110
Anaerobic digester gas	35
Waste heat (sulfuric acid conversion)	140
Ocean current	750
Total	**136,393 - 142,862**

While the *technical potential* indicates what is technically achievable, Navigant also quantified the *achievable potential* for these technologies. Navigant's conclusions were based on a number of economic conditions and policy options, such as the adoption of Renewable Energy Certificates (RECs).[32] Navigant found that, even without RECs, the installed renewable capacity in Florida could range from 2,000 to 8,000 MW, and account for 4 to 16 percent of electricity sales in 2020.[33]

Under Navigant's mid-case, no RECs scenario, they forecast the introduction of 18,668 GWh of renewable energy into Florida by 2019.[34] Since Progress Energy accounts for 17.6 percent of Florida's total end-use consumption, this implies a renewable energy potential of 3,213 GWh by 2019 for Progress Energy alone. [35]

The combined impact of the aggressive energy efficiency (1.5 percent per year) and renewable energy (3,213 GWh by 2019) scenarios is shown in the following graph of load forecast for the company.

[32] Renewable energy certificates are the transferable right associated with the generation of one megawatt-hour of electricity from a renewable generator. Because electrons are themselves indistinguishable by generation source, RECs are means to document the environmental and/or other non-power attributes of renewable electricity generation for REC buyers and sellers. RECs are generally priced based on a per megawatt-hour basis.
[33] With RECs, the achievable potential for the state would be between 2,500 and 16,000 MW, depending on economic conditions, which would account for 5 to 24 percent of retail electricity sales in 2020.
[34] At the low end of Navigant's ranges is 9,573 GWh (under the unfavorable scenario without RECs), and at the high end is 40,529 GWh (under the favorable scenario with RECS) by 2019.
[35] Florida Public Service Commission. Statistics of Florida Electric Utility Industry 2007. (September 2008) Available at http://www.publicpower.com/pdf/stats/statistics-2007.pdf.

Exhibit 8. Adjustments to Progress Energy's 2010 Load Forecast through the Adoption of Aggressive Energy Efficiency and Navigant 2008 Mid-Range Renewable Energy Potential

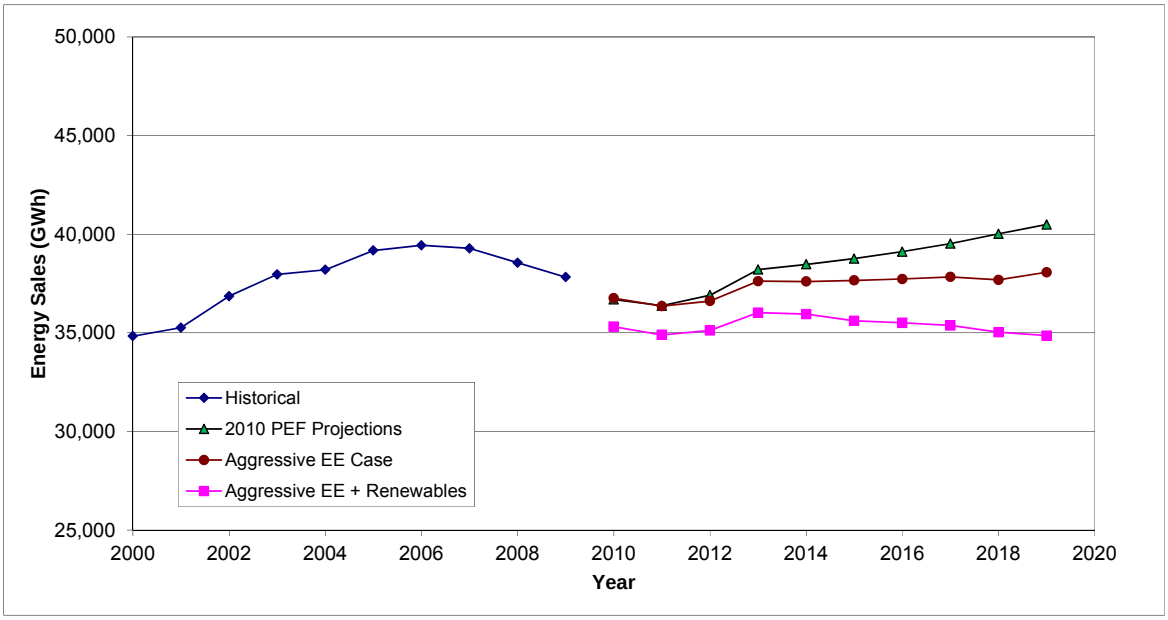


Exhibit 8 illustrates that through a concerted effort to increase energy efficiency and renewable energy, Progress could reduce its need for thermal generation to 2000 levels by 2019.

Findings & Recommendations

This analysis shows that there are much less costly alternatives available to meet the electricity needs of utility customers in Florida than the proposed new nuclear reactors at Levy. These alternatives include more aggressive energy efficiency programs, renewable energy development, and potentially natural gas plants—all of which could be implemented at lower cost, in smaller increments, and more quickly than the proposed Levy project.

Despite the availability of these lower-cost and less risky options, Progress Energy Florida continues to pursue a $22.5 billion project that will result in increasingly higher costs and present much greater risks to its ratepayers.

Key findings of our analysis include the following:

- The project schedule for Levy 1 and 2 has been significantly delayed due to regulatory challenges and deteriorating economic conditions in the state since the plant was first proposed, adding five years to the initially proposed operating dates. Concurrent with these delays in the project schedule, Progress has increased its construction cost estimates by $5 billion, or approximately 30 percent, between 2008 and 2010. An analysis of industry trends leads us to be skeptical that the company's projected cost for the project will remain at $22.5 billion.
- Our mid-range analysis of the levelized cost for the project is $164 per MWh. This would place the cost of the two units well above our mid-range cost estimates for alternatives such as energy efficiency, renewable energy resources, and conventional generation.

- Progress Energy's own filings show that, based on current cost estimates, its residential ratepayers will pay $718 per year by 2021 for the Levy project—even before it generates any electricity. Should project costs increase further, customers will see a corresponding increase in their bills.

Based on these findings, we strongly recommend that the State of Florida and Progress Energy pursue more sustainable and cost-effective alternatives to the Levy project. Specifically:

- Florida should take steps to increase its energy efficiency targets to levels more consistent with leading states. If Progress Energy were to pursue an aggressive energy efficiency target of 1.5 percent of annual retail energy sales, the company could maintain its energy load below 2006 levels based on its 2010 Ten-Year Site Plan retail sales forecast—without the Levy units. While a 1.5 percent annual target is well above Florida's current energy efficiency goal (expected to achieve a total of 2 percent energy savings over 10 years), it is well below savings targets achieved by utilities in leading states.
- Any additional demand growth in Florida can be met through available and cost-effective renewable energy resources and conventional resources such as natural gas. Development of these resources could further allow Progress to retire some older, less-efficient, and more expensive generating plants.

4. Georgia: Vogtle 3 and 4

Georgia Power and its consortium partners have started site work to expand the Vogtle nuclear station by adding two new units, Vogtle 3 and 4. Combined, these new units would add approximately 2,200 MW of generation capacity. Georgia Power anticipates that Vogtle 3 will be completed in 2016 and Vogtle 4 in 2017, at a total cost of $14 billion.

Both the scheduled completion date and total estimated cost of the project remain the same as when the project was announced in 2006; however, given recent press announcements about delays with rebar, backfill, and NRC licensing of the Westinghouse AP1000 design, we anticipate that the final project cost and schedule are far from certain.[36]

According to our analysis, the levelized cost range for Vogtle 3 and 4 is $63 – $168 per MWh. In all of the estimates, we have included the impact of the federal loan guarantee and production tax credits for the project.

- **Low estimate:** At the low end, using Georgia Power's current project cost of $14 billion, the levelized cost of electricity from Vogtle 3 and 4 would be $63 per MWh.
- **High estimate:** In the absence of well-documented, publically available information from the company on which to base our analysis, we have based the high estimate for Vogtle on historical precedent. In 1972, Georgia Power estimated the cost for the original Vogtle project (Vogtle 1 and 2) to be $5.63 billion (in inflation adjusted 2007$).[37] When both units were completed in 1988, the final cost was $17.09 billion, or a real cost increase of 304 percent. For Vogtle 3 and 4, we calculated the high end of the cost range by taking two-thirds of the historical 304-percent increase for Vogtle 1 and 2.[38] This results in a high-cost estimate of $168 per MWh for the project. The high-end estimate for this plant does not necessarily imply certainty in project costs, only a possible outcome that should be considered given the lack of well-documented, publically available information from the company. The final cost of the next generation of nuclear plants is simply unknown.
- **Mid-range estimate:** Our mid-range cost estimate for Vogtle 3 and 4 is one half of the Vogtle 1 and 2 high estimate cost trajectory, resulting in an estimate of $115 per MWh.

These levelized cost estimates factor in two subsidies currently available to the Vogtle project:

- Under the Department of Energy (DOE) Title XVII loan guarantee program, the project has been awarded $8.33 billion in federal loan guarantees that will allow Vogtle's owners to finance a substantial portion of their construction costs at interest rates well below market rates, and to increase their debt fraction, which significantly reduces overall financing costs.

[36] Recent testimony from the project's construction monitor, William Jacobs, highlights unresolved issues relating to the project. See Jacobs, W. Direct Testimony of and Exhibits of William Jacobs, Jr., PhD. Docket 29849. Dated December 10, 2010. (p.5-6).
[37] From EIA Form 257 data provided by James Hewett of EIA.
[38] We chose the historical costs for Vogtle 1 and 2 as a starting point for our cost projections for several reasons. One, Vogtle 1 and 2 have the same ownership structure as Vogtle 3 and 4. Two, all four units would be on the same location, so site specific issues would be the same. Three, the cost escalations for Vogtle 1 and 2 are documented.

- Vogtle's current project schedule would also allow the plant to receive a production tax credit capped at $125 million per year per 1,000 MW of capacity for the first eight years of production—assuming the project comes online in time to qualify.

Lack of Transparency and Associated Risks

A key risk specific to the Vogtle project is the lack of transparency. While detailed information about the project's cost and schedule is provided to the Georgia Public Service Commission (PSC) in Georgia Power's construction monitoring filings,[39] the company has classified almost all of this cost and schedule information as trade secret.

In June of 2010, the Georgia PSC found that Georgia Power's estimated cost for its share of the project is reasonable and remains at $6.1 billion, since the company was granted the early recovery of financing costs in 2009 through the passage of the Georgia Nuclear Energy Financing Act.[40] The lack of transparency surrounding this project, however, undermines such assurances of cost reasonableness, hinders independent analyses of Georgia Power's assumptions, and exposes Georgia Power's ratepayers to greater risk.

While Georgia Power has redacted quantitative information, some of the risks associated with the Vogtle project have been expressed in qualitative terms in filings made by the Independent Construction Monitor (ICM). The ICM was hired by the Georgia PSC, using Georgia Power's money, to provide monthly progress reports on the Vogtle project.

In June of 2011, testimony from the ICM identified unresolved issues from the previous construction monitoring report that include:[41]

- Design and fabrication of modules and sub-modules at the Shaw Modular Solutions ("SMS") facility as required to meet the project schedule; and
- Production of Vogtle-specific Certified for Construction ("CFC") construction packages as required to meet the project schedule.

The ICM's testimony also identified new issues that could potentially impact the project schedule, including:

- Certification of the AP1000 Design Control Document ("DCD") by the NRC as required to meet the project schedule;
- Issuance of the Vogtle Combined Operating License ("COL") by the NRC as required to meet the project schedule; and
- Recovery of Unit 3 COD to April 1, 2016.

The following exhibit outlines some of the benchmarks associated with the Vogtle project to date:

[39] Georgia Public Service Commission. Docket No. 29849.
[40] Georgia Public Service Commission. Docket No. 27800, Georgia Power's Application for the Certification of Units 3 and 4 at Plant Vogtle and Updated Integrated Resource Plan Order on Remand. June 17, 2010. The Commission's June 2010 order in Docket 27800 references Georgia Power's original estimate of $6.4 billion and the adjustment to $6.1 billion based on the recovery of financing costs from Georgia Power ratepayers through the passage of the Georgia Nuclear Energy Financing Act.
[41] Jacobs, William. Direct Testimony and Exhibits In the Matter of Georgia Power Company's Fourth Semi-Annual Vogtle Construction Monitoring Report." Docket 29849, filed June 9, 2011. Page 6.

Exhibit 9. Chronology of Events for Georgia Power: Vogtle 3 and 4

Year	Month	Event	Completion Date	Cost Estimate	Note
2006	Aug.	Early site permit application filed with NRC			1
2007	Aug.	Limited work authorization application filed with NRC			2
2008	March	Construction and operating license application filed with NRC			3
2008	March	Georgia Power files certification request with Georgia Public Service Commission			4
2008	April	Contract signed with Westinghouse for reactor design			5
2008	Aug.	Environmental Impact Statement filed			6
2009	March	Georgia PSC approves new Vogtle units. Total cost of project estimated at $14 billion. Georgia Power's share will be $6.4 billion			7
2009	Aug.	NRC grants Early Site Permit			8
2010	Feb.	Georgia PSC approves cost of new units. Stipulation lowers cost from $6.4 to $6.1 billion	2016 Unit 3 2017 Unit 4	$14 billion	9
2010	Feb.	Federal loan guarantees granted. Total guaranteed borrowings would not exceed 70 percent of the company's eligible projected costs, or approximately $3.4 billion, and are expected to be funded by the Federal Financing Bank. Any guaranteed borrowings would be full recourse to Georgia Power and secured by a first priority lien on the company's 45.7 percent ownership interest in the project.			10, 11
2010	Sept.	NRC's draft Supplemental Environmental Impact Statement states that it has not found an environmental reason to deny a COL			12
2011	Jan.	Beginning of early cost recovery plan upon ratepayers			13
2012		Anticipated approval of construction and operating license application			14

Notes:
1. http://www.nrc.gov/reactors/new-reactors/esp/vogtle.html
2. http://www.nrc.gov/reactors/new-reactors/esp/vogtle.html
3. http://www.nrc.gov/reactors/new-reactors/col/vogtle/documents/nrc-2008.html
4. http://www.world-nuclear-news.org/NN-Georgia_PSC_approves_new_Vogtle_units-1803094.html
5. http://www.world-nuclear-news.org/IT-EPC_contract_signed_for_new_Vogtle_units_-090408.html
6. http://www.nrc.gov/reactors/new-reactors/esp/vogtle.html
7. http://www.world-nuclear-news.org/NN-Georgia_PSC_approves_new_Vogtle_units-1803094.html
8. http://www.nrc.gov/reactors/new-reactors/esp/vogtle.html
9. http://www.walb.com/global/Story.asp?s=12045857
10. http://www.world-nuclear-news.org/NN-Georgia_Power_accepts_Vogtle_loan_guarantee-2106107.html
11. http://southerncompany.mediaroom.com/index.php?s=43&item=2044
12. http://www.world-nuclear-news.org/NN-NRC_gives_planned_Vogtle_units_environmental_OK-0809104.html
13. http://www.world-nuclear-news.org/NN-NRC_gives_planned_Vogtle_units_environmental_OK-0809104.html
14. http://www.powermag.com/nuclear/Plant-Vogtle-Leads-the-Next-Nuclear-Generation_2247.html

Exhibit 9 shows that, despite major changes in market conditions since 2006 and the risks identified in the ICM's testimony, Georgia Power has not altered its cost or schedule projections for the project since the initial announcement.

Ultimately, the risks associated with the Vogtle project—including the lack of transparency, and the likelihood of cost escalation and regulatory and construction delays—are likely to result in very high costs to ratepayers. As in Florida, ratepayers in Georgia are required by law to fund this expensive nuclear energy project long before it begins producing energy, whether or not it ever does.

Cost Recovery Mechanisms: Shifting Risks to Ratepayers

The Georgia Nuclear Energy Financing Act, signed into law in 2009, allows regulated utilities to recover from their customers the financing costs associated with the construction of nuclear generation projects—years before those projects begin producing benefits for ratepayers. In effect, this shifts the financing costs of these massive, risk-prone projects away from utilities and onto ratepayers.

Of Georgia Power's estimated $6.1 billion Vogtle costs, $1.7 billion is financing costs.[42] The utility began recovering these financing costs from its customers starting in 2011. According to Georgia Power's website, effective in 2011, "all bills rendered subject to the Nuclear Construction Cost Recovery Schedule shall be respectively increased in an amount equal to 5.8619% of their base bill calculations." For 2011, that translates to Georgia Power electric bills going up by an average of $3.73 per month.

Georgia Power estimates that this monthly charge will escalate so that by 2018, a Georgia Power residential customer using 1,000 kWh per month will see their bill go up by $10 per month, or approximately $120 per year, due to Vogtle 3 and 4.[43]

Should the cost of the project increase in coming years, due to regulatory and construction delays or other causes, future charges to Georgia Power ratepayers will increase accordingly.

Loan Guarantees and the PTC: Shifting Risks to Taxpayers

In February 2010, the DOE announced that it had awarded, on a conditional basis, $8.33 billion in federal loan guarantees to underwrite the construction costs of Vogtle 3 and 4. The total amount is spread among three of the four owners of the project:[44]

- $3.4 billion for Georgia Power[45]
- $3.0 billion for Oglethorpe Power[46]
- $1.8 billion for MEAG Power[47]

Under the terms of the agreement, the loan guarantees will allow the owners of the project to borrow at below-market Federal Financing Bank rates with the assurance of the U.S. Government.[48]

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[42] The Atlanta Business News, "Impact of new Georgia Power reactors on monthly bills uncertain." August 5, 2011. Available at http://www.ajc.com/business/impact-of-new-georgia-1079955.html.
[43] The Atlanta Business Chronicle, "GA Power files cost plan for nuclear project." August 5, 2011. Georgia Power. (2011) Costs. Retrieved from http://www.southerncompany.com/nuclearenergy/costs.aspx.
[44] Exact terms and conditions for each of the loan guarantees are not detailed. Sum does not equal total announced loan guarantee.
[45] http://www.southerncompany.com/news/dyn_pressroom.aspx?s=43&item=2044
[46] http://www.faqs.org/sec-filings/100521/OGLETHORPE-POWER-CORP_8-K/a10-10697_1ex99d1.htm
[47] http://online.wsj.com/article/SB10001424052748704541304575099384196590568.html

For the Vogtle consortium, the federally backed loan guarantee reduces the project's financing costs. During an analyst conference call, Southern Company president David Radcliffe indicated that the federal loan guarantee would reduce Georgia Power's cost of borrowing its pro rata share of the $8.33 billion loan guarantee by 50 basis points, or by 0.5 percent.[49]

A very significant impact is that the federal loan guarantee allows those building Vogtle to increase their debt financing and reduce their equity requirements. Since the cost of equity is much greater than the cost of borrowing, this substantially reduces the levelized cost for the plant. Although the final debt/equity fractions for the project are uncertain, we believe that a 75 percent debt/25 percent equity fraction is quite reasonable for this project, compared to a more typical 50 percent/50 percent mix.

While these loan guarantees will covey considerable benefits to the plant's developers, they pose risks to U.S. taxpayers. How significant are these risks? The federal loan guarantee program, authorized by Congress in 2005, came about because investors would not provide financing for the new-generation nuclear energy projects without them. When institutional lenders denied financing to these projects, Congress put taxpayer dollars on the line to shoulder the risks that neither Wall Street nor the utilities themselves were willing to bear.

Moreover, concerns have been raised about the process used to select applications for the federal loan guarantee program.[50] The Southern Alliance for Clean Energy (SACE) filed a lawsuit pertaining to the lack of information provided by DOE specific to the Vogtle loan guarantee, stating that the loan guarantees result in "socializing the risk and privatizing the profits for big power companies." [51] The SACE lawsuit follows the issuance of a report by the Government Accountability Office (GAO) that expressed concern that the DOE "has not developed all the tools necessary to assess progress."[52] Specifically, the GAO report found that the DOE has not fully developed performance goals associated with the loan guarantee program.

Another factor to consider is the Production Tax Credit (PTC). While the PTC will lower the cost of the Vogtle project for Georgia Power and, ultimately, its ratepayers, it will be provided using taxpayer dollars. The fact that billions in taxpayer money is on the line to help pay for the Vogtle reactors provides additional incentive to investigate whether this project is the best, most cost-effective option available to meet Georgia's energy needs. It further begs the question, "Why should taxpayers throughout the U.S. subsidize over-priced nuclear energy for Georgia?"

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[48] http://www.ucsusa.org/nuclear_power/nuclear_power_and_global_warming/nuclear-loan-guarantees.html. Nuclear power plant project owners will have to pay a Credit Subsidy Fee that in theory covers the risk of default; however, the nuclear industry is lobbying to have the fee set at around 1 percent of the principle of the loan guarantee.

[49] For the other owners of the plant, the reduction in the cost of borrowing may be more significant, since Georgia Power/Southern Company has such a strong credit rating.

[50] A detailed critique of risks associated with loan guarantees for new nuclear plants was conducted by David Schlissel, Michael Mullet, and Robert Alvarez in "Nuclear Loan Guarantees: Another Taxpayer Bailout Ahead" (2009) Available at http://www.synapse-energy.com.

[51] http://www.cleanenergy.org/index.php?/Press-Update.html?form_id=8&item_id=181

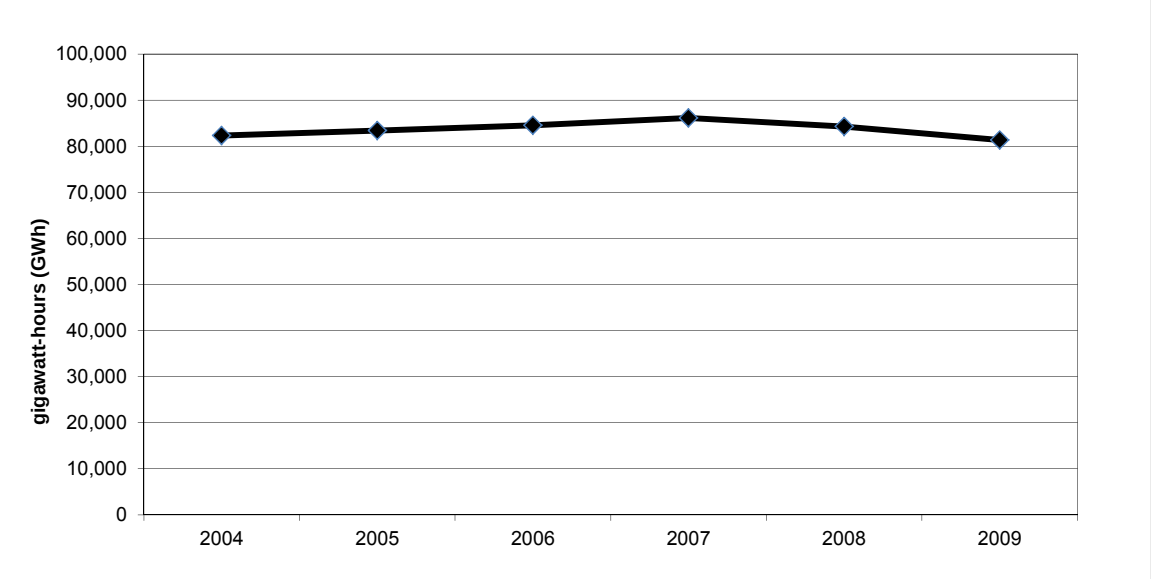
[52] http://www.gao.gov/products/GAO-10-627

Better Alternatives Available in Georgia

Time on Our Side

Growth in electricity usage is one of the determinants utilities use to assess the need for new supply resources. While Georgia Power does not provide publicly available energy sales or load growth projections, it is reasonable to assume that the 2008 recession, which slowed economic growth in Georgia, also impacted energy sales growth in Georgia Power's service territory. Therefore we will focus our analysis on past (actual) Georgia Power energy sales trends. The historical energy sales growth for Georgia Power from 2004 through 2009 is presented in the following chart.

Exhibit 10. Georgia Power Historical Energy Sales



Source: Georgia Power 2010 IRP

Similar to what we saw in Florida, Georgia Power has seen a decline in energy sales since 2007. The historical compound annual growth rate (CAGR) for Georgia Power from 2004 through 2007, 2007 through 2009, and 2004 through 2009 are shown in the following table.

Exhibit 11. Historical Compound Annual Growth Rate of Georgia Power's Retail Energy Sales by Segment

Segment	2004 - 2007	2007 - 2009	2004 - 2009
Residential	2.6%	-1.1%	1.1%
Commercial	2.7%	-0.8%	1.3%
Industrial	-0.9%	-7.5%	-3.6%
Government	0.8%	3.4%	1.8%
Georgia Power	**1.5%**	**-2.8%**	**-0.2%**
Data from Georgia Power IRP (public disclosure)			

Exhibit 11 shows that growth in Georgia Power's retail sales appears to have peaked in 2007 at 86,137 GWh following a period of 1.5 percent annual growth from 2004 to 2007. As the national and regional economy slowed down, Georgia Power saw a corresponding decline in sales to 81,347 GWh in 2009. Overall, growth in retail sales across Georgia Power has stayed flat from 2004 to 2009 at *negative* 0.2 percent, with modest growth in the residential and commercial sectors offset by declines in sales in the industrial sector.

Based on this trend and the slow rate of economic recovery in the U.S., it is likely that future load growth in Georgia Power's service territory will be slower than pre-recession levels. Specific growth forecasts are redacted in the company's Integrated Resource Plan (IRP) filings. However, comments made by Georgia Power executives during Wall Street analyst conference calls shed some insight into the company's growth projections, which appear to be noticeably scaled back from historical growth. During the company's 2010 second quarter analyst call, company executives anticipated that residential growth would be between 1.2 and 1.3 percent, representing approximately 30 percent of Georgia Power's annual sales.[53] Absent actual load projections from Georgia Power, we have assumed that retail load will continue to grow at the actual 2004 to 2009 growth rate of 1.1 percent for the residential sector, below the historical growth of 1.5 percent achieved from 2004 to 2007.[54] We have also assumed that there will be no changes to Georgia Power's investment in energy efficiency. Based on these assumptions, we calculate that Georgia Power will reach its 2007 load peak in 2014, which is consistent with the company's 2010 IRP assertion that its resource mix is adequate through 2015.

Because energy sales growth for Georgia Power has slowed considerably compared to earlier projections, we find that it is entirely possible for the company to meet future retail energy sales growth through investments in energy efficiency, which is the lowest-cost resource compared to all supply-side generating options, as well as through modest investment in affordable and available renewable resources.

Energy Efficiency

Georgia currently does not have any statewide energy efficiency targets. By comparison, 17 states have set energy efficiency targets of between 1.0 and 2.3 percent of total electricity sales per year. This includes six states that have targets of 2.0 percent per year or more.

Meanwhile, several studies support the fact that Georgia has large, untapped energy efficiency potential.

- In 2005, the Georgia Environmental Finance Authority commissioned the consulting firm ICF to conduct an energy efficiency potential study.[55] The study found that Georgia could achieve 3,339 GWh of savings, or 2.3 percent of electricity sales, by 2010 under a minimally aggressive energy efficiency scenario. Under a very aggressive scenario, the

[53] Southern Company. 2nd Quarter Call July 28, 2010. Available at http://seekingalpha.com/article/217222-southern-q2-2010-earnings-call-transcript.
[54] Using a 1.1 percent growth rate for all end-use sectors probably understates historical commercial sector growth, but overstates historical industrial sector sales.
[55] ICF Consulting. Assessment of Energy Efficiency Potential in Georgia Final Report. May 5, 2005. Available at http://www.gefa.org/index.aspx?page=192.

state could achieve 12,515 GWh of savings by 2010. EIA data shows that in 2008, Georgia achieved just 62 GWh of savings through energy efficiency.

- In 2007, Georgia Power commissioned Nextant to conduct an energy efficiency potential study for its service territory as a follow-up to the 2005 ICF report.[56] While detailed findings from the report are redacted, the report's theoretically achievable potential for cumulative energy efficiency reductions range from 1.7 to 6.2 percent of 2010 forecast sales. This study, which was funded by Georgia Power, concluded that the energy savings would come at "a substantial cost to ratepayers." They reached this conclusion based on the application of the so-called Ratepayer Impact Measure (RIM) test, a flawed and misleading test that looks only at impacts on electricity *rates*, and ignores the substantially lower *costs* resulting from energy savings. When the same study applied the more comprehensive Total Resource Cost (TRC) test, the net benefits to ratepayers from energy efficiency were estimated to be between $0.8 and $3.1 billion. In sum, the Nextant report confirms a large, cost-effective energy efficiency potential within Georgia Power's service territory.
- In a more recent study, Chandler and Brown reviewed Georgia's energy-efficiency studies in *Meta-Review of Efficiency Potential Studies and Their Implications for the South* (2009).[57] Their study indicated that Georgia could achieve electricity savings ranging from 11 to 27 percent from projected energy consumption under the maximum achievable scenarios they modeled.
- Another recent study, by the Ochs Center for Metropolitan Studies, found that six of Georgia's Electric Membership Corporations (EMC) could achieve lifetime energy efficiency savings of 22,930 GWh at a cost of $0.06 per kWh over a 14-year implementation period.[58] In 2007, these six EMCs consumed 7,675 GWh of the 137,274 GWh of electricity consumed in Georgia.[59] While this analysis was conducted in the context of the proposed 850 MW Plant Washington coal-fired power plant in Washington County, it provides additional context to the potential for energy efficiency and associated costs within Georgia.
- According to ACEEE's 2010 State Energy Efficiency Scorecard, Georgia ranked 37th out of 50 states in its national ranking of states for energy efficiency in 2010. Also according to ACEEE, Georgia's per capita spending on energy efficiency was $2.16 across the state for all utilities, which is well below the national average per capita spending of $11.08. Leading states are investing even more in energy efficiency; the top five states per capita spending on energy efficiency range from $27.01 to $49.38.[60]

[56] Available at http://www.seealliance.org/pdf/GAIRPTechGAPowerPotentialStudy_052007.pdf.
[57] See http://www.seealliance.org/se_efficiency_study/georgia_efficiency_in_the_south.pdf.
[58] Tharp, William., Quillen, Lori. "Energy Efficiency as an Alternative Strategy for the Power4Gerogians EMCs." The Ochs Center for Metropolitan Studies. March 2010. Available at http://www.cleanenergy.org/images/files/PlantWashingtonFinal030510.pdf.
[59] Ibid. The six EMCs are Central, Cobb, Pataula, SSEMC, Upson, and Washington, representing 43 counties within the state.
[60] ACEEE (2010). Per capita spending on energy efficiency for the top five states: 1) Vermont ($49.38), Rhode Island ($28.01), 3) Massachusetts ($27.88), 4) Hawaii ($27.41), and 5) California ($27.01).

Despite the large, untapped potential for energy efficiency in Georgia, Georgia Power continues to under-invest in these low-cost measures, instead spending many times more per year on the high-risk Vogtle project at ratepayer expense.

In the company's 2010 IRP, Georgia Power recommended a budget of $17 million for energy efficiency for all end-use sectors in 2010.[61] By comparison, the company anticipated spending $700 million in 2010 for the construction of Vogtle 3 and 4—more than 40 times what it was spending on efficiency—according to its 2010 first-quarter conference call with Wall Street analysts.[62]

Renewable Energy

While increased energy efficiency could flatten or reverse load growth for Georgia Power, any additional investment in renewable energy could further negate the need for massive, high-risk generation projects like Vogtle 3 and 4.

No renewable energy mandates currently exist in Georgia, and the potential for renewable energy development is significant. A 2009 Southern Alliance for Clean Energy (SACE) report, which summarized several studies and data sources, calculated that, even without tapping into the state's large potential for off-shore wind resources, Georgia has the potential to generate 47,021 gigawatt-hours (GWh) of electricity from in-state renewable energy sources by 2025. As a point of reference, EIA data indicate that Georgia's 2008 retail electricity sales were 135,174 GWh; thus the SACE report shows that renewable energy potential in the state is approximately 35 percent of 2008 retail electricity sales.[63] The current generation mix for Georgia Power is presented in Appendix C.

Exhibit 12 (below) shows the results of SACE's analysis.

Exhibit 12. Georgia Renewable Energy Potential from 2009 SACE Southeast Report

SACE Maximum Feasible Potential Generation for Georgia by Source	
Energy Source	**2025 (GWh)**
Onshore Wind	3,635
Offshore Wind	52,788
Biomass	22,703
Hydroelectric	2,015
Solar	18,668
Total	99,809
Total excluding offshore wind	47,021
From: SACE 2009	

A discussion of specific renewable resources in Georgia that have been investigated in greater detail is provided in Appendix G.

[61] Georgia Power 2010 IRP.
[62] From http://seekingalpha.com/article/201874-southern-co-q1-2010-earnings-call-transcript?part=qanda.
[63] U.S. Energy Information Administration. Form EIA-861, "Annual Electric Power Industry Report."

In addition to having considerable potential for renewable energy development, Georgia could implement these resources faster and at a lower cost than the Vogtle plant. Exhibit 13 below shows the mid-range levelized cost of electricity for the Vogtle project compared to alternative resources. These results are based on Synapse calculations and assumptions specific to Georgia, outlined in detail in Appendix B. Exhibit 13 shows that energy efficiency, combined-cycle natural gas, biomass, on-shore wind, and coal are all more cost-effective than the mid-rage cost estimate for the Vogtle project.

Exhibit 13. Levelized Cost of Electricity: The Proposed Vogtle Nuclear Plant vs. Other Resources (2016 In-Service Date, 2010$)

Category	Units	EE	NG CC	Biomass	Wind On-Shore	Coal	Wind Offshore	Solar PV	Vogtle (Mid)
Capital Cost	$/kW	N/A	$1,200	$4,400	$2,250	$3,000	$6,000	$3,300	$10,775
Capital Cost	$/MWh	$40	$17.44	$57.73	$83.64	$43.61	$167.28	$184.01	$101.53
Fuel Cost	$/MWh	0	$47.08	$30.13	$0.00	$20.49	$0.00	$0.00	$8.58
O&M (Fixed and Variable)	$/MWh	0	$3.72	$16.02	$12.02	$8.64	$25.30	$6.95	$13.13
Emission Cost	$/MWh	0	$14.91	$0.04	$0.00	$36.45	$0.00	$0.00	$0.00
Tax Credits	$/MWh	0	$0.00	-$13.63	-$13.63	$0.00	-$13.63	-$55.20	-$7.89
All-In Costs	$/MWh	**$40**	**$83.15**	**$90.30**	**$82.04**	**$109.19**	**$178.96**	**$135.76**	**$115.35**

Synapse's analysis assumes an extension of the biomass and wind production tax credits (10 years), which are scheduled to expire in 2013 and 2012 respectively.[64] We have also included the 30-percent Investment Tax Credit (ITC) for solar PV resources in this analysis. If the production tax credits expire, the impact would be to increase the 20-year levelized cost of electricity for biomass and wind resources by $13.63/MWh. If the ITC were to expire, then the levelized cost of electricity for solar PV would increase by $55.20/MWh.

As with energy efficiency, Georgia Power is investing very little in renewable energy, failing to capitalize on the large potential for these resources in Georgia and their lower levelized costs as compared to the Vogtle project.

Georgia Power's 2010 IRP summarized the company's plan for renewable energy as follows:

> In response to the Commission's 2007 IRP Order, the Company took the following actions…. Worked with Commission Staff and other interested parties to develop a time table and an action plan that is leading to the development of cost-effective renewable resources as set out in the Company's IRP. The Company continues to pursue various options in order

[64] The wind production tax credit is set to expire on December 31, 2012 and the biomass production tax credit is set to expire on December 31, 2013. See http://www.irs.gov/pub/irs-pdf/f8835.pdf.

> to develop up to three cost-effective renewable projects with capacity of 30 MWs or less. [65]

If all three projects are developed within the IRP timeframe, this would result in the addition of 90 MW. This would represent less than one percent of the company's 2009 generation capacity of 15,995 MW.[66]

Findings & Recommendations

This analysis shows that there are less costly and far less risky alternatives available to meet the electricity needs of Georgia Power customers than the proposed new nuclear reactors at Vogtle. These alternatives include more aggressive energy efficiency programs, biomass and onshore wind development, and potentially natural gas plants—all of which could be implemented at lower cost, in smaller increments, and more quickly than the proposed Vogtle project.

Despite the availability of these lower-cost and less risky options, Georgia Power and its consortium partners continue to pursue a $14 billion-plus project that will present much greater risks and result in higher costs for their ratepayers. U.S. taxpayer money is also on the line to subsidize this multi-billion-dollar project.

Key findings of our analysis include the following:

- Georgia Power has stated that it will complete Vogtle 3 by 2016 and Vogtle 4 by 2017, and has implied that the cost estimate for the project will remain at $14 billion. Detailed information about the project's schedule and the cost projections have been redacted from public documents by Georgia Power. Our analysis suggests that the final project cost is far from certain, and is likely to be much higher than the current estimate.
- Our mid-range analysis of the levelized cost for the project is $115 per MWh, based on a percentage of the cost increases experienced by Georgia Power during the construction of Vogtle 1 and 2. This would place the cost of the two units above all of our mid-range cost estimates for energy efficiency, renewable resources (except off-shore wind and solar PV), and conventional generation.
- Georgia Power ratepayers will pay an estimated $120 per year by 2018 in financing charges, prior to the operation of the project, based on the annualized monthly tariff submitted by Georgia Power at the *current* cost estimate. Should the cost of the project increase, then the impact on customer bills will also increase.
- Available studies show that the substantial energy efficiency and renewable energy resource potential in Georgia could be utilized to meet the state's future energy needs at far lower cost and risk.

Based on these findings, we strongly recommend that the State of Georgia, Georgia Power and its partners pursue more sustainable and cost-effective alternatives to the Vogtle project. Specifically:

- Georgia should commission new, independent energy efficiency and renewable energy studies for the entire state to help inform and guide policymakers in weighing the costs

[65] Georgia Power. 2010 Integrated Resource Management Plan: Main Document. January 2010. (Page 1-5)
[66] Information accessed from http://www.georgiapower.com/about/facts.asp.

and benefits of different alternatives for meeting future energy needs. The last energy efficiency potential study was conducted in 2005, and the state has never commissioned a study to assess the renewable resource potential in Georgia.

- Georgia should take immediate steps to set statewide energy efficiency and renewable energy targets that are consistent with those of leading states. Existing studies suggest that Georgia Power could viably and economically meet its projected energy sales growth though a reasonable mix of energy efficiency and renewable energy resources—without the proposed new Vogtle reactors. Cost-effective investment in these resources could further allow Georgia to reduce its reliance on imported nuclear fuel, and avoid increasing costs and risks associated with on-site storage of spent nuclear fuel.

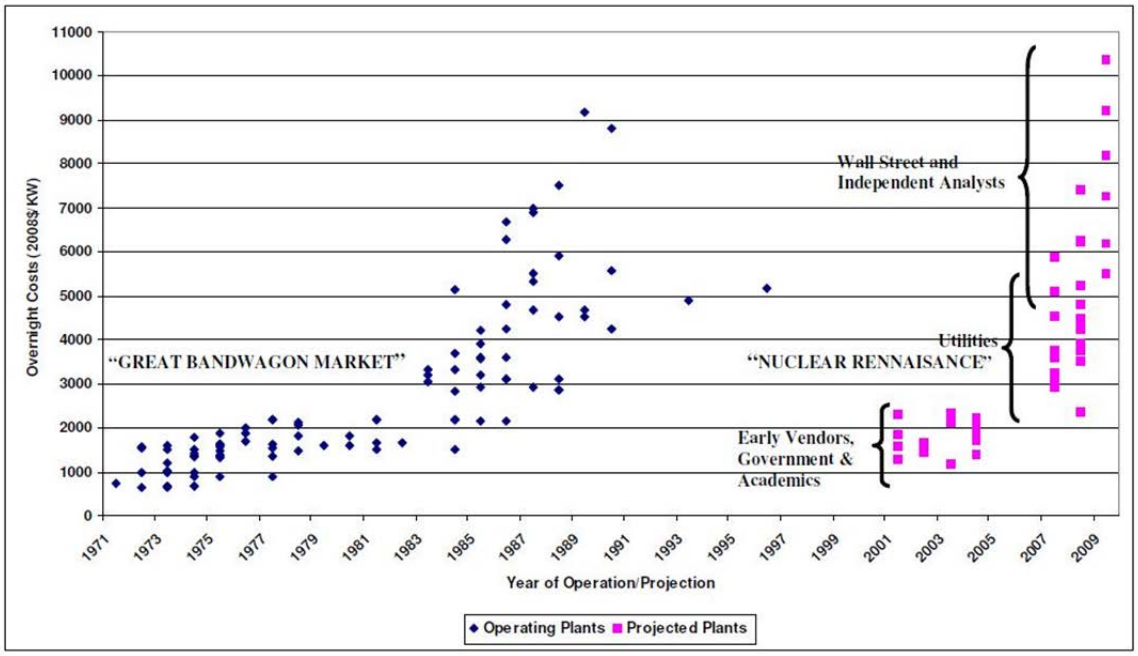
Appendix A: Nuclear Costs and Risks

Historically, the experience of nuclear construction has been increasing costs.[67]

The largest component of nuclear power costs are the capital costs associated with the construction of the project. However, cost estimates for nuclear projects are often marked "trade secret" or redacted by companies.

A view of historic and current nuclear project costs comes from a 2009 report by Mark Cooper.[68] The exhibit below compares the historical overnight capital costs (not including financing) in 2008$ of actual nuclear power plant projects, and plots some current estimated costs associated with announced projects.

Exhibit A-1. Nuclear Reactor Overnight Cost Estimates Taken from *Economics of Nuclear Reactors: Renaissance or Relapse*



Two trends are apparent in this analysis. One, history shows a dramatic incline in nuclear construction costs starting in the mid-eighties. Second, analyses of proposed projects by Wall Street and third parties are less optimistic than either utility or academic cost projections for projects.

Factors and resulting consequences that would influence cost estimates are presented below for both Progress Energy and Georgia Power, and for comparable nuclear power projects around the world.

[67] Schlissel, David., Biewald, Bruce. Nuclear Plant Construction Costs. July 2008. Available at http://www.synapse-energy.com.

[68] Cooper, M. *The Economics of Nuclear Reactors: Renaissance or Relapse?* June 2009. Available at http://www.vermontlaw.edu/Documents/Cooper%20Report%20on%20Nuclear%20Economics%20FINAL[1].pdf.

Cost Escalation Risk

The nuclear industry has had a very poor track record in predicting project construction costs and avoiding cost overruns. In a report to Congress, the Department of Energy provided a table of the actual costs of 75 of the existing nuclear power plants in the U.S. that exceeded the initially estimated costs.[69]

Exhibit A-2. Comparison of Historical Projected and Actual Nuclear Power Plant Construction Costs in the United States

Construction Starts		Average Overnight Costs[a]		
Year Initiated	Number of Plants[b]	Utilities' Projections (Thousands of dollars per MW)	Actual (Thousands of dollars per MW)	Overrun (Percent)
1966 to 1967	11	612	1,279	109
1968 to 1969	26	741	2,180	194
1970 to 1971	12	829	2889	248
1972 to 1973	7	1,220	3,882	218
1974 to 1975	14	1,263	4,817	281
1976 to 1977	5	1,630	4,377	169
Overall Average	**13**	**938**	**2,959**	**207**

Source: Congressional Budget Office (CBO) based on data from Energy Information Administration, An Analysis of Nuclear Power Plant Construction Costs, Technical Report DOE/EIA-0485 (January 1, 1986).

Notes: Electricity-generating capacity is measured in megawatts (MW); the electrical power generated by that capacity is measured in megawatt hours (MWh). During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.
The data underlying CBO's analysis include only plants on which construction was begun after 1965 and completed by 1986.
Data are expressed in 1982 dollars and adjusted to 2006 dollars using the Bureau of Economic Analysis's price index for private fixed investment in electricity-generating structures. Averages are weighted by the number of plants.

a. Overnight construction costs do not include financing charges.
b. In this study, a nuclear power plant is defined as having one reactor. (For example, if a utility built two reactors at the same site, that configuration would be considered two additional power plants.)

While companies claim that new nuclear construction projects are different, the past experience of project construction serves as a useful reminder to maintain vigilance on these complicated projects.

As noted in a 2007 Energy Policy study[70], the estimated costs of the AP1000 reactor and other similar Generation III+ reactors are currently well below the historical experience of constructed reactors in the United States. In their conclusion of nuclear construction costs, the authors of the study state that:

> Those estimates may yet be proved right, but our data suggest the need for additional scrutiny of assumptions. While reactor designs have been standardized, licensing procedures have been streamlined, and construction

[69] Schlissel, David., Biewald, Bruce. Nuclear Plant Construction Costs. July 2008. Available at http://www.synapse-energy.com.

[70] Koomey, J., Hultman, N. A reactor-level analysis of busbar costs for US nuclear plants,1970–2005. Energy Policy 35(2007) 5630-5642.

> management techniques are much more sophisticated than before, some old problems remain, and new ones may emerge. The policy and design changes represented by Gen III+ and Gen IV reactors do represent improvements over the current fleet, but the interlinked issues of reactor scale, customization of site-built technologies, slow electricity demand growth, intense competition from other energy sources, deregulated electricity markets, slow speed of industry learning, nuclear waste disposal, terrorism, and proliferation remain potential impediments to the cost competitiveness of next-generation nuclear power in the 21st century.

At a general level, a 2010 *Electricity Policy* article on an analysis of the French nuclear industry further notes that:

> These findings also suggest a need for in-depth sensitivity analysis across a much wider range of technological cost uncertainties. Perhaps climate policy analysis could begin by embracing in sensitivity analyses the engineering rule of thumb that large-scale infrastructure construction projects trend to always cost 2–3 times the original estimate. Nuclear is not the only example of a large-scale, complex technology that might be subject to this engineering rule: coal-based integrated gasification combined cycles with carbon capture and sequestration (or very large-scale solar plants in desert areas) would be prime candidates as well.
>
> Lastly, the French nuclear case has also demonstrated the limits of the learning paradigm: the assumption that costs invariably decrease with accumulated technology deployment. The French example serves as a useful reminder of the limits of the generalizability of simplistic learning/experience curve models[71]

Both the Levy and Vogtle projects are subject to the risks outlined in the excerpts above—all of which could lead to significant escalation in costs.

Additional Research

- A 2008 Synapse Energy Economics report detailed two major categories of risk that are impacting nuclear construction costs:[72] These include:
  - Limited experience in new reactor designs
  - Competition for limited construction and fabrication materials and expertise

  Those risks have not diminished since our report, and continue to plague the nuclear industry.

[71] Gruebler, A. The costs of the French nuclear scale-up: A case of negative learning by doing. Energy Policy. 38 (2010) 5174-5188.
[72] Ibid.

- In recent testimony filed before the Florida Public Service Commission, Dr. Mark Cooper, testifying on behalf of SACE, identified additional factors that have influenced the cost of new nuclear reactors.[73] These include:
    - Declining natural gas costs
    - Declining estimates of carbon prices
    - Declining demand due to the economic slowdown
    - Reduced need for nonrenewable generation due to likely efficiency and renewable mandates in climate change legislation, which was pending at the time
    - Rising projections of nuclear construction costs
    - High degree of uncertainty in the economic environment that new reactors face

  A more detailed description of these impacts is provided in his testimony. While Dr. Cooper's testimony is specific to Progress Energy, these risks are also applicable to Georgia Power and to other proposed nuclear power plant construction projects.
- A 2009 Citigroup equity research report cited several cost overruns and delays in the current generation of nuclear power plants. We highlight some examples of cost escalation trends from the report, along with subsequent developments, which confirm that trend:[74]
    - Towards the end of 2008, the French company EdF increased its cost assumptions for the Flamanville 3-reactor unit, raising the cost to €4 billion/$5.6 billion or €2,434/kW or $3,400/kW in real money terms. These costs were confirmed in mid-2009, when EdF had already spent nearly €2 billion. In July 2011, EdF announced that the plant was expected to cost €6 billion, and pushed back the unit operating date to 2016.[75]
    - NRG, in June 2009, said that the cost of two 1,350 MW GE Westinghouse units at the South Texas Project near Houston would be about $10 billion—not including financing costs. This would be a merchant plant, not a regulated one, operating on cost-plus basis with the first unit expected on line in 2016. At the time, this equated to $3,700/kW. However, in late 2009 Toshiba, the plant's main contractor, notified plant owners that costs would be up to $4 billion more.[76] In April 2011, NRG Energy Inc., the primary investor in the project, announced that it was abandoning the permitting process for the two new units due to the ongoing expense of planning the reactors combined with lower wholesale electricity prices

[73] Cooper. (2010) p. 5.
[74] Atherton, Peter., Simms, Andrew., Savvantidou, Sofia., and Hunt, Stephen. "New Nuclear- The Economics Say No" Citi Investment Research and Analysis. November 9, 2009. Available at https://www.citigroupgeo.com/pdf/SEU27102.pdf.
[75] "Flamanville-3 operations delayed to 2016." Platts. July 21, 2011.
[76] http://www.mysanantonio.com/news/environment/article/Nuclear-cost-estimate-rises-by-as-much-as-4-844529.php

and the uncertainty raised by the ongoing nuclear disaster in Fukushima; NRG subsequently wrote off its $331 million investment in the project.[77]

- The Finnish EPR at Olkiluoto has been plagued by many delays during construction and is currently three years behind schedule, having originally targeted commissioning in 2009. Citigroup noted that the original cost estimate for Olkiluoto was €3 billion. However, due to delays, planning problems (construction started in 2005), and issues with materials, a 2009 Areva estimate indicated that costs for the project increased by €2.3 billion and could increase further depending on the outcome of negotiations between the owner, TVO, and Areva on the timeline for completion. In June 2010, Areva announced €400 million of further provisions, taking the cost overrun to €2.7 billion, while the timescale slipped to the end of 2012 from June 2012, with operation set to start in 2013.[78] [79]

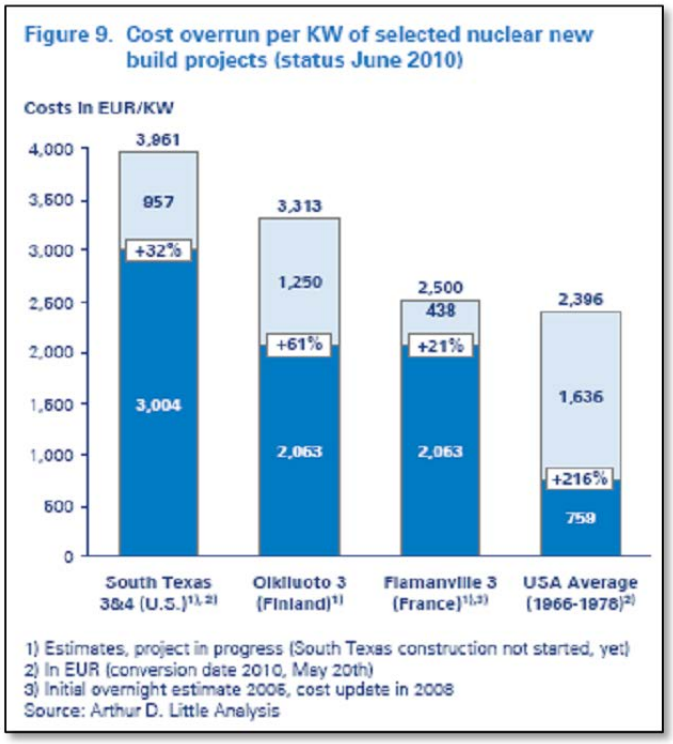
- The Victoria County Station in Texas is another recent example. In 2010, Exelon Nuclear Texas Holdings, LLC (Exelon) filed with the NRC to remove its application for a Combined Operating License and instead submitted an application for an early site permit for a plant that may never get built.[80] At the time, John Rowe, Exelon chairman and CEO, said he expected natural gas prices to remain low for at least a decade. "As long as natural gas is anywhere near current price forecasts, you can't economically build a merchant nuclear plant." [81]

- Entergy, the operator of 12 nuclear units at ten plants across the country, has also been hesitant to invest in new nuclear construction projects. In a November 2010 article, Entergy's CEO, J. Wayne Leonard, is quoted about Southern Company's Vogtle project: "I've wondered how Southern—how anybody—makes the numbers work. Sitting on the outside looking in, they have some reason we don't see."[82] One distinct possibility is that both Georgia Power and Progress Energy have nuclear construction early cost recovery clauses approved in Florida and Georgia, as discussed in the report.

Finally, a 2010 research report issued by Arthur D. Little (ADL) shows the proportional increase associated with some of the noted construction delays. Figure 9 from the ADL report illustrates cost overruns from some examples.[83]

[77] http://www.dallasnews.com/business/energy/20110419-nrg-ends-project-to-build-new-nuclear-reactors.ece
[78] http://www.mineweb.co.za/mineweb/view/mineweb/en/page72103?oid=107035&sn=Detail&pid=102055
[79] http://www.world-nuclear-news.org/NN-Startup_of_Finnish_EPR_pushed_back_to_2013-0806104.html
[80] http://www.exeloncorp.com/newsroom/pages/pr_20100325_Nuclear_VictoriaPermit.aspx?k=victoria%20county
[81] http://saxo.dailyherald.com/article/20100910/business/309109888/#ixzz1Vyd94kY8
[82] http://www.reuters.com/article/idUSTRE64N5S420100524.
[83] Von Bechtolsheim, Matthias., Kruse, Michael., and Junker, Jan. "Nuclear New Build Unveiled: Managing the Complexity Challenge" Arthur D. Little. June 2010. Available at http://www.adl.com/reports.html?view=483.

Exhibit A-3. ADL 2010 Cost Overrun Analysis



What is most telling about this exhibit, taken from the 2010 ADL report, is that current events have overtaken the estimates presented in the exhibit. As noted above, NRG has abandoned the permitting process for the proposed South Texas project and has written off $331 million in the process. Delays at Flamanville 3 have pushed the cost up to 6 billion euros, or about 3,000 euros/kW. And delays at Olkiluoto 3 that would delay its operational date to 2013 have added approximately another 275 euros/kW to the costs shown in the exhibit. As such, the exhibit demonstrates that both project risk and cost risk may appear quickly.

Appendix B: Detailed Levelized Cost Inputs

Following is a detailed description of the inputs used in the levelized cost assumptions for this analysis.

Nuclear Project Inputs

For both projects, the following major common inputs included:

- 15-year accelerated depreciation
- 85 percent capacity factor
- Fixed and variable operations and maintenance costs of $93.9/kW-year based on AEO projections

Levy Specific Inputs

For the Levy project, capital cost data incorporated cost data provided in Progress Energy Florida's Ten-Year Site Plan. The company's Return on Equity of 10.5 percent is based on the company's last base rate case, as determined by the Florida PSC.

The Levy project cost estimates exclude the production tax credit since Levy 1 is not expected until 2021, after the cutoff date for the program. In addition, the Levy project does not include nuclear federal loan guarantees.

Vogtle Specific Inputs

For the Vogtle project, capital cost data incorporated generalized cost data, since specific cost data has been marked trade secret by Georgia Power. The company's Return on Equity of 11.15 percent is based on the company's last base rate case, as determined by the GA PSC.[84]

In addition, the Vogtle project cost estimates include the nuclear production tax credit (PTC) of 1.8 cents per kWh for the first 1,000 MW of capacity for each unit up to $125 million per year for the first eight years of operation. Both Vogtle units in our analysis are expected to receive the PTC, which decreases the levelized cost of the project by $7.9 per MWh in all three scenarios. By far the most important driver of our cost estimate for Vogtle 3 and 4 is the federal nuclear loan guarantee, which effectively reduces Georgia Power's cost of borrowing (which already is lower than Progress Energy's) and increases the debt fraction of the project. Because Georgia Power receives favorable credit ratings, the ability for Georgia Power to borrow from the Federal Financing Bank does not materially impact the cost of borrowing for the project. We also make the assumption that the federal loan guarantee allows a debt financing fraction of 75 percent for the plant. This further reduces the overall financing and levelization rates.

Exhibit B-1 below provides a summary of cost inputs for Levy and Vogtle based upon our described methodology.

[84] In December 2010 a Return on Equity (ROE) rate of 11.15 percent was approved.

Exhibit B-1. Levelized Cost Inputs and Results for Levy and Vogtle

Category	Units	Levy			Vogtle		
		Low	Mid	High	Low	Mid	High
Capital Cost	$/kW	8,286	9,529	10,771	5,388	10,775	16,163
Levelized Real Fixed Charge Rate[85]	%	11.13%	11.13%	11.13%	6.76%	7.02%	7.10%
Capital Cost Annualized	$/kW-yr	921.9	1060.2	1198.5	363.9	756.0	1148.1
Fixed O&M	$/kW-yr	93.9	93.9	93.9	93.9	93.9	93.9
Capacity Factor	%	85%	85%	85%	85%	85%	85%
Energy Based Fixed Costs	$/MWh	136.4	155.0	173.6	61.5	114.1	166.8
Fuel	Type	Uranium	Uranium	Uranium	Uranium	Uranium	Uranium
Fuel Price	$/mmBtu	0.82	0.82	0.82	0.82	0.82	0.82
Heat Rate	Btu/kWh	10,488	10,488	10,488	10,488	10,488	10,488
Fuel Cost	$/MWh	8.6	8.6	8.6	8.6	8.6	8.6
Variable O&M	$/MWh	0.5	0.5	0.5	0.5	0.5	0.5
Emission Cost	$/MWh	0.0	0.0	0.0	0.0	0.0	0.0
Production Tax Credit	$/MWh	0	0	0	7.9	7.9	7.9
All in Costs	**$/MWh**	**145.5**	**164.1**	**182.7**	**62.7**	**115.4**	**168.0**

Cost Information Sources

For our comparison cost analysis, we selected resource cost and performance assumptions with an emphasis on Florida and Georgia locations. Specifically, we consulted and relied upon information from the following reports and sources:

- Black & Veatch. *Black & Veatch's (RETI'S) Cost of Generation Calculator*. Prepared for California Energy Commission Cost of Generation Workshop (May 16, 2011)[86]
- Progress Energy. *Progress Energy Florida, Inc. Ten Year Site Plan*. March 31, 2011.[87]
- Hahn, V., Fix, J., Schmalz, J., Wennen, M., Couppis, E., Ratafia-Brown, J. *EOP III Task 1606, Subtask 3- Review of Power Plant Cost and Assumptions for NEMS Technology Document Report*. R.W. Beck, Inc. Science Applications International Corporation (SAIC). October 2010.[88]

[85] A significant factor in the reduced rate for Vogtle is the greater debt fraction made possible by federal loan guarantees.
[86] Available at http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-16_workshop/presentations/Ryan_Pletka_B&V.pdf.
[87] Available at http://www.psc.state.fl.us/utilities/electricgas/10yrsiteplans.aspx.
[88] Available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf.

- R.W. Beck Inc. *Task 692, Subtask 6.2 – Review of Power Plant Cost and Performance Assumptions for NEMS- Technology Documentation Report*. October 2010.
- National Renewable Energy Laboratory. *Energy Technology Cost and Performance Data*. July 2010.[89]
- Lazard. *Levelized Cost of Energy Analysis – Version 4.0*. May 2010.
- Keith, G., Biewald, B., Takahashi, K., Napoleon, A., Hughes, N., Mancinelli, L., Brand, E. *Beyond Business as Usual: Investigating a Future without Coal and Nuclear Power in the U.S.* Synapse Energy Economics. May 11, 2010.[90]
- U.S. Energy Information Administration. *Annual Energy Outlook 2010 with Projections to 2035*. DOE/EIA-0383(2010). April 2010.[91]
- Lazard. *Levelized Cost of Energy Analysis – Version 3.0*. June 2009.[92]
- Cleetus, R., Clemmer, S., Friedman, D. *Climate 2030 A National Blueprint For a Clean Energy Economy*. Union of Concerned Scientists. May 2009.[93]
- Navigant Consulting Inc. *Florida Renewable Energy Potential Assessment*. Prepared for the Florida Public Service Commission, Florida Governor's Energy Office, and Lawrence Berkeley National Laboratory. December 30, 2008.[94]

General Input Assumptions

Based on these reports, our general input assumptions are summarized as follows:

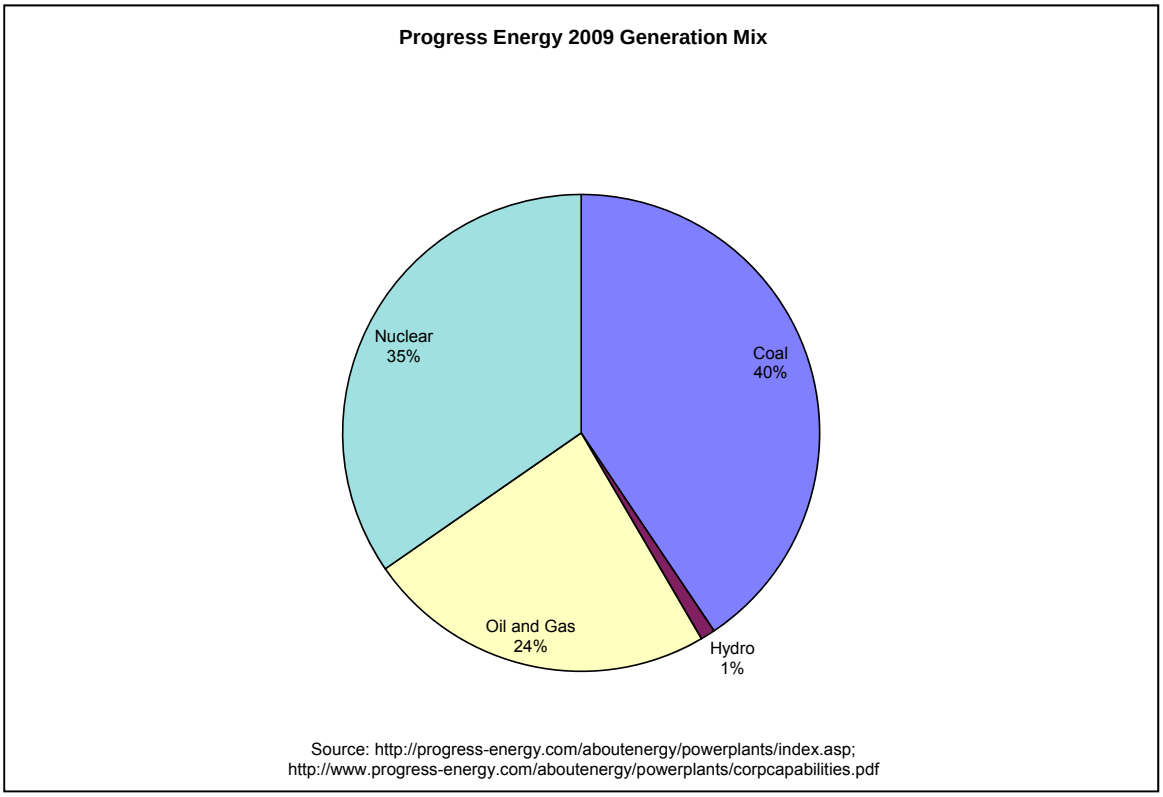
- All values are stated in 2010 dollars
- 20-year levelization period across resources
- 2016 in-service date for alternative resources
- 2.0 percent inflation rate
- Nominal discount rate of 7.09 percent
- Real discount rate of 4.99 percent
- 50/50 debt equity ratio
- Debt cost of 5.125 percent (30-year treasuries plus 125 basis points)
- Equity rate of 11.0 percent
- 38 percent income tax rate
- Levelization rate for fossil fuel generators: 10.82 percent
- Levelization rate for renewable energy: 9.77 percent

[89] Available at http://www.nrel.gov/analysis/costs.html.
[90] Available at http://www.synapse-energy.com/Downloads/SynapseReport.2010-05.CSI.Beyond-Business-as-Usual.10-002.pdf.
[91] Available at http://www.eia.doe.gov/oiaf/archive/aeo10/pdf/0383(2010).pdf.
[92] Available at http://efile.mpsc.state.mi.us/efile/docs/15996/0145.pdf.
[93] Available at http://www.ucsusa.org/global_warming/solutions/big_picture_solutions/climate-2030-blueprint.html.
[94] Available at http://www.psc.state.fl.us/utilities/electricgas/RenewableEnergy/FL_Final_Report_2008_12_29.pdf.

Appendix C: Generation Mix for Progress Energy Florida and Georgia Power

The following two figures provide the current generation mix for the two companies. Progress Energy's 2009 generation mix is presented in the following figure.

Exhibit C-1. Progress Energy 2009 Generation Mix

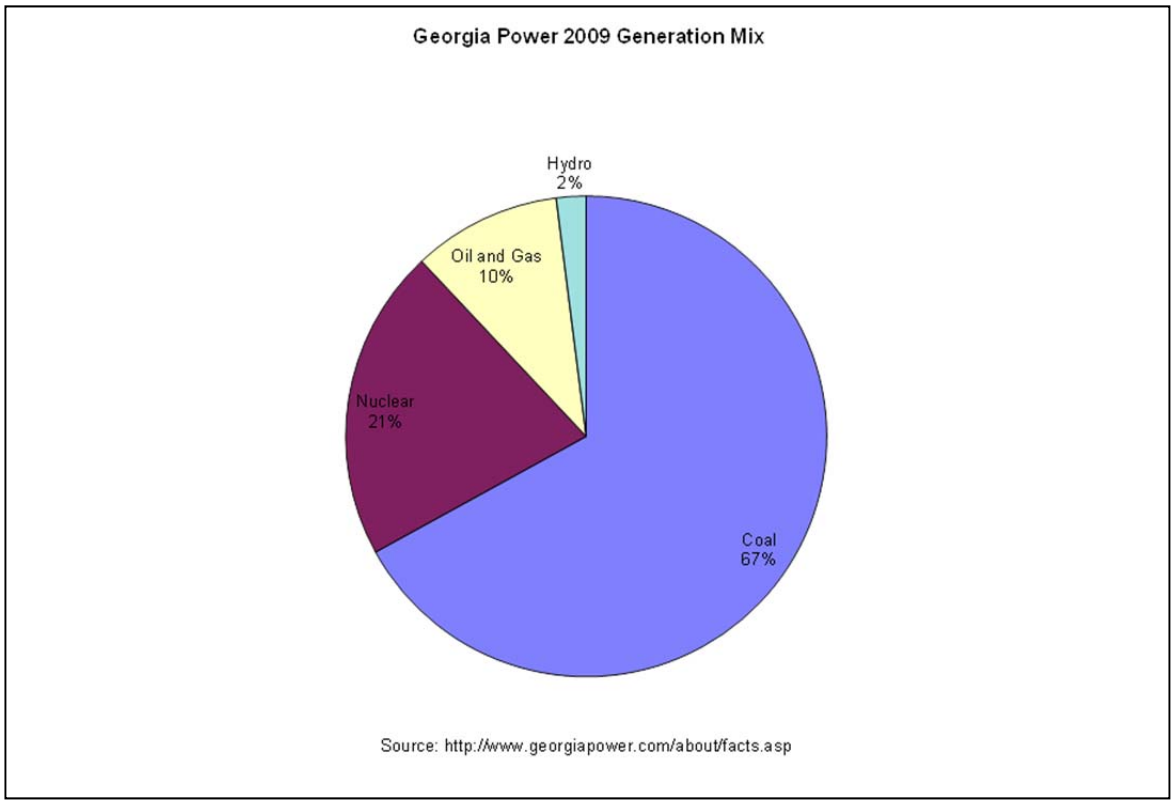


Progress Energy's generation mix currently contains approximately 40 percent coal-fired generation. In a consent decree, Progress Energy Florida agreed to retire the coal-fired Crystal River 1 and 2 generating units following one fuel cycle for Levy 1 and 2.[95] Under the current schedule for the project, this would mean that Crystal River 1 and 2 would retire some time in 2025, thus retiring 867 MW of net summer capacity and replacing it with nuclear generation.

Georgia Power is even more reliant on coal-fired generation to meet its generation needs. Taken from Georgia Power's website, the company's 2009 generation mix is presented in the following figure, which shows that 67 percent of the utility's electricity generation came from coal-fired plants.

[95] According to Progress Florida, one fuel cycle is approximately 18 to 24 months. Available at http://progress-energy.com/aboutus/news/article.asp?id=20402.

Exhibit C-2. Georgia Power 2009 Generation Mix



Coal is Georgia Power's dominant fuel source for electricity generation. If built, Vogtle 3 and 4 would increase the company's nuclear capacity by about 50 percent, which would lower, but not dramatically reduce, the company's reliance on coal.

Appendix D: Drivers of Cost Uncertainty

Capital Costs

For nuclear and renewable energy resources, capital costs are the most significant part of the levelized costs.

For non-coal conventional generating resources (e.g. natural gas plants), capital costs are fairly stable. The technology is mature and surprises are rare. Nevertheless, the costs for a given technology can vary from site to site by as much as 20 percent depending on special conditions such as fuel supply, financing costs, transmission infrastructure, and regional construction cost differences.

Fuel Costs

For natural gas and coal plants, the fuel and operating costs are the most significant part of the levelized costs. For natural gas plants, fuel costs account for more than half of the total levelized cost. Thus variations in capital cost are of lesser importance. Although natural gas prices were fairly high and volatile several years ago, the current development of non-conventional resources such as the Marcellus shale has turned that around.

For wind and solar technologies, the fuel cost would be zero. For nuclear power, the fuel costs of uranium represent less than 10 percent of the levelized cost of a project.

The development of shale gas has dramatically altered projections of natural gas reserves in the last few years. Shale gas is now generally viewed as the long-term marginal source of gas in North America. This means that the cost of producing shale gas is expected to set the market price. Due to the apparent availability of ample quantities of shale gas and declines in gas use due to the recession, natural gas prices in 2009 and 2010 were substantially lower than prices in the prior years.

The most recent Annual Energy Outlook released by the Department of Energy's Energy Information Administration (EIA) identifies that natural gas reserves in the United States are double from a year ago. In addition it noted that,

> Because of a revised representation of natural gas pricing and a significant increase in estimated technically recoverable shale gas resources, the price of natural gas at the wellhead is consistently lower in the AEO2011 Reference case than it was in AEO2010.
>
> The annual average natural gas wellhead price remains under $5 per thousand cubic feet through 2022, but it increases thereafter because significantly more shale wells must be drilled to meet growth in natural gas demand and offset declines in natural gas production from other sources.[96]

[96] http://www.eia.doe.gov/forecasts/aeo/early_prices.cfm

Greenhouse Gas Costs and Other Regulatory Risks

Although some form of greenhouse gas regulation is probably inevitable, the precise form that this will take and the resulting CO_2 prices are quite uncertain. The effect would be to increase the levelized costs for all plants burning fossil fuels (coal, oil, and natural gas). In this analysis we use a mid-range estimate based on a previous Synapse study.[97]

Other regulatory risks include uncertainty regarding the extension of the production tax credit and the availability of federal loan guarantees.

Inflation Rates, Technology Progress, and Learning by Doing

Levelized costs are also affected by three dynamic forces that drive changes in plant costs over time. These factors have been detailed by the EIA, and include: [98]

- The projected relationship between rate of inflation for key drivers of plant costs, such as materials and construction costs, and the overall economy-wide rate of inflation. A projected economy-wide inflation rate that exceeds projected inflation for key plant cost drivers results in a projected decline in real (inflation-adjusted) capital costs.
- Projected technology progress over time.
- Learning-by-doing, which allows for additional reductions in projected capital costs as a function of cumulative additions of new technologies, has a further effect on technology costs.[99]

[97] *Synapse 2008 CO2 Price Forecasts*, July 2008. http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf
[98] http://www.eia.gov/oiaf/beck_plantcosts/index.html
[99] Although as noted in the section of nuclear cost uncertainty, for the nuclear industry the reverse has also been true, in that learning has resulted in increasing costs.

Appendix E: Cost of Energy Efficiency

Energy efficiency has been consistently proven to be one of the most cost-effective electricity resources available.[100] For example, efficiency programs were recently incorporated into electric capacity markets in New England, and these resources, along with demand response programs, have helped to drive down the costs of capacity in the region.[101]

The cost of saved energy (CSE) from utility energy efficiency programs is currently well below the all-in cost of new conventional supply-side resources. In 2009, ACEEE conducted a study that reviewed the cost of saved energy in utility and third party efficiency programs from 14 leading states, and concluded that the average utility costs ranged from 1.5 to 3.4 cents per kWh, an average value of 2.5 cents/kWh.[102] That study also found that, on average, utilities bear about 60 percent of the energy efficiency cost and customers about 40 percent. This implies that the total cost of energy efficiency measures, including participants' costs, is about 4 cents/kWh.

Both Florida and Georgia have significant room for improvement when it comes to making energy efficiency investments. According to ACEEE, in 2010, overall Georgia ranked 37th and Florida ranked 30th as benchmarked against six energy efficiency categories, including 1) program funding and policy, 2) transportation, 3) building energy, 4) combined heat and power, 5) state government initiatives, and 6) appliance efficiency.[103] For specific attributes, we have detailed Georgia and Florida's rankings compared to leading states. One metric is how the states' incremental savings compared to electricity sales. ACEEE used 2008 electricity sales in its recent scorecard analysis, as shown in Exhibit E-1 below.

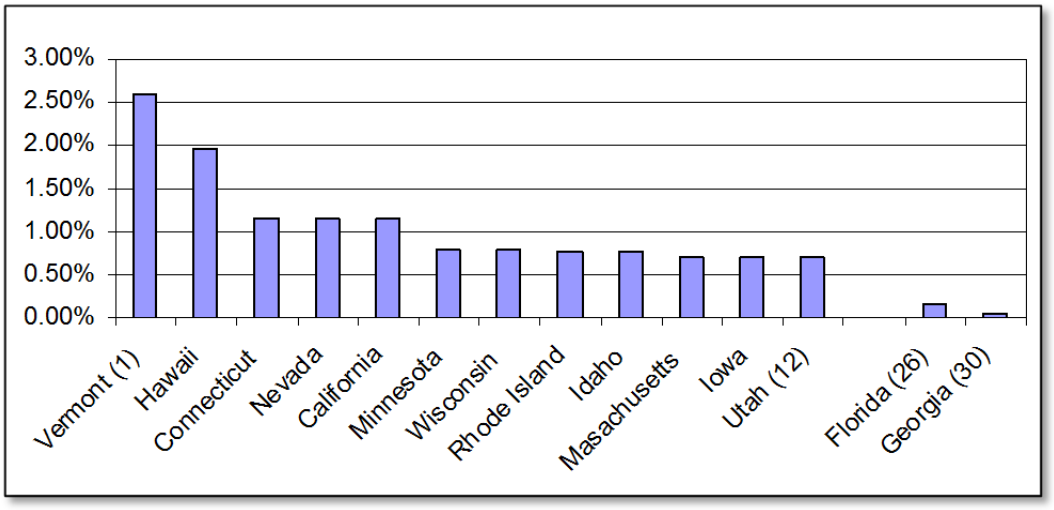
[100] Friedrich, Katherine., Eldridge, Maggie., York, Dan., Witte, Patti., Kushler, Marty. Saving Energy Cost-effectively: A National Review of the Cost of Energy Saved through Utility-sector Energy Efficiency Programs. ACEEE. September 2009.

[101] In the first Forward Capacity Auction, February 2008, the auction ended at the floor price of $4.50 per kW per month with an excess capacity of 2,047 MW above the installed capacity requirement of 32,305 MW. In the auction, 2,554 MW of capacity were from demand resources (including efficiency). Thus it is likely that without the demand resources, the clearing price would be above the floor price of $4.50 per kW per month since there would not have been an excess of capacity to meet the installed capacity requirement. Taken from, Jenkins, C., Neme, C., Enterline, S.. "Energy efficiency as a resource in the ISO New England forward capacity market." 2009. Available at http://www.veic.org/Libraries/Resource_Library_Documents/ISO_NewENgland_ECEEE_Jenkins.sflb.ashx.

[102] The utility cost of saved energy through energy efficiency programs represents the costs incurred by the utility or efficiency program administrator. This metric typically includes the costs associated with program administration, marketing, measurement and evaluation, and participant incentives and rebates, but it excludes participants' costs – the cost participants pay minus the amount of utility incentives. Total costs capture both cost categories.

[103] The full report is available at http://www.aceee.org/sector/state-policy/scorecard.

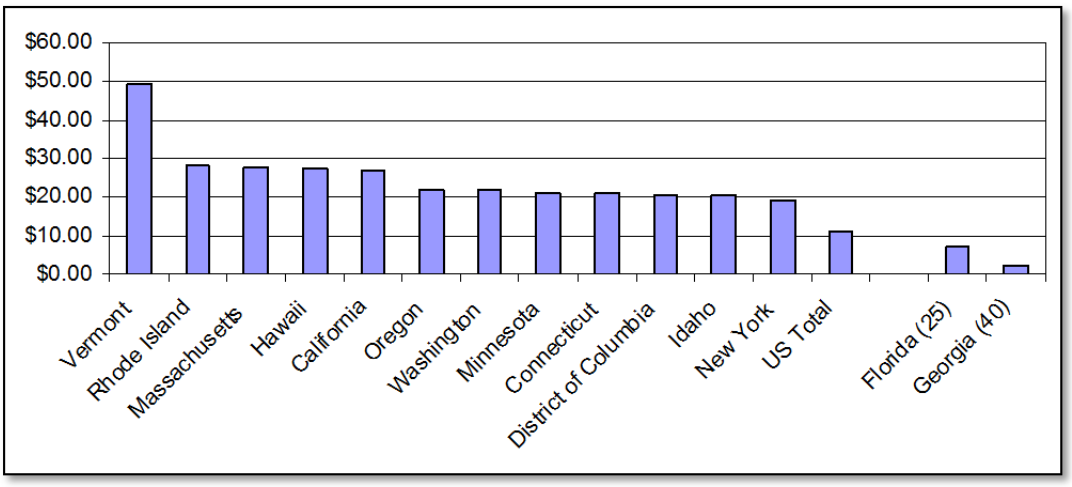
Exhibit E-1. 2008 Incremental Savings from Energy Efficiency as a Percentage of Electricity Sales



Using this metric, Florida (0.15 percent) and Georgia (0.05 percent) are ranked 26th and 30th respectively. The 2008 incremental savings for both Georgia and Florida are both well below the U.S. total of 0.28 percent, and even further below the leading 12 states shown in Exhibit E-1.

In terms of energy efficiency spending per capita, Georgia and Florida are ranked 40th and 25th, and are below the U.S. average of $7.15 per capita. Exhibit E-2 shows that the top 12 leading states and the District of Columbia spend significantly more on customer energy efficiency than either Florida or Georgia.

Exhibit E-2. 2009 Per Capita Spending on Energy Efficiency as Compiled by ACEEE

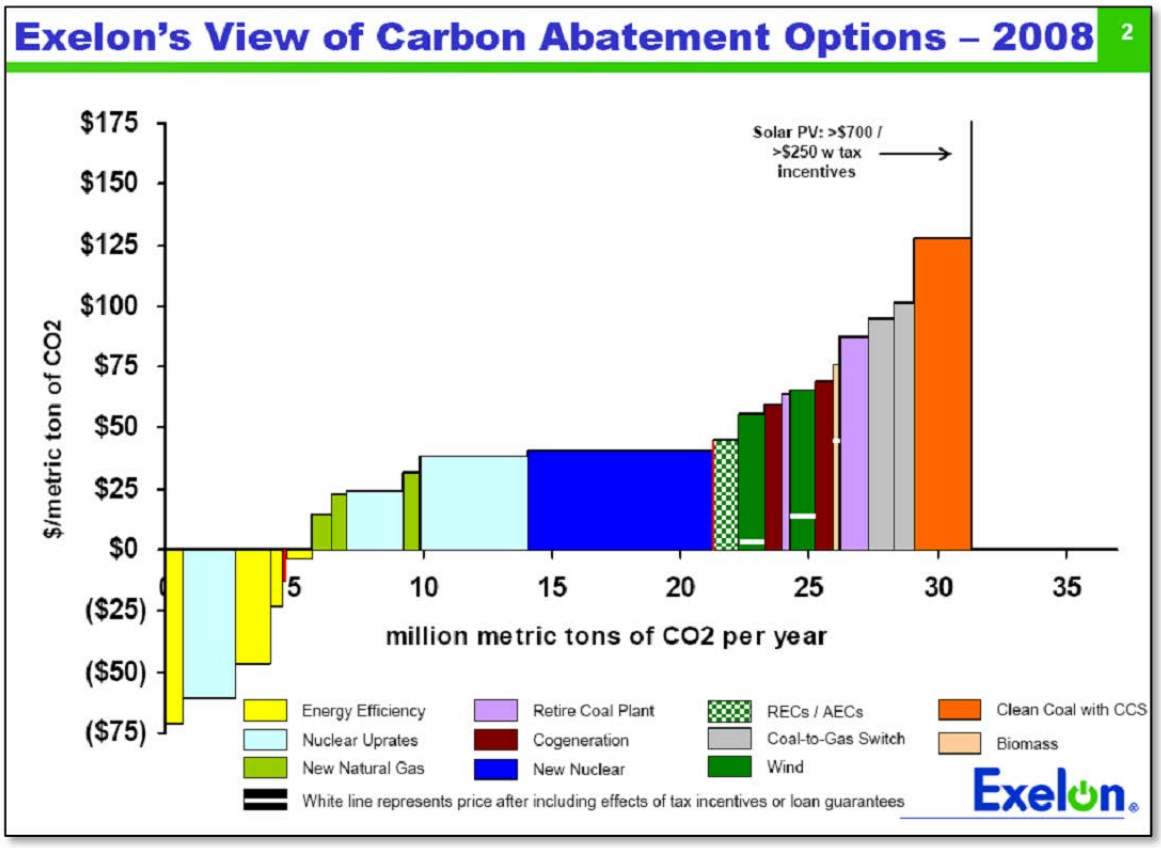


Appendix F: Cost of Greenhouse Gas Abatement

One of the advantages cited by project developers is that Levy 1 and 2 and Vogtle 3 and 4 would not emit carbon when operating. Thus, another way to examine the cost of the projects from a carbon-reduction standpoint is to compare them to the cost of other technologies relative to the amount of CO_2 avoided. One way to do this is to examine the cost of carbon abatement options across both supply- and demand-side options.

The projected cost per ton of reducing CO_2 has dramatically changed over the past several years, even within the nuclear industry. Exelon, the country's largest nuclear power operator, owns and operates ten nuclear plants across the country.[104] Exelon CEO John Rowe stated in several recent speeches that building new nuclear plants was not an economic option, and that the company would focus on implementing less-costly uprates to its existing nuclear fleet and pursuing other lower cost options to reduce its carbon emissions, including implementing energy efficiency and natural gas generation. Exelon's accompanying analysis of abatement costs shows significant changes between 2008 and 2010 for nuclear and other technologies, as shown in the following two figures.

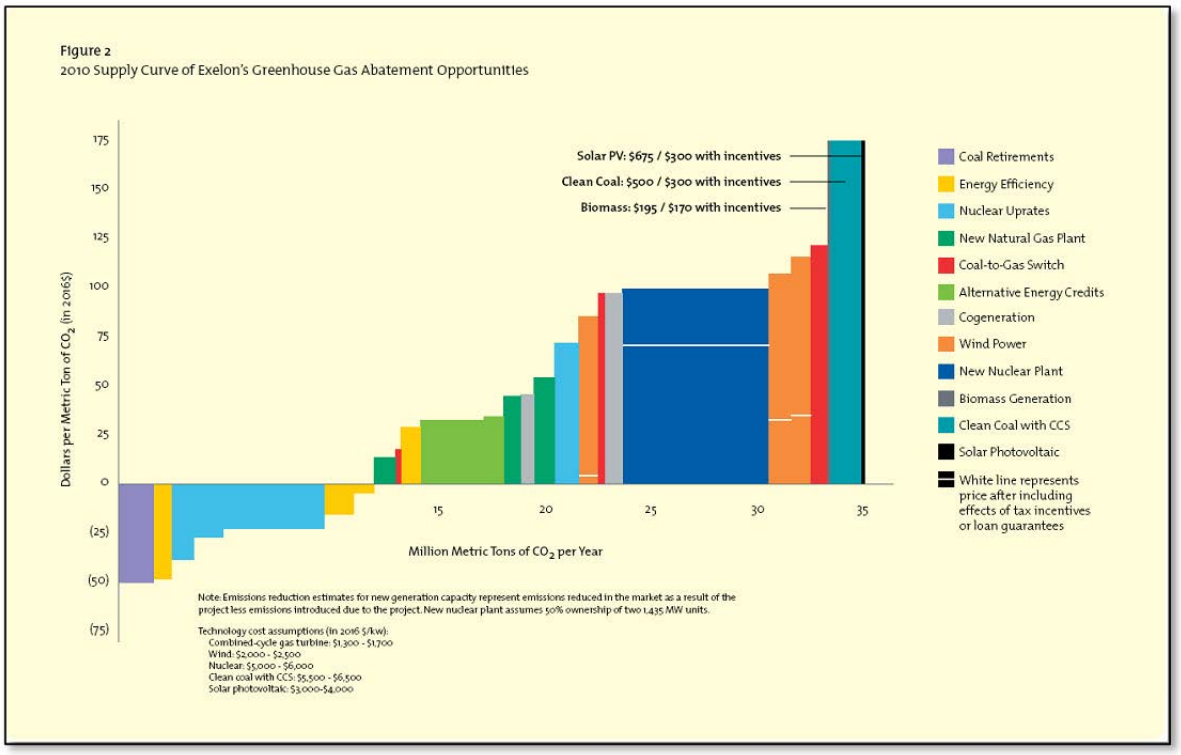
Exhibit F-1. 2008 Exelon Abatement Curve



[104] The ten plants incorporate 17 reactor units, or according to Exelon, 20 percent of the nation's nuclear capacity. http://www.exeloncorp.com/energy/generation/nuclear.aspx.

In 2008, Exelon's analysis indicated that new nuclear reactors had an abatement cost of around $45 per metric ton of CO_2. Exelon's latest analysis shows that the company now estimates that cost of abatement at $100 per ton.

Exhibit F-2. Exelon's Fall 2010 Update



The importance of this latest estimate is this: The U.S. company with the most experience in nuclear power plants has seen a dramatic increase in the abatement cost of nuclear power in a very short time, resulting in more than a doubling of its estimated cost of reducing a ton of CO_2. Exelon's analysis of the 2010 cost of abatement includes tax incentives and loan guarantees for new nuclear, which equal about $30 per ton of CO_2.[105] Importantly, both analyses show that the CO_2 abatement costs of energy efficiency, natural gas, and some renewable energy alternatives remain less expensive than nuclear.

In a recent report to the Southern Governor's Association, the Center for Climate Change Strategies evaluated several policy options for reducing greenhouse gas emissions in the Southeast. The Center found that expanding nuclear power in the Southeast would be the second most expensive policy option on a per metric ton of CO_2 equivalent basis. The table below shows that new nuclear plants are one of the most expensive ways to reduce greenhouse gas emissions.

[105] Exelon has not provided details of its analysis to understand how their cost estimates and impacts were generated.

Exhibit F-3. Center for Climate Change Strategies Policy Options Ranking[106]

Sector	Climate Mitigation Actions	Estimated 2020 Annual GHG Reduction Potential (MMtCO2e)	Estimated Cost or Cost Savings per ton GHG Removed ($)
TLU-1	Anti-Idling Technologies and Practices	13.13	-$83.51
TLU-2	Vehicle Purchase Incentives, including rebates	59.04	-$70.85
RCI-3	Appliance standards	26.32	-$44.29
RCI-1	Demand Side Management Programs	201.94	-$40.33
RCI-2	High Performance Buildings (private and public sector)	108.33	-$36.05
TLU-3	Mode Shift from Truck to Rail	13.71	-$35.52
RCI-4	Building Codes	93.83	-$18.00
AFW-1	Soil Carbon Management	9.24	-$12.76
AFW-2	Nutrient Management	3.25	-$10.10
AFW-4	MSW Landfill Gas Management	20.81	-$0.42
TLU-5	Smart Growth/Land Use	33.02	$0.00
RCI-5	Combined heat and power	90.99	$1.61
ES-4	Coal Plant Efficiency Improvements and Repowering	80.04	$10.72
TLU-6	Transit	5.54	$12.73
AFW-7	Reforestation/Afforestation	87.89	$13.60
AFW-3	Livestock Manure - Anaerobic Digestion and Methane Utilization	2.53	$14.63
AFW-5	Enhanced Recycling of Municipal Solid Waste	84.03	$18.84
AFW-6	Forest Retention	28.22	$19.11
ES-1	Renewable Portfolio Standard	203.93	$19.62
ES-3	CCSR	61.45	$28.84
TLU-4	Renewable Fuel Standard (biofuels goals)	40.28	$40.51
ES-2	Nuclear	100.94	$41.55
AFW-8	Urban Forestry	16.75	$57.20

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; TLU = transportation and land use; AFW = agriculture, forestry, and waste management; RCI = residential, commercial, and industrial; ES = energy supply

[106] Table 2-1. "Southern Regional Economic Assessment of Climate Policy Options and Review of Economic Studies of Climate Policy White Paper Report Prepared by the Center for Climate Strategies for the Southern Governors' Association." October 2009. Available at http://www.climatestrategies.us/template.cfm?FrontID=6081.

Appendix G: Renewable Potential in Georgia

The following section provides more detail about biomass and off-shore wind potential in Georgia.

Biomass Potential

A number of studies have investigated the biomass potential in Georgia:

- In its 2010 IRP, Georgia Power found that Georgia has significant woody biomass potential:

> The state of Georgia and the Southeast have an abundance of forestry and woody biomass resources available for energy use, as evidenced, for example, by fuel studies for Plant Mitchell, as well as data produced by the Georgia Forestry Commission and the U.S. Forest Service.[107]

- In addition, Southern Company has commissioned the Electric Power Research Institute to conduct feasibility studies into converting existing power plants to biomass.[108] These studies are ongoing and their results are not currently publicly available. One example has been the discussion of converting the 156 MW coal-fired Plant Mitchell into a 96 MW biomass plant.[109]
- A 2005 study conducted for the Georgia Forestry Commission identified approximately 23,000 GWh, or approximately 17 percent of 2008 statewide retail electricity sales, of biomass potential in Georgia.[110] It further identified 18.8 million dry tons of wood biomass available annually.[111] While this value does not represent what is economically possible since it ignores transport costs and new plant infrastructure, it does suggest that there is a resource potential that should be analyzed in the context of new resource planning within the state.

As a rough exercise, we converted the annual available dry tons to electricity to determine an approximate technical potential for woody biomass for the state. To convert the woody biomass to heat energy content, we used conversion factors from a 2007 woody biomass study conducted for the City of Gainesville, FL.[112] We then multiplied the heat energy content by a heat rate of a biomass boiler, in this case 8,657 Btu/kWh with an 80 percent capacity factor taken from a 2007

[107] Georgia Power. 2010 Integrated Resource Plan Main Document. Georgia Public Service Commission Docket 31081. (p.10-16)
[108] Georgia Power. (2010) (p.10-14)
[109] Georgia Power. (2010) (p.15-4)
[110] General Bioenergy Inc. "Biomass Wood Resource Assessment on a County-by-County Basis for the State of Georgia." November 9, 2005. Available at http://www.gfc.state.ga.us/ForestMarketing/documents/BiomassWRACountybyCountyGA05.pdf.
[111] General*Bioenergy Inc. "Biomass Wood Resource Assessment on a County-by-County Basis for the State of Georgia." November 9, 2005. Available at http://www.gfc.state.ga.us/ForestMarketing/documents/BiomassWRACountybyCountyGA05.pdf.
[112] Carter, Douglas., Langholtz, Matthew., Schroeder, Richard. Biomass Resource Assessment Part I: Availability and Cost of Analysis of Woody Biomass for Gainesville Regional Utilities. October, 2007. Available at http://www.gru.com/AboutGRU/PublicDiscussion/FuturePower/default.jsp.

Black and Veatch study for the City of Gainesville, FL.[113] Exhibit G-1 shows the results of our analysis:

Exhibit G-1. 2005 Georgia Wood Biomass Potential Converted to Electricity

Category	Amount Available (dry tons)	MMBtu/dry ton	MMBtus	GWh
	(1)	(2)	(3)=(2)*(1)	(4)=((3)/8,657)*80%
Unmerchantable Timber	13260175	15.2	201554660	18625.82049
Harvesting Residue	5048572.65	8.6	43417724.79	4012.265199
Mill Residue	79702.76	8.6	685443.736	63.34238059
Urban Wood Waste	86209	8.6	741397.4	68.51310154
Pecan Shells	21182.15	8.6	182166.49	16.83414485
Paper Mill Sludge	375450	8.60	3228866	298.38
Black Liquor Production	0	8.60	0	0.00
Total Biomass Potential	**18,871,291**		**249,810,258**	**23,085**

Notes
Unmerchantable timber at 20-year growth cycle
Heat energy of biomass sources based on Carter et al. (2007) and Oak Ridge National Laboratory
Heat rate of 8,657 Btu/kWh from Black and Veatch (2007) used for conversion
80% capacity factor assumed for biomass boiler

Data Sources
General Bioenergy Study (2005) for Georgia Forestry Commission
Carter et al. (2007) for City of Gainesville, FL
Black and Veatch (2007) for City of Gainesville, FL

The resulting calculation indicates that all of the biomass identified in the 2005 Georgia Forestry Commission study could generate 23,085 GWh of electricity for the state of Georgia.[114] Using the same 2008 EIA data as noted above, the 2005 Forestry Commission data of biomass potential represents approximately 17 percent of 2008 retail electricity sales in Georgia.[115]

Offshore Wind

A 2009 Southern Alliance for Clean Energy (SACE) report, which summarized several studies and data sources, identified a feasible potential of 17,180 MW, or 52,788 GWh, of offshore wind potential for Georgia by 2025.[116] Although neither the Georgia PSC nor Georgia Power has conducted a state-specific offshore wind resource assessment for the state, in 2007, Southern Company collaborated with Georgia Tech to conduct an offshore wind potential and siting study.[117]

[113] Black and Veatch. Biomass Sizing Study Final Report. B&V Project Number 145639. January 2007. Available at http://www.gru.com/AboutGRU/PublicDiscussion/FuturePower/default.jsp. The Black and Veatch biomass heat rate of 8,657 Btu/kWh is comparable to the heat rate used in our calculations of 8,608 Btu/KWh.
[114] Vogtle 3 and 4 would provide approximately 16,750 GWh of electricity per year assuming an 85 percent capacity factor.
[115] U.S. Energy Information Administration. Form EIA-861, "Annual Electric Power Industry Report."
[116] SACE's total potential capacity cited 71,472 MW from a 2006 AWS Truewind report for Georgia. In 2010 NREL released an assessment of offshore wind potential across the United States. The 2010 report identified 60,425 MW of offshore wind potential for Georgia. The NREL report is available at http://www.nrel.gov/docs/fy10osti/45889.pdf.
[117] Report available at http://www.southerncompany.com/planetpower/pdfs/WindReport.pdf.

This report did not attempt to evaluate the full potential of offshore wind in Georgia; rather, it was a Georgia Power analysis of a specific offshore wind project. The Southern Company report concluded that a 160 MW offshore wind farm could cost $88 per MWh on a 20-year levelized basis (2010$).[118]

[118] We have inflated the Company's reported levelized dollars from $82 per MWh in 2006$ to $87.7 in 2010$.

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Alan Goodrich, Ted James, and Michael Woodhouse

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Prepared under Task No. SS12.2250

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Executive Summary

The price of photovoltaic (PV) systems in the United States (i.e., the cost to the system owner) has dropped precipitously in recent years, led by substantial reductions in global PV module prices. However, system cost reductions are not necessarily realized or realized in a timely manner by many customers. Many reasons exist for the apparent disconnects between installation costs, component prices, and system prices; most notable is the impact of Fair Market Value considerations on system prices. To guide policy and research and development strategy decisions, it is necessary to develop a granular perspective on the factors that underlie PV system prices and to eliminate subjective pricing parameters. This report's analysis of the overnight capital costs (cash purchase) paid for PV systems attempts to establish an objective methodology that most closely approximates the book value of PV system assets.

The analysis shows the following benchmark 2010 U.S. PV system prices (cash purchase, before subsidy and considering reported target installer operating overhead and profit margins):[1]

- \$5.71/$W_{P\,DC}$ – 5 $kW_{P\,DC}$ residential rooftop
- \$4.59/$W_{P\,DC}$ – 217 $kW_{P\,DC}$ commercial rooftop
- \$3.80/$W_{P\,DC}$ – 187.5 $MW_{P\,DC}$ fixed-axis utility-scale ground mount
- \$4.40/$W_{P\,DC}$ – 187.5 $MW_{P\,DC}$ one-axis utility-scale ground mount.

Significant variation (standard deviations of 5%–8%) exists in these estimates due to regional and site-specific cost factors. Most notable is the impact that the wide range of U.S. labor rates and installer productivity (experience) factors can have on installation costs. This uncertainty analysis excluded the impact of system size, which can also play a significant role in determining installed system prices.

Although the cost structure of PV systems designed for use in each market segment are very different, module price and performance remains a significant opportunity for future cost reductions across all PV sectors. In addition to the expected evolutionary cost reductions at the module level (price and efficiency enhancement), advanced installation methods, such as unitized construction techniques, are expected to provide considerable installation labor and materials-related cost benefits by 2020. As the U.S. market matures, competition among installers, as well as improved supply chain and regulatory costs, will likely contribute to significant cost reductions by 2020. This dynamic has been observed in the German PV market. The analysis shows the following 2020 evolutionary PV system price estimates, which are compared with the price targets for 2020 set under the U.S. Department of Energy's SunShot Initiative:

- \$2.29/$W_{P\,DC}$ – 5 $kW_{P\,DC}$ residential rooftop
  (SunShot target: \$1.50/$W_{P\,DC}$)
- \$1.99/$W_{P\,DC}$ – 217 $kW_{P\,DC}$ commercial rooftop
  (SunShot target: \$1.25/$W_{P\,DC}$)

[1] $W_{P\,DC}$ = peak watt of direct-current capacity.

- \$1.71/ $W_{P\ DC}$ – 187.5 $MW_{P\ DC}$ fixed-axis utility-scale ground mount (SunShot target: \$1.00/$W_{P\ DC}$)
- \$1.91/ $W_{P\ DC}$ – 187.5 $MW_{P\ DC}$ one-axis utility-scale ground mount (*modified*-SunShot target: \$1.20/$W_{P\ DC}$).

As these results show, the evolutionary estimates of U.S. PV system prices fall short of the 2020 SunShot targets. This highlights the challenges that remain before solar energy can compete with incumbent electricity technologies without subsidy.

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1. Introduction

Unlike traditional energy-production technologies that have ongoing consumables costs, nearly all of the costs for photovoltaic (PV) systems must be paid at the beginning. Reducing those initial capital costs is crucial to reducing the cost of solar electricity. In addition to module price, many factors contribute to the price of a PV system, including installation labor, power electronics, permitting and other regulatory costs, and—in the case of ground-mount systems—site acquisition and preparation costs.

Under its SunShot Initiative, the U.S. Department of Energy (DOE) has established very aggressive system price targets for each of the three major PV market sectors: residential rooftop, commercial rooftop, and utility-scale ground mount. Achieving these targets will require total system cost reductions of approximately 75% by 2020. Industry stakeholders must understand the ever-changing PV system cost structure. As module prices continue to fall, the contribution of non-module costs to the cost of solar energy will increase. There are also critical relationships between system components, such as the relationship between module conversion efficiency and non-module area-related costs and the relationship between module configuration and installation methods. Research and development (R&D) managers, policymakers, system installers, and component manufacturers must understand the current cost of PV systems in adequate detail to allocate effectively the resources needed for further cost reductions and to design effective market policies. The resolution into PV system price drivers that is required for these decisions is difficult to attain from surveys of system prices, or by retrospective means. Results deviate based on regional, installer, and job-specific details, making accurate price comparisons between systems very difficult, unless conducted from the bottom up.

This report presents detailed, bottom-up 2010 benchmark system prices for residential and commercial rooftop systems and utility-scale ground-mount systems. These results are intended to depict the installed price[2] for U.S. PV systems in the second half of 2010, i.e., the unsubsidized cost (cash purchase) of the system from the owner's perspective. For each system type, the major cost drivers are identified, and the sensitivities to key assumptions (e.g., module efficiency, system scale) are presented.

Following the benchmark system price analysis, this report presents results of a bottom-up analysis of potential PV system price reductions through 2020, assuming an evolutionary path of technological and market improvement. These projections are compared with the 2020 system price targets established under the SunShot Initiative. The difference between the evolutionary projections and SunShot targets highlights the need for innovative system designs and installation methods to complement module-level cost reductions.

[2] Note: *installed system price* here refers to the overnight capital cost, or cash purchase price, for a system installed in the second half of 2010 (the period for which cost data underlying the model were provided).

2. PV System Price Metrics: Fair Market Value vs. Bottom-up Analysis

PV system prices are often characterized using Fair Market Value (*market price*), but this metric does not provide the resolution necessary for understanding system price drivers. Thus, the National Renewable Energy Laboratory (NREL) developed a bottom-up price analysis methodology—which is used to generate the results in this report—to provide the necessary resolution. The *market price* and bottom-up approaches are described below.

2.1. Fair Market Value

PV system prices reported to incentive programs, such as the California Solar Initiative (CSI), reflect the systems' Fair Market Value, which is subject to market dynamics. By definition—whether one relies on income, residual value, or some other methodology—Fair Market Value introduces subjectivity to the estimate, i.e., it depends on a customer's willingness to pay a certain price based on personal preferences and market dynamics.[3] Trends in system prices do not necessarily reflect trends in system costs, but rather the perception by willing and knowledgeable customers, who are under no compulsion to buy, of the value offered by a PV system.

The income-based Fair Market Value methodology, for example, establishes the value of a PV system based on the capitalization of the expected cash flows from that asset. The value of PV systems, as reported to many incentive programs and by Barbose et al. (2011), for example, generally reflects the difference between solar electricity costs and local offset electricity rates, net of any investment- or production-based incentives, state renewable energy credits (RECs), tax credits, and financial contracts (e.g., power purchase agreements [PPAs]). Progress in cost-reduction efforts does not necessarily impact the Fair Market Value of PV systems. In addition, a time lag between system cost reductions and system prices may exist owing to market dynamics.

Surveys of reported system prices show that the price of PV modules—the most expensive component in a PV system—has decreased sharply in recent years, but the total cost of systems has not fallen as quickly (Barbose et al. 2011). Between 2008 and 2010, the global price of PV modules decreased by approximately $1.36 per peak watt of direct-current (DC) capacity ($W_{P\,DC}$; capacity-weighted average) (Mints 2010), while U.S. PV system (capacity weighted) prices fell by $1.38/$W_{P\,DC}$ (Barbose et al. 2011). However, Barbose et al. (2011) also report that U.S. non-module system costs fell by $0.60/$W_{P\,DC}$ during that same period. Therefore, nearly $0.60/$W_{P\,DC}$ of global module price reduction does not appear to have impacted U.S. system prices.

Multiple factors may contribute to this apparent disconnect between module and total system price trends. Prices for modules and systems are largely based on different supply and demand dynamics. Module prices may be more dependent on global factors impacting manufacturing costs, while the remaining system costs depend on the regional installation experience base (i.e., installer productivity), wage rates, and regulatory costs.

[3] Fair market value (definition): value that an asset could be sold for (or an obligation discharged) in an orderly market, between willing buyers and sellers; often, but not always, it is current market value (Easton et al. 2010).

Delays in the supply chain may also contribute to a delay in module price declines being realized. Retail sales channels may include inventory changeover time at multiple distribution nodes in the supply chain. A reduction in the ex-factory gate module price, therefore, may not reach retail customers until other inventory has been sold, or written down. In utility markets, the construction period for large projects may be as long as three years. During this time, the price of modules may fall significantly. Typically, the engineering, procurement, and construction (EPC) entity will build into the project price a hedge against changing material costs. These derivative instruments mitigate, but do not eliminate, volatile price fluctuations in key materials, like modules. Over the course of the construction period, as module prices change, there may be only a limited pass through to the customer; installed module prices may lag current module prices by several months, depending on the rate of price decline and the terms of the procurement contract. Over the past two years, the rate of module price change has been rapid enough that a delay in delivery from factory to installer of only one quarter could be enough to account for, in some cases, nearly $\$0.34/W_{P\,DC}$ at the installed system price (Mints 2010).

Throughout the remainder of this report, Fair Market Value PV system prices are referred to as *market prices* – a term that is intended to be synonymous with Fair Market Value.

2.2. Bottom-up Analysis

Because of the limited usefulness of *market price* for understanding PV system price drivers, this report uses a highly detailed and transparent bottom-up analysis of installed PV system prices developed by NREL, in collaboration with industry, relying on methods frequently employed by U.S. solar project developers. This methodology characterizes the unsubsidized cash purchase price of PV systems, an objective measure that most closely approximates the *book value* of an asset. The methodology includes all materials, labor, overhead and profit (O&P), land acquisition and preparation costs, and regulatory costs for a PV system up to the point of grid tie-in (e.g., for utility-scale PV, it includes substation but excludes transmission infrastructure). The detailed results can be used to guide R&D efforts aimed at reducing PV system prices and to understand the potential benefits of proposed technological improvements.

3. Bottom-up Installed System Price Analysis: 2010 Benchmark

The PV industry generally consists of three market segments: residential rooftop, commercial rooftop, and ground-mount utility-scale systems. The analyses in this report show price structures across the full spectrum of PV system sizes and complexities, from small (residential) rooftop systems to large (utility-scale) ground-mount systems. Section 3.1 discusses assumptions used in the analyses. Sections 3.2–3.4 show benchmark (2010) system prices for the three PV market segments, and Section 3.5 summarizes the benchmark prices for all market segments.

3.1. Analysis Assumptions

For each system, a bill of materials (BoM) was developed based on NREL's review of completed PV projects. The BoM informs not only material-related cost estimates, but also installation labor requirements. In some cases, material categories are presented in aggregate for illustration purposes. The category "wiring," for example, contains many subcomponents that range from wire and conduit to electrical connectors, excluding installation labor. Wiring materials may be further broken into two categories: DC and alternating-current (AC) materials. DC wiring consists of all components that make up the electrical pathway from the module up to, but excluding, the inverter. Wiring from the modules to the combiner box may be completed by general or carpentry labor. Beyond the combiner box—the handoff point—electrician labor is typically required. Skilled, electrician labor is generally required for AC wiring, which consists of all components and the electrical pathway that follows the inverter but excludes utility substation components. In this analysis, for utility-scale PV, the substation and grid tie-in costs are included as a component of "Permitting and Commissioning" costs.

A markup on the ex-factory gate price for module components is included for each of the three market sectors based on the typical installer supply chain costs and project overhead rates. The typical residential installer portrayed in this analysis purchases all materials through retail sales channels, incurring a 10% markup on ex-factory gate module prices. Larger commercial rooftop installations, which often use materials purchased through wholesale channels, incur a 5% markup. The utility-scale installer is modeled as if that company also acts as the EPC contractor for the project, as is becoming increasingly common in this market segment. As a result, no markup on ex-factory gate module price is assumed for utility-scale systems.

For simplicity, project overhead rates—which include interest during construction, inventory, and project-contingency costs—are rolled into a further markup on all materials, including modules. NREL has observed that these costs can vary widely from project to project, based on differences in regional and project-specific costs. Based on conversations with installers and a review of detailed project cost data, it is estimated that the typical residential installer passes through a markup of up to 30% on the retail price for all materials to cover the project-related costs described above. Owing to economies of scale and more efficient supply chains, commercial projects incur a 20% markup and utility-scale projects a 10% markup for the same materials and supply chain related costs.

All labor costs are calculated using U.S. national average wage rates and standard burden rates,[4] including payroll taxes, insurance and retirement benefits, and liability insurance as well as operating overhead costs that vary by market sector, installer size, and experience. The operating overhead rate in 2010 assumed for residential installers (54%) reflects not only the size of the firm, but also its experience in preparing and completing PV system designs and regulatory filings (e.g., building and electrical permits). As PV system design experience increases, installers likely will be able to prepare the necessary drawings and permits more efficiently. Moreover, as the size of the installer and number of PV jobs performed increases, certain overhead costs, such as the cost of trips to the permitting office, also will be reduced (i.e., amortized over more PV jobs).

Commercial rooftop installations may be completed by independent installers or vertically integrated companies. Owing to the size of these rooftop systems, the operating overhead costs incurred by the installer are typically less than for residential systems: approximately 32%, as reported to NREL by collaborating installers. Utility-scale installations generally have lower overhead costs than rooftop installations largely owing to economy-of-scale benefits as well as standardized ground-mount system designs. In 2010, the typical installer operating overhead rate for the utility-scale PV sector (22%), as observed by NREL, more closely approximates that of a mature U.S. electrical contractor (16%) whose annual billings exceed $4 million (RS Means 2010).

Because the levelized cost of energy (LCOE, in $/kWh) generated by the PV system is one of the most relevant competitive benchmarks, it is necessary to also include an estimate of the installer's profit margin, i.e., to calculate the price paid by the system owner, rather than simply the cost to install. Installers of residential systems tend to target a margin of 30%[5] on all installation labor services (costs), which is nearly triple the margin of contractor services in analogous, but more mature industries.[6] In addition to the significant impact of *market price* — the price a customer is willing to pay for solar energy—installer experience and market maturity (competition) can influence available margins heavily. A lack of residential installer competition in a geographic region may contribute to these higher-than-expected installer margins. Also, the accuracy with which rooftop systems are quoted can be limited by the installer's experience. Residential installers have reported to NREL that unexpected rooftop or building features, weather delays, and permitting delays often contribute to relatively large margins of error between a prepared quote and the realized project cost. To achieve an acceptable average gross margin, installers may account for these uncertainties by targeting higher margins. As a residential installer's experience and local competition both increase, it will benefit the installer to improve quotation accuracy and tighten the targeted profit margin. Installers of commercial rooftop PV systems target lower margins (approximately 20%) owing to differences in company and project size.

[4] A breakdown of burdened labor rates is as follows: worker's compensation insurance, 6.4%; federal and state unemployment insurance, 6.2%; Social Security taxes (FICA), 7.65%; builder's insurance, 0.44%; and public liability insurance, 2.02% (RSMeans 2010).
[5] Installer margin is considered a markup on labor costs only. Materials are marked up separately based on channel-to-market costs and project-related costs (contingency, inventory, interest during construction, etc.).
[6] The average U.S. electrical contractor (annual billings > $4 million) profit margin is 10% (RSMeans 2010).

The EPC entities for utility-scale PV systems tend to target a profit margin on installation labor that is more representative of mature contractor service industries (~10%). The difference in target profit margin between utility and residential market segments reflects not only a difference in system scale, but also competing electricity costs. Utility-scale systems are often installed to help a utility meet state renewable energy production goals. These goals, along with peak power demand (pricing) and project alternatives, contribute to the negotiated PPA price signed between a utility and the system owner. Depending on the specifics of this contract, the price that the system owner is willing to pay may vary, impacting the EPC entity's profit margin.

In the United States, utility-scale PV system EPC contractors, who are often the module manufacturers, may use a far more standardized installation system than is found in most residential rooftop applications. This standardization will lead to more favorable volumetric pricing for materials and improved installation (labor) efficiencies. SunPower, for example, has estimated that savings from the company's standardized Oasis Powerblock design may be as high as 25% over traditional one-off system designs (Campbell 2011a).

In the same way that standardization (i.e., economies-of-scale and experience-related cost reduction) has lowered the cost of module manufacturing, the opportunity associated with standardized systems is critical to future PV system cost reductions. For many years, the price of modules has followed a well-documented learning curve of a 20% reduction for every doubling of global module shipments (see Appendix C). A module manufacturer benefits from the shared knowledge and experience gained at all of its global factories (Nemet 2006). For example, First Solar has often touted the benefits of its Copy Smart production approach, which includes standard process and facility designs. In this approach, a manufacturing improvement developed at a facility in one country can more easily be implemented at a firm's other facilities, regardless of geographic proximity, because of standardized production methods and equipment. PV installations, on the other hand, generally require a system design customized to rooftop or ground-site features, local regulatory requirements, and customer preferences. This level of specialization, along with the more disaggregate nature of the PV installation business, results in very little sharing of knowledge across companies or geographies and limits experience-based cost-reduction opportunities. As the market matures, component manufacturers standardize system designs for utility-scale and rooftop applications, and installer best practices are shared, it is expected that immediate cost reductions similar in magnitude to the learning-curve benefits experienced by module manufacturers will be possible.

3.2. Residential Rooftop PV Systems: 2010 Benchmark Prices

Rooftop PV systems are often categorized into two discrete market segments—residential and commercial—based on the type of building on which they are installed. Generally, these markets are defined by electricity rates, PV system sizes, and rooftop slopes. In the United States, residential PV systems are generally 2–10 $kW_{P\,DC}$ and installed on sloped roofs, while commercial systems may be between 10 $kW_{P\,DC}$ and multi-megawatts and are most often installed on flat or low-slope roofs.

For the purposes of this comparison, NREL modeled a typical residential rooftop with 35 m^2 of total available space that is well suited for PV.[7] The baseline system includes 27 crystalline

[7] For background about PV-suitable spaces on residential rooftops, see Paidipati et al. (2008).

silicon (c-Si) modules (0.808 m × 1.580 m) installed in a portrait orientation using through-roof mounts and a standard rail mounting structure. The median c-Si module considered provides 14.5% conversion efficiency, producing approximately 185 $W_{P\,DC}$ per module, resulting in a system size of ~5 $kW_{P\,DC}$. The algorithms used by NREL to estimate racking, wiring, and wiring-subcomponent requirements are based on guidance from collaborating residential system installers and consider module orientation, row-to-row and module spacing, string size, and building code parameters.

For each material category, subcomponent price and installation labor requirements were estimated using a project cost estimation tool designed by NREL in cooperation with installers. The estimates of direct labor costs are sensitive to changes to independent variables such as module efficiency, module and string size, and other system design parameters. The general set of PV system components (depicted in Figure 1) can vary substantially depending on regional and local building or utility requirements; the variable number of AC/DC disconnects is one example (Coddington et al. 2008). In the baseline residential system design profiled here, there is one standalone AC disconnect in addition to the disconnect components that are integral to the inverter and breaker box components.

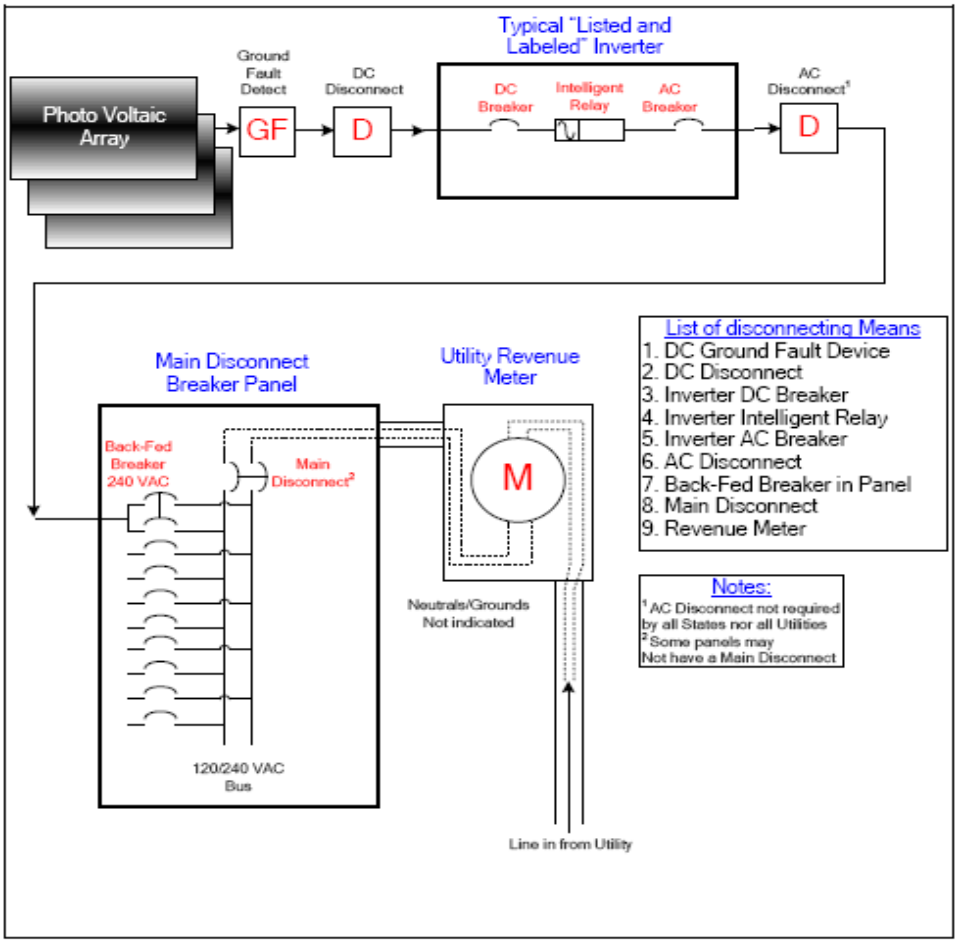


Figure 1. Schematic of a grid-connected rooftop PV system (Coddington et al. 2008).

It is assumed that nearly all non-mounting hardware components that constitute a residential PV system require skilled electrical labor, although this requirement may vary by region or state. The national average electrical contractor wage rate is $49.00/hr, before insurance and benefits, while the average wage rate for a roofer is approximately $33.00/hr (RS Means 2010). At these rates, and with the estimated labor requirements per unit, the cost to install a PV system's electrical components is estimated to be around $1,261 ($0.26/$W_{P\,DC}$). Despite a lower cost per hour for unskilled labor, and owing to the time required to install through-roof hardware, the cost to install the non-electrical (hardware) components is approximately $1,321 ($0.27/$W_{P\,DC}$). Table 1 shows the benchmark system parameters, including labor requirements by component.

Table 1. Benchmark 2010 Residential PV System Parameters (35 m^2 system area, 27 14.5%-efficient c-Si modules): BoM, Installation Labor Allocation Rates (by component), and Total Installation Labor Requirements.

Material Category	Component costs[8] (per $W_{P\,DC}$)	Installation labor allocation requirements			
		Units/system	Units	Electrical (hr/unit)	General (hr/unit)
Module	$2.15[9]	27	Modules	0.20	
Inverter	$0.42	1	Inverters	4.0	2.0
Wiring	$0.03	237[10]	Linear ft	0.05	
Other electrical[11]	$0. 19	1	Electrical subsystem	4.5	
Mounting hardware	$0.37	27	Modules		1.40
	$3.16				
Total Installation Labor Requirements (hr/system):				25.7	39.9

When markups for the applicable labor burden (22.7%), profit (30%) and operating overhead (54%) on labor are added to the base wage rates, the full cost of labor for this residential PV system is estimated to be $6,345 ($1.27/$W_{P\,DC}$). Installer profit and operating overhead rates contribute approximately $0.29/$W_{P\,DC}$ and $0.34/$W_{P\,DC}$ to this estimate, respectively. By reducing the profit and operating overhead rates to reflect those of a more mature service business, e.g., electrical contractor services, the total labor costs could be reduced from $1.27/$W_{P\,DC}$ to $0.81/$W_{P\,DC,}$ and the total system price could be reduced by approximately 8%.[12]

[8] Price paid by EPC contractor or system installer; excludes installer markup but includes channel costs.
[9] $1.95/$W_{P\,DC}$ ex-factory gate module price (Knoll and Siemer 2010) × (1 + 10% retail markup) = $2.15/$W_{P\,DC}$.
[10] Total wiring (237 linear ft) = home run wiring (77 ft) + row to combiner wiring (160 ft).
[11] Other electrical includes meter, system monitor, and disconnects.
[12] Assumes installer operating overhead (54%) and profit (30%) are reduced to 16% and 10%, respectively, according to the national average overhead and profit rates for electrical contractors (RSMeans 2010).

The project's "soft costs," which include local building and utility-mandated permit fees, are estimated to contribute around 3% to the total system price. The labor costs associated with permitting paperwork and regulatory filings are included in the installer operating overhead rate (54%) described previously. In some locations, it has been reported that utility "commissioning fees" may also apply to rooftop systems. These fees, which can range from $900 to $2,000 per system, may include upgrades to existing (building) electrical infrastructure or the addition of net-metering components.

The analysis results in a total installed price for a benchmark 2010 residential PV system of $5.71/ $W_{P\,DC}$. Figure 2 shows the price breakdown by element. Modules contribute the most to the price (38%), followed by labor costs (22%, electrical and hardware labor plus installer O&P) and supply chain costs (17%).

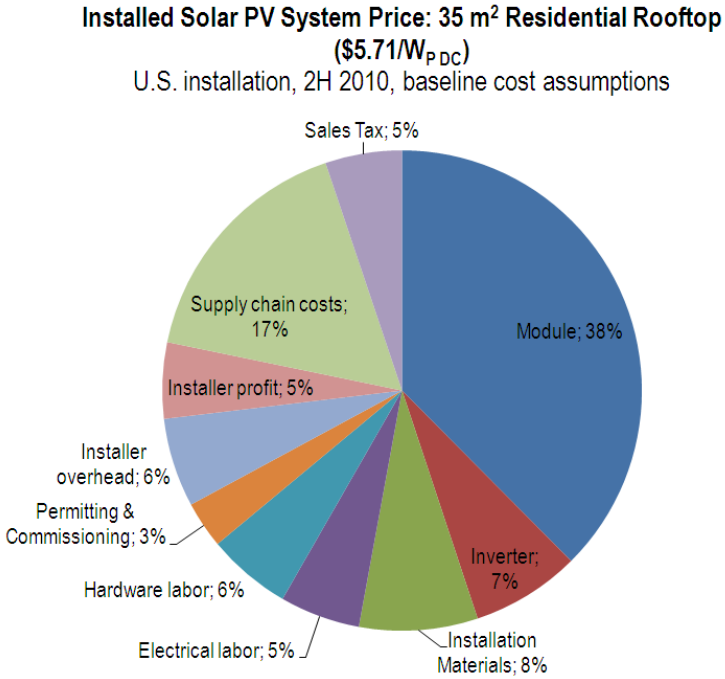


Figure 2. Benchmark 2010 residential PV system price: breakdown by element.

3.3. Commercial Rooftop PV Systems: 2010 Benchmark Prices

The design, and therefore cost, of PV systems for commercial rooftops varies significantly based on preexisting building features and roof materials. The commercial rooftop market segment includes one- to two-story warehouses and big-box stores, office buildings with more than two stories, skyscrapers, and architecturally unique buildings like churches. Commercial rooftops are most often low or no slope and use bitumen, standing-seamed metal, or ballasted-membrane surfaces. As in residential markets, commercial structures may have limited capacity for additional loads, particularly in the southern United States where snow fall is not a consideration. Another example of a region-specific system design requirement is the use of anchors for ballasted PV systems to satisfy municipal and county seismic-zone building requirements.

Building/roof characteristics and design requirements affect installation methods, system designs, and hardware requirements substantially.

The commercial rooftop PV system (914 c-Si modules, 0.992 m × 1.653 m, 14.5% efficiency) considered in this analysis is installed on a standing-seam metal roof without through-roof penetrations. Mounting hardware consists of four clips per module affixed directly to the roof's anchored roof seams.

Table 2 shows the benchmark system parameters, including labor requirements by component.

Table 2. Benchmark 2010 Commercial PV System Parameters (1,500 m^2 system area, 914 14.5%-efficient c-Si modules): BoM, Installation Labor Allocation Rates (by component), and Total Installation Labor Requirements.

Material Category	Component costs[13] (per $W_{P\,DC}$)	Installation labor allocation requirements			
		Units/system	Units	Electrical (hr/unit)	General (hr/unit)
Module	$2.05[14]	914	Modules	0.43	
Inverter	$0.37	1	Inverters	16.0	16.0
Wiring	$0.02	6,164[15]	Linear ft	0.08	
Other electrical[16]	$0. 74	1	Electrical subsystem	111	
Mounting hardware	$0.06	914	Modules		
Stage project	$0.00	1	None		36.6
	$3.21				
Total Installation Labor Requirements (hr/system):				1,010.1	52.6

An experienced crew of eight can install up to 150 modules per day using the direct-attach method available for standing metal seam rooftops. In contrast, the flashed points of penetration for through-roof systems are installed at a rate of 25 per day by an experienced eight-person crew. Depending on module size and design requirements (maximum span, cantilever, etc.), approximately 0.07 penetrations may be required per module. In addition to penetration hardware, the rate at which modules may be attached to the through-roof rail-type system is approximately 600 modules per day by an eight-person crew. In total, the approximate time

[13] Price paid by EPC contractor or system installer; excludes installer markup but includes channel costs.
[14] $1.95/$W_{P\,DC}$ ex-factory gate module price (Knoll and Siemer 2010) × (1 + 5% wholesale markup) = $2.05/$W_{P\,DC}$.
[15] Total wiring (6,164 linear ft) = home run wiring (3,084 ft) + row to combiner wiring (3,080 ft).
[16] Other electrical includes conduit, switchboard, system monitor, combiner boxes (5), disconnects (4), and commissioning.

required to install a complete through-roof system is approximately 10%–15% faster than for the standing seam-attached system profiled in this report.

Ballasted mounting systems, which generally require no through-roof mounts, may be installed at a rate of approximately 1,000 modules per day by an experienced eight-person crew, depending on project-staging techniques and local and building requirements. The ballasted system may provide a 15%–20% labor savings over standing-seam mounting systems but is generally limited to no- or low-slope roof designs and membrane-type roofing materials.

In the commercial standing-seam system design considered in this analysis, approximately 77 module strings (12 c-Si modules per string) are connected to each of five combiner boxes. Conduit is installed between the three-story building's rooftop and the inverters/control and monitoring system located in the basement. The DC wiring passes through four disconnects located between the rooftop combiner boxes and the inverters. For redundancy, two inverters are included in the system architecture, along with one switchboard and one system monitor.

The cost of the system monitoring components can vary due to functionality, often as specified by a local utility. In some regions, utilities require that commercial systems greater than 1–3 $MW_{P\,DC}$ have advanced system monitoring and controls, which may include remote shut-off capabilities.

System overhead costs (i.e., "Permitting & Commissioning" costs) may include system design and engineering expenses, utility upgrades to the building, building permits, and delays caused by permit-related activities. In this case, design and engineering expenses are assumed to be approximately $10,000, while commissioning fees (upgrade to the building's utility panel) are assumed to be approximately $2,000. It has been reported to NREL that some locations charge a permit fee as high as 10% of projects costs.

The analysis results in a total installed price for a benchmark 2010 commercial PV system of $4.59/ $W_{P\,DC}$. Figure 3 shows the price breakdown by element. Modules contribute the most to the price (45%), installation materials and supply chain costs each contribute 14%, and labor costs (electrical and hardware labor plus installer O&P) contribute 11%.

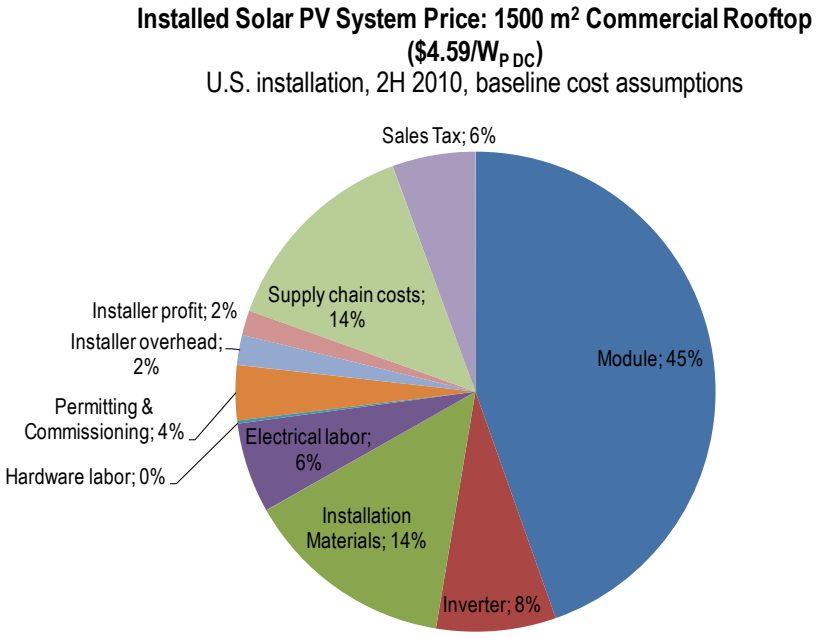


Figure 3. Benchmark 2010 commercial PV system price: breakdown by element.

3.4. Ground-Mount Utility-Scale Fixed- and One-Axis PV Systems: 2010 Benchmark Prices

The scale of individual ground-mount utility-scale PV systems installed in the United States has grown rapidly in recent months. Announcements such as SunPower's California Solar Valley Ranch (SunPower 2010b) and First Solar's Agua Caliente (First Solar 2010) installations represent a trend toward system sizes greater than 100 $MW_{P\,DC}$. At this size, the economy-of-scale benefits are clear, because the fixed costs for ground-mount systems—including permitting and regulatory costs, project transaction costs, and engineering design—are amortized over a greater system size. The scale of utility PV systems is also a significant factor that differentiates this sector from the residential rooftop market, because system size affects not only the configuration of system components, but also their installation methods, channels to market, and resulting system cost structure. Figure 4 shows the sensitivity of PV system price to system size for residential rooftop, commercial rooftop, and ground-mount utility-scale systems.

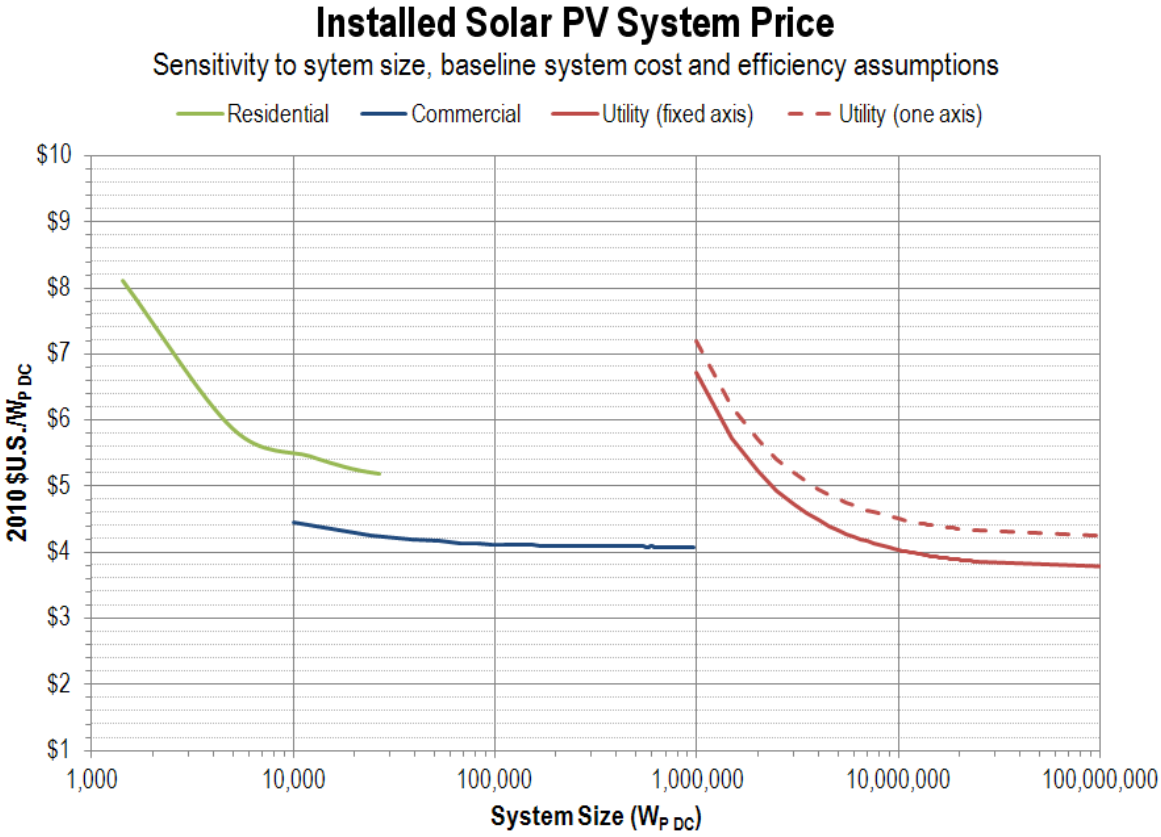


Figure 4. Economy-of-scale benefits: residential and commercial rooftop, ground-mount utility-scale PV.

Rather than a fixed-area (m^2) requirement, as in the rooftop analyses, the utility-scale systems are modeled based on a target system power of 187.5 $MW_{P\ DC}$ with an area dependent on module efficiency and system ground coverage ratio. Fixed-axis ground-mount systems based on 14%- to 15%-efficient c-Si modules typically require approximately 5 acres/$MW_{P\ DC}$, while systems based on the same modules using one-axis tracking require approximately 8 acres/$MW_{P\ DC}$ (Goodrich et al. 2011). System area requirements are based on row-to-row spacing as well as site features (e.g., size and unbuildable areas such as environmentally protected zones, rock formations, etc.) and the project's energy (kWh) production objectives. System installers may be obligated by a project's PPA contract, for example, to build a system that generates a minimum amount of energy per year. Installers may, therefore, purchase more land than is required by their initial design estimates to accommodate uncertainties in energy harvest estimates and to allow for possible project expansions.

Many c-Si module-based utility-scale systems installed in 2010 or planned for 2011 use one-axis tracking. Although the capital cost of one-axis tracking may add 10%–20% to the cost of a fixed-axis system, for c-Si modules the energy-production benefits (typically 25%–30% more kWh/kW per year in areas with high solar resources) often warrant the added capital costs (Campbell 2011a). NREL's analysis of utility-scale PV systems profiles fixed- and one-axis systems using the same standard c-Si modules designed for utility-scale applications (1.96 m^2 with 14.5%

efficiency). Across the range of module efficiencies and correlated module prices, lower-cost, lower-efficiency cadmium telluride (CdTe) modules were also considered for fixed-axis systems only (see Appendix A, simulation of fixed-axis system price-range assumptions).

The general component categories for a ground-mount utility-scale PV system are similar to those of a rooftop installation. The principal difference between rooftop and ground-mount systems is the lack of an existing structure on which the PV may be mounted; instead of a pre-existing structure and roof, the land for a site must be permitted, acquired, and prepared. The value of land used in PV installations is determined by its proximity to transmission infrastructure, available solar resources, subsurface conditions, zoning, and other factors likely to impact a site's PV energy generation and system construction costs. The demand for land that is well suited for PV has risen as the PV market has grown.[17] Speculators have contributed to the rising cost of PV-suitable land, often charging a premium for even small areas that enable large continuous swaths to be acquired for very large PV projects (Woody 2008). Of course, lower-efficiency modules increase the system land area requirements (and, therefore, overall costs) to achieve a desired system power output; the material and labor costs are also greater as fewer watts are being installed per component and per hour of labor. In 2010, the average cost of land best suited for PV in the United States was approximately $5,025 per acre (see Appendix B).

Generally, most PV sites will require clearing, leveling, grading, sediment control, hydrology work, and construction of access roads and fencing. Well-suited sites and low-impact system designs can minimize the site-preparation requirements; furthermore, low-impact site preparation increases the probability of a successful and timely environmental review. Average site-preparation costs have been observed to be approximately $25,000, although this can vary from $5,000–$25,000 per acre, depending on site specifics (see Appendix B).

The cost of permitting a site for PV also varies by region. Installers have reported the cost of environmental impact studies to be as low as $100,000, but also up to $5.0 million for more rigorous reviews, such as those required under the California Environmental Quality Act. These costs have the potential to be much higher based on the nearly unlimited litigation opportunities afforded to all stakeholders in the permitting process. Projects scoped by utilities to meet their state's renewable production standard goals avoid many of these "soft" costs by selecting pre-zoned sites that are collocated with existing energy generation or industrial infrastructure. Developers of so-called Greenfield projects are often willing to pay a premium for land that has been used for agricultural or industrial purposes because it may expedite the environmental review process. NREL has observed typical environmental review costs to be approximately $1.0 million for projects whose construction began in 2010 (see Appendix B).

This analysis considers the capital cost of a utility-scale PV system up to the point of grid tie-in (i.e., the costs of new transmission infrastructure or upgrades to existing transmission, grid interconnection studies, etc. are not considered in this report). The permitting and commissioning costs depicted here include the cost of the abovementioned environmental permitting and the cost of substation installation labor and materials. The cost of the substation and grid tie-in for

[17] The costs of new transmission, transmission upgrades, or interconnection (utility) studies were not considered in this analysis. It has been reported to NREL that these costs can quickly eliminate the cost feasibility of a project (costs are $20–$80 million for sites not situated near existing power generation).

the system is a function of the system's size. For the baseline utility-scale PV system (187.5 $MW_{P\ DC}$) described in this analysis, the cost of the commissioning can be $1.0–$10.0 million, depending on system size. In 2010, NREL observed typical substation costs to be approximately $1.6 million (Goodrich et al. 2011). In total, site-related costs—including land acquisition, preparation, permitting, and commissioning—contribute less than 10% to the total utility-scale system price.

Because utility-scale ground-mount PV systems have no existing structure to use in their construction, the mounting structure requires footings that are often, but not always, driven into the ground and cemented. Strategies for these poles and foundations may also include non-penetrating cement feet. In this analysis, driven poles are considered; the pile driving is accomplished using a semi-automated machine and general construction labor. The racking components, to which the modules are affixed using clamps, are mounted atop these poles, also using general hardware or unskilled construction labor. Using modules that are less efficient than the 14%- to 15%-efficient modules modeled here would increase the amount of system area and mounting hardware required to achieve the desired system power, along with costs. One-axis trackers increase both the cost of the hardware as well as the total system area requirements because they must be separated by sufficient distance to avoid row-to-row shadowing; this also increases land, wiring material, and labor costs.

Table 3 shows the benchmark system parameters for fixed-axis utility-scale systems, including labor requirements by component. Table 4 shows the parameters for systems with one-axis tracking.

Table 3. Benchmark 2010 Fixed-Axis Utility-Scale Ground-Mount PV System (187.5 $MW_{P\ DC}$, 14.5%-efficient c-Si modules): BoM, Installation Labor Allocation Rates (by component), And Total Installation Labor Requirements.

Material Category	Component costs[18] (per $W_{P\ DC}$)	Installation labor allocation requirements			
		Units/system	Units	Electrical (hr/unit)	General (hr/unit)
Module	$1.95[19]	659,747	Modules	0.45	
Inverter	$0.29	156	Inverters	40.0	8.0
Wiring	$0.15	3.8 million m^2	System area	0.19	
Other electrical[20]	$0.02	54,978	Module strings	0.52	
Mounting hardware	$0.23	1.3 million m^2	Active area		0.30
	$2.64				
Total Installation Labor Requirements (hr/system):				1,035,198	389,179

[18] Price paid by EPC contractor or system installer; excludes installer markup but includes channel costs.
[19] $1.95/$W_{P\ DC}$ ex-factory gate module price (Knoll and Siemer 2010) – no supply chain markup.
[20] Other electrical includes meters, monitors, array disconnects, and other non-substation system components.

Table 4. Benchmark 2010 One-Axis Utility-Scale Ground-Mount PV system (187.5 $MW_{P\ DC}$, 14.5%-efficient c-Si modules): BoM, Installation Labor Allocation Rates (by component), and Total Installation Labor Requirements.

Material Category	Component costs[18] (per $W_{P\ DC}$)	Installation labor allocation requirements			
		Units/system	Units	Electrical (hr/unit)	General (hr/unit)
Module	$1.95[19]	659,747	Modules	0.45	
Inverter	$0.29	156	Inverters	40.0	8.0
Wiring	$0.25	6.0 million m^2	System area	0.19	
Other electrical[20]	$0.02	54,978	Module strings	0.52	
Mounting hardware ***includes tracker***	$0.38	1.3 million m^2	Active area	0.10	0.30
	$2.88				
Total Installation Labor Requirements (hr/system):				1,523,164	389,179

The cost of wiring materials—including all wiring materials and subcomponents such as conduit, connectors, and grounding pathways as well as wiring-related installation labor—is a function of system area, module size, and module count. In this architecture, parallel strings of modules are connected in series to central inverters, which are then connected to a central grid tie-in location (substation). Wiring material costs, including material markups for a fixed-axis ground-mount system using 14%- to 15%-efficient c-Si modules are estimated to contribute approximately \$0.15–\$0.25/$W_{P\,DC}$, excluding installation labor. Systems that rely on one-axis mounting structures require additional wiring materials for the same power output, proportional to the larger system area requirements needed to avoid row-to-row shadowing losses.

Utility-scale inverters are often sized between 500–600 $kW_{P\,DC}$ per unit. NREL has observed that, for utility-scale PV systems, inverter pairs are most often housed in a storage shed, along with a single 34.5-kV medium-voltage transformer. These preassembled inverter-transformer systems, including switch gear, etc. weigh on the order of 6,700 kg and are installed in approximately 1 day (two workers) if proper site preparation is completed beforehand. Access roads are not always needed for their installation, depending on site specifics. The prices of utility-scale inverters have fallen considerably in recent years and are distributed over a relatively wide range. Recent prices observed by NREL have ranged from \$0.15–\$0.35/$W_{P\,DC}$, including the transformer and storage shed but excluding installation labor. A typical inverter-transformer assembly price for the period profiled in this analysis (second half of 2010) is \$0.29/$W_{P\,DC}$. Other electrical components include the meters and system monitors whose requirements depend on local regulations and customer preferences.

The analysis results in a total installed price for a benchmark 2010 fixed-axis ground-mount utility-scale PV system of \$3.80/ $W_{P\,DC}$. Figure 5 shows the price breakdown by element. Modules contribute the most to the price (51%), labor costs (electrical and hardware labor plus installer O&P) contribute 14%, and installation materials (including supply chain costs) contribute 17%.

The analysis results in a total installed price for a benchmark 2010 one-axis-tracking ground-mount utility-scale PV system of \$4.40/ $W_{P\,DC}$. Figure 6 shows the price breakdown by element. Modules contribute the most to the price (44%), labor costs (electrical and hardware labor plus installer O&P) contribute 18%, and installation materials (including supply chain costs) contribute 17%.

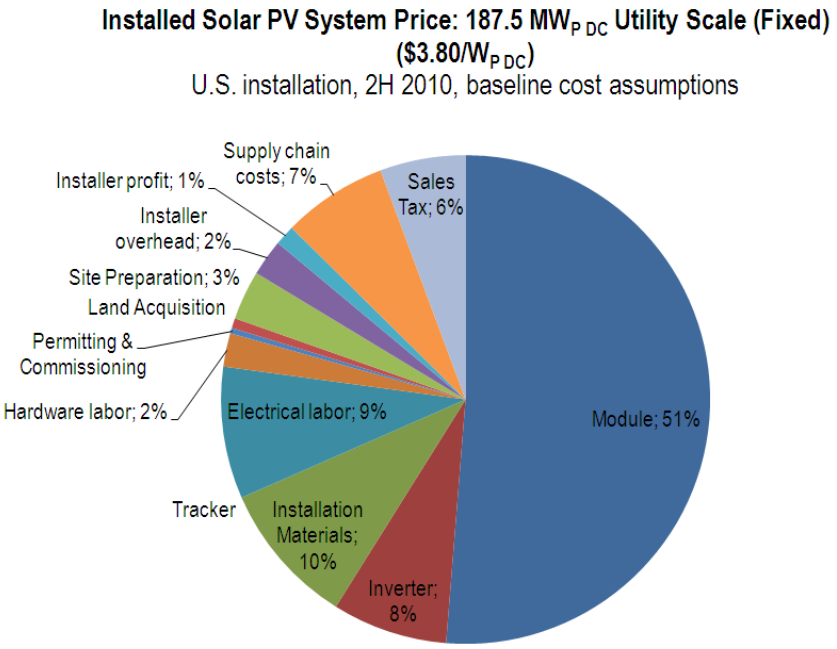


Figure 5. Benchmark 2010 fixed-axis utility-scale PV system price: breakdown by element.

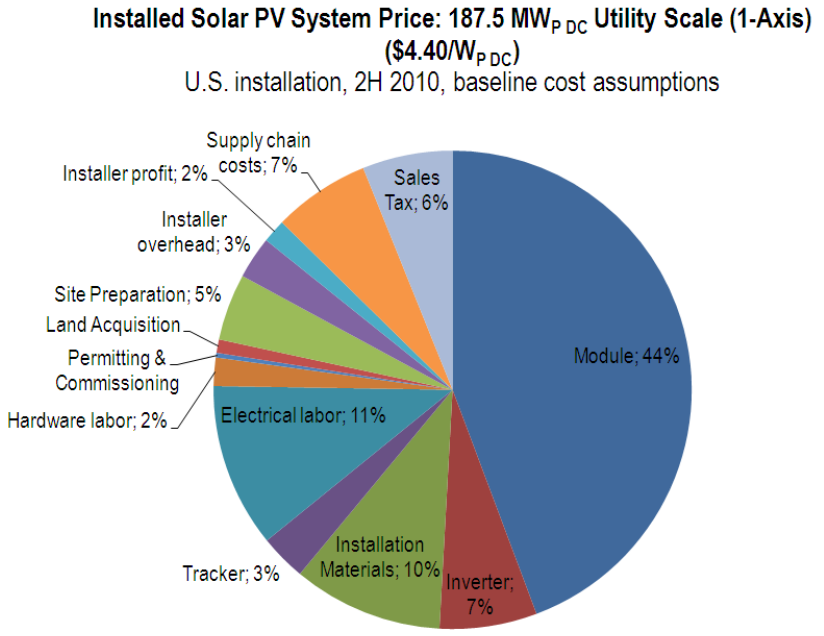


Figure 6. Benchmark 2010 one-axis-tracking utility-scale PV system price: breakdown by element.

3.5. Summary of 2010 Benchmark Prices

Figure 7 summarizes the 2010 benchmark price breakdowns by element for residential rooftop, commercial rooftop, and fixed- and one-axis utility-scale PV systems. The price of PV systems varies across market sectors based primarily on differences in system scale and installer channels to market. Excluding differences in system size, results may vary (as described in Appendix A) based on local labor and permitting costs, technology-selection decisions, installer productivity, and site-related costs. Regardless of these variations, system scale has a significant and beneficial impact on rooftop and ground-mount system prices. Large PV systems not only better amortize fixed project overhead expenses, but also improve installer efficiencies and drive more efficient supply chain strategies.

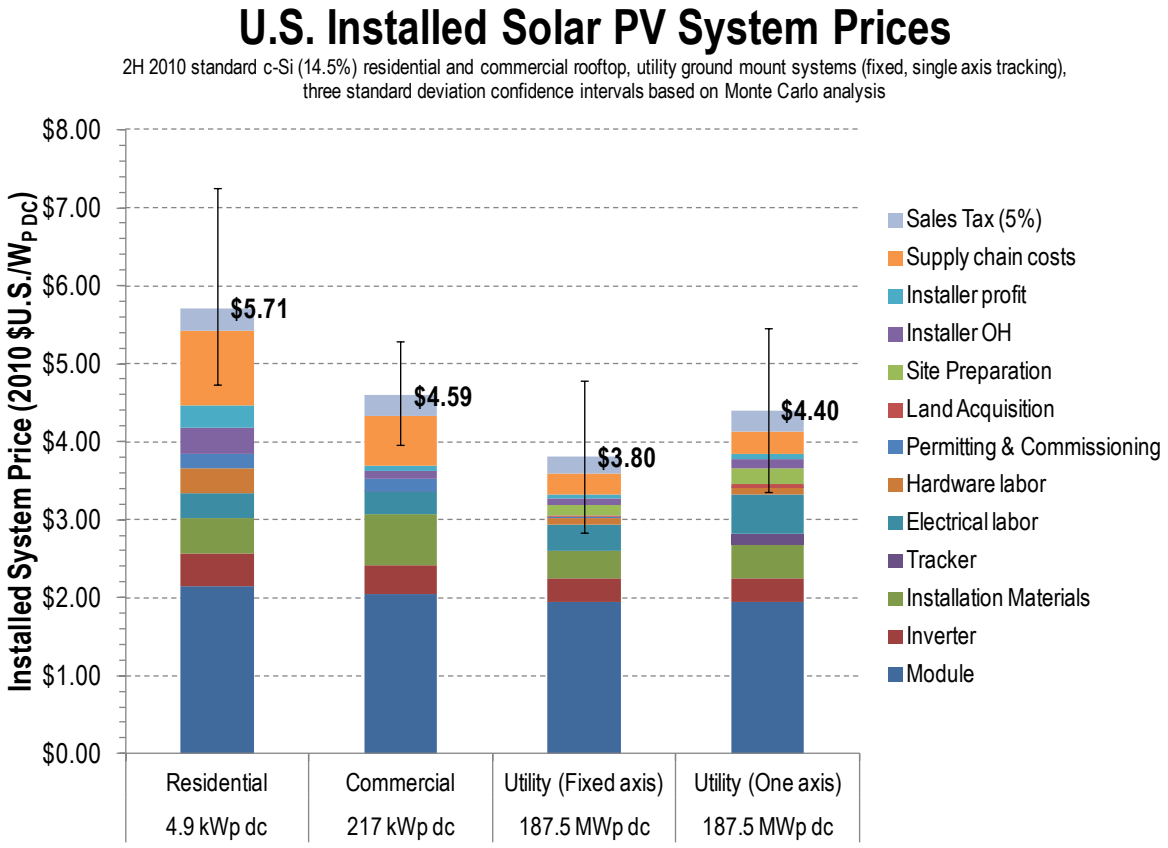


Figure 7. Benchmark 2010 PV system prices, all three sectors: breakdown by element.

Despite the recent precipitous drop in global PV module prices, these components continue to contribute a significant amount to total system price. In addition to module price, module selection decisions also impact conversion efficiencies, which are a critical price driver, especially for area-constrained rooftop systems (Figure 8).

Across most PV technologies, the efficiency of commercially available PV modules varies from about 10% (for tandem microcrystalline-amorphous silicon) to 19.6% (for super monocrystalline silicon). By increasing the power/efficiency of each module installed, the area-related costs of

the system may be reduced. This relationship is not linear, however, but offers diminishing returns. The asymptote for this relationship is defined by power-related costs, such as module and inverter components. Because cost structures vary by market sector, the value of module efficiency varies by market.[21]

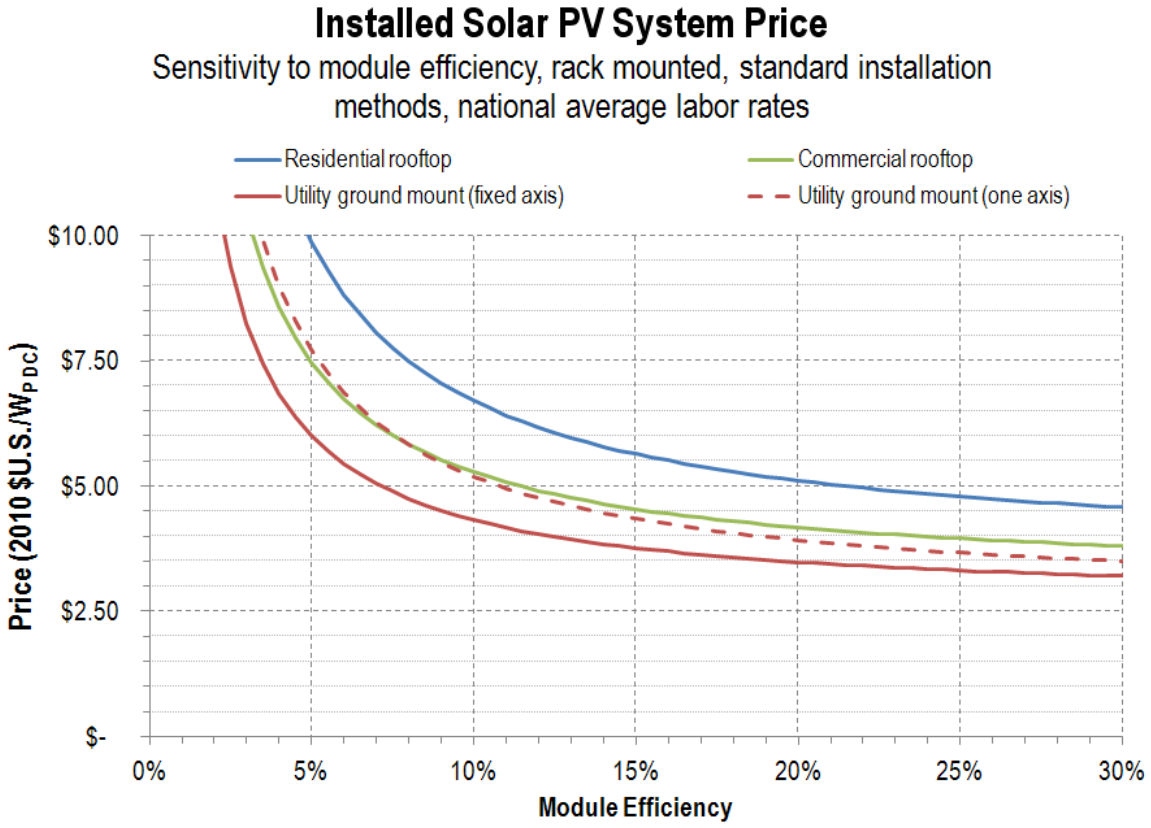


Figure 8. Sensitivity of 2010 benchmark installed PV system prices to module efficiency (module price is fixed).

For relatively mature PV module technologies like single-junction c-Si, which are approaching a practical module efficiency limit from a manufacturing perspective, the value of increased efficiency is low, relative to the value of improving the performance of lower-efficiency thin film modules such as those based on CdTe. For standard, 14.5%-efficient c-Si modules, the value of increased efficiency (per absolute point of efficiency) ranges from $\$0.07/W_{P\,DC}$ (for utility-scale systems) to $\$0.14/W_{P\,DC}$ (for residential rooftop systems).

The value of module efficiency improvements depends on the existing module efficiency, i.e., the starting point of the analysis. Improving the efficiency of a module used in residential applications from 10% to 11% provides $\$0.29/W_{P\,DC}$ of system-level cost savings, while

[21] Rooftop systems were modeled as fixed areas (m^2); thus, their power varied by module efficiency. In contrast, utility-scale (i.e., ground-mount) systems were modeled as fixed (target) system power; thus, their area (m^2) varied to accommodate varying module efficiencies.

improving a module in the same market segment from 19% to 20% provides cost reductions of only $0.08/$W_{P\ DC}$. Therefore, while module efficiency is an important system price driver, particularly for area-constrained applications such as residential rooftops, the value of pursuing ever-higher efficiencies is diminishing for many technologies, such as super monocrystalline-based modules. In contrast, while it is of diminishing value to pursue ever-increasing module efficiencies for high-performing technologies like super monocrystalline silicon, the cost penalty for technologies that are significantly less efficient is quite high.

4. Bottom-up 2020 Evolutionary PV System Price Projections vs. SunShot Targets

In collaboration with industry, NREL has developed detailed simulations of silicon module manufacturing costs (Goodrich et al. 2010). These tools provide a means of quantitatively evaluating alternative technical improvement pathways, including low cost polysilicon (PS) feedstock materials (e.g., produced via the fluidized bed reactor [FBR] process); ultra thin, kerfless wafers produced using diamond wire saws; and high-efficiency interdigitated back contact (IBC) cell architectures that eliminate front-side shadowing losses found in standard silicon cells.

Using these models, NREL has estimated that an evolutionary—or business-as-usual—development trajectory for PV modules will lead to industry median c-Si modules with an ex-factory gate price of about $\$1.01/W_{P\ DC}$ by 2020 (Figure 9, "Technology Group 2"). Importantly, it was estimated that this price could be achieved along with a substantial increase in median production module efficiency, to 21.5%—equivalent to a practical single-junction silicon cell efficiency limit of approximately 24% in high-volume production. Increasing module efficiency generally requires more advanced cell-processing techniques, resulting in higher module manufacturing costs. These added costs may, however, reduce many area-related system costs, providing a favorable cost tradeoff. Nevertheless, it is unlikely that these module improvements will be sufficient to meet the DOE SunShot Initiative targets and ensure that PV is competitive with incumbent energy sources without subsidy by 2020 in residential rooftop, commercial rooftop, or ground-mount utility-scale applications. Therefore, additional cost reductions will be required to meet the SunShot targets for each market sector.

The following sections describe the projected evolutionary pathways from the 2010 benchmarks described above through 2020 for residential rooftop, commercial rooftop, and ground-mount utility-scale PV systems. In addition, the system prices resulting from the evolutionary pathways are compared with the SunShot targets for each sector.

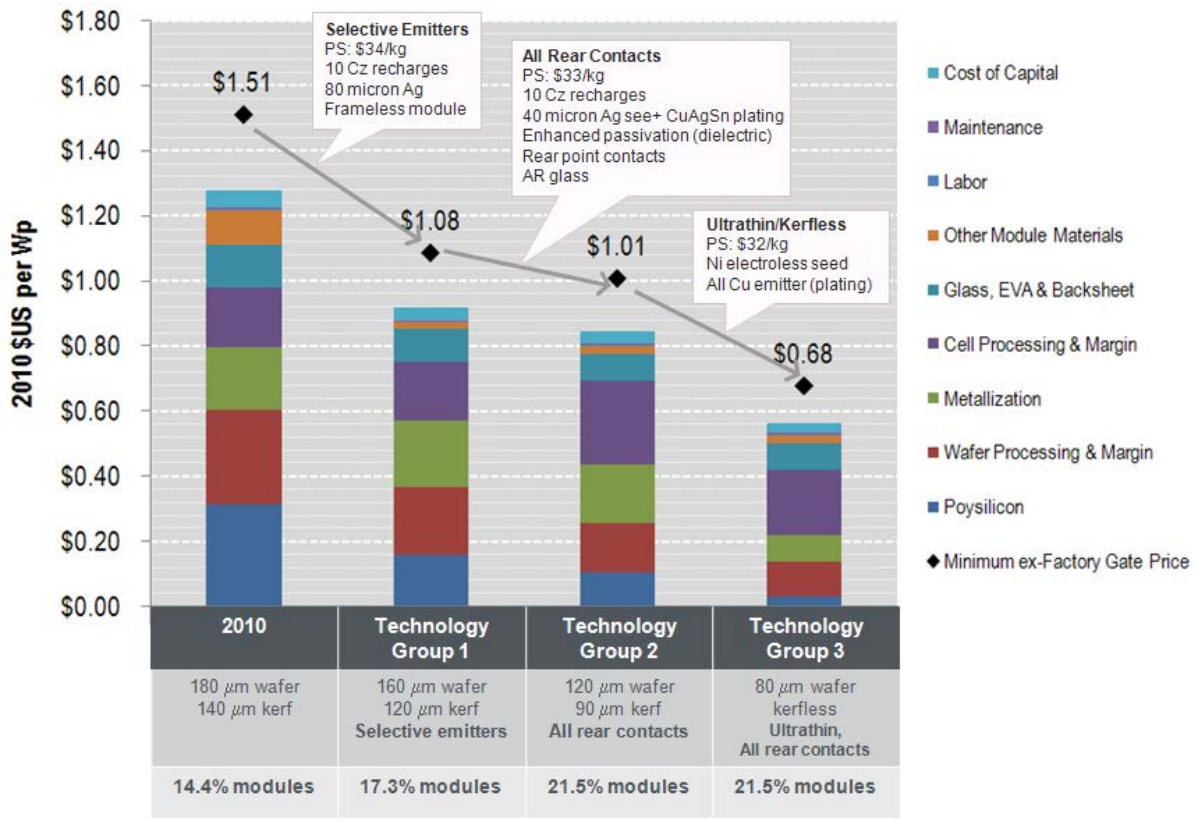


Figure 9. Current and projected single-junction wafer-based c-Si PV module costs and minimum sustainable prices.

(Goodrich 2010)

The Evolution of Non-Module Costs

As the U.S. market matures and installer experience increases, it is likely that non-module installation costs will be reduced. Cost elements like work productivity and supply chain costs (channels to market) are likely to approach those of more mature contractor services, like electrical contractors due to cumulative learning effects, reduced regulatory costs, and increased installer competition. The scale of these cost reduction opportunities is evidenced by comparing German installation prices† to the U.S. (Figure 10). Although direct and indirect labor costs in Germany are higher than in the U.S., installers there have also benefited from the experience that comes with having more than eight times the grid-connected PV capacity of the U.S.

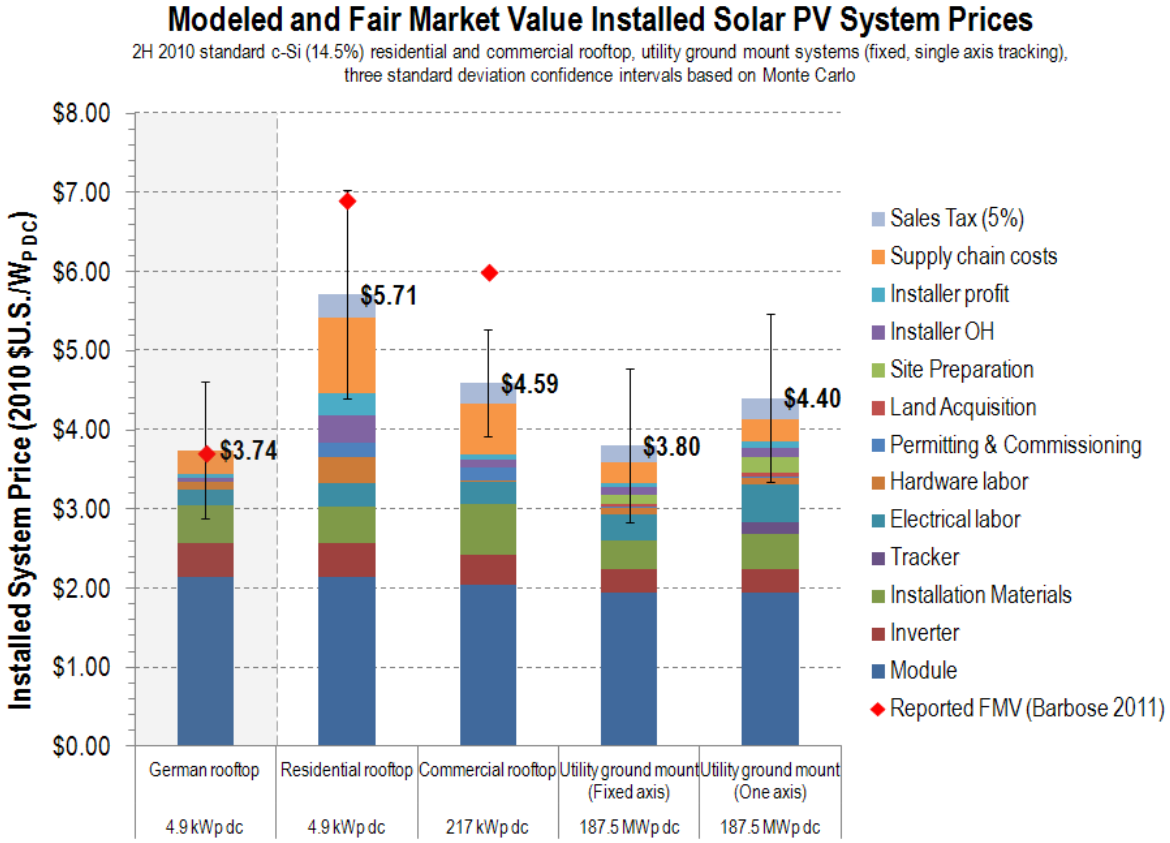


Figure 10. Benchmark 2010 U.S. and German PV system prices: breakdown by element, comparison to reported *market prices* (FMV) (Barbose 2011).

In contrast to the modeled U.S. results, the subjective prices for systems in Germany more closely approximate the estimate of the objective book value, due to a more competitive installer market and differences in demand-side incentive structures.

†Modeled German system price assumptions (differences relative to U.S. system costs): Supply chain (materials) markup reduced from 30% (U.S.) to 10%, Installer overhead rate reduced from 54% (U.S.) to 16%, Installer profit on labor reduced from 30% (U.S.) to 10%, Installation labor productivity improved by 50% relative to U.S. case, Installer electrician hourly wage rate raised from $49 (U.S.) to $68.11 (Germany), Installer carpenter hourly wage rate lowered from $33.10 (U.S.) to $20.85 (Germany), Sales (U.S.) or Value Added Tax (Germany), permitting and commissioning fees waived.

4.1. Residential Rooftop PV Systems

Figure 11 shows the evolutionary pathway for residential rooftop PV system prices from the benchmark of \$5.71/$W_{P\,DC}$ in 2010 to \$2.29/$W_{P\,DC}$ in 2020. It also shows the SunShot residential rooftop target of \$1.50/$W_{P\,DC}$ for comparison.

A reduction in module price from the retail-2010 benchmark \$2.15/$W_{P\,DC}$ (14.5% module) to the \$1.01/$W_{P\,DC}$ (21.5% module) projected in 2020 contributes nearly \$1.42/$W_{P\,DC}$ to residential system price reductions, net of supply chain markup and sales tax benefits. The projected increase in module efficiency would reduce system prices by an additional \$0.71/$W_{P\,DC}$.

By 2020, the evolutionary residential system price estimate assumes that installation methods, installer experience (productivity), and supply chain costs will become more streamlined, bringing the PV industry more in line with other contractor service industries. Like central air conditioning systems, rooftop PV systems use standardized components for the construction of customized home systems. As the market for rooftop PV grows and matures, like the market and price for central air conditioning systems matured, system design and installation methods will likely become more standardized (Lacey 2011). These market maturity-related cost reductions have already been seen in the German PV market, where rooftop system prices are about 42% lower than NREL's estimate of U.S. residential system prices and 52% lower than the *market price* of comparable U.S. rooftop systems (Barbose et al. 2011).

Because components are generally fungible, and there does not appear to be a significant German labor-cost (wage rate or benefits on labor) advantage, it is reasonable to conclude that installer experience and competition, as well as supply chain efficiencies gained through the German market's rapid growth are the principal factors that explain these regional differences. In addition, broad German market acceptance of PV provides a considerable savings by reducing the high cost of onerous permitting processes. A lack of standard permit requirements and diversity of regulations among the many local jurisdictions in the United States contributes to the high (54%) markup for overhead expenses on labor for U.S. installers. NREL estimates that eliminating PV system permit fees could save the typical residential installation approximately \$0.12/$W_{P\,DC}$ in direct costs and contribute to a reduction in operating expenses. As the industry matures, O&P rates could fall to those of more mature service industries, providing up to \$0.19/$W_{P\,DC}$ in savings by 2020.

Unitized construction methods already have been shown to provide significant (30%) reductions in labor content by transferring assembly operations to more efficient factory settings (Koshmrl 2011). Further innovation related to installation methods and increased installer productivity are anticipated, which could contribute to a 50% reduction in installation labor content by 2020 and provide up to \$0.45/$W_{P\,DC}$ in price reduction.

Materials-related cost savings may be attributed to more efficient channels to market for installers (i.e., reduced supply chain costs) and reduced material content/prices. By reducing the current residential markup on materials (30%) for "supply chain costs" (e.g., inventory and contingency costs) to 20%, system prices could be reduced by \$0.20/$W_{P\,DC}$.

The price of residential inverters is expected to fall by nearly two thirds over the next decade, which would contribute approximately \$0.20/$W_{P\,DC}$ to system price reductions. The prices of

other system materials may be reduced through changes to system architecture, e.g., high-voltage strings that use smaller-gauge wiring. A savings of 50% in the area of "other materials" may contribute as much as \$0.14/$W_{P\ DC}$ to system price reductions by 2020.

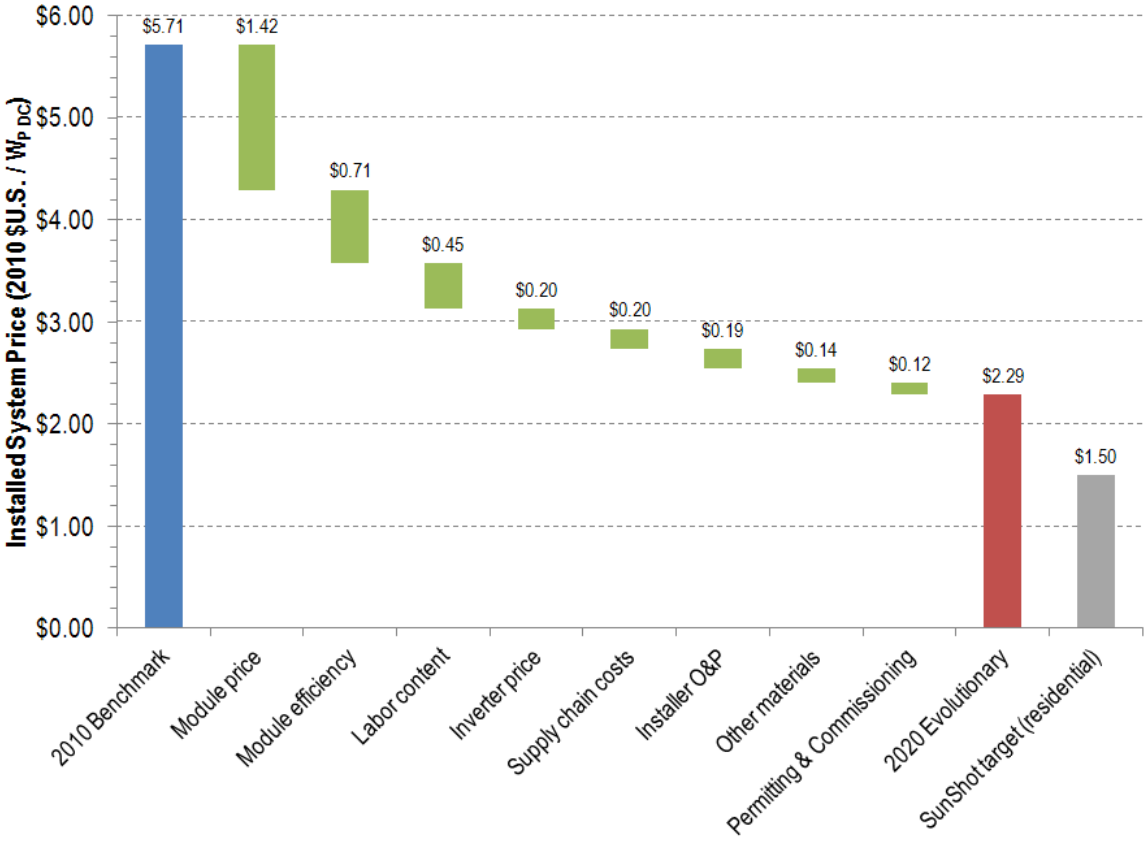


Figure 11. Evolutionary residential PV system price reductions and DOE SunShot target, 2010–2020.

NREL concludes from this analysis that the price of residential rooftop PV systems based on c-Si modules is likely to go below \$2.30/$W_{P\ DC}$ through a combination of anticipated market-driven cost reductions and evolutionary module and inverter technology advancements. Many factors will affect the rate of price reduction, but efforts and announcements by leading solar companies lead NREL to conclude that the proposed timeline in Figure 11 is plausible (Sunpower 2010a). The evolutionary price reduction falls about 34% short of the 2020 DOE SunShot target for residential systems.

4.2. Commercial Rooftop PV Systems

Figure 12 shows the evolutionary pathway for commercial rooftop PV system prices from the benchmark of \$4.59/$W_{P\,DC}$ in 2010 to \$1.99/$W_{P\,DC}$ in 2020. It also shows the SunShot commercial rooftop target of \$1.25/$W_{P\,DC}$ for comparison.

In absolute terms, the value of projected evolutionary c-Si module price trends is expected to contribute less to commercial rooftop system price reduction because of the lower materials-related markups (streamlined supply chain), relative to the residential rooftop sector. As a percentage, however, modules constitute a greater portion of current commercial rooftop system prices. By 2020, evolutionary module price reductions and efficiency enhancements are expected to reduce commercial rooftop PV system prices by 38%.

Other notable areas for improvements include the cost of non-module, non-inverter ("other") materials. By developing systems that operate at higher voltages (lower-gauge wire) and have fewer part counts (e.g., integrated wiring, eliminating some conduit materials), commercial system prices may be reduced by a further \$0.29/$W_{P\,DC}$.

Although the markups assumed for 2010 installer O&P margin are competitive with many mature industries, supply chain costs remain an area of cost-reduction potential. By reducing construction and permitting times, and by streamlining the supply chain for system materials, inventory and project contingency costs can be reduced. If the markup on materials can be reduced to that of mature industries, like electrical contractor services in other building sectors, then system prices may be reduced by \$0.18/$W_{P\,DC}$.

The trend towards unitized construction methods, including ballasted modules with installation labor requirements that can be less than half those for through-roof modules, is prominent in the commercial rooftop PV sector. Further innovation, in terms of product design and installation method, may further reduce the amount of labor required to install a commercial system by 50%, resulting in a price reduction of \$0.16/$W_{P\,DC}$.

NREL estimates that by 2020 the industry will achieve, through aggressive, but evolutionary cost reductions an installed system price for commercial rooftop PV of less than \$2.00/$W_{P\,DC}$, still about 37% short of the 2020 DOE SunShot target for this market sector (\$1.25/$W_{P\,DC}$).

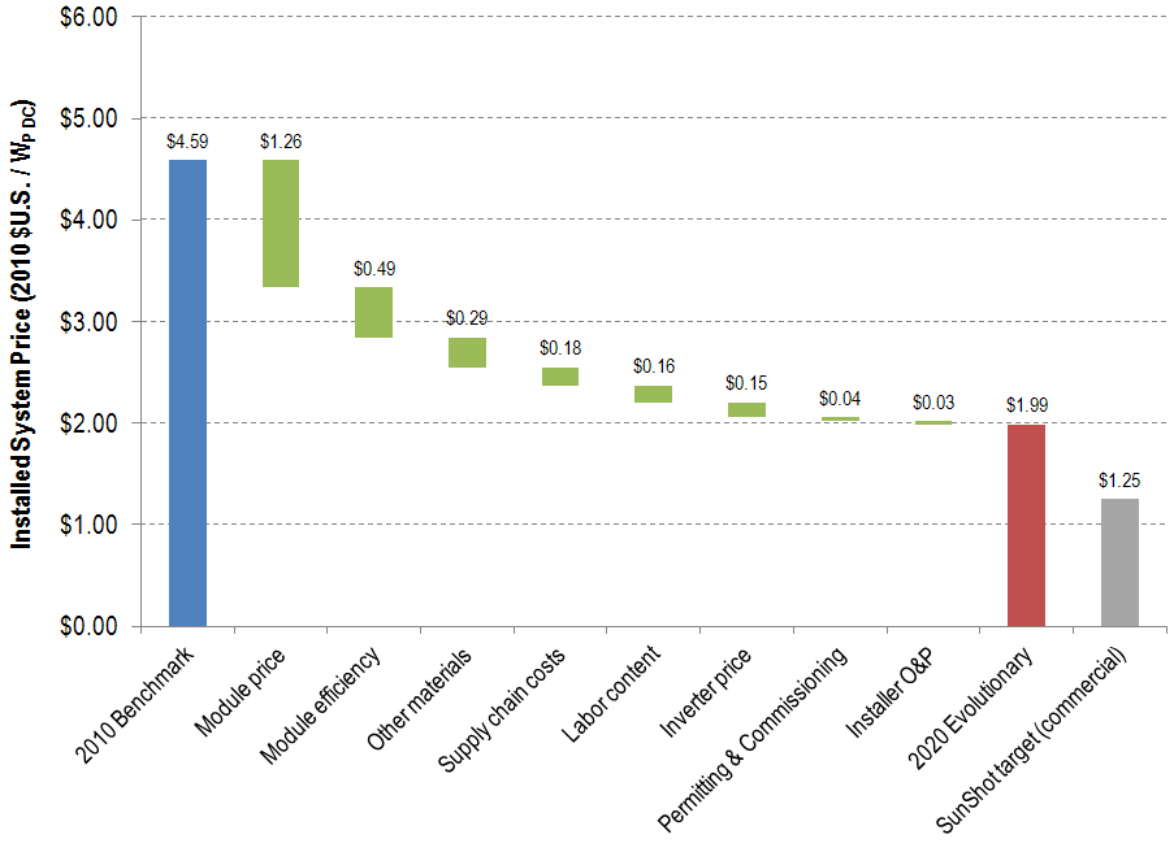


Figure 12. Evolutionary commercial PV system price reductions and DOE SunShot target, 2010–2020.

4.3. Ground-Mount Utility-Scale PV Systems

Figure 13 shows the evolutionary pathway for ground-mount, utility-scale, one-axis tracking PV system prices from the benchmark of $\$4.40/W_{P\,DC}$ in 2010 to $\$1.91/W_{P\,DC}$ in 2020. It also shows the SunShot utility-scale target of $\$1.00/W_{P\,DC}$ for comparison.

As this report quantifies, the price structure of utility-scale PV systems with one-axis tracking is vastly different than that of rooftop systems; so too are the price reductions needed to compete with conventional electricity generation costs. The owner and operator of utility-scale PV systems must compete with the cost of generating electricity using traditional production technologies, rather than competing with the wholesale or industrial price of electricity as in the commercial market, or retail price of electricity as in the residential rooftop market.

Projected evolutionary module price reductions over the next decade contribute less to utility-scale system price reductions ($\$1.10/ W_{P\,DC}$) than in residential or commercial applications due to differences in the supply chain costs (markups on material costs). Expected efficiency gains provide less benefit for utility-scale systems than for residential systems because of fewer restrictions and costs related to system area. Residential customers tend to be more bound to an absolute maximum system size (m^2), as defined by the size of the home and the PV-suitable area. Utility-scale developers can, in theory, purchase additional land to achieve a given system size

(power output, peak W_{DC}) using less efficient modules. Nevertheless, NREL estimates that an improvement in module efficiency from ~14.5% to greater than 21% will provide \$0.57/$W_{P\,DC}$ in utility-scale system price reductions.

Future labor-cost reductions may be possible, for example through the integration of subcomponents in a factory setting (i.e., unitized construction methods). In a factory setting, economies of scale and automation can reduce electrical and hardware installation labor content (costs) for PV systems. NREL assumed, for the purposes of this illustrative analysis, that, by better integrating wiring subcomponents and preparing unitized sub-assemblies, the in-the-field electrical labor content may be reduced by half, thus decreasing system price by ~\$0.28/$W_{P\,DC}$.

Utility-scale inverter prices have fallen dramatically in recent years. It is anticipated that the price of a utility-scale inverter will approach \$0.10/$W_{P\,DC}$ by the end of the decade as the need for step-up transformers and switching gear is eliminated, and as input voltages for inverters are increased (i.e., increased module-to-inverter ratio). This projected reduction in inverter price (from \$0.29/$W_{P\,DC}$ to \$0.10/$W_{P\,DC}$) will provide up to \$0.22/$W_{P\,DC}$ in system price benefits, net of supply chain markups on materials and sales tax.

Improvements to the system's electrical architecture may also reduce the cost of 'other materials' (non-module, non-inverter components). Increasing the string size (up to, or greater than 1,000 V), for example, will reduce the gauge of electrical wiring. Integration of subcomponents as part of a unitized construction strategy may reduce or eliminate some conduit. As one-axis tracker technologies become more widely used, the cost of these components will continue to fall. NREL estimates that, by 2020, a 50% reduction in the cost of "other materials" used throughout the utility-scale PV system will lead to a price savings of \$0.23/$W_{P\,DC}$.

Low-impact system designs that require a minimal amount of site preparation (e.g., grading) may significantly lower the 2010 estimated cost of "site preparation" (reduce by 50%, from \$25,000 to \$12,500 per acre) and reduce system price by ~\$0.07/$W_{P\,DC}$.

Today's estimated utility-scale PV installer overhead (22%) may be lowered to minimally sustainable levels (i.e., to 16%) through increased competition and improved installation business practices (standardized system designs, streamlined permitting process, etc.). It is estimated that this improvement in installer operating costs may reduce the total system price by ~\$0.01/$W_{P\,DC}$. Although the cost of environmental permits can be high (estimated to be \$1.0 million in the benchmark scenario), at scales greater than 100 $MW_{P\,DC}$ the contribution of permit fees to system price is quite small. Therefore, reducing the permit fees by half will provide less than \$0.01/$W_{P\,DC}$ benefit to future system prices.

Figure 14 shows the evolutionary pathway for ground-mount, utility-scale, fixed-axis tracking PV system prices from the benchmark of \$3.80/$W_{P\,DC}$ in 2010 to \$1.71/$W_{P\,DC}$ in 2020. Overall, the evolutionary price reduction falls about 40%–48% short of the 2020 DOE SunShot target for utility-scale systems[22].

[22] The DOE SunShot goal for (fixed axis) utility-scale systems is \$1/$W_{P\,DC}$. Crystalline silicon modules mounted on one axis trackers may experience a capacity factor benefit of between 25-30% (Campbell 2010b) in high solar resource locations, although the capital (system) penalty may be between 10-20%. In the future (2020), as the price of (one-axis) trackers comes down (e.g.

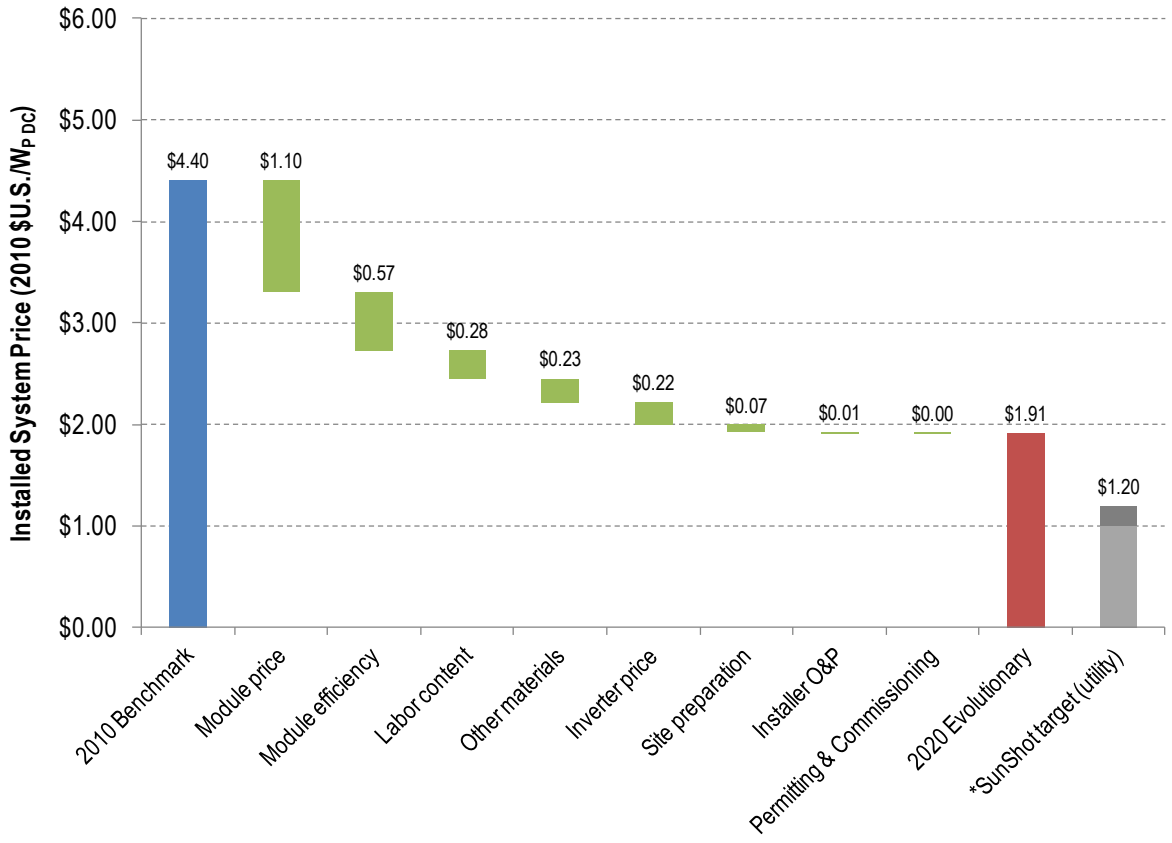


Figure 13. Evolutionary utility-scale (one-axis tracking) PV system price reductions and DOE SunShot target, 2010–2020.
***Single-axis utility scale PV SunShot target modified (20%) to account for enhanced capacity factor (25%; c-Si modules), less added system cost (5%; tracker).**

system cost penalty approaches 5%), the net-benefit of tracking c-Si modules in high resource areas may approach 20%. Because capacity factor and module efficiency are linearly correlated, the *modified* SunShot target for one-axis c-Si modules is estimated to be approximately $\$1.2/W_{P\,DC}$; equivalent to the $\$1/W_{P\,DC}$ fixed axis SunShot goal, when adjusted for tracking benefits and costs.

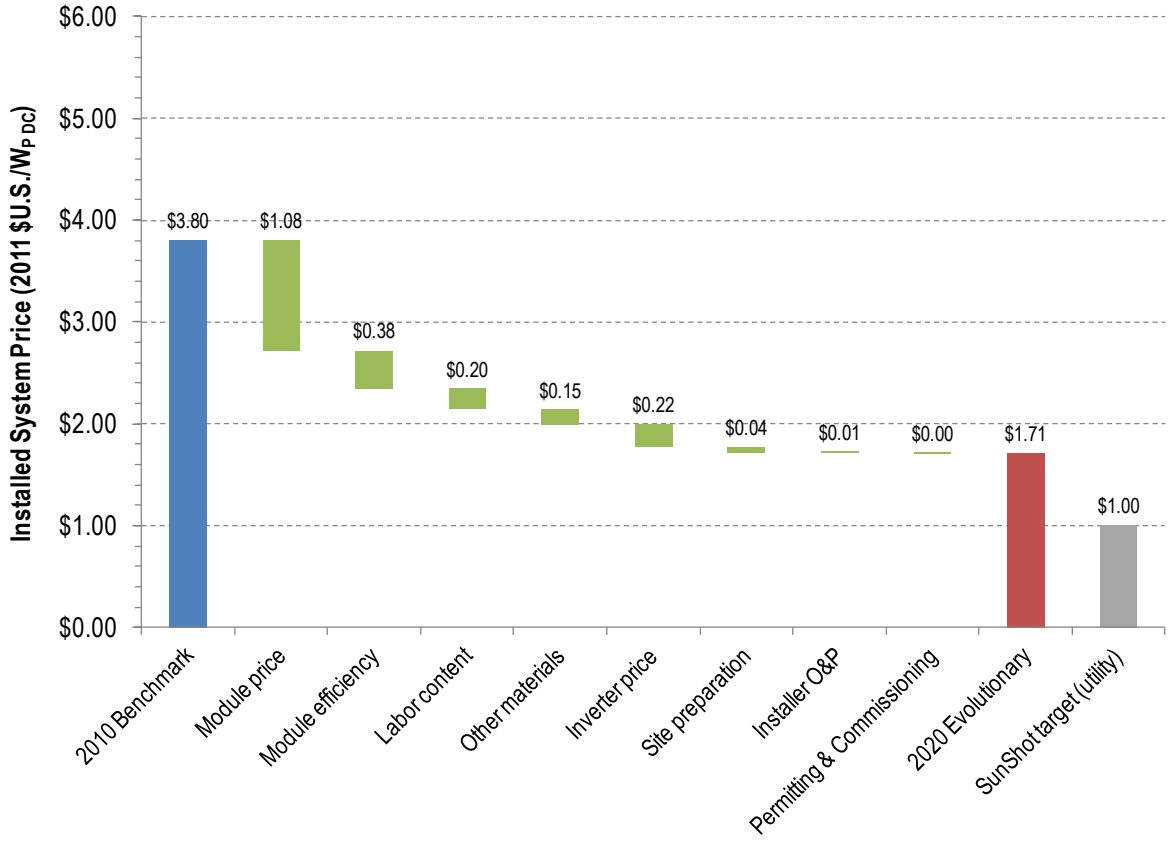


Figure 14. Evolutionary utility-scale (fixed-axis tracking) PV system price reductions and DOE SunShot target, 2010–2020.

This analysis illustrates the need for technological advancements at the module (cost, efficiency) and non-module levels to achieve the aggressive SunShot targets. Under the evolutionary scenario described above, by 2020, non-module costs are expected to account for between $\$0.70/W_{P\,DC}$ (41%) and $\$0.90/W_{P\,DC}$ (47%) of utility-scale system price, for fixed- and one-axis tracking system architectures, respectively. If, more optimistically, the price of single-junction c-Si modules were to approach the longer-term $\$0.68/W_{P\,DC}$ price (see Appendix C), then the estimate for 2020 (fixed axis) system prices would be approximately $\$1.38/W_{P\,DC}$, still 28% short of the SunShot target. This highlights the need for innovative system designs and installation methods to compliment module-level cost reductions.

2011 Benchmark System Prices

The precipitous decline in global PV module prices has continued during the completion of this report. Since the last quarter of 2010, ex-factory gate c-Si module prices have reportedly fallen from \$1.95/$W_{P\,DC}$ to approximately \$1.10/$W_{P\,DC}$ (between \$1.05 and \$1.25/$W_{P\,DC}$), while industry-median conversion efficiency has increased from 14.5% to 14.8%. The pace of module manufacturing cost reductions has increased due largely to declines in polysilicon feedstock costs, but also due to competitive pressures from leading thin film technologies (e.g., CdTe-based modules). Manufacturer margins also have been compressed because of global overcapacity for cells and modules.

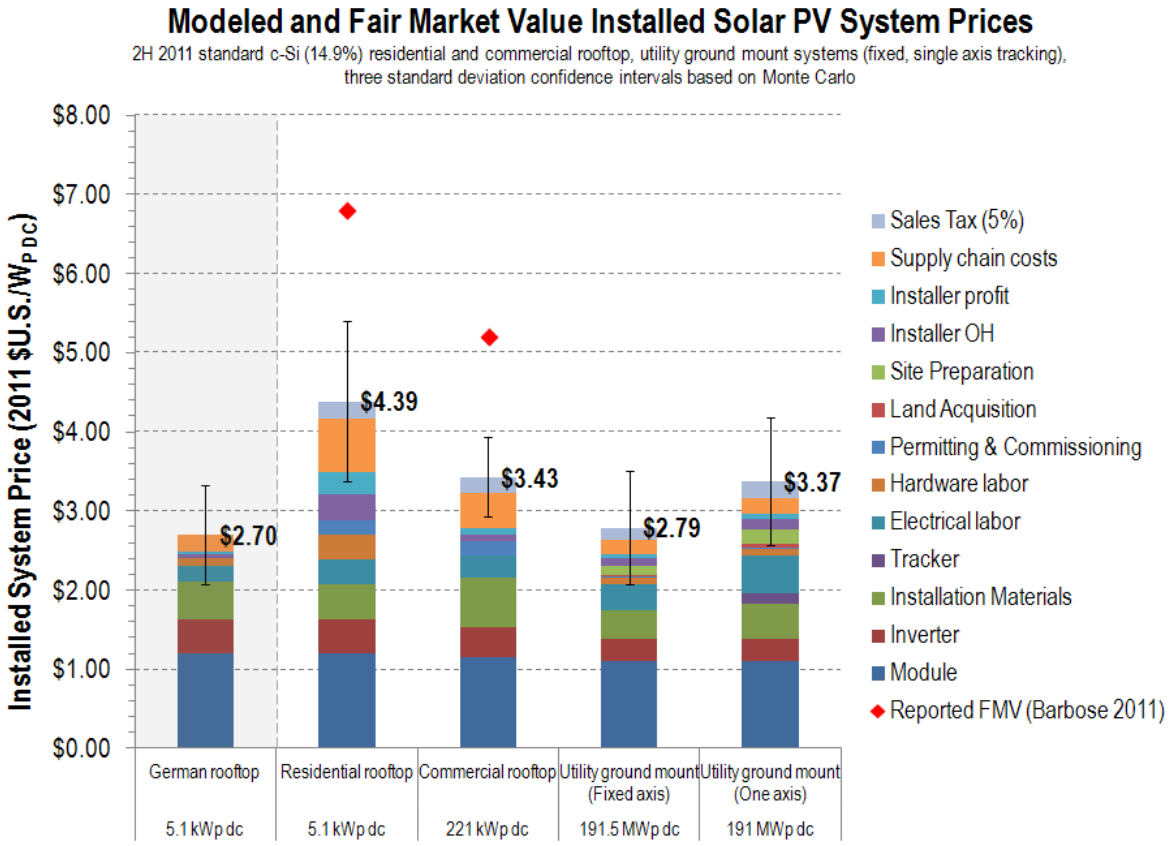


Figure 15. Benchmark 2011 PV system prices, all three sectors: breakdown by element. Note: Reported *market prices* (FMV) include only partial year 2011 (Barbose 2011).

The impact of reducing module prices by \$0.85/$W_{P\,DC}$ is magnified in the system price analysis the models' supply chain costs multiplier, which accounts for inventory and project contingency costs as a percentage of module price. As a result of module price declines that have occurred between the second half of 2010 and the second half of 2011, system prices have fallen by 23%–27% (Figure 15).

5. Conclusion: PV Price Reductions—the Road Ahead

Because of the rapid U.S. PV system cost reductions resulting from global module price declines, *market price* data have become insufficient for providing policy makers and industry stakeholders with an accurate and current understanding of system-price drivers. A time-lag effect and the dynamics of a nascent industry disconnect reported system prices from underlying system costs. This report shows an objective methodology for approximating the underlying costs of PV systems with the resolution necessary for understanding system price drivers. Comparing these objective values with *market price* data provides valuable insights into the U.S. PV market's inefficiencies, which may be useful for developing policies and practices that address these inefficiencies. Understanding the forces driving PV system price reductions—and their limitations—is also important.

The price of U.S. PV systems has fallen by nearly 30% since the second half of 2010, and further near-term price reductions are likely as the U.S. market matures. Most PV system components are based on commodities that have global prices. Thus, installation costs are largely responsible for the disparities in PV system prices among different countries and regions. The diffusion of installation knowledge and expertise throughout the U.S. market, increased local competition, and consolidation of U.S. installation companies should reduce these disparities substantially. Based on evidence from the more mature German PV market, factors such as improved installer productivity, reduced installer overhead and profit (due to competition), lower supply chain costs, and lower regulatory costs could reduce 2011 U.S. benchmark PV system prices by an additional 40%.

The tight polysilicon supply and high prices during 2007–2008 may also help reduce PV system prices in the near term. Polysilicon is the feedstock for the dominant c-Si PV technology. The recent price spike caused new entrants to build polysilicon production facilities, many of which are now coming online. The resulting overcapacity of polysilicon—along with weakening European demand for c-Si modules—has driven polysilicon contract prices down by more than half compared with contract prices in 2008. In addition, the 2007–2008 polysilicon shortage encouraged larger-scale production of thin film alternatives to c-Si PV, which also has contributed to lower global PV module prices. At the same time, the larger polysilicon production base has reduced the likelihood of another polysilicon shortage/price imbalance as severe as the one in 2007–2008.

The abovementioned factors likely will contribute to lower U.S. PV system prices in the coming years. This report provides detailed roadmaps to evolutionary c-Si PV system price reductions and performance improvements, including substantial reductions in module and non-module costs. By 2020, these roadmaps would enable U.S. PV systems to approach—but not meet—DOE's SunShot Initiative price targets. To accelerate PV price reduction toward meeting these aggressive targets, revolutionary improvements to module and non-module system components and installation methods are needed.

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Appendix A: Uncertainty Analysis of PV System Prices

The analysis of PV system prices presented in this report relies on national average labor rates and frequently encountered system cost assumptions. Labor rates are a significant source of uncertainty in this analysis. Labor costs vary across U.S. states (wage rates) and from company to company (productivity), including operating O&P margin assumptions. Other areas of uncertainty include inverter prices, wiring materials content, supply chain costs (installer channel to market), and site-specific costs (land acquisition, preparation, permitting costs, etc.). For these reasons, it is very difficult to compare one project to another or to generalize the cost of PV systems without including a substantial error bar.

The following uncertainty analysis considered a reasonable range of values for major system parameters based on published data and installer-reported information. The values depicted in this analysis are benchmark 2010. Due to rapidly changing conditions, assumptions for parameters such as module prices may vary significantly from those presented here if the first quarter of 2011 were to be considered, for example.

Triangular distributions were assumed for all of the key variables. The most frequently reported values for each assumption ("mode") were provided by collaborating system installers or, in the case of wage rates, depict U.S. national average values (2010). However, much of the U.S. PV market has occurred, to date, in California, which has a wage rate higher than the national average. Therefore, the distribution function depicted in this analysis does not necessarily depict the distribution of prices that may be encountered or reported in the United States in 2010. The Monte Carlo analysis is intended to provide insights into those factors that most contribute to uncertainty in the price analysis results based on the assumptions presented above.

Figure 16 summarizes the results of the Monte Carlo analysis for residential, commercial, and utility-scale (fixed- and one-axis) systems. The following sections detail the analyses for each type of system.

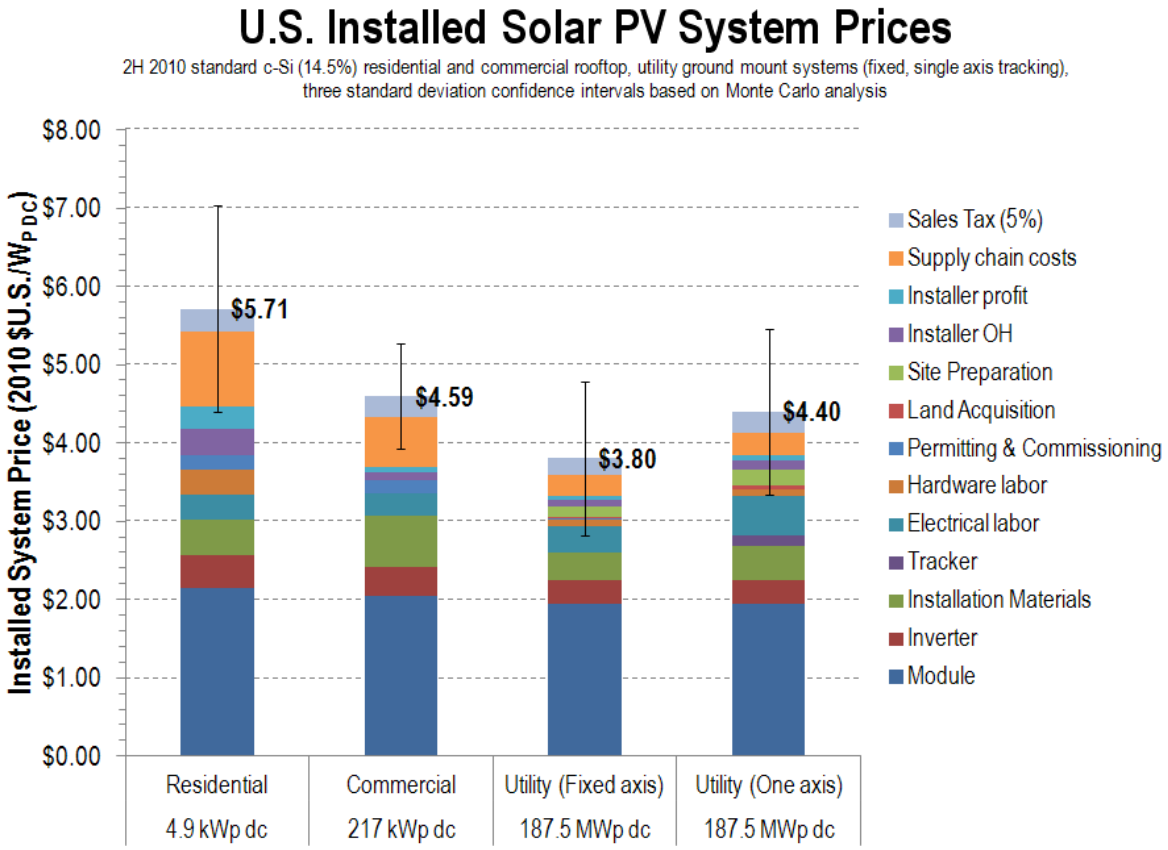


Figure 16. PV system price analysis: Monte Carlo analysis results.

Residential Rooftop PV Systems

The following Monte Carlo simulation of residential PV system prices resulted in a standard deviation of $\$0.44/W_{P\,DC}$, or 7.7%. Based on a range of reasonable 2010 U.S. assumptions for the independent variables considered in Table 5, and considering a 35-m^2 system size, a reasonable range of residential PV system prices was found to be between $4.39 and $7.04 per $W_{P\,DC}$, before consideration of subjective values that influence customer perception of system value (price), such as incentives, local retail electricity rates, etc.

Table 5. Residential PV System Price Analysis: Monte Carlo Simulation Assumptions.

Residential PV System Price: Key Assumptions (Monte Carlo variables)

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	13.4%	14.5%	19.60%
[2] Module price	per $W_{P\,DC}$	$1.87	$2.15	$2.35
[3] Module size	m^2	1.28	1.28	1.64
Installation Labor				
[4] Electrical	$ per hour	$16.66	$49.00	$81.34
[4] General construction	$ per hour	$11.25	$33.10	$54.95
[5] Labor content (all types)	hours	48.5	64.7	80.9
[6] Operating overhead		25%	54%	65%
[7] Profit on labor		10%	30%	35%
Inverter				
[†] Inverter price	per $W_{P\,DC}$	$0.25	$0.42	$0.65
Installation Materials				
[†] Mounting hardware	per module	$52.29	$69.71	$89.25
[†] Wiring, conduit, connectors	per module	$3.60	$4.80	$6.14
[†] Supply chain costs	%-materials price	15%	30%	35%
Site work				
[†] Permitting		$0.00	$0.00	$500.00
[†] Grid Interconnect		$0.00	$900.00	$2,000.00

[1] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[2] Beate Knoll, "Downward path", Module Price Survey, Photon International, January 2011;
Jeremy Heron, "Shining the Light", Photon International, September 2010 (20% gross margin assumption)

[3] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[4] U.S. BLS, National average labor rate (electrical contractor), min/max, 2009

[5] Private conversations with U.S. installers (labor hours by component, ±25% productivity variation based on installer experience, site specifics)

[6] *Average operating overhead (16%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[7] *Average profit (10%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[†] 2010-2011 NREL (authors) private conversations with installers (review of confidential project cost data provided by installers under Non-Disclosure Agreements)

This range falls short of the ranges reported by the CSI for the same period (Barbose et al. 2011). An explanation of the deviation between NREL's expected system prices and CSI-reported data must include the following factors: system size (m^2), time lag between ex-factory gate module and retail prices, *market price* (impact of financing and incentive options), regional differences in labor and regulatory (permitting and commissioning) costs, and the potential for correlations between these factors. For example, high regulatory costs may correlate to high wage rate locations, such as the case in California. Figure 17 shows results of the Monte Carlo analysis for residential PV systems.

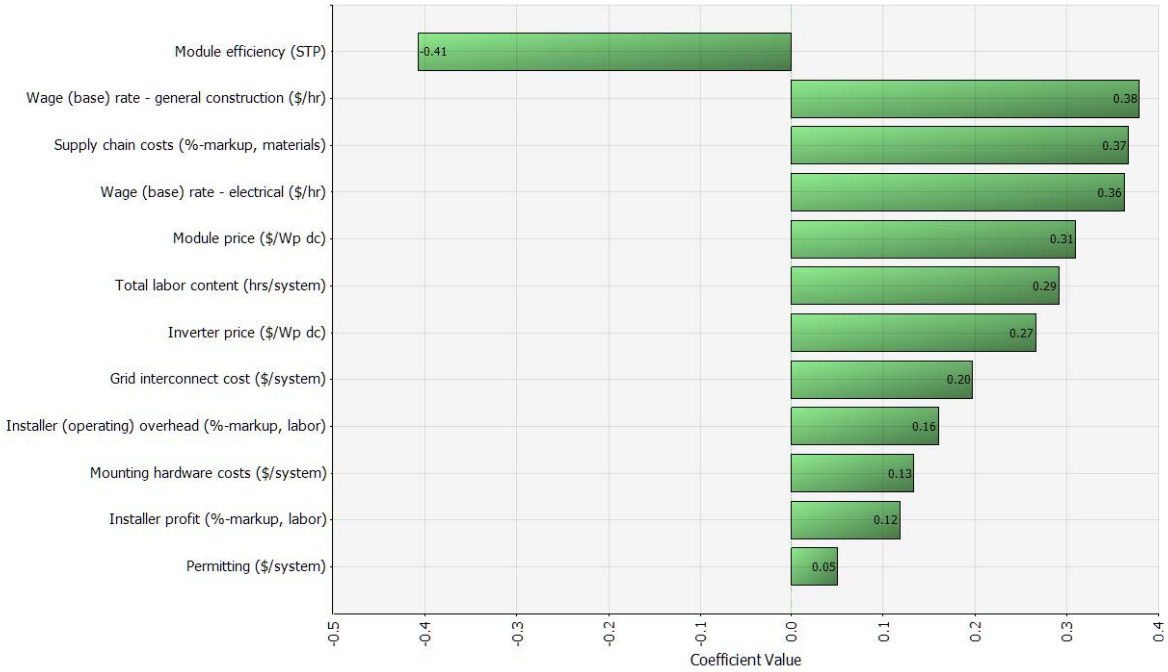


Figure 17. Residential PV system price analysis: Monte Carlo analysis results, regression coefficients (key variables).

The value of module efficiency is greatest in area-constrained (e.g., rooftop) PV systems. In residential rooftop systems, module efficiency is critical because many of the project overhead, hardware, and labor costs are either area related or fixed, making system size critical to a low $/W system price.

Labor and supply chain (material) costs contribute significantly (coefficients greater than 0.35) to the uncertainty in NREL's estimate of 2010 residential PV system prices. This is due to the large standard deviation observed in U.S. wage rates (regional) in 2010 and the relatively high contribution of material prices to system price.

Commercial Rooftop PV Systems

PV systems installed on commercial buildings (rooftops) tend to use c-Si modules due to the high value of module efficiency in area-constrained rooftop applications. Module efficiency and price assumptions were based on the range of data collected by NREL in the second half of 2010, which included standard multicrystalline through nonstandard monocrystalline modules. Relative to residential rooftop systems, module efficiency has less effect on the commercial rooftop price uncertainty analysis. This is primarily due to the reduced relative contribution of labor (O&P) and materials (supply chain) related cost multipliers. As the cost of labor and area-related hardware is reduced, the value of efficiency gains is diminished.

With regard to installer overhead, including operating overhead and installer-margin rates, the commercial rooftop PV sector lies somewhere between a residential system (high overhead costs) and a utility installation performed by a vertically integrated module

manufacturer/installer. The markup of burdened labor costs to account for overhead rate (mode = 32%) and profit margin (mode = 20%) are based on the rates observed by NREL during 2010. While these costs are lower than the rates observed in the residential sector, they are still higher than in a mature industry, such as electrical contractor services. The markup on materials (mode = 20%) related to supply chain costs, like inventory and contingency, reflects the more streamlined channels to market that commercial rooftop system installers rely on, relative to residential installers. These wholesale distribution channels afford commercial installers lower-cost materials.

The commercial rooftop PV system was found to have a standard deviation of $\$0.224/W_{P\,DC}$, or 4.9%. Based on the range of assumptions considered here (Table 6), in 2010 a reasonable objective system price for commercial rooftop systems was found to be between $\$3.92/W_{P\,DC}$ and $\$5.27/W_{P\,DC}$ for a 217-$kW_{P\,DC}$ U.S. commercial PV system, cash purchase, before subsidy.

Figure 18 shows results of the Monte Carlo analysis for commercial PV systems. In addition to the relative contribution of module efficiency to both the residential and commercial rooftop sectors, the impact of module size is a notable variable to contrast, in terms of its impact on system price. In residential systems, module size (m^2) did not have a significant effect on system price. However, as the rooftop system size is increased from 5 kW to 217 kW, the contribution of module size (m^2) becomes more prominent. That is, the relative contribution of module installation time (hours per module × number of modules) and labor costs is greater as a percentage of project costs for commercial systems than it is for residential systems.

Table 6. Commercial PV System Price Analysis: Monte Carlo Simulation Assumptions.

Commercial PV System Price: Key Assumptions (Monte Carlo variables)

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	13.4%	14.5%	19.60%
[2] Module price	per W_{PDC}	$1.79	$2.05	$2.25
[3] Module size	m^2	1.28	1.64	1.64
Installation Labor				
[4] Electrical	$ per hour	$16.66	$49.00	$81.34
[5] General construction	$ per hour	$11.25	$33.10	$54.95
[6] Operating overhead		16%	32%	54%
[7] Profit on labor		10%	20%	30%
Inverter				
[†] Inverter price	per W_{PDC}	$0.20	$0.37	$0.55
Installation Materials				
[†] Mounting hardware	per module	$52.29	$69.71	$87.14
[†] Wiring, conduit, connectors	per module	$3.60	$4.80	$6.00
[†] Supply chain costs	%-materials price	10%	20%	30%
Site work				
[†] Permitting		$0.00	$10,000.00	$50,000.00
[†] Grid Interconnect		$0.00	$2,000.00	$2,000.00

[1] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[2] Beate Knoll, "Downward path", Module Price Survey, Photon International, January 2011;
Jeremy Heron, "Shining the Light", Photon International, September 2010 (20% gross margin assumption)

[3] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[4] U.S. BLS, National average labor rate (electrical contractor), min/max, 2009

[6] *Average operating overhead (16%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[7] *Average profit (10%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[†] 2010-2011 NREL (authors) private conversations with installers (review of confidential project cost data provided by installers under Non-Disclosure Agreements)

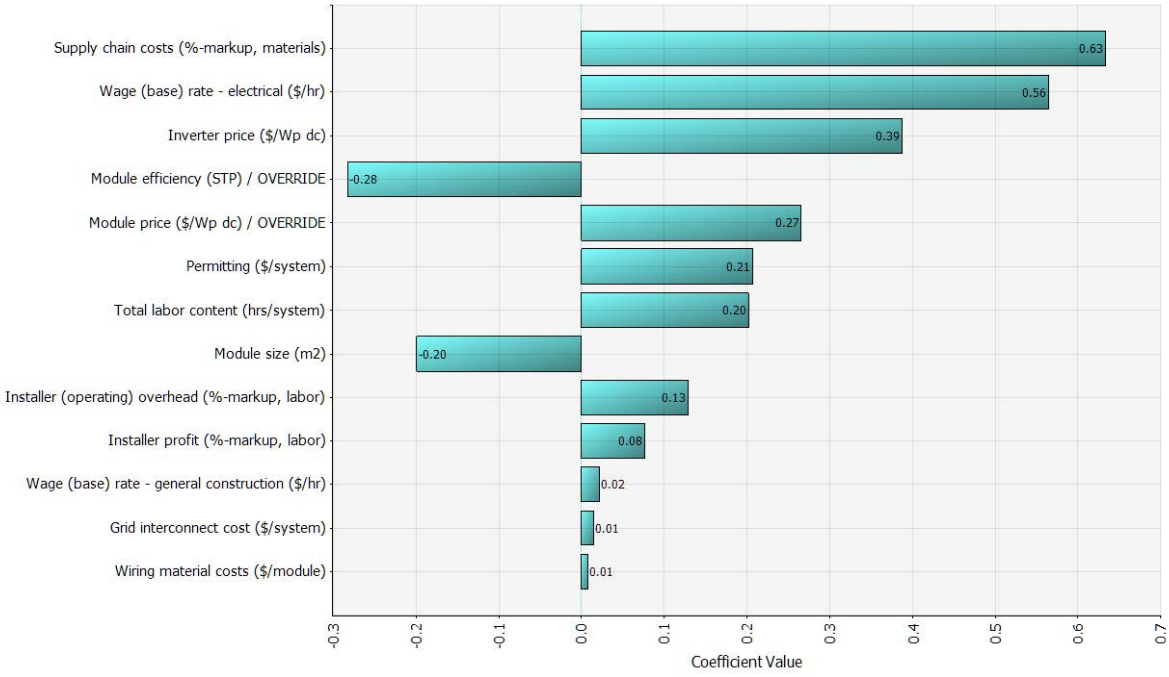


Figure 18. Commercial PV system price analysis: Monte Carlo analysis results, regression coefficients (key variables).

Ground-Mount Utility-Scale PV Systems

Utility-scale PV systems that use one-axis tracking tend to rely on c-Si PV modules. For one-axis systems, the range of module prices and correlated efficiencies, both of which are important to system price estimates, are based on commercially available c-Si modules only. For fixed-axis utility-scale systems, CdTe modules were also considered (module price, efficiency, area per module).

Labor cost assumptions were based on national average wage rates. All other independent variables included in the Monte Carlo analysis were based on ranges commonly encountered by collaborating installers of utility-scale systems in 2010.

The price estimate for one-axis, ground-mount, utility-scale PV systems was found to have a standard deviation of $0.352, or 8.0%. Based on the range of assumptions considered (Table 7), in 2010 a reasonable objective system price was found to be between $3.35/$W_{P\ DC}$ and $5.46/$W_{P\ DC}$ for a 187.5-$MW_{P\ DC}$ U.S.-based, one-axis, utility-scale, ground-mount PV system, cash purchase, before subsidy.

Figure 19 shows results of the Monte Carlo analysis for one-axis utility-scale PV systems. The most significant factor affecting price was found to be electrician wage rate, followed by land use. Land use drives many system-related price factors, such as site preparation, wiring materials, and wiring-related labor. Land-acquisition cost is a relatively small contributor to system price. The wide range of U.S. wage rates for electricians has a significant impact on system price estimates. Although average U.S. wage rates were considered in the baseline

analysis, many installations have been constructed in California, where wage rates tend to be higher than the national average.

Module size also had a major effect on system price owing to a fixed module installation time (hr/module) and short wiring requirements (materials and labor). As long as larger modules do not require special installation equipment (such as cranes, etc.), then there is a beneficial economy of scale for large modules. CdTe modules, such as those sold by First Solar, are available in 0.72-m^2 sizes, while a module from SunPower for utility applications is available in a size of 2.16 m^2 (First Solar 2011, SunPower 2011).

One-axis systems were found to be approximately 15%–20% more expensive than fixed-axis systems. Fixed-axis systems were found to have a standard deviation of approximately \$0.34/$W_{P\,DC}$ (7.7%). Many of the factors that affect fixed-axis systems price are similar to those described above for the one-axis system, including module size, electrician wage rate, and land use. Module price, however, had more effect on fixed-axis than on one-axis systems because CdTe modules were excluded from the one-axis system analysis but included for the fixed-axis analysis. Thus, the range of module prices was narrower for the one-axis systems, thereby reducing the impact of module price on system price uncertainty. Table 8 shows the assumptions considered for fixed-axis utility-scale PV systems, and Figure 20 shows the corresponding Monte Carlo analysis results.

Table 7. One-Axis Utility-Scale PV System Price Analysis: Monte Carlo Simulation Assumptions.

Utility (1-Axis) PV System Price: Key Assumptions (Monte Carlo variables)

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	13.4%	14.5%	18.50%
[2] Module price	per W_{PDC}	$1.70	$1.95	$2.14
[3] Module size	m^2	1.28	1.96	2.16
Installation Labor				
[4] Electrical wage	$ per hour	$16.66	$49.00	$81.34
[5] Electrical labor content	hours/kW_{PDC}	0.633	0.844	1.055
[4] General construction wage	$ per hour	$11.25	$33.10	$54.95
[5] General construction labor content	hours/kW_{PDC}	0.139	0.185	0.231
[6] General overhead		22.70%	22.70%	22.70%
[6] Operating overhead		16%	22%	28%
[7] Profit on labor		10%	10%	30%
Inverter				
[†] Inverter price	per W_{PDC}	$0.15	$0.29	$0.35
Installation Materials				
[†] Tracker	per m^2 (active area)	$7.5	$10	$80
[†] Other mounting hardware	per m^2 (active area)	$20	$30	$40
[†] Wiring, conduit	per m^2 (system area)	$3.3	$6.5	$9.8
[†] Supply chain costs	%-materials price	5%	10%	15%
Site work				
[†] Land requirements	acres/MW_{PDC}	5.0	8.0	12.0
[†] Land acquisition	per acre	$500.0	$5,025	$10,000
[†] Site preparation	per acre	$5,000	$25,000	$60,000
[†] Environmental permitting	$ millions	$0.10	$1.00	$5.00
[†] Grid Interconnect		$1.00	$1.60	$10.00

[1] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[2] Beate Knoll, "Downward path", Module Price Survey, Photon International, January 2011;
Jeremy Heron, "Shining the Light", Photon International, September 2010 (20% gross margin assumption)

[3] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[4] U.S. BLS, National average labor rate (electrical contractor), min/max, 2009

[5] Private conversations with U.S. installers (labor hours by component, ±25% productivity variation based on installer experience, site specifics)

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[7] *Average profit (10%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[†] 2010-2011 NREL (authors) private conversations with installers (review of confidential project cost data provided by installers under Non-Disclosure Agreements)

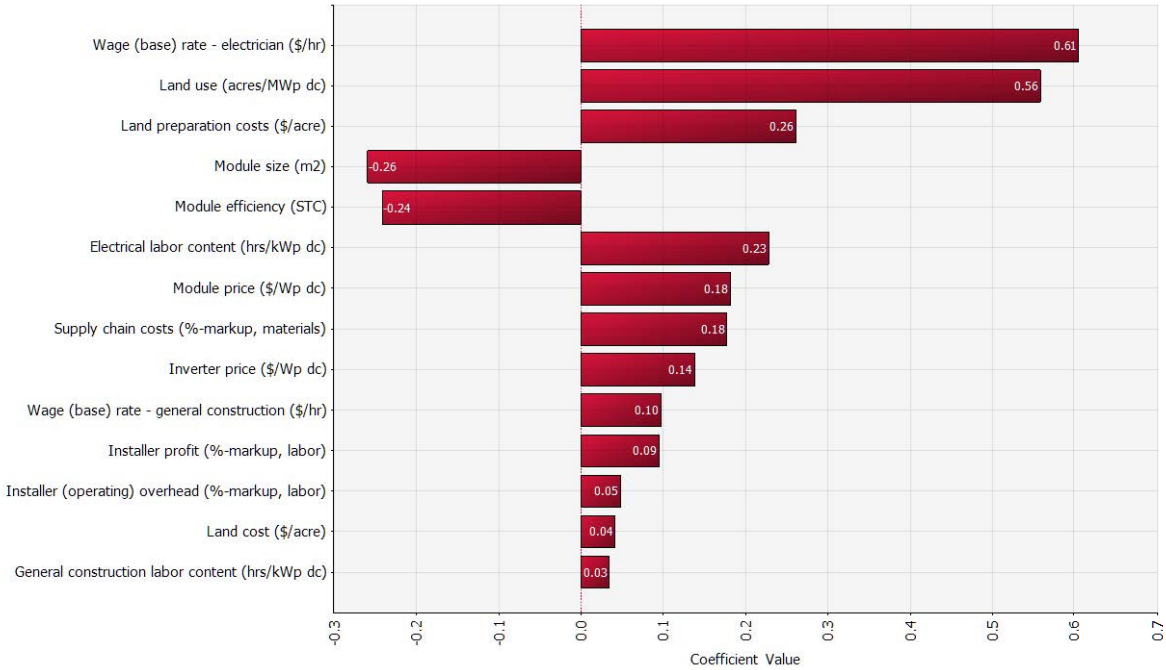


Figure 19. One-axis utility-scale PV system price: Monte Carlo analysis results, regression coefficients (key variables).

Table 8. Fixed-Axis Utility-Scale PV System Price Analysis: Monte Carlo Simulation Assumptions.

Utility (Fixed) PV System Price: Key Assumptions (Monte Carlo variables)

Module		min	mode	max
[1] Module efficiency	@STC, 1000 W/m^2	11.6%	14.5%	18.50%
[2] Module price	per $W_{P\,DC}$	$1.29	$1.95	$2.14
[3] Module size	m^2	0.72	1.96	2.16
Installation Labor				
[4] Electrical wage	$ per hour	$16.66	$49.00	$81.34
[5] Electrical labor content	hours/$kW_{P\,DC}$	0.633	0.844	1.055
[4] General construction wage	$ per hour	$11.25	$33.10	$54.95
[5] General construction labor content	hours/$kW_{P\,DC}$	0.139	0.185	0.231
[6] General overhead		22.70%	22.70%	22.70%
[6] Operating overhead		16%	22%	28%
[7] Profit on labor		10%	10%	30%
Inverter				
[†] Inverter price	per $W_{P\,DC}$	$0.15	$0.29	$0.35
Installation Materials				
[†] Other mounting hardware	per m^2 (active area)	$20	$30	$40
[†] Wiring, conduit	per m^2 (system area)	$3.3	$6.5	$9.8
[†] Supply chain costs	% -materials price	5%	10%	15%
Site work				
[†] Land requirements	acres/$MW_{P\,DC}$	3.0	5.0	8.0
[†] Land acquisition	per acre	$500.0	$5,025	$10,000
[†] Site preparation	per acre	$5,000	$25,000	$60,000
[†] Environmental permitting	$ millions	$0.10	$1.00	$5.00
[†] Grid Interconnect		$1.00	$1.60	$10.00

[1] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[2] Beate Knoll, "Downward path", Module Price Survey, Photon International, January 2011;
Jeremy Heron, "Shining the Light", Photon International, September 2010 (20% gross margin assumption)

[3] Non-exhaustive survey of standard c-Si module datasheets, Sunpower E18 / 400 datasheet

[4] U.S. BLS, National average labor rate (electrical contractor), min/max, 2009

[5] Private conversations with U.S. installers (labor hours by component, ±25% productivity variation based on installer experience, site specifics)

[6] *Average operating overhead (16%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[7] *Average profit (10%), electrical contractor (annual billings >$4MM)* , Electrical Contractor Handbook, RS Means, 2010

[†] 2010-2011 NREL (authors) private conversations with installers (review of confidential project cost data provided by installers under Non-Disclosure Agreements)

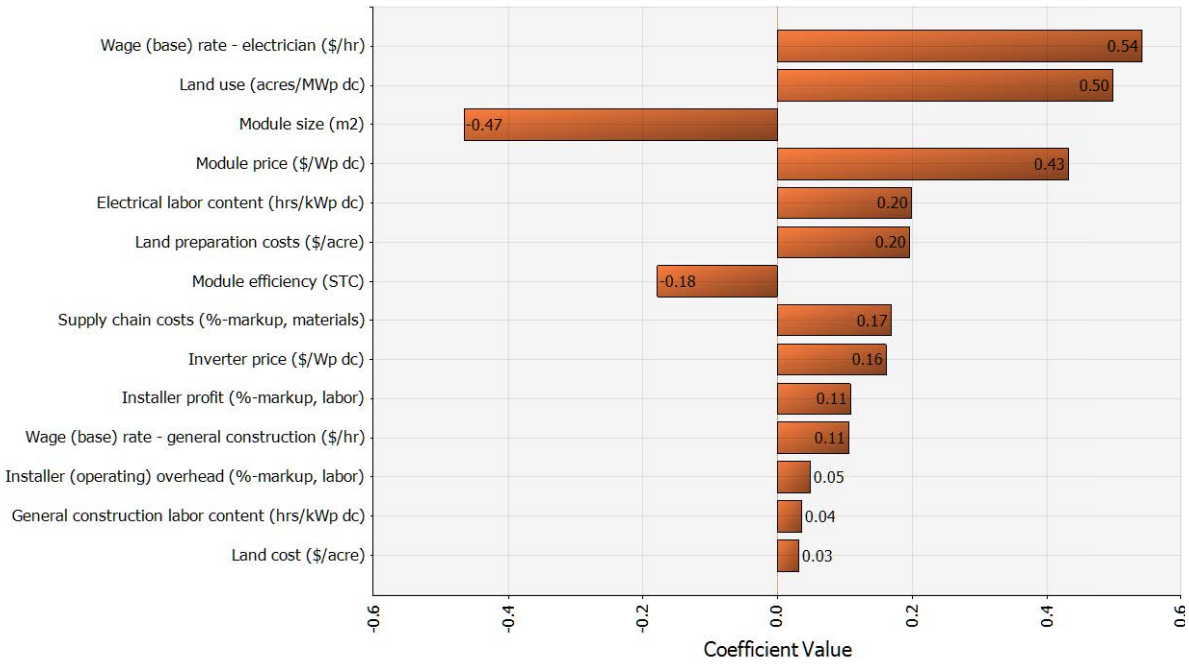


Figure 20. Fixed-axis utility-scale PV system price: Monte Carlo analysis results, regression coefficients (key variables).

Appendix B: PV System Land Costs

In collaboration with industry stakeholders, NREL has developed detailed models to quantify residential rooftop, commercial rooftop, and ground-mount utility-scale PV system installation prices. A number of assumptions used in this bottom-up cost and price analysis contribute to the uncertainty levels for ground-mount utility-scale systems (mean system price, fixed-axis utility: $\$3.80/W_{P\ DC}$, standard deviation = $\$0.33/W_{P\ DC}$). A particularly wide range of U.S. land costs has been observed over the past two years, from $500 to $105,000 per acre.

This appendix summarizes NREL's research of the factors that drive land costs for solar farms and their impact on installed system prices. Public and private information sources were used in this analysis. Data from third-party collaborators have been aggregated to ensure the protection of potentially business-sensitive data.

The cost of land for ground-mount utility-scale PV farms generally varies by region. More specifically, the cost varies by the following eight site-evaluation criteria (listed in order of importance by impact on land costs, according to system developers interviewed for this report).

1. **Available solar resources**
   Developers of solar projects first evaluate potential locations based on each site's available solar irradiance. If the level of solar resources is not acceptable, a site is not considered. If a site is considered to have suitable solar resources, the estimated amount of energy that can be produced from the site affects a developer's land-cost estimate.
2. **Proximity to transmission infrastructure**
   The proximity of a potential site to buildable transmission infrastructure can make or break a project, in terms of costs. It has been estimated that grid interconnection costs (substation materials and labor, commissioning) range, depending on project size, from $1.0 million (69 kV) to $3.0 million (230 kV). The cost of constructing new transmission infrastructure or adding capacity to existing transmission lines can be $20–$80 million for a 20-MW system ($1/W–$4/W). In most cases, the high end of this estimated range would be prohibitive for project developers.
3. **Expected permit fees and delays ("permit-ability")**
   The cost of permitting a prospective site depends greatly on local requirements as well as current zoning for the location and its estimated population of endangered species. Sites that have been used in the past for industrial or agricultural purposes ("previously disturbed") may be more easily developed than virgin land, which desert tortoises or other protected species may inhabit.
4. **Topography (site-preparation requirements)**
   In terms of preferred PV site topography, the "flatter the better." Nevertheless, PV's requirement for leveling is far less than would be required for solar thermal towers, for example. If a site is relatively flat, then a PV developer may only have to complete a minimal amount of leveling for construction. Reducing the amount of grading and leveling that must be performed not only reduces costs, but it can also speed up the community acceptance of a project and the site-permitting processes.

In addition to the cost of the land itself, site-preparation costs can range from $5,000 to $25,000 per acre, which includes leveling, sediment control, hydrology, road construction, and vegetation removal.

5. **Size (continuous acreage)**
   For large PV farms, a continuous tract of suitable land can be difficult to acquire. In some cases, oddly shaped parcels of land can increase construction costs. It is estimated that 5–8 acres are required per MW of capacity, depending on efficiency and mounting configuration (fixed-axis systems are typically at the lower end of the range, one-axis tracking systems are typically at the higher end). However, it has been observed that initial land purchases can be up to 1.8–2.0 times greater than these figures. For large projects, it reportedly adds little to no cost to negotiate with multiple land owners.
6. **Availability of water for construction**
   Water is required during construction of a solar farm for the purpose of dust control. Transporting water can increase construction costs.
7. **Community acceptance of PV**
   Communities that oppose the construction of a PV farm can add permitting and litigation costs to a project and contribute to project delays. The project delay period due to permitting is 1 year (minimum) and up to 2–3 years in most cases, including interconnection and transmission permitting.

   In California, for example, the Solar Environmental Quality Act (SEQA) can add approximately $1 million to a project that targets construction in a community that is relatively "accepting." The SEQA process affords opponents of a project the opportunity to add significant delays to the construction of a PV farm, via the following steps: 1) Scoping meeting—developer and county planning agencies explain project to public; 2) Conditional use permit is requested by developer; 3) Interveners have the opportunity to raise objections, draft impact statements; 4) Interveners can appeal decisions regarding their objections; 5) Finally, if appeals fail, interveners can sue the developer.
8. **Subsurface conditions**
   A site's subsurface conditions can impact a project's hardware and site-preparation costs. If, for example, a desert location has dry, cracked soil, a polymer-based emulsion such as Gorilla Snot may be required to treat the surface prior to construction. Unstable subsurface conditions may require additional footings for ground-mount hardware.

According to industry stakeholders interviewed by NREL, most "prime land is tied up" by speculators or system developers. This includes not only private land, but also parcels owned by the Bureau of Land Management (BLM). Stakeholders interviewed for this analysis also recommended a streamlined permitting process for standardized system designs. Specifically, they said state and municipal permitting agencies should be encouraged to accept standard system designs that have been pre-approved, which should fast track standard systems.

Based on the above criteria that system developers and installers use to identify "suitable" land for PV projects, the cost of land (purchase price) is generally about twice the *market price*. Speculators and the demand for sites that are well suited to PV has created a "land rush" and driven up the price for PV lands in many areas (Woody 2008).

Installers have generally estimated the cost of privately owned solar-suitable land to be $5,000 –$10,000 per acre (statistical mode) but as low as $500 per acre and as high as $105,000 per acre, in extreme cases (Beck and Hillman 2009). A land lease generally costs 10% of the estimated land purchase price per acre per year. Land owned by the BLM is often double these market figures, in terms of equivalent lease costs ($800–$1,200 per acre per year). Projects developed on leased land have lower upfront capital costs but are subject to additional operating costs. Because land leases are currently a popular choice for acquiring land for solar projects, it is important that all analyses pertaining to the capital cost of solar projects note this variation.

The land requirements for PV systems vary depending on each project's module technology (efficiency) and mounting structure (tracking or fixed). It has been estimated that standard (industry median) c-Si modules (14%–15% efficiency) require 5 acres/MW for fixed-axis and 8 acres/MW for one-axis tracking configurations. For one-axis tracking systems, the space between rows must be greater to allow for larger shadow lengths (avoid shadowing losses). The land requirement for lower-efficiency (e.g., 11%-efficient thin film) modules on fixed-axis mounting structures is estimated to be about 7 acres/MW.

The above estimates for land use may differ somewhat from reported land purchases and project sizes due to two factors. First, developers often purchase additional land that may be used if a site has limiting features, such as wetlands, difficult topography, or protected areas. Second, developers often purchase more land than is required to ensure that they can meet minimum power production guarantees issued under PPAs and other contractual agreements.

The cost of land for ground-mount PV is typically less than 1% of the system price. Nevertheless, a poorly chosen site can add more than 100% to an installed system price due to transmission costs. For the purpose of this report, mean site-preparation ($25,000/acre) and land-acquisition costs ($5,025/acre) were considered.

The cost of permitting a site ($1,000,000) also includes project delays, which NREL chose to capture both in terms of materials markup (10%, reflecting the cost of materials inventory and project contingencies) and installer overhead rates (16%, reflecting the cost of filing permits). Materials markup, labor overhead, and installer profit are captured in "installer overhead and profit."

Appendix C: Long Term Module Price Trajectories

NREL has constructed detailed manufacturing cost models for wafer-based c-Si PV and other PV technologies. As discussed in the body of the paper, NREL used these models to estimate that an evolutionary development trajectory for PV modules will lead to industry median c-Si modules with an ex-factory gate price of about $\$1.01/W_{P\,DC}$ by 2020. Further, it is estimated that these costs could be achieved along with an average production module efficiency of 21.5%—equivalent to a production cell efficiency of approximately 24%. As shown in Figure 9, under a more optimistic set of model assumptions, 21.5%-efficient, single-junction, wafer-based c-Si PV could reach a direct manufacturing cost of $\$0.58/W_{P\,DC}$ and a minimally sustainable average selling price of $\$0.68/W_{P\,DC}$. While these levels of cost reductions and technological improvements would represent substantial progress, they are not sufficient to achieve the SunShot Initiative's overall installed system target of $1/W. This appendix explores the trajectories required for achieving substantial module price reductions as the PV industry grows over time.

The rate at which manufacturers of c-Si modules can achieve the cumulative production experience that is needed to reach ambitious cost and performance targets is highly uncertain. Learning curves for c-Si and CdTe are shown in Figure 21. A learning curve is a log-log plot of the cost or price of a product versus the cumulative production volume of that product.[23] Studies of historical data from multiple industries indicate there is typically a constant reduction in cost or price for every doubling of cumulative production volume. This is termed the progress ratio. For PV modules, data going back about 30 years have shown that the learning curve yields an approximate 20% reduction in cost for every doubling of cumulative volume. Two aspects of learning curves should be stressed, however. One is that the historical cost reductions represent many different factors in scale and innovation; in other words, "learning" does not just happen but is the result of specific actions and investments. The second aspect is that continued progress is not guaranteed and that over time a learning curve may flatten out. That being said, learning curves have been used to set benchmarks for and to project future cost reductions.

Using the historical PV learning curve to project future cost reductions suggests that, if historic learning trends continue, the cumulative installed c-Si capacity would need to reach about 4 TW in order to achieve a module average selling price (ASP) of $\$0.68/W_{P\,DC}$. For comparison, total global installed electricity generating capacity was 4.4 TW in 2007 and is projected to grow to about 7 TW by 2035 (International Energy Agency 2010).

Single-junction PV modules based on CdTe materials have similar first principle constraints that limit the extent to which efficiency can be increased and costs reduced. First Solar is the largest manufacturer of these devices and has provided investors with guidance on the cost and performance roadmap for their modules, including a 2014 cost target of $\$0.52/W_{P\,DC}$ and module efficiency of 14.4% (First Solar 2009). Assuming these targets are met, and further assuming that single-junction CdTe modules can achieve a module efficiency of 18% at no added ($/m^2) cost, then a manufacturing cost of $\$0.39/W_{P\,DC}$ could be reached.[24] This corresponds to a minimum

[23] Learning curves can be based on either cost or price, although learning curves using price can be distorted due to changes in margins over time.
[24] It is estimated by NREL that the pathway to 18%-efficient CdTe modules will incur added costs per square meter, including, for example, the cost of low-iron glass and reduced process throughputs. Here, the net zero cost impact

module selling price of $\$0.49/W_{P\ DC}$. The CdTe-based learning curve shown in Figure 21 suggests that, if the historical learning rates can be maintained, then a cumulative installed CdTe capacity of 100 GW would need to be reached to achieve a module ASP of $\$0.49/W_{P\ DC}$.

Having estimated the best practical manufacturing costs and device efficiencies (experience curve asymptotes), it is possible to forecast the time required to reach these targets using historical learning rates and a range of global PV market growth projections. In order to bracket the uncertainty in this analysis, two cases were considered: Case 1 (10% of electricity from PV by 2050) and Case 2 (20% of electricity from PV by 2050). Both cases assume that the global demand growth rate for PV installations will, at some point, saturate and diminish to a mature rate that is representative or equal to the growing demand for all electric energy. In these scenarios, it is assumed that the demand for PV grows to approximately 10% or 20% of global energy production by 2050 and that current c-Si and CdTe device market shares remain constant at 88% and 12%, respectively.

As shown in Figure 22, projecting module selling prices based on historical learning rates using the 10% and 20% growth trajectories implies that c-Si will reach its lower bound price of $\$0.68/W_{P\ DC}$ around 2040 or later, and CdTe will asymptote at $\$0.49/W_{P\ DC}$ around 2020 or later. In order to assess how these module prices relate to achieving a total installed system price of $1/W, they need to be combined with non-module system costs and installer margins.

assumes that these added costs will be offset by further manufacturing efficiency and economies of scale benefits. This is an optimistic set of assumptions, given the aggressive module performance assumed.

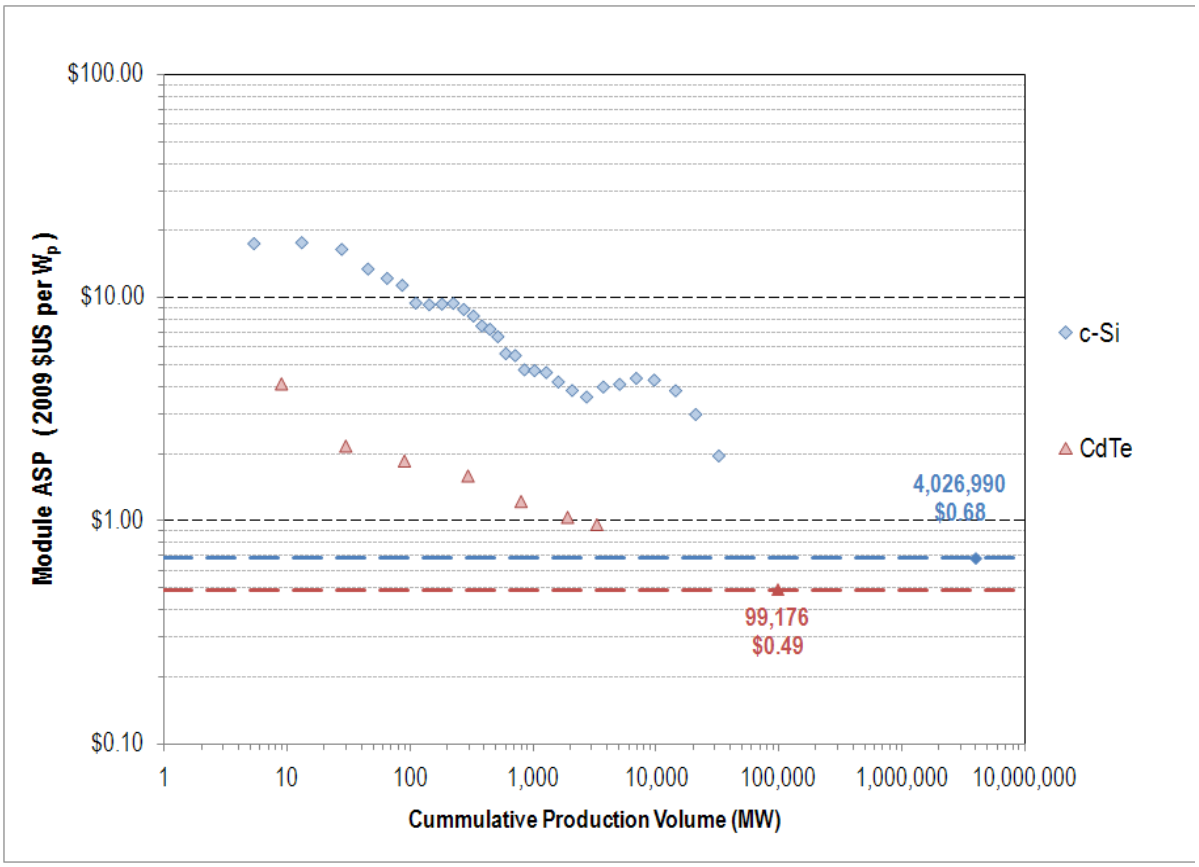


Figure 21. Single-junction c-Si and CdTe PV module experience learning curves
Source: First Solar (2009), Mints (2006), Mints (2010), Strategies Unlimited (2003), NREL internal cost models.

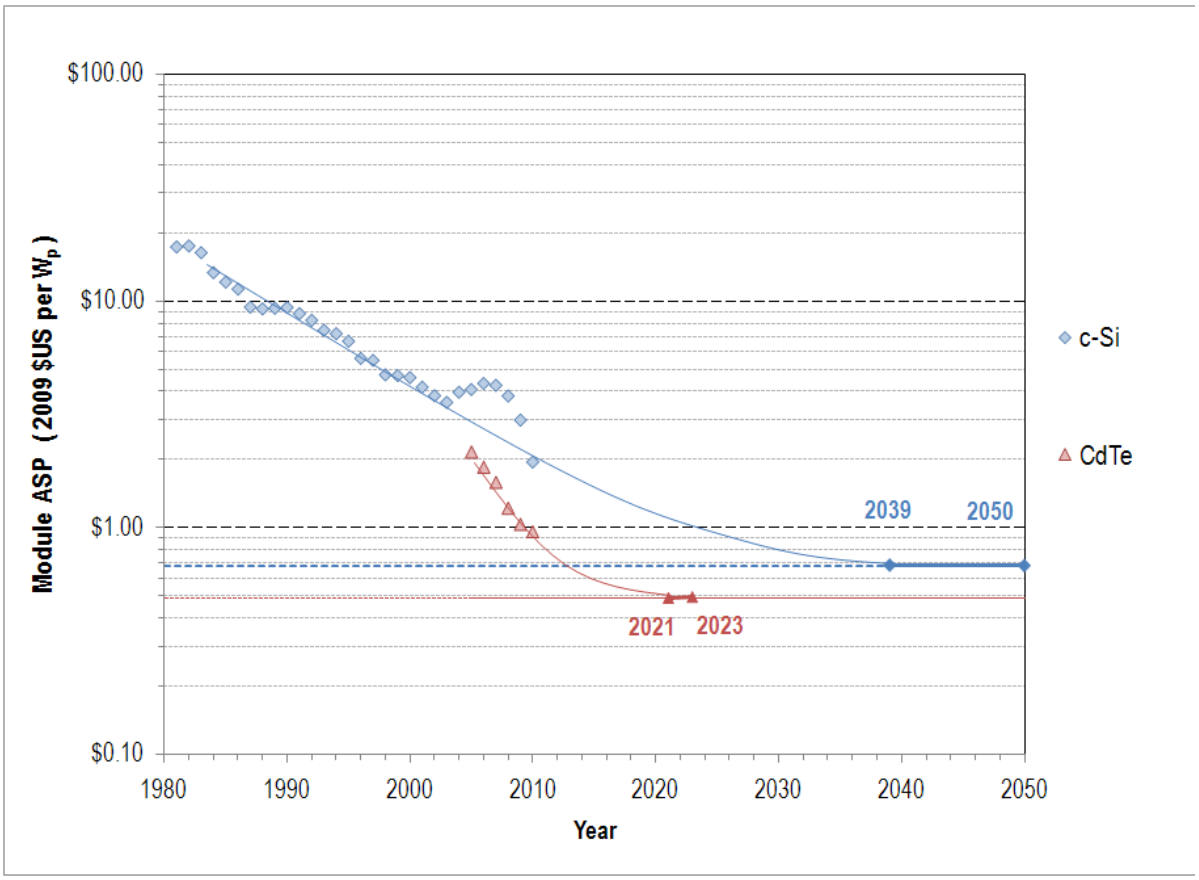
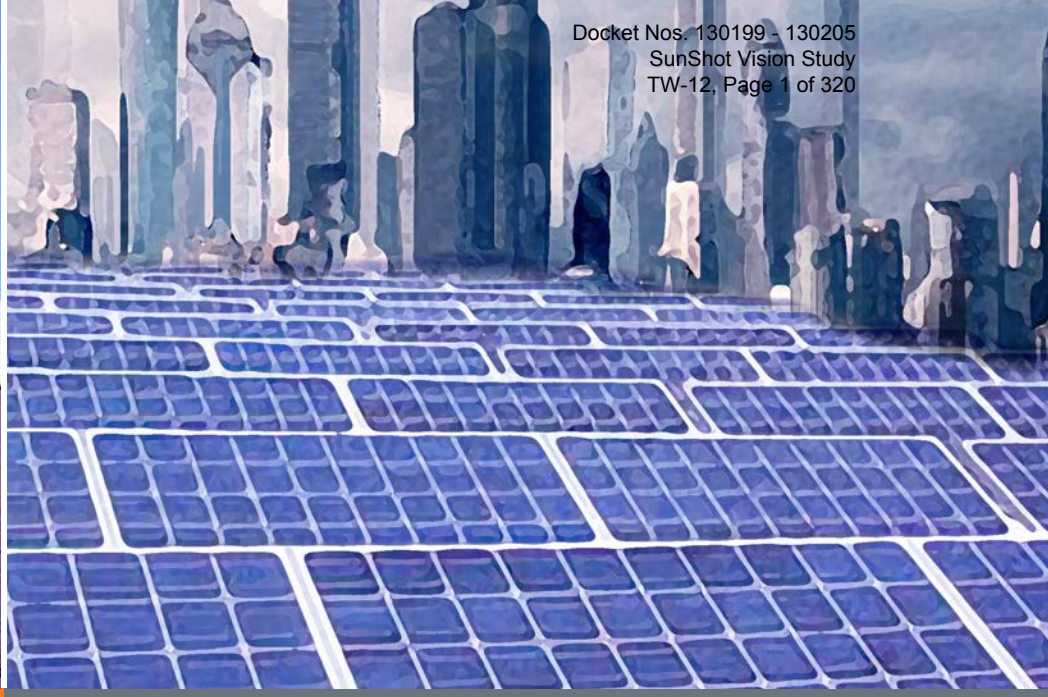


Figure 22. Historical and projected c-Si and CdTe module average selling prices (ASPs) Source: First Solar (2009), Mints (2006), Mints (2010), Strategies Unlimited (2003), NREL internal cost models.





SunShot
U.S. Department of Energy

SunShot Vision Study

February 2012







ACKNOWLEDGMENTS

The U.S. Department of Energy would like to acknowledge the project coordination and in-depth analysis conducted by the National Renewable Energy Laboratory (NREL) and the contributions by the Solar Energy Industries Association, Solar Electric Power Association, and the many organizations that participated in the development of this report. The preparation and production of this report was coordinated by New West Technologies, LLC, Energetics Incorporated, and NREL. All contributors to the report are listed in Appendix D.

Cover photo renderings by Joshua Bauer, NREL

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U.S. Department of Energy

MESSAGE FROM THE DIRECTOR OF THE SUNSHOT INITIATIVE

The SunShot Initiative was launched in February 2011 with the goal of making solar energy cost-competitive with conventional electricity generating technologies within the decade. Achieving this goal will require dramatic decreases in the cost structure of solar technologies—on the order of a 75% reduction—across all markets including residential, commercial, and utility-scale deployments of solar. To do this most effectively, the SunShot Initiative spans the full spectrum from basic science to applied research and development. It also spans across multiple U.S. Department of Energy (DOE) offices, including Energy Efficiency and Renewable Energy (EERE), Advanced Research Projects Agency-Energy (ARPA-E) and the Office of Science (SC).

The *SunShot Vision Study* explores the implications of achieving the SunShot Initiative's targets both in terms of potential benefits as well as potential challenges. The potential benefits include solar contributing an increasingly significant share of electricity generation over the next 20 to 40 years, creating thousands of new jobs, and saving consumers money by placing downward pressure on electricity prices. The potential challenges include scaling-up manufacturing capacity, integrating large amounts of solar energy into the grid, and improving access to financing. The benefits and challenges of achieving the SunShot vision are discussed in detail in the study.

By design, this study focuses on solar technologies and presents a "best case" solar scenario. It was specifically designed this way to highlight the potential for solar electricity to significantly impact the electricity generation portfolio and to explore the challenges likely to be encountered as the industry grows. The basic elements of this study include an analysis of the share of the total electricity market under the SunShot targets, while keeping other competing technologies (such as wind, geothermal, natural gas, etc.) on nominal cost-reduction curves. The reason to explore such an aggressive hypothesis was to ask the fundamental question: what is the upper bound of the electricity market share that can be captured by solar electricity, given the envisioned SunShot cost structures?

This study is not intended to be viewed as a prediction that solar will beat out other competing technologies, but rather an exploration of how far solar could go under a specific set of assumptions. The study indicates that under these assumptions, solar electricity could contribute up to 14% and 27% of the total electricity demand by 2030 and 2050, respectively. While there are many challenges along the way, achieving this vision would represent a transformation in the way we generate, store, and utilize solar energy.



Ramamoorthy Ramesh
Director, SunShot Initiative

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Abbreviations and Acronyms

AC	alternating current
AEO	Annual Energy Outlook
Ag	silver
ANSI	American National Standards Institute
APS	Arizona Public Service
AR	anti-reflection
ARRA	American Recovery and Reinvestment Act
a-Si	amorphous silicon
ATC	available transfer capacity
BA	Balancing Authority
BIPV	Building-integrated photovoltaics
BLM	Bureau of Land Management
BOS	balance-of-systems
Btu	British thermal unit
c-Si	crystalline silicon
CA	California
CAES	compressed air energy storage
CAGR	compound annual growth rate
CAISO	California Independent System Operator Corporation
CapEx	capital expenditure
CC	combined cycle
CCS	carbon capture and storage
Cd	cadmium
CDC	Center for Disease Control
CdTe	cadmium telluride
CEC	California Energy Commission
CEDA	Clean Energy Deployment Administration
CEQA	California Environmental Quality Act
CES	clean energy standard
CESA	California Endangered Species Act
CF	capacity factor
CIGS	copper indium gallium diselenide
CIS	copper indium diselenide
CLFR	compact linear Fresnel reflector
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPUC	California Public Utilities Commission
CPV	concentrating photovoltaics

CREB	clean renewable energy bond
CREZ	competitive renewable energy zone
CSI	California Solar Initiative
CSP	concentrating solar power
CT	combustion turbine
Cu	copper
DC	direct current
DER	distributed energy resource
DG	distributed generation
DNI	direct-normal irradiance
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DRECP	Desert Renewable Energy Conservation Plan
DSM	demand side management
EESA	Emergency Economic Stabilization Act
EIA	Energy Information Administration
EIS	environmental impact statement
EISA	Energy Independence and Security Act
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESA	Endangered Species Act
EVA	ethylene vinyl acetate
FERC	Federal Energy Regulatory Commission
FHFA	Federal Housing Finance Agency
FIT	feed-in tariff
FPA	Federal Power Act
FPL	Florida Power & Light Company
ft^2	square foot
FRCC	Florida Reliability Coordinating Council
FTE	full-time equivalent
g	gram
GA	gallium
gal	gallon
gas-CC	combined cycle natural gas plant
gas-CT	gas combustion turbine
GDP	U.S. Gross Domestic Product
GE	General Electric
GHG	greenhouse gas
GIS	geographic information system

GW	gigawatt
GWh	gigawatt-hour
GW-mi	gigawatt-mile
GW_{th}	gigawatt thermal
Hz	hertz
ha	hectare
HTF	heat-transfer fluid
HVDC	high-voltage direct current
ID	Idaho
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IGCC	integrated gasification combined cycle
In	indium
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
IRS	Internal Revenue Service
ISO	independent system operator
ISO-NE	Independent System Operator - New England
ITC	investment tax credit
kg	kilogram
km	kilometer
km^2	square kilometer
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LaaR	Loads acting as a Resource
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy
LFR	linear Fresnel reflector
LMP	location marginal pricing
LVRT	low voltage ride-through
m	meter
m^2	square meter
m^3	cubic meter
mc	multicrystalline
mm	millimeter
MACRS	modified accelerated cost recovery system
MISO	Midwest Independent Transmission System Operator
MJ	multijunction
MMT	million metric tons

MN	Minnesota
Mo	molybdenum
MOU	memorandum of understanding
MPR	Market Price Referent
MRO	Midwest Reliability Organization
MT	metric ton
MVA	mega-volt amperes
MW	megawatt
MW_e	megawatt electric
MWh	megawatt-hour
MW_t	megawatt thermal
NARUC	National Association of Regulatory Utility Commissioners
NCAR	National Center for Atmospheric Research
NCEP	National Commission on Energy Policy
NEC	National Electrical Code
NEF	New Energy Finance
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NF_3	trifluoride
NLCS	National Landscape Conservation System
NMPRC	New Mexico Public Regulation Commission
NOPR	Notice of Proposed Rulemaking
NO_x	nitrogen oxides
NPCC	Northeast Power Coordinating Council
NRDC	National Resources Defense Council
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
NV	Nevada
NW	Northwest
NYISO	New York Independent System Operator
O&M	operation and maintenance
OGS	oil/gas/steam
OMB	U.S. Office of Management and Budget
OPV	organic photovoltaics
OR	Oregon
PACE	property-assessed clean energy (financing)
Pb	lead
PCA	power control area
PCC	point of common coupling
PCM	phase-change material
PE	private equity
PEIS	programmatic environmental impact statement

PHS	pumped hydropower storage
PJM	PJM Interconnection LLC
PM	particulate matter
$PM_{2.5}$	particulate matter less than 2.5 microns in size
PPA	power purchase agreement
PPSA	Florida Electrical Power Plant Siting Act
PR	progress ratio
PTC	production tax credit
PUC	public utility commission
PUCN	Public Utility Commission of Nevada
PUCT	Public Utility Commission of Texas
PUHCA 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utilities Regulatory Policy Act
PV	photovoltaics
PV/T	combined photovoltaic/thermal
Quad	quadrillion British thermal units
RAM	Renewable Auction Mechanism
R&D	research and development
RC	reliability coordinator
RD&D	research, development, and demonstration
REC	renewable energy certificate
ReEDS	Regional Energy Deployment System
RES	renewable electricity standard
RETA	Renewable Energy Transmission Authority
RETI	Renewable Energy Transmission Initiative
REZ	renewable energy zone
RFC	Reliability First Corporation
ROW	rest of world
RPS	renewable portfolio standard
RROE	rate of return on equity
RSI	Renewable Systems Integration
RTO	Regional Transmission Organization
SAM	System Advisor Model
Sandia	Sandia National Laboratories
SCADA	supervisory control and data acquisition
Se	selenium
SEGS	Solar Energy Generating Systems
SEIA	Solar Energy Industries Association
SERC	Southeastern Electric Reliability Council
SES	Stirling Energy Systems
SETP	Solar Energy Technologies Program
SGIP	Small Generator Interconnection Procedure
$SiCl_4$	silicon tetrachloride

SiN_4	silicon nitride
Sn	tin
Solar ABCs	Solar America Board for Codes and Standards
SolarDS	Solar Deployment System
Solar PEIS	Solar Programmatic Environmental Impact Statement
SO_x	sulfur oxides
SO_2	sulfur dioxide
SPP	Southwest Power Pool
SRCC	Solar Rating and Certification Corporation
SREC	solar renewable energy certificate
T&D	transmission and distribution
TDY	typical DNI year
Te	tellurium
TES	thermal energy storage
TIO	technology improvement opportunities
TOU	time of use
TRE	Texas Reliability Entity
TW	terawatt
TWh	terawatt-hour
USEC	Uniform Solar Energy Code
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VC	venture capital
VER	variable energy resources
W	watt
WA	Washington
WACC	weighted average cost of capital
WAPA	Western Area Power Administration
WDG	wholesale distributed generation
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association
Wp	peak watt
WREZ	Western Renewable Energy Zones
yr	Year

Executive Summary

The objective of the *SunShot Vision Study* is to provide an in-depth assessment of the potential for solar technologies to meet a significant share of electricity demand in the United States during the next several decades. Specifically, it explores a future in which the price of solar technologies declines by about 75% between 2010 and 2020—in line with the U.S. Department of Energy (DOE) SunShot Initiative's targets. As a result of this price reduction, solar technologies are projected to play an increasingly important role in meeting electricity demand over the next 20–40 years, satisfying roughly 14% of U.S. electricity demand by 2030 and 27% by 2050.[1] In terms of technology, the SunShot Initiative and this report both focus on photovoltaics (PV) and concentrating solar power (CSP). Details about how the SunShot Initiative is organized to achieve its targets and increase American competitiveness in solar energy can be found on the initiative's website (www.eere.energy.gov/solar/sunshot/).

The *SunShot Vision Study* uses the National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS) and Solar Deployment System (SolarDS) models to develop and evaluate a SunShot scenario and a reference scenario. In both scenarios, the models are used to develop a least-cost geographical deployment of solar technologies and other generating technologies (conventional and other renewable). The scenarios assume the federal investment tax credit (ITC) and production tax credit (PTC) run through their currently established expiration dates—end of 2016 and 2012, respectively—but that existing supports for conventional technologies that are embedded in the tax code or through other provisions continue indefinitely. Further, the scenarios do not incorporate any additional costs for mercury and air toxins, carbon emissions, or other environmental externalities associated most strongly with conventional generation technologies. Key variables evaluated by the models include solar resource quality, cost of electricity, transmission requirements, reserve requirements, variability impacts, and projected fuel prices. For the SunShot scenario, solar technology installed system prices are assumed to reach the SunShot Initiative's targets by 2020: $1/watt (W) for utility-scale PV systems, $1.25/W for commercial rooftop PV, $1.50/W for residential rooftop PV, and $3.60/W for CSP systems with up to 14 hours of thermal energy storage capacity.[2] The reference scenario is modeled with moderate solar energy price reductions to enable comparison of the costs, benefits, and challenges relative to the reference case of achieving the SunShot price targets.

The *SunShot Vision Study* examines the potential pathways, barriers, and implications of achieving the SunShot Initiative's price-reduction targets and resulting market-penetration levels. Key factors examined include current and

[1] All results in this report refer to the *contiguous* United States (excluding Alaska and Hawaii), unless otherwise noted, e.g., solar technologies are projected to satisfy roughly 14% of contiguous U.S. electricity demand by 2030 and 27% by 2050.

[2] Note that throughout this report all "$/W" units refer to 2010 U.S. dollars per peak watt-direct current (DC) for PV and 2010 U.S. dollars per watt-alternating current (AC) for CSP, unless otherwise specified.

projected costs, raw material and labor availability, manufacturing scale-up, grid integration, financing, and siting and environmental issues.

The *SunShot Vision Study* does not prescribe a set of policy recommendations for solar energy in the United States, nor does it present a vision of what the total mix of energy sources should look like in the future. The *SunShot Vision Study* does, however, provide analysis and insights that could help policymakers design and implement measures aimed at optimizing solar energy's potential within an integrated national energy policy framework. The study's focus on both a 20- and 40-year time horizon allows sufficient time to implement and realize the benefits of policy changes. It also provides a framework for analyzing both the short- and long-term evolution of the U.S. electricity-generation system, and is long enough to envision substantial change to the system as a whole. Thus, this study provides insights about both the near- and long-term technology investments and policy changes that may be required to achieve the envisioned levels of market penetration.

The *SunShot Vision Study* is meant to be the most comprehensive review of the potential for U.S. solar electricity generation to date. The study was initiated by the DOE Solar Energy Technologies Program (SETP) and managed by NREL.[3] Key findings of the *SunShot Vision Study* include the following:

- *Achieving the level of price reductions envisioned in the SunShot Initiative could result in solar meeting 14% of U.S. electricity needs by 2030 and 27% by 2050. However, realizing these price and installation targets will require a combination of evolutionary and revolutionary technological changes.* The SunShot Initiative aims to reduce the price of solar energy systems by about 75% between 2010 and 2020. Achieving this target is expected to make the cost of solar energy competitive with the cost of other energy sources, paving the way for rapid, large-scale adoption of solar electricity across the United States. Existing challenges can be addressed through technological advances—e.g., efficiency improvements, materials substitutions, and expanded material supplies—and planning. Significant manufacturing scale-up is required under the SunShot scenario, but solar manufacturers have demonstrated the ability to scale up rapidly over the past decade. The continued expansion and price reductions anticipated over the next decade should enable the required high-volume, low-cost production.
- *Achieving the SunShot price targets is projected to result in the cumulative installation of approximately 302 gigawatts (GW) of PV and 28 GW of CSP by 2030, and 632 GW of PV and 83 GW of CSP by 2050*. To achieve these cumulative installed capacities, annual installations must reach 25–30 GW of PV and 3–4 GW of CSP in the SunShot scenario between 2030 and 2050. By 2030, this translates into PV generating 505 terawatt-hours (TWh) per year of electricity or 11% of total U.S. electricity demand, and CSP generating 137 TWh per year or 3% of total demand. By 2050, this

[3] This study draws heavily on research, analysis, and material developed for DOE's draft *Solar Vision Study*. The *Solar Vision Study* was launched in June 2009 and drew on a steering committee and working groups with more than 140 representatives from solar companies, utilities, financial firms, universities, national laboratories, non-profit organizations, industry associations, and other organizations. A draft of the *Solar Vision Study* was circulated for external review during June 2010. The post-review version of the *Solar Vision Study* was used as the starting point for the *SunShot Vision Study*.

translates into PV generating 1,036 TWh per year or 19% of total demand, and CSP generating 412 TWh per year or 8% of total demand.

- *Annual U.S. electricity-sector carbon dioxide (CO_2) emissions are projected to be significantly lower in the SunShot scenario than in the reference scenario: 8%, or 181 million metric tons (MMT), lower in 2030, and 28%, or 760 MMT, lower in 2050.* This would provide carbon emissions reductions that are equivalent to taking 30 and 130 million cars off the road by 2030 and 2050, respectively. The emissions reductions are primarily a result of the displacement of natural gas and coal generation. Before 2030, solar primarily offsets natural gas generation, while post-2030, solar begins to significantly offset coal generation.
- *Both the SunShot and reference scenarios require significant transmission expansion. In the reference scenario, transmission is expanded primarily to meet growing electricity demand by developing new conventional and wind resources. In the SunShot scenario, transmission is expanded at a similar level, but in different locations in order to develop solar resources.* In the reference scenario, transmission capacity is projected to increase from about 88,000 gigawatt-miles (GW-mi) in 2010 to 102,000 GW-mi in 2030, and 110,000 GW-mi in 2050—a 15% and 25% increase, respectively. In the SunShot scenario, transmission capacity is expected to increase to 100,000 GW-mi in 2030 and 117,000 GW-mi in 2050, a 13% and 32% increase, respectively. Expanding transmission at these rates would require a level of investment well within the historical range of transmission investments during the past few decades.
- *The level of solar deployment envisioned in the SunShot scenario poses significant but not insurmountable technical challenges with respect to grid integration and could require substantial changes to system planning and operation practices.* The main grid integration challenges at the bulk system levels are expanding access to transmission capacity and dealing with the additional variability and uncertainty of solar generation. The impact and cost of variability and uncertainty can be reduced by improving access to flexible resources in the system (both generation and load) and optimizing their deployment. Improved solar production forecasts and better access to well-functioning electricity markets are two key enabling factors. At the distribution system level, the main technical challenges are related to control of voltage and system protection with high-penetration PV. In addition to technological advances, existing codes and standards must be revised, and better models and analysis techniques are needed.
- *The land area that is potentially suitable for solar deployment is enormous and thus land, per se, is not a constraint on meeting the SunShot scenario level of deployment. However, it is important to make careful selection of sites in order to provide access to available or planned transmission, and to minimize conflicts with environmental, cultural, and aesthetic interests.* The land area required to supply all end-use electricity in the United States using PV is only about 0.6% of the country's total land area.[4] Similarly, the technical potential for CSP is enormous: about 17,500 TWh of annual CSP

[4] This calculation is based on deployment/land in the entire United States (including Alaska and Hawaii).

electricity generation, which is more than four times the 2010 U.S. annual demand, could be sited in seven southwestern states on land that has been pre-screened to avoid prominent land-use issues and to meet technical requirements such as insolation and slope. About 370,000–1,100,000 hectares (ha) (900,000–2,700,000 acres) are required for utility-scale solar installations in 2030 under the SunShot scenario, and about 860,000–2,500,000 ha (2,100,000–6,300,000 acres) are required in 2050. The required land area is equivalent to about 0.05%–0.14% of the contiguous U.S. land area in 2030 and about 0.11%–0.33% in 2050. Solar development in the SunShot scenario is greatest in the South and Southwest. Often the highest-quality solar resource areas are dry environments that are typically not well suited for cropland or offer little value for forestry and rangeland.

- *Siting poses significant, but not insurmountable, regulatory challenges to achieving the level of solar market penetration envisioned in the SunShot scenario.* The regulatory framework for siting utility-scale solar projects and associated transmission infrastructure is complex, costly, and time consuming. Similarly, distributed PV installers, both in the residential and commercial sectors, face the challenges and expense associated with complex and variable codes and permits, zoning ordinances, and restrictive covenants. Streamlining of siting and regulatory requirements for utility-scale and distributed solar projects, as well as electricity-transmission projects, would help to enable the rapid solar development envisioned under the SunShot scenario.
- *Water-use constraints will require CSP technologies to transition away from wet cooling toward dry and hybrid cooling.* Although PV requires very little water (for occasional panel washing), CSP with traditional wet cooling uses similar amounts of water as used by some conventional electricity-generation technologies. However, dry or hybrid CSP cooling technologies can reduce water use by 40%–97% compared with wet cooling. Because most land suitable for CSP is in the Southwest, where water availability is constrained, it is very likely that in order to achieve the level of deployment projected in the SunShot scenario, most CSP plants will need to use dry or hybrid cooling.
- *Financing the scale of expansion in the SunShot scenario will require significant new investments in the solar manufacturing supply chain and in solar energy projects.* Building out U.S. PV and CSP manufacturing capacity to meet the level of installations envisioned in the SunShot scenario would require cumulative investments of roughly $25 billion through 2030 and $44 billion through 2050. On an annual basis, the required level of investments would be on the order of $1–$3 billion, well below private sector investments in solar in the United States during the past couple of years. Investments in the solar supply chain have historically been financed by a mix of venture capital, private equity, public equity, and corporate debt. Financing solar project deployment under the SunShot scenario, however, will cost much more than financing the supply chain—on the order of $40–$50 billion per year between 2030 and 2050. On a cumulative basis, this translates into roughly $250 billion through 2030 and $375 billion through 2050. The primary financing challenge will be managing the transition from the pre-2020 period, when solar electricity is less cost competitive with

other electricity sources, to the post-2020 period, when the availability of cost-competitive solar energy should stimulate private solar investment and facilitate use of mainstream financial instruments.

- *Achieving the SunShot scenario level of solar deployment would result in significant downward pressure on retail electricity prices.* By 2030, the average retail price for electricity in the SunShot scenario is projected to be 0.6 cents/kilowatt-hour (kWh) less than in the reference scenario, which translates into a cost savings of about $6 per month, per household. By 2050, the average retail price of electricity is projected to be 0.9 cents/kWh less, which translates into a cost savings of about $9 per month, per household. Across all market sectors, the lower electricity prices in the SunShot scenario translate into about $30 billion in annual cost savings by 2030 and $50 billion in annual savings by 2050, compared to the reference scenario.
- *Achieving the SunShot scenario level of solar deployment could support 290,000 new solar jobs by 2030, and 390,000 new solar jobs by 2050*. These figures include direct and indirect jobs for the PV and CSP supply chains. The U.S. PV workforce is expected to grow from about 46,000 in 2010 to 280,000 in 2030 and to 363,000 in 2050. The U.S. CSP workforce is expected to grow from about 4,500 in 2010 to 63,000 in 2030 and to 81,000 in 2050. Labor requirements for manufacturing of PV and CSP components are readily transferable from other industries. Similarly, CSP power plant development can tap into the same skilled engineering and construction labor pool used for conventional fossil-fuel power plant development. The workforce to support distributed PV installations will require additional training and certification within the existing residential and commercial construction industries.
- *Sensitivity analyses indicate that a number of factors could influence the level of solar deployment envisioned in the SunShot scenario, including more aggressive cost reductions in other renewable and conventional electricity-generation technologies, fossil fuel prices, electricity demand growth, and other assumptions*. For example, sensitivity analyses indicate that there is a solar price threshold at which solar deployment increases non-linearly as price decreases. Similarly, sensitivity analyses show that assuming larger price reductions for non-solar renewable technologies in the SunShot scenario would result in higher penetration of those technologies, particularly wind. Some sensitivity analyses are presented in Appendix C. Additional sensitivity analyses will be published in supplementary technical reports. The *SunShot Vision Study* looks primarily at the implications of and challenges associated with a very low-cost solar future, and generally assumes much less aggressive improvements in other renewable technologies. There are, however, significant opportunities to reduce the cost of other renewable technologies and thus see additional benefits from their market penetration as well.

1. Introduction

1.1 The SunShot Vision: Deep Price Reductions Spur Rapid, Large-Scale Solar Deployment

Achieving the level of price reductions envisioned in the SunShot Initiative could result in solar meeting 14% of U.S. electricity needs by 2030 and 27% by 2050. However, realizing these price and installation targets will require a combination of evolutionary and revolutionary technological changes.

Solar energy offers a number of strategic benefits to the United States. Replacing fossil-fuel combustion with solar energy reduces emissions of human-induced greenhouse gases (GHGs) and air pollutants. Sunlight is a free resource. Thus, once solar technologies are installed, they have very low operating costs and require minimal non-solar inputs—this provides insurance against conventional fuel supply disruptions and price volatility. In addition, growing the domestic solar energy industry could establish the United States as a global leader in solar technology innovation, and support a growing number of solar-related jobs.

Despite these benefits, solar energy currently supplies only a small fraction of U.S. energy needs, largely because it historically has cost more than conventional energy sources. However, solar manufacturing costs and sales prices have dropped dramatically over the past few decades, and solar technologies are approaching energy-price parity with conventional generating sources in some regions of the United States and abroad. Further, experience accumulated by solar manufacturers and developers, utilities, and regulatory bodies has shortened the time and expense required to install a fully operating solar system. These gains have come partly through research and development (R&D) and partly through U.S. and global solar market stimulation. An additional strong, coordinated effort could enable solar energy technologies to become increasingly cost competitive with conventional electricity-generation technologies in the United States. over the next decade.

The U.S. Department of Energy (DOE) is providing this type of strong, coordinated effort through its SunShot Initiative. Launched in 2011, the SunShot Initiative aims to reduce the price of solar energy systems by about 75% between 2010 and 2020. Achieving this target is expected to make the unsubsidized cost of solar energy competitive with the cost of other currently operating energy sources, paving the way for rapid, large-scale adoption of solar electricity across the United States.

To assess the potential benefits and impacts of achieving the SunShot Initiative targets, DOE's Solar Energy Technologies Program (SETP) produced this *SunShot Vision Study*. This study assumes that the SunShot price targets are achieved by

2020 and models the resulting penetration of solar technologies in the United States. Solar growth based on non-cost factors (e.g., GHG-reduction and energy security benefits) is not considered in this analysis, but could result in additional solar market penetration. The results suggest that solar energy could satisfy roughly 14% of U.S. electricity demand by 2030 and 27% by 2050.[5]

These levels of solar penetration represent a dramatic transformation of the U.S. electricity system. Based on the scenario assumptions discussed in Section 1.4, the projected benefits of achieving the SunShot targets versus a reference case projection could include the following:

- Displacing the use of about 2.6 quadrillion British thermal units (Quads) of natural gas and 0.4 Quads of coal per year by 2030, and about 1.5 Quads of natural gas and 7.3 Quads of coal per year by 2050. This corresponds to a fuel savings of about $34 billion per year by 2030 and $41 billion per year by 2050.
- Reducing annual electric-sector carbon-dioxide (CO_2) emissions 8% below projected reference case levels in 2030 and 28% below projected reference case levels in 2050, equivalent to taking 30 and 130 million cars off the road.
- Reducing emissions of other pollutants including mercury, nitrogen oxides, sulfur oxides, and particulate matter.
- Supporting roughly 290,000 new solar-related jobs by 2030 and 390,000 new solar-related jobs by 2050.
- Reducing retail electricity rates by 0.6 cents/kilowatt-hour (kWh) in 2030 and 0.9 cents/kWh in 2050 compared to the reference scenario.
- Saving electricity consumers across all market sectors about $30 billion per year by 2030 and $50 billion per year by 2050.

This chapter begins by providing basic information about solar energy technologies and the status and potential of solar energy in the United States. Next, the SunShot scenario and analysis methodology are summarized, and several electric-sector impacts of achieving the SunShot targets are discussed. Finally, potential barriers to realizing the level of solar market penetration envisioned in the SunShot scenario—and strategies for overcoming them—are discussed. The body of the report contains all supporting details and references.

1.2 Solar Energy Basics

There are two major categories of solar energy technologies included in this study, which are distinguished by the way they convert sunlight into electricity: photovoltaics (PV) and concentrating solar power (CSP).

PV employs a semiconductor material—traditionally silicon but, increasingly, other materials as well—to convert sunlight directly into electricity. Sunlight enters a PV

[5] All results in this report refer to the contiguous United States (excluding Alaska and Hawaii) unless otherwise noted, e.g., solar technologies are projected to satisfy roughly 14% of *contiguous* U.S. electricity demand by 2030 and 27% by 2050.

module and is converted into direct-current (DC) electricity. For applications that are connected to the electrical grid, an inverter transforms this DC electricity into the alternating-current (AC) electricity that the grid carries. In this report, relatively small PV systems installed on structures such as rooftops, parking garages, and awnings, are called distributed or rooftop PV systems. Rooftop PV systems range in size from a few kilowatts (kW) for residential systems to hundreds of kilowatts or a few megawatts (MW) on large commercial roofs. Larger systems installed on the ground are called utility-scale PV. These systems can range from a few megawatts to hundreds of megawatts. Large utility-scale systems greater than 20 MW are typically connected to the electricity-transmission system which transmits electricity from generating plants to electrical substations. Smaller utility-scale systems can be located near areas of high-electricity demand and be connected to the electricity-distribution system which distributes electricity from electrical substations to end users.

CSP uses mirrors or lenses to concentrate sunlight and produce intense heat, which is used to produce electricity via a thermal energy conversion process similar to those used in conventional power plants. Several CSP technologies accomplish this by using concentrated sunlight to heat a fluid, boil water with the heated fluid, and channel the resulting steam through a steam turbine to produce electricity. An alternate approach uses gases heated with concentrated sunlight to drive a closed cycle heat engine that produces electricity. Most CSP systems can incorporate thermal energy storage or natural gas back-up, which can be used to smooth out short-term transients (e.g., collector shading from passing clouds) and enable CSP systems to continue producing electricity during the late afternoon and evening hours. Adding multiple hours of storage to CSP systems is critical because it is an enabler for the integration of substantial solar and wind generation in the SunShot scenario. Although some CSP technologies are capable of being deployed at the distributed level, most are designed for utility-scale operation and connected to the electricity-transmission system.

1.3 Solar Energy History, Status, and Potential

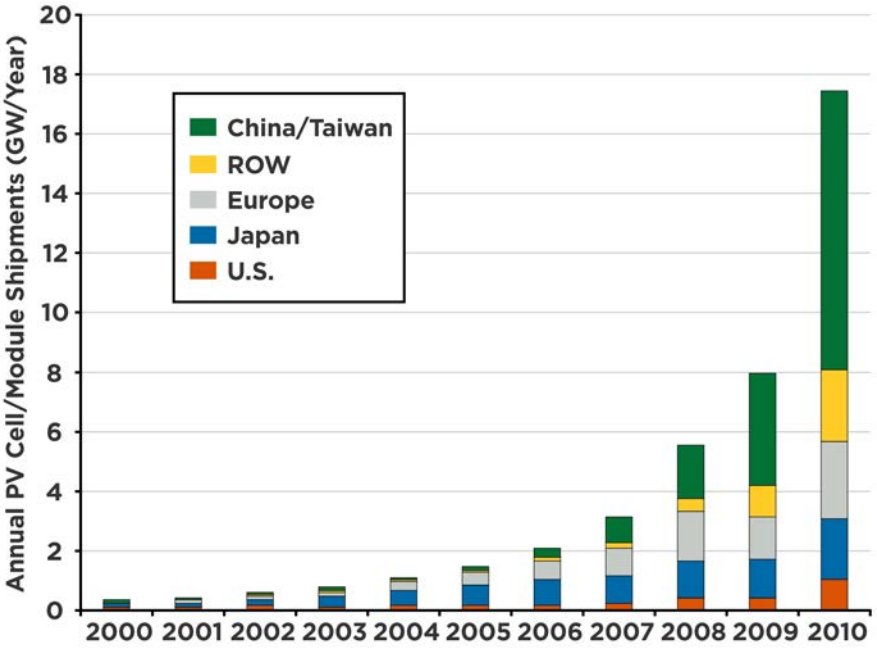
The global PV market has achieved a 53% annual growth rate, on average, over the past decade.

In 2010, solar energy provided less than 0.1% of U.S. electricity demand. This is comparable to the amount supplied by nuclear energy in 1960, which subsequently grew to 11% by 1980 and to 19% by 1990 (EIA 2010a). Over the past decade, U.S. solar deployment has lagged behind deployment in European and Asian countries, primarily because these countries instituted strong solar-promoting policies, while solar policies in the United States were limited and inconsistent. In considering the potential for future growth, it is useful to examine historical growth rates in global markets.

Figure 1-1 shows the regional PV cell and module shipments from the United States, Japan, Europe, China/Taiwan, and the rest of the world (ROW) over the past decade.

Between 2000 and 2010, PV module shipments achieved a compound annual growth rate of 53%, reaching 17 gigawatts (GW) of annual module shipments in 2010, and

Figure 1-1. Regional PV Cell and Module Shipments, 2000–2010



Source: Mints (2011a)

bringing the cumulative global PV shipments to about 40 GW. Although the United States accounted for 30% of global shipments in 2000, the U.S. market share declined significantly during the past decade. In 2010, the United States accounted for only 6% (about 1,000 MW) of PV module supply and only 8% (or about 1,400 MW) of demand (Mints 2011a, Mints 2011b). As of mid-2011, continued R&D and market forces have helped reduce PV prices sharply and, together with a mix of state and federal policies, have positioned the U.S. PV market for rapid future growth.

Almost 10 GW of CSP projects were under development in the United States at the end of 2010.

Historically, CSP market growth has been sporadic. After a number of CSP plants were built in California in the late 1980s, almost 15 years passed before the next commercial CSP plant was built, followed by a number of new plants in the United States and Spain during 2007–2010. By the end of 2010, global CSP capacity was about 1,300 MW, with 512 MW in the United States and most of the rest in Spain. In the United States, almost 10 GW of CSP projects were under various stages of development at the end of 2010. Even if only a small fraction of these projects are built, the industry will experience very rapid growth in the near future.

Although solar energy's contribution to U.S. energy supply has been small to date, its technical potential is enormous. For example, one estimate suggested that the area required to supply an amount of electricity equivalent to all end-use electricity in the United States using PV is only about 0.6% of the country's total land area (Denholm and Margolis 2008).[6] PV can also be installed on rooftops with essentially

[6] This calculation is based on deployment/land in the entire United States (including Alaska and Hawaii).

no land-use impacts. About 17,500 terawatt-hours (TWh) of annual CSP electricity generation—more than four times the current U.S. annual demand—could be sited in seven southwestern states on land that was screened for use restrictions and technical requirements such as solar insolation and land slope.

1.4 Modeling the SunShot Scenario

The *SunShot Vision Study* models the potential impact of achieving the SunShot price reduction targets by 2020 in the U.S. electric sector through 2050. To understand how this scenario evolves, the effects in 2030 (10 years after the price targets are achieved) and 2050 (30 years after the price targets are achieved) are highlighted here.

1.4.1 Defining the SunShot and Reference Scenarios

For the SunShot scenario, solar technology installed system prices were assumed to reach the SunShot Initiative's targets by 2020: $1/watt (W) for utility-scale PV systems, $1.25/W for commercial rooftop PV, $1.50/W for residential rooftop PV, and $3.60/W for CSP systems with 14 hours of thermal storage capacity.[7] These installed system prices represent a set of very aggressive, but technically possible targets that would translate into solar technology having a similar levelized cost of energy (LCOE) as competing electricity sources in each market segment. In other words, $1/W for PV and $3.60/W for CSP is expected to enable these solar technologies to be competitive in the wholesale electricity market, while $1.25/W is expected to enable PV to be competitive in the commercial retail market, and $1.50/W is expected to enable PV to be competitive in the residential retail market.

For the purposes of modeling the SunShot scenario, these installed system prices are assumed to remain constant through the 2020–2050 time frame, i.e., no further price reductions are modeled for solar technologies beyond 2020. Installed system price estimates for the development of all conventional and other renewable (including wind) electricity-generating technologies are based on Black & Veatch (forthcoming). Fuel prices and price elasticities are based on the Energy Information Administration's (EIA's) *Annual Energy Outlook 2010* (*AEO 2010*) (EIA 2010b) and are extrapolated through 2050 based on modeled fuel demand. Unless otherwise noted, all prices and values in the *SunShot Vision Study* are given in 2010 U.S. dollars. Future costs are discounted using a 7% real discount rate, per guidance from the U.S. Office of Management and Budget (OMB 2003).

A reference scenario with moderate solar energy price reductions was also modeled to enable comparison of the costs, benefits, and challenges of achieving the SunShot price targets. Future installed system price estimates for all technologies, including solar, are based on Black & Veatch (forthcoming) in the reference scenario. In both the SunShot and reference scenarios, electricity demand is assumed to increase by about 1% per year through 2050. This assumption is consistent with projections through 2035 provided by EIA (2010b), and an extension of EIA's projected trend through 2050. At this rate, demand reaches about 4,400 TWh by 2030 and 5,100

[7] Note that throughout this report, all "$/W" units refer to 2010 U.S. dollars per peak watt-direct current (DC) for PV and 2010 U.S. dollars per watt-alternating current (AC) for CSP, unless specified otherwise.

TWh by 2050. Table 1-1provides a breakdown of PV and CSP prices including benchmarked prices in 2010 and projected prices in 2020 for both the SunShot and reference scenarios.

Table 1-1. Benchmarked 2010 Solar Prices and Projected 2020 Solar Prices (2010$/W)

Technology/Market	Benchmark 2010 Price	Reference 2020 Price	SunShot 2020 Price
Utility-Scale PV ($/$W_{DC}$)	**4.00**	**2.51**	**1.00**
Commercial Rooftop PV ($/$W_{DC}$)	**5.00**	**3.36**	**1.25**
Residential Rooftop PV ($/$W_{DC}$)	**6.00**	**3.78**	**1.50**
CSP ($/$W_{AC}$)	**7.20[a]**	**6.64[a]**	**3.60[b]**

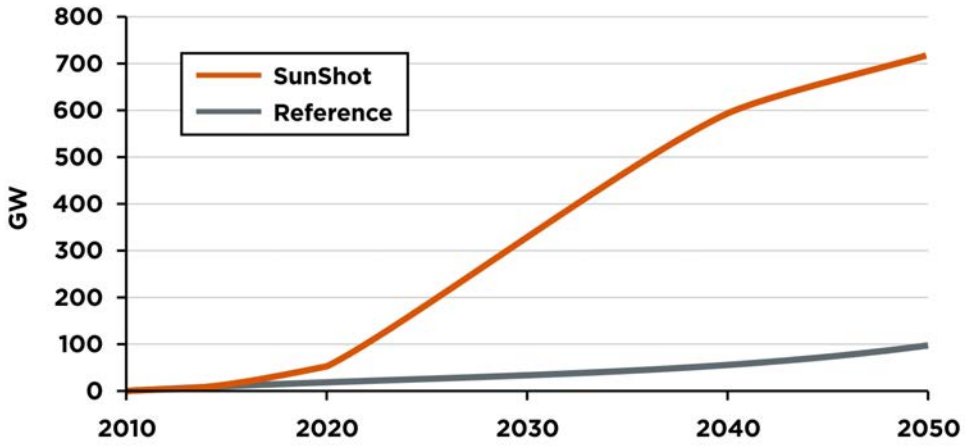
[a] CSP system with 6 hours of thermal storage
[b] CSP system with 14 hours of thermal storage

Several modeling tools were used to develop and evaluate the SunShot and reference scenarios. The Regional Energy Deployment System (ReEDS) capacity-expansion model, developed at the National Renewable Energy Laboratory (NREL), simulated the least-cost deployment and operation of utility-scale electricity-generating resources in the reference and SunShot scenarios. The Solar Deployment System (SolarDS) model, also developed at NREL, simulated the evolution of the residential and commercial rooftop PV markets. These models evaluated the trade-offs between solar resource quality, cost of electricity, transmission requirements, and other factors to determine a least-cost geographical deployment of the various solar technologies and configurations. Similarly, the remaining mix of electricity-generating technologies (conventional and other renewable) were determined on a least-cost basis, with considerations including the impacts of variability, reserve requirements, and projected fuel prices. The scenarios assume the federal investment tax credit (ITC) and production tax credit (PTC) run through their currently established expiration dates—end of 2016 and 2012, respectively—but that existing supports for conventional technologies that are embedded in the tax code or through other provisions continue indefinitely. Further, the scenarios do not incorporate any additional costs for mercury and air toxins, carbon emissions, or other environmental externalities associated most strongly with conventional generation technologies. In addition, GridView—a production-cost model frequently used by electric service providers to schedule and dispatch generation resources—was used to verify the real-world operability of the SunShot scenario.

1.4.2 Solar Growth Results

Achieving the SunShot targets is projected to result in the cumulative installation of approximately 302 GW of PV and 28 GW of CSP by 2030. By 2050, the cumulative installed capacities are projected to increase to 632 GW of PV and 83 GW of CSP. To achieve this level of cumulative installed capacity, annual installations would need to reach about 25–30 GW for PV and about 3–4 GW for CSP. Solar grows much more slowly in the reference scenario (Figure 1-2).

Figure 1-2. Total Solar Capacity under the SunShot and Reference Scenarios



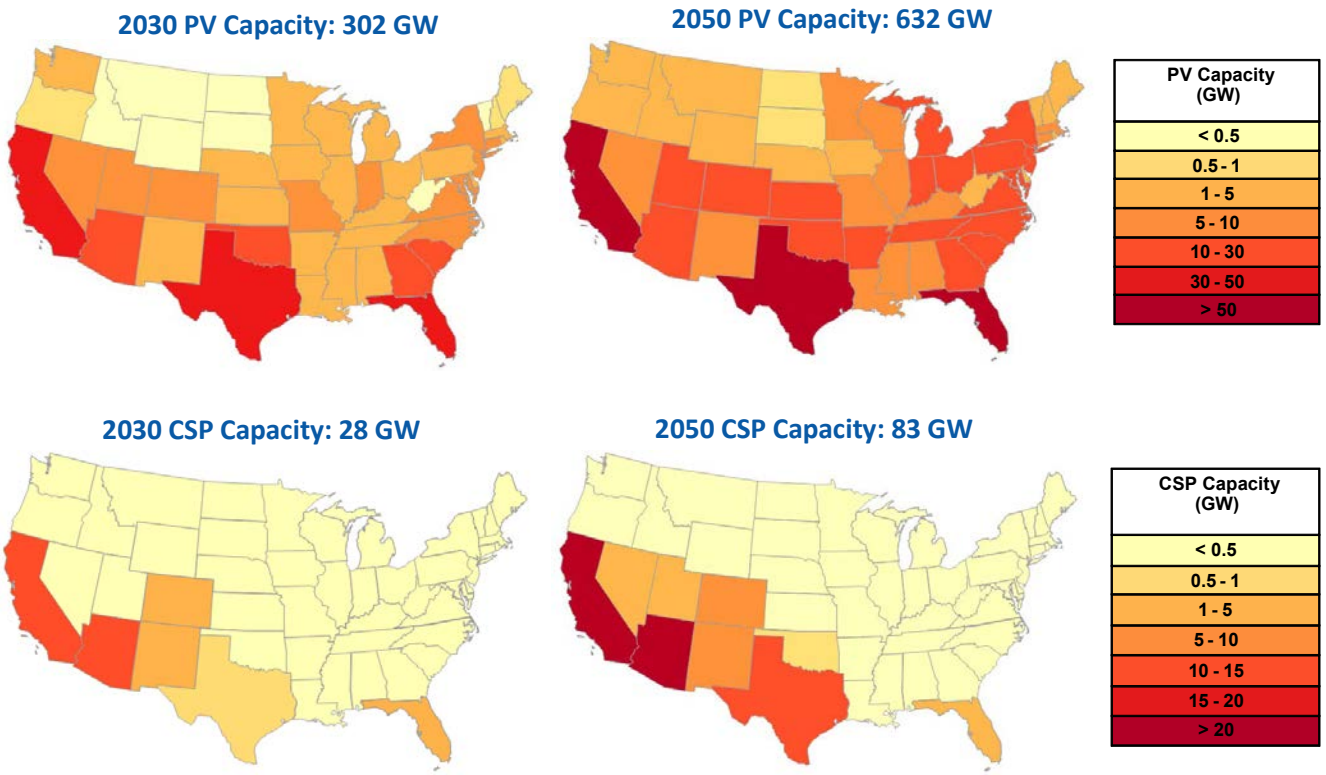
By 2030, the SunShot scenario levels of installations translate into PV generating 505 TWh of electricity, or 11% of total electricity demand, and CSP generating 137 TWh, or 3% of total demand. By 2050, PV is projected to generate 1,036 TWh, or 19% of total demand, and CSP is projected to generate 412 TWh, or 8% of total demand. Table 1-2 summarizes the electricity generation and installed capacity of PV and CSP in 2030 and 2050.

Table 1-2. Overview of SunShot Scenario Results

Year	Technology	Electricity Generation (TWh)	Installed Capacity (GW)
2030	PV	505	302
	CSP	137	28
2050	PV	1,036	632
	CSP	412	83

Figure 1-3 shows the geographical deployment of PV and CSP under the SunShot scenario in 2030 and 2050. Strong PV markets develop in all U.S. states, while CSP is primarily deployed in the arid Southwest, where direct-normal irradiance (DNI)—the intense sunlight needed for CSP—is highest. The SunShot scenario results shown in Figure 1-2 and Figure 1-3 present a case in which solar plays an increasingly important role in the U.S. electricity-generation system. Some sensitivity analyses are also discussed in the accompanying text box and Appendix C. Additional sensitivity analysis will be published in supplementary technical reports.

Figure 1-3. Cumulative Installed PV and CSP Capacity in the SunShot Scenario in 2030 and 2050



1.4.3 Differences between PV and CSP Deployment and Electricity Production

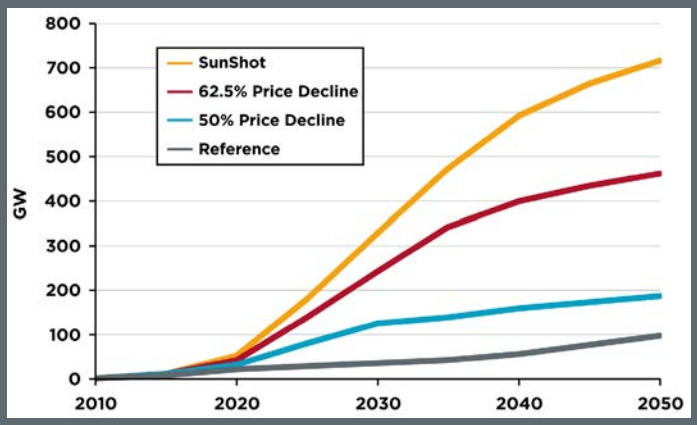
In the SunShot scenario, approximately 11 times more PV capacity than CSP capacity would be installed by 2030, and 8 times more by 2050. However, the amount of electricity produced by PV is only 4 times greater than the amount of electricity produced by CSP in 2030 and only 3 times greater in 2050. CSP produces more electrical energy per unit of capacity because, on average, CSP is deployed where solar resources are higher, CSP systems always use solar tracking, and CSP resources are deployed with several hours of thermal storage capacity which significantly increases the capacity factor of a CSP plant. The collector area for a CSP system can be expanded significantly to collect solar energy in excess of the peak load requirements of the power generator (also called the power block) and storing it as thermal energy, which can be used to generate electricity during non-sunny times of the day or into the evening and nighttime. In contrast, the peak power for PV is determined by the size, efficiency, and location of the collector area, and the capacity factor is determined by the local solar resource and the ability to track the sun.

The higher deployment of PV compared with CSP occurs for several reasons that are related to the cost and value of electricity produced by each of the technologies. First, the price per unit of capacity is lower for PV ($1.00–$1.50/W) than for CSP ($3.60/W); thus, much more PV capacity than CSP capacity can be installed for a given amount of investment. This factor is particularly important through 2030,

Sensitivity of SunShot Scenario Results to Renewable Target and Price Assumptions

Sensitivity analyses indicate that there is a solar price threshold at which solar deployment increases non-linearly as price decreases. As shown in Figure A, in order to explore the sensitivity of solar deployment to solar technology prices, solar deployment was modeled using two price scenarios, in addition to the SunShot and reference scenarios. These two scenarios included cost reductions that were less aggressive than the SunShot targets: 1) Photovoltaic (PV) prices decline by 50% between 2010 and 2020, and 2) PV prices decline 62.5% between 2010 and 2020. Both sensitivity cases included comparable price declines for CSP. Additional sensitivity analyses indicate that assuming larger price reductions for non-solar renewable technologies in the SunShot scenario would result in higher penetration of those technologies, particularly wind. For details see Appendix C.

Figure A. Solar Capacity under a Range of SunShot Solar Price-Reduction Scenarios



when solar is at relatively low levels of market penetration. Under these conditions, peak PV electricity generation coincides with the hours of peak electricity demand, and peak electricity prices, corresponding to a relatively high PV capacity value. However, after 2030, PV generation begins to saturate the peak electricity-demand window, CSP with energy storage becomes increasingly more valuable to the system, and CSP markets begin to grow more rapidly.

Second, residential and commercial rooftop PV systems generate electricity at the customer's facility, and thus PV competes largely against retail rather than wholesale electricity prices. This enables PV to compete in a broader set of markets with higher electricity prices than CSP.

Third, because CSP must be built in areas with good DNI, CSP deployment is constrained primarily to the Southwest. This constraint also means that new transmission lines may need to be built to carry CSP-generated electricity to demand centers, which slows deployment and adds cost. In contrast, PV can be deployed economically in a wider geographic area, including in close proximity to demand centers, which reduces the expense and time required to develop new transmission infrastructure.

1.5 SunShot Impacts

Achieving the level of solar deployment envisioned in the SunShot scenario could affect the U.S. electricity system in a number of areas: the mix of electricity-generating resources, fossil-fuel use, electricity distribution and transmission, electricity costs, environmental impacts, and employment. These areas are discussed briefly below and in detail in the body of this report.

1.5.1 Electricity Generation and Fossil-Fuel Use

The SunShot scenario results in a reduction in the need for new conventional generation capacity and the use of fossil fuels—primarily natural gas and coal. Figure 1-4 shows the evolution of the electric sector in the SunShot and reference scenarios. Before 2030, solar generation primarily offsets natural gas generation in the SunShot scenario. This is because midday solar generation corresponds well with times of peak midday electricity demand, and solar electricity frequently offsets more expensive peaking generation resources, like natural gas combustion turbines (CTs). However, once a large amount of solar generation has been added to the system (14% of demand by 2030), the "net load" of the system, defined as electricity demand minus solar and wind generation, shifts from midday to evening. Once this happens, solar generation offsets the new buildout of coal capacity seen in the reference scenario, and solar begins to significantly offset coal use after 2030. Additional natural gas resources are developed after 2030 to satisfy the evening peak in net load, and CSP resources are deployed with several hours of storage providing a dispatchable solar generation resource.

Figure 1-4. Evolution of Electricity Generation in the Reference and SunShot Scenarios

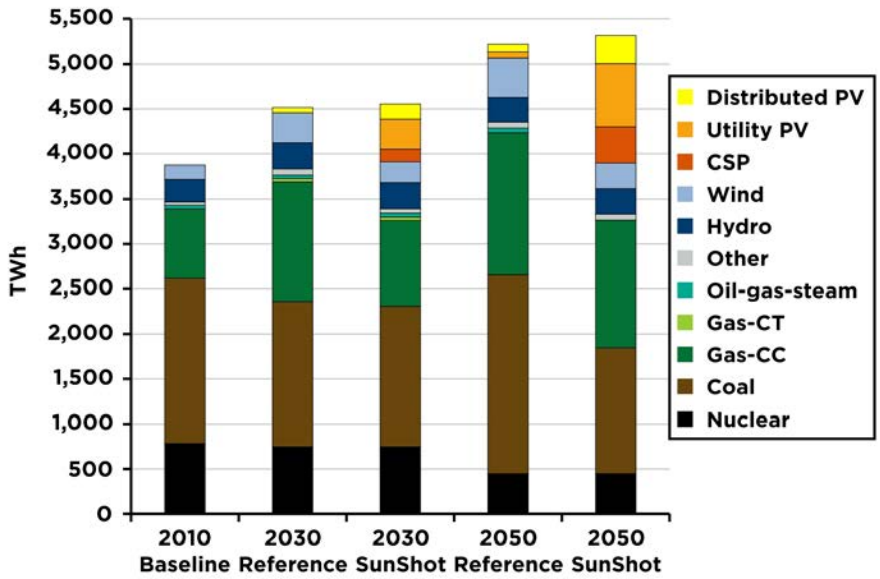
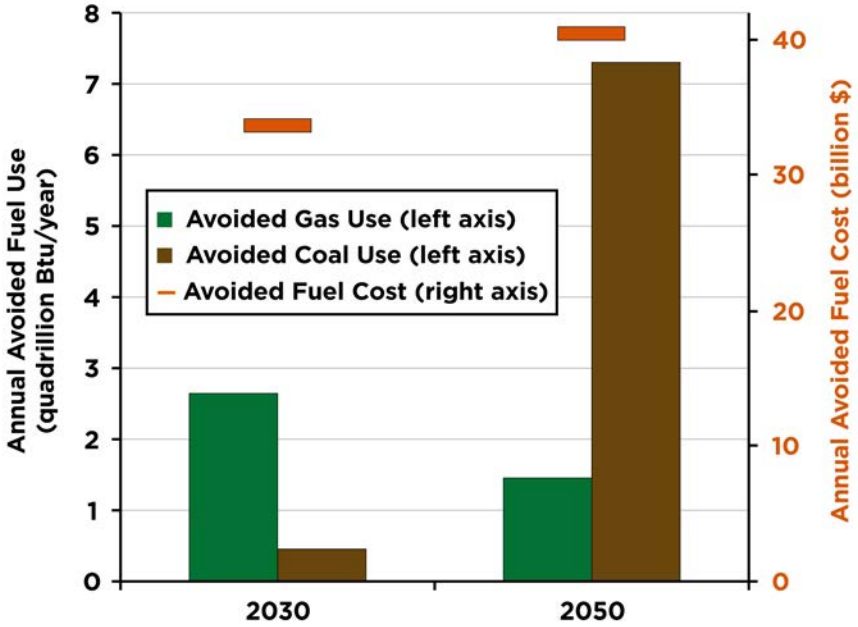


Figure 1-5 shows the avoided fuel use in the SunShot scenario relative to the reference scenario. In the SunShot scenario, solar displaces about 2.6 Quads of natural gas and 0.4 Quads of coal per year by 2030. Based on projected fuel prices from *AEO 2010*, as adjusted in ReEDS based on demand fluctuations, this represents

Figure 1-5. Avoided Fuel Use in the SunShot Scenarios



projected annual fuel-cost savings of about $34 billion per year by 2030. In 2050, the projected annual savings are 1.5 Quads of natural gas and 7.3 Quads of coal, which results in about $41 billion in fuel-cost savings per year.

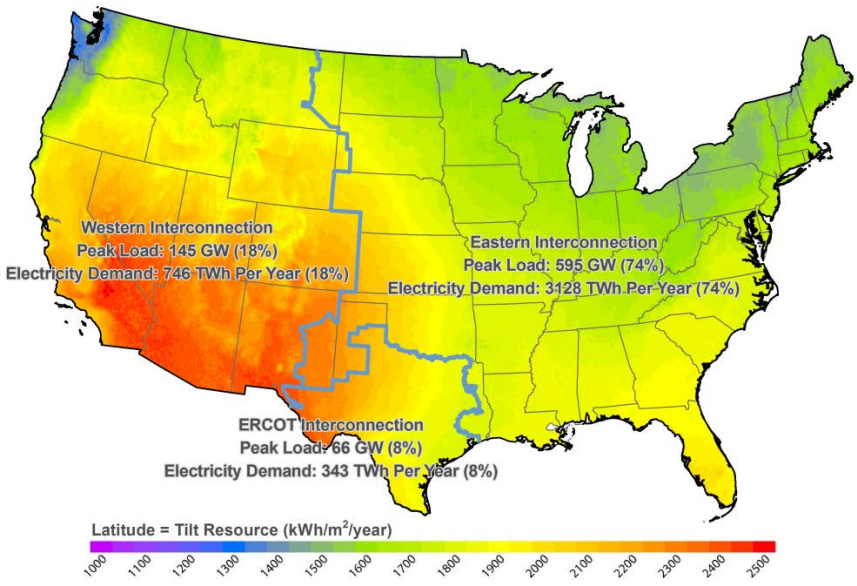
1.5.2 Electricity Transmission

Solar resources are not distributed evenly across the United States. For example, a 1-axis tracking PV module installed near Los Angeles will generate about 23% more electricity than the same module installed near New York City.[8] Although there is significant generation potential at the distributed level, in many cases, the best solar resources are located far from regions with high-electricity demand. The same is true for wind resources. In the reference scenario, transmission is expanded primarily to meet growing electricity demand by developing new conventional and wind resources. In the SunShot scenario, transmission is expanded at a similar level, but in different locations, in order to develop solar resources.

The electricity grid in the continental United States is comprised of three interconnections: the Western Interconnection; the Eastern Interconnection; and the Electric Reliability Council of Texas (ERCOT) Interconnection, sometimes also referred to as the Texas Interconnection. Figure 1-6 shows the U.S. solar energy resource for a south-facing PV system tilted at latitude, along with peak and annual electricity demand for each interconnection. In the United States, the Western Interconnection represents about 18% of peak load, the ERCOT Interconnection represents 8%, and the Eastern Interconnection represents 74%. Achieving the SunShot scenario leads to higher relative solar deployment levels in the Western and ERCOT Interconnections than in the Eastern Interconnection, particularly for CSP.

[8] PV generation profiles were calculated using version 2001.8.30 of the System Advisor Model (SAM) www.nrel.gov/analysis/sam. Accessed September 2011.

Figure 1-6. Global Horizontal Solar Resource (South Facing, Tilted at Latitude with Electricity Use Statistics by Interconnection

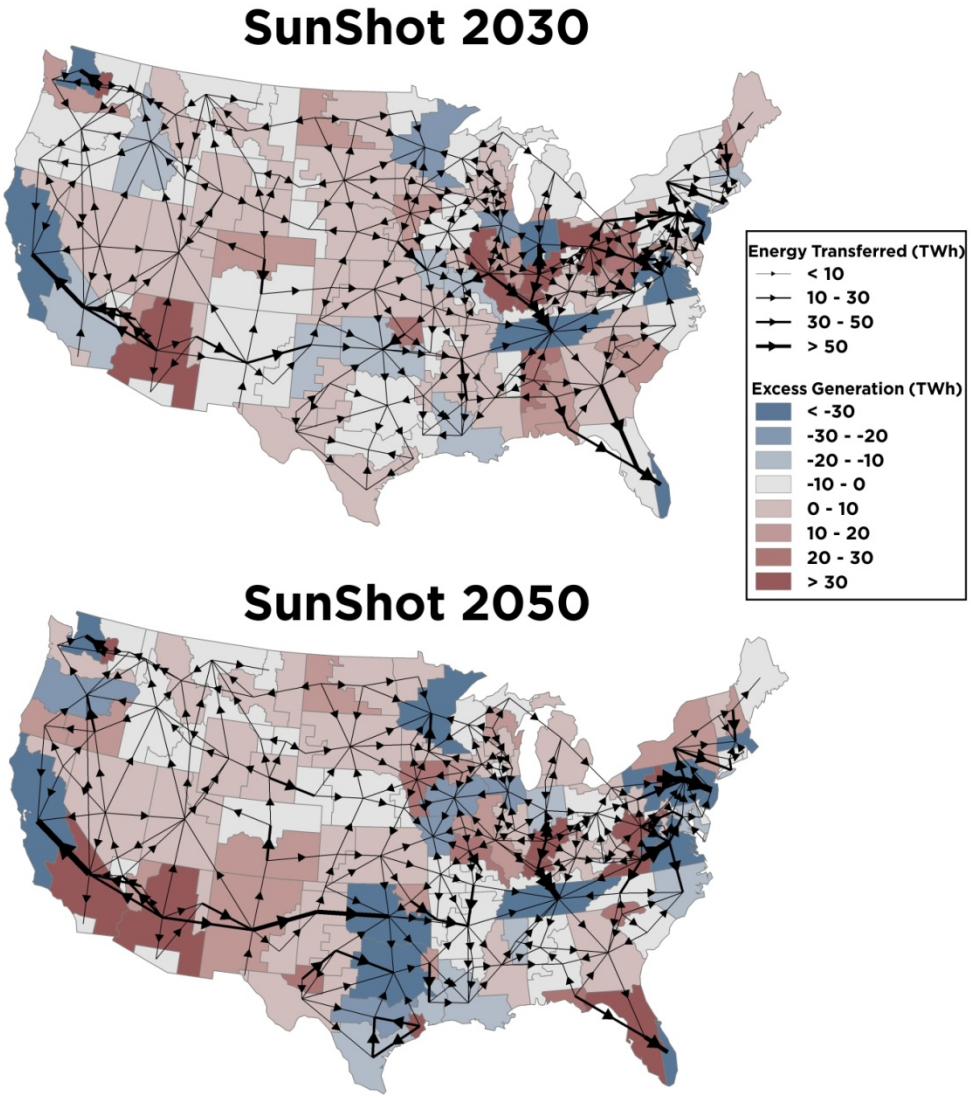


Source: NREL

Modeled transmission capacity is summarized using units measured in gigawatt-miles (GW-mi), i.e., miles of transmission lines multiplied by the capacity of the lines in gigawatts. In the reference scenario, transmission capacity is projected to increase from about 88,000 GW-mi in 2010 to 102,000 GW-mi in 2030 and 110,000 GW-mi in 2050, a 15% and 25% increase, respectively. In the SunShot scenario, transmission capacity is expected to increase to 100,000 GW-mi in 2030 and 117,000 GW-mi in 2050, a 13% and 32% increase, respectively. In other words, the SunShot scenario requires slightly less additional transmission capacity than the reference scenario through 2030, because a significant amount of utility-scale PV capacity is developed near load centers and near existing underutilized transmission lines. However, the SunShot scenario requires more additional transmission capacity than the reference scenario by 2050, primarily to connect remote CSP resources to load centers. The projected cost of expanding transmission in both the SunShot and reference scenarios through 2050 is about the same, roughly $60 billion dollars. This level of investment, which would be spread out over 40 years, represents about 2% of the total electric-sector costs under the SunShot scenario, and is well within the historical range of annual transmission investments by investor-owned utilities during the past few decades.

Figure 1-7 illustrates the patterns of electricity supply and demand in 2050 by showing the different regions in terms of excess generation—power generated that cannot be used locally and needs to be exported to other regions. Regions that generate more electricity (from all sources) than local demand are shown in shades of red, and importing regions are shown in shades of blue. Regions with significant CSP and wind deployment are frequently export regions. This trend is particularly strong in the Southwest for CSP and the Northern Plains for wind.

Figure 1-7. Mean Transmitted Energy for the SunShot Scenario, with Net Exporting (Red) and Importing (Blue) Regions and Interregional Energy Transmission (Arrows)

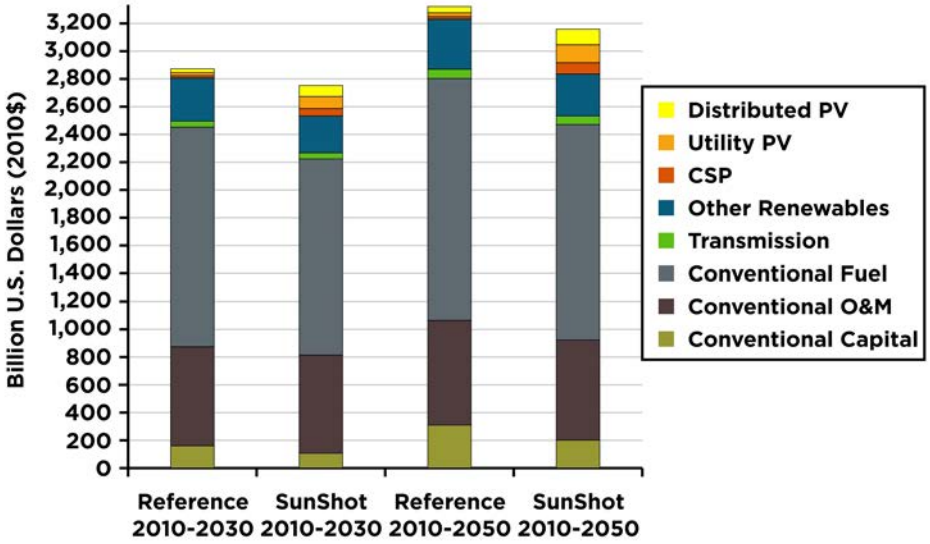


1.5.3 Cost

The cost of achieving the SunShot scenario presents a trade-off between investments in up-front capital for solar generation capacity and reduced annual expenditures on fossil fuels and operations costs for thermal generation capacity. Figure 1-8 shows the present value of the total direct electric-sector investment for the SunShot and reference scenarios. These costs include the capital investment in renewable and conventional capacity additions, transmission expansion, fuel, and operation and maintenance (O&M). The costs from expanding generation and transmission capacity are accounted for through the estimate year, i.e., 2030 or 2050; however, to capture the value of adding renewable generation capacity through a given year, the value of the

Achieving the SunShot targets could result in a significant reduction in the cost of electricity, enabling consumers across all market sectors to save about $30 billion annually by 2030 and $50 billion annually by 2050.

Figure 1-8. Direct Electric-Sector Costs for the Reference and SunShot Scenarios



installed capacity's output, plus fuel and O&M costs for running the system for an additional 20 years, are also included in the cost calculation. The capacity-addition costs include the cost of distributed rooftop PV installations, but do not include potential impacts on electricity-distribution costs.

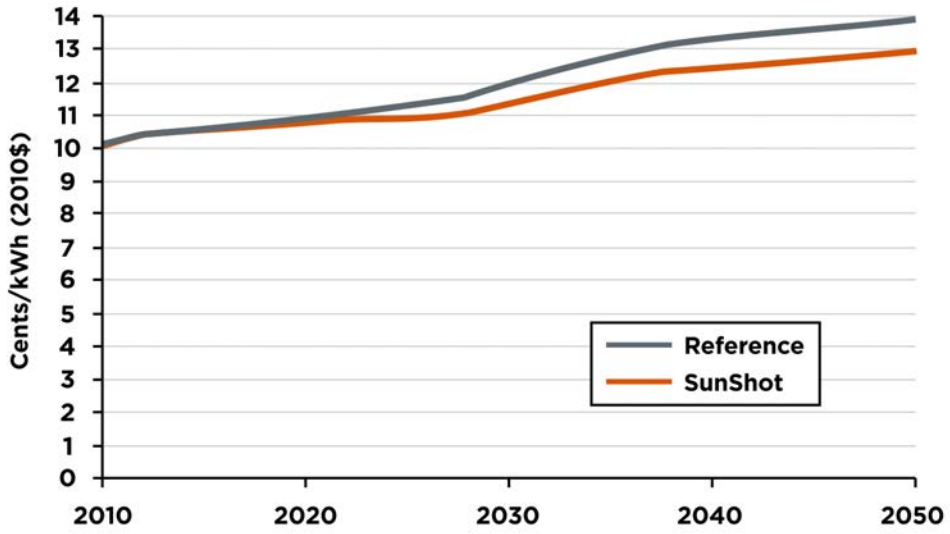
Figure 1-8 shows that the discounted cost of the SunShot scenario is projected to be about 4% below the cost of the reference scenario in 2030 and about 5% below the cost of the reference scenario in 2050. Transmission costs are similar in the SunShot and reference scenarios and are significantly less than generation capacity investments.

The impact of achieving the SunShot scenario on the cost of retail electricity is projected to be significant (Figure 1-9). By 2030, the average retail electricity price is about 0.6 cents/kWh less than the price in the reference scenario, saving an average household about $6 per month. By 2050, the electricity price is about 0.9 cents/kWh less than in the reference scenario, or about $9 lower per month, per household. Across all market sectors, the lower electricity prices in the SunShot scenario translate into about $30 billion in annual cost savings by 2030 and $50 billion in annual savings by 2050.

1.5.4 Environment

All energy-generating technologies, including solar technologies, affect the environment in many ways. However, the potential for solar technologies to reduce the environmental impacts of energy generation compared with other generating technologies is among the most important reasons for widespread solar use. Significant reductions in U.S. GHG emissions are calculated under the SunShot scenario. As shown in Figure 1-10, total annual electric-sector CO_2 emissions in 2030 are 8% lower in the SunShot scenario than in the reference scenario. Annual electric-sector emissions in 2050 are 28% lower in the SunShot scenario than in the reference scenario. Relative to the reference scenario, the SunShot scenario results in

Figure 1-9. Average U.S. Retail Electricity Rates under the SunShot and Reference Scenarios



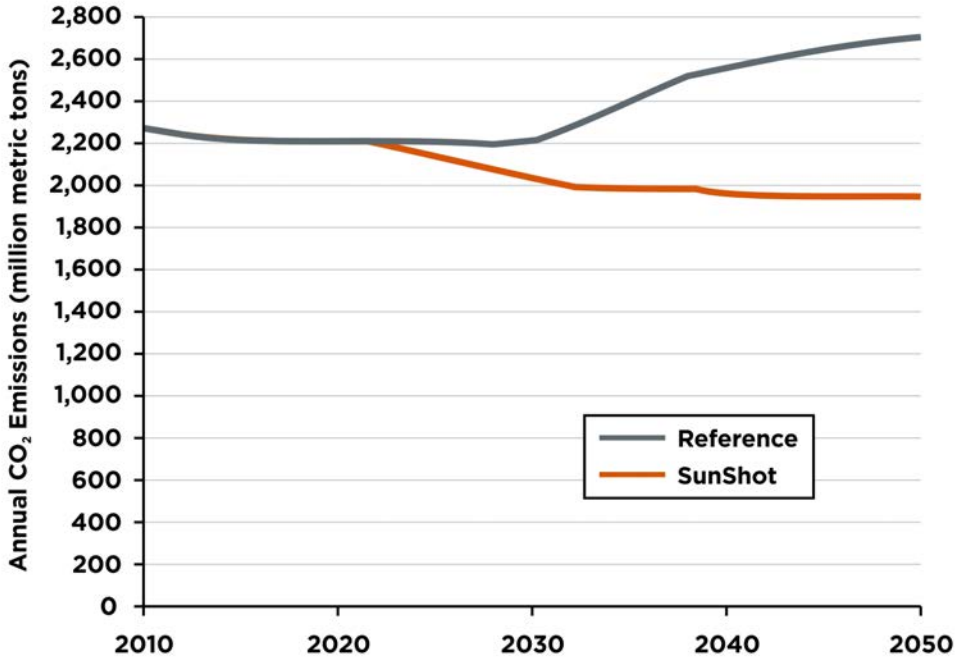
annual reductions of 181 and 760 million metric tons (MMT) of CO_2 by 2030 and 2050, respectively. This is equivalent to the annual emissions from 30 and 130 million cars. The SunShot scenario also results in emissions reductions of other potentially harmful pollutants such as mercury, nitrogen oxides, sulfur oxides, and particulate matter.

The water impacts of the SunShot scenario depend largely on the type of CSP technology deployed. PV requires very little water for washing panels occasionally depending on local climate conditions, and thus, by displacing fossil-fuel generation, it reduces water consumption from electricity generation significantly. In contrast, if CSP is deployed with wet cooling, its water consumption can be comparable to the water consumption of several conventional generation technologies that use evaporative cooling systems (i.e., cooling towers). Wet-cooled tower and trough CSP plants consume about 750–1,020 gallons/Megawatt-hour (MWh), which is slightly more than the levels of water consumed in pulverized coal plants (425–784 gallons/MWh), and similar to the levels consumed in pulverized coal plants with CO_2 capture (855–1,024 gallons/MWh) and nuclear plants (655–1,030 gallons/MWh).[9] Given the limits of water availability in the Southwest, however, it is likely that CSP will be deployed with significant amounts of dry or hybrid cooling, which can reduce water use by 40%–97%, compared with wet cooling, and have a relatively small impact on overall system performance. For the purposes of modeling CSP in the SunShot scenario, CSP cost and performance characteristics assumed dry cooling.

The primary potential ecological impacts of solar energy technologies relate to land used for utility-scale PV and CSP. In 2030, about 370,000–1,100,000 hectares (ha)

[9] Details on this data are provided in Table 7-3. Citations are provided below:
CSP: Cohen et al. (1999) and Viebahn et al. (2008);
Pulverized coal: DOE (2006), NETL (2010), and NETL (2007);
Pulverized coal with CO_2 capture: DOE (2006) and NETL (2010);
Nuclear: DOE (2006), NETL (2010), and NETL (2007).

Figure 1-10. Annual Electric-Sector CO_2 Emissions under the SunShot and Reference Scenarios



of land—equivalent to 900,000–2,700,000 acres or 0.05%–0.14% of the contiguous U.S. land area—could be required under the SunShot scenario. In 2050, about 860,000–2,500,000 ha—equivalent to 2,100,000–6,300,000 acres or 0.11%–0.33% of the contiguous U.S. land area could be required. Most of this would be in the South and Southwest. The specific ecological and other land-use impacts of solar energy technologies, for example, on local wildlife, will vary from region to region and will depend on policies implemented and approaches adopted to reduce the impacts.

Proper waste management and recycling are important parts of achieving the environmental benefits of the SunShot scenario. Current production, recycling, and disposal techniques have demonstrated the ability to minimize the introduction of hazardous materials into waste streams and avoid unintended consequences that would reduce the environmental benefits of large-scale solar deployment.

1.5.5 Employment

The overall U.S. solar workforce is expected to increase from about 51,000 in 2010 to about 340,000 in 2030 and 440,000 in 2050.

In estimating the potential workforce needed for meeting the SunShot scenario solar deployment levels, 2010 solar labor intensities were estimated using recent market analyses (McCrone et al. 2009, Solar Foundation 2010). The 2010 labor intensities represent current solar market dynamics, and labor intensities are likely to decrease with decreasing solar prices in the SunShot scenario, and as solar markets mature and become more efficient. The projected reductions in PV and CSP labor intensities in the SunShot scenario reflect that as costs per megawatt decline, the number of jobs per megawatt will also decline, i.e., labor productivity is assumed to increase in proportion to

overall system-cost reductions. However, total solar jobs at any point in time are a product of labor intensity and installations. Using this approach, the overall U.S. solar (PV and CSP) workforce is expected to increase from about 51,000 in 2010 to about 340,000 in 2030 and to about 440,000 in 2050. This could support about 290,000 new solar jobs by 2030, and 390,000 new solar jobs by 2050.

In the PV-manufacturing environment, labor is readily transferable from other manufacturing industries. Similarly, PV power plant and utility-scale distributed development is likely to draw from the same skilled engineering and construction labor pool as traditional fossil-fuel power plant development. Distributed PV for rooftop projects can use much of the same labor pool as the residential and commercial construction industries, although additional training and certification is required. Additional jobs supported in the PV industry will include accountants, salespeople, engineers, computer analysts, factory workers, truck drivers, mechanics, and so forth. The U.S. PV workforce is expected to grow, in terms of gross jobs, from about 46,000 in 2010 to 280,000 in 2030 and to 363,000 in 2050. These estimates include direct and indirect jobs throughout the PV supply chain, with about 89% and 83% designated under manufacturing and installation in 2030 and 2050, and the remainder in O&M.

CSP power plant development is also likely to draw from the same skilled engineering and construction labor pool as traditional fossil-fuel power plant development. The workforce will include laborers, craftsmen, supervisory personnel, support personnel, and construction management personnel. The U.S. CSP workforce is expected to grow, in gross jobs, from about 4,500 in 2010 to 63,000 in 2030 and to 81,000 in 2050. These estimates include direct and indirect jobs throughout the CSP supply chain, with about 85% and 66% designated under manufacturing and installation in 2030 and 2050, and the remainder in O&M.

1.6 REALIZING THE SUNSHOT VISION

Several conditions would need to be met to achieve the SunShot Initiative's price reduction targets and to enable the projected large-scale deployment of solar technologies envisioned in the SunShot scenario. The performance of solar technologies would need to be improved significantly, with a corresponding decrease in the cost of solar energy. An adequate supply of raw materials and manufacturing capabilities would need to be available. Numerous solar installations would need to be sited and integrated with the electricity grid. New financing vehicles that encourage solar growth would need to be implemented, especially in the 2010–2020 time frame before solar prices reach the SunShot targets.

Meeting these conditions poses many challenges. However, vast new raw materials supplies, unprecedented manufacturing scale-up, or radical financing and policy approaches will not be required. The challenges to meeting the SunShot Initiative's price reduction targets and the level of solar deployment envisioned in the SunShot scenario, and potential strategies for addressing these challenges, are discussed briefly below and in detail throughout the body of this report.

1.6.1 Technology Improvements and Cost Reductions

To realize the SunShot targets, continued solar cost reductions and performance improvements are required. Many solar technologies have been demonstrated commercially since the 1970s or 1980s and have a strong record of cost reductions and performance improvements resulting from R&D investments, manufacturing scale-up, and accumulated experience. The technological progress envisioned in this study is significant, requiring a combination of evolutionary and revolutionary technology improvements.

Chapter 4 provides a detailed bottom-up engineering analysis of the opportunities for continued PV cost reductions and compares these cost reductions with historical trends. Key challenges to achieving the levels of PV penetration in the SunShot scenario are evaluated, including manufacturing scale-up and the supply of feedstock materials. To meet the SunShot targets, the total price of PV (and the corresponding LCOE) would need to be reduced by roughly 75% by 2020. This would make residential PV broadly competitive with retail electricity rates, commercial PV broadly competitive with commercial retail electricity rates, and utility-scale PV broadly competitive with utility wholesale electricity rates by 2020. These price reductions would result from a combination of R&D advances, more efficient manufacturing methods, reduced supply chain inefficiencies, and benefits from economies of scale as markets continue to grow and mature.

Chapter 5 provides a similar analysis for CSP technologies, including parabolic trough, linear Fresnel, power tower, and dish/engine technologies. Costs are discussed for all of these technologies; however, the analysis focuses primarily on trough and tower technologies. The potential role of integrating thermal energy storage and/or fossil-fuel hybridization into CSP plant designs as well as a range of component-specific advances are also examined. To meet the SunShot targets, continued R&D and learning-associated improvements would need to reduce the total price of CSP (and the corresponding LCOE) by roughly 70% by 2020. This would make utility-scale CSP broadly competitive with utility wholesale electricity rates by 2020. In particular, adding thermal energy storage or hybridization to CSP plants enables them to serve as dispatchable resources and thus to be more easily integrated into the electricity grid. The dispatchability of CSP also enables it to play a key role in helping to integrate other variable renewable energy technologies—e.g., PV and wind—as discussed in Chapter 6.

1.6.2 Raw Materials

PV technologies use a number of materials that could be subject to shortages at the increased production levels required by the SunShot scenario, including tellurium, indium, selenium, gallium, germanium, ruthenium, copper, silver, and molybdenum. The biggest concerns are tellurium and indium for use in PV. As discussed in Chapter 4, to avoid potential material shortages for any of the PV technologies, one or more of the following strategies could be pursued:

- Increase efficiency (less material per delivered watt)
- Reduce material use through thinner layers
- Improve process utilization and in-process recycling

- Increase ore extraction and refining
- Shift to using materials that are more abundant.

The most important raw materials for CSP, as discussed in Chapter 5, are aluminum, steel, glass, heat-transfer fluid, and molten salt. In general, these materials are not subject to rigid supply limits, but they are affected by changes in commodity prices.

1.6.3 Manufacturing Scale-Up

Substantial increases in the manufacturing capacity of PV and CSP components and systems will be required to achieve the SunShot scenario, especially because the rest of the world will likely be scaling up its solar capacity at the same time. However, domestically and globally, these solar industries have demonstrated an ability to scale-up production volumes rapidly and realize associated cost reductions, particularly over the past decade.

The PV industry is expanding its manufacturing capacity, helped by new market entrants bringing capital as well as technology, manufacturing, and supply chain management experience, often from other successful industries—e.g., computer semiconductor, liquid crystal display, and specialized material industries. Manufacturing scale-up should not limit the PV deployment envisioned in the SunShot scenario.

Manufacturing of many CSP components can draw on the existing capabilities of other industries, such as fossil-fuel boiler manufacturers to produce steam or molten salt receivers and the automotive industry to produce CSP engines. Components unique to CSP systems are made of common materials and are relatively simple in design. Manufacturing scale-up should not present a barrier to achieving the SunShot scenario.

1.6.4 Grid Integration

The variability and uncertainty associated with PV and, to a lesser extent CSP, adds challenges to the operation of the U.S. electricity transmission and distribution systems. To verify that the electricity system can be operated under the SunShot scenario, GridView, a production cost/power flow model made by engineering company ABB, was used to evaluate the ReEDS model's projected capacity mix and identify operational challenges. In particular, ReEDS and GridView were compared with regard to how they dispatch generation resources, transmit and curtail electricity, and analyze electric-sector fuel use and emissions.

A number of conclusions can be drawn from this analysis and from previous wind and solar integration studies. Although the GridView modeling confirmed the basic operational feasibility of the SunShot scenario, meeting both load and reserve requirements during all hours of the year, it also demonstrated the same challenges shown in previous studies of large-scale wind deployment. These include greatly increased rates and ranges over which the generation fleet must ramp, uncertainty in net load, and potential curtailment of variable generation during low-load periods in the spring. As discussed in Chapter 6, a number of strategies can be pursued to increase the ability to integrate variable and uncertain energy resources:

- Increasing the flexibility from conventional generation
- Sharing of energy supply, demand, and reserves over larger areas
- Incorporating thermal storage or hybridization into CSP systems
- Increasing operating reserves
- Incorporating forecasting into operations (including operation of distributed PV) and scheduling conventional units over short periods
- Employing load/demand-side management or storage technologies to increase system flexibility.

Many of these strategies may guide energy market development to integrate solar in the most cost-effective manner. In general, lower cost and easier integration will result from markets that are more flexible, larger, and more diverse.

Increased reliance on load-sited and distributed resources can present both additional challenges and potential benefits to managing the electricity-distribution system. New standards are needed to maintain system reliability and safety, and modifications to PV inverter and distribution equipment may be needed. In addressing many of these challenges, there may also be ways to leverage emerging "smart grid" technologies to enable market participation of customer-sited generation and loads to maximize grid efficiency.

1.6.5 SITING

As discussed in Chapter 7, there would be challenges to siting the SunShot scenario's large and numerous solar installations. One set of challenges applies to utility-scale solar technologies and another to distributed solar technologies.

More than enough suitable land is available to enable the SunShot scenario's utility-scale solar deployment and required transmission expansion. However, it will be important to make careful selection of sites to minimize conflicts with environmental, cultural, and aesthetic interests—particularly with respect to public lands. Even with the most careful land selection, the utility-scale solar development and related transmission expansion will have environmental impacts, especially on portions of the southern United States. These potential impacts—and ways to reduce them—are being studied by various stakeholders. Approaches include identifying solar energy study areas and renewable energy zones that can accommodate solar development with minimal environmental conflicts as well as promoting the use of land already damaged by contamination, mining, and other uses. The regulatory framework for siting utility-scale solar projects and associated transmission infrastructure is complex, costly, and time consuming. Streamlining this process, such as, with clear and consistent criteria that leverage the cooperation of federal, state, and regional authorities, would help to enable the rapid levels of development envisioned in the SunShot scenario.

Distributed rooftop solar technologies do not require the use of undeveloped land, but have a unique set of siting challenges. More than enough potential distributed sites are available to achieve the SunShot scenario deployment. Even after accounting for limiting factors such as shading, and orientation, U.S. rooftops alone

could accommodate more than 600 GW of PV capacity, and additional opportunities exist on sites such as parking structures, awnings, and airports (Denholm and Margolis 2008). Most of the siting challenges distributed PV faces relate to its installation on structures, including complex and variable codes and permits, zoning ordinances, and restrictive covenants. Again, to enable rapid levels of deployment in the SunShot scenario, it would help to streamline and unify distributed solar siting requirements and processes and establish strong solar access and rights laws to protect the rights of consumers to install solar energy systems.

1.6.6 Financing

Financing the scale of expansion in the SunShot scenario would require significant new investments in the solar manufacturing supply chain and in solar energy projects. Attracting adequate investment to the solar supply chain—such as manufacturing facilities for PV modules and CSP mirrors—should be relatively straightforward because many of the mechanisms for doing so are already well developed and liquid. Financing SunShot scenario-scale solar project deployment—the widespread construction of distributed and central solar electricity-generating plants—is a greater challenge, with different considerations in the pre-2020 and post-2020 periods.

As discussed in Chapter 8, building out U.S. PV and CSP manufacturing capacity to meet the level of installations envisioned in the SunShot scenario would require cumulative investments of roughly $25 billion through 2030 and $44 billion through 2050. Although these levels of cumulative investments are not trivial, on an annual basis the required investments would be on the order of $1–$3 billion, well below private sector investments in solar in the United States during the past couple of years. Moreover, the necessary financing instruments and structures are well developed and well understood in the capital markets.

Financing solar project deployment under the SunShot scenario, however, will cost much more than financing the supply chain—on the order of $40–$50 billion per year between 2030 and 2050. On a cumulative basis, this translates into roughly $250 billion through 2030 and $375 billion through 2050. To put these numbers into context, it is important to compare them to the total capital required to build all types of electric-generating equipment—conventional and renewable. The difference in total capital required between the SunShot and reference scenarios through 2050 is less than 1%. Thus, it is not so much the total level of investment in electricity generation that needs to change in the SunShot scenario, but the pattern of investment.

Securing adequate financing for solar project deployment will be particularly challenging during the pre-2020 period, before solar electricity is cost competitive with other electricity sources. In 2020 and beyond, the availability of cost-competitive solar energy should stimulate private solar investment and facilitate use of mainstream financial instruments.

1.7 CONCLUSION

Achieving the SunShot Initiative's price reduction targets could enable solar energy to become competitive with other electricity-generation technologies by 2020 and could result in large-scale solar energy deployment through 2030–2050. Private capital would need to be invested to scale up the manufacturing and installation of solar energy technologies. Public investment in R&D and market transformation would be required to enable low-cost, rapid solar growth. The U.S. electrical transmission and distribution systems would need to be optimized to enable rapid solar growth. With these challenges addressed, the potential benefits of the SunShot Initiative—reduced fossil fuel use, lower GHG and other pollutant emissions, and solar job growth—could be realized along with a significant reduction in the projected average retail price of electricity. In short, realizing the price reduction targets of the SunShot Initiative would enable the nation to accelerate its evolution towards a cleaner, more cost-effective, and more secure energy system.

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2. Solar Energy Market Evolution and Technical Potential

This chapter provides context for the SunShot scenario by reviewing the evolution of global and U.S. markets for photovoltaics (PV) and concentrating solar power (CSP). It also examines the maximum potential of U.S. solar markets as determined by the potential of solar technologies to convert available sunlight into electricity and thermal energy.

The global PV market has accelerated over the past decade, with PV shipments averaging 53% annual growth and reaching 17 gigawatts (GW) in 2010, bringing cumulative shipments to about 40 GW. In 2010, the United States accounted for 8% or about 1,400 megawatts (MW) of PV market demand and 6% or about 1,000 MW of supply. The technical potential of the U.S. PV market is large. In fact, one estimate of the land area required to supply all end-use electricity in the United States using PV is only about 0.6% of the country's total land area or about 22% of the "urban area" footprint (Denholm and Margolis 2008a).[10]

The technical potential for CSP is also large. After implementing filters that account for insolation, slope, and land-use restrictions, the technical potential of the U.S. CSP market is about 7,500 GW of potential generating capacity—several times higher than the entire U.S. electric grid's capacity—in seven southwestern states (Turchi 2009). However, CSP market growth has been historically sporadic. After CSP plants were built in California in the late 1980s, almost 15 years passed before the next commercial CSP plant was built, followed by a surge of new plants in the United States and Spain during 2007–2010. At the end of 2010, global CSP capacity was about 1,300 MW, with about 39% in the United States and 57% in Spain; parabolic trough technology accounted for about 96% of the global total and tower technology for 3%.

2.1 Evolution of U.S. Solar Markets

This section discusses market evolution for PV and CSP, including changes in global and U.S. supply and demand and the current status of U.S. solar technology manufacturing. Also discussed are the factors affecting solar market evolution and recent solar industry employment statistics. Putting all the information together, a picture emerges of a solar industry that has come a long way over the past few decades, setting the stage for SunShot-scale deployment during the next several decades.

[10] This calculation is based on deployment/land in all 50 states.

2.1.1 PHOTOVOLTAICS

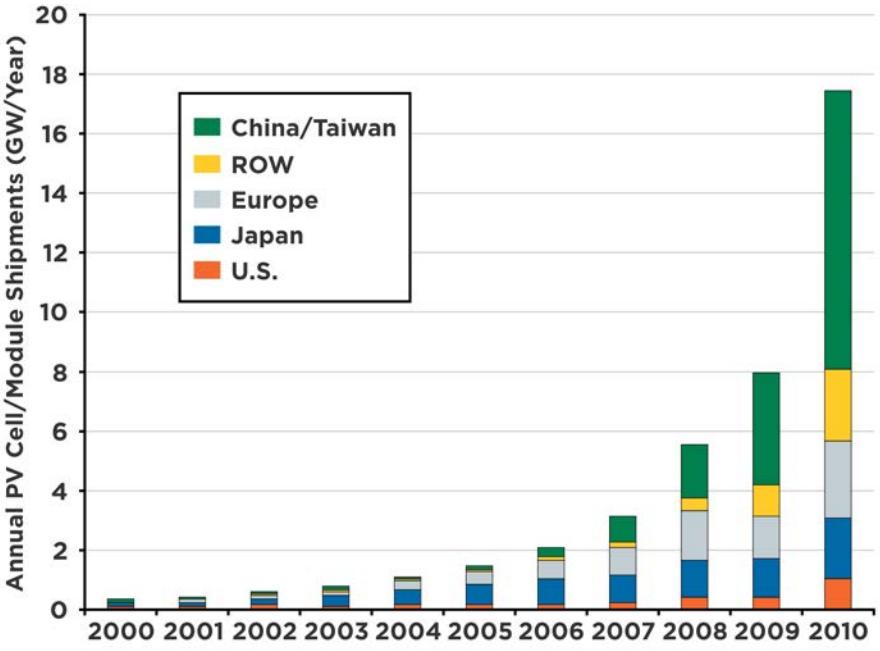
While the global PV market grew rapidly during the past decade, the U.S. market position declined based on more rapid growth in Asia and Europe. During the past couple of years, federal and state policies have helped to drive PV market demand growth and a renewed interest in PV manufacturing in the United States.

Global PV Supply and Demand

Shipments of PV cells and modules by region are a key indicator of market evolution. Shipments attributed to a given region represent PV supplied by that region, as measured at the first point of sale. However, not all shipped cells and modules end up in the market the year they are produced or in the country in which they were first sold.

Figure 2-1 shows the dramatic growth in PV shipments during the past decade: a 53% compound annual growth rate from 2000 through 2010, reaching 17.4 GW in annual shipments in 2010. The United States accounted for 30% of global PV shipments in 2000, but then lost market share over the next decade, first to Japan, then to Germany, and finally to China and Taiwan. In 2010, China and Taiwan accounted for 53% of global PV shipments. The Japanese market surge resulted largely from its residential subsidy program, which began during the mid-1990s. The European surge resulted largely from the German feed-in tariff, which was implemented in 2000, streamlined over the next couple of years, and adopted by a number of other European countries during the past 5 years. During 2006–2010, China and Taiwan invested heavily in PV manufacturing and demonstrated an ability to scale-up production rapidly while reducing manufacturing cost substantially.

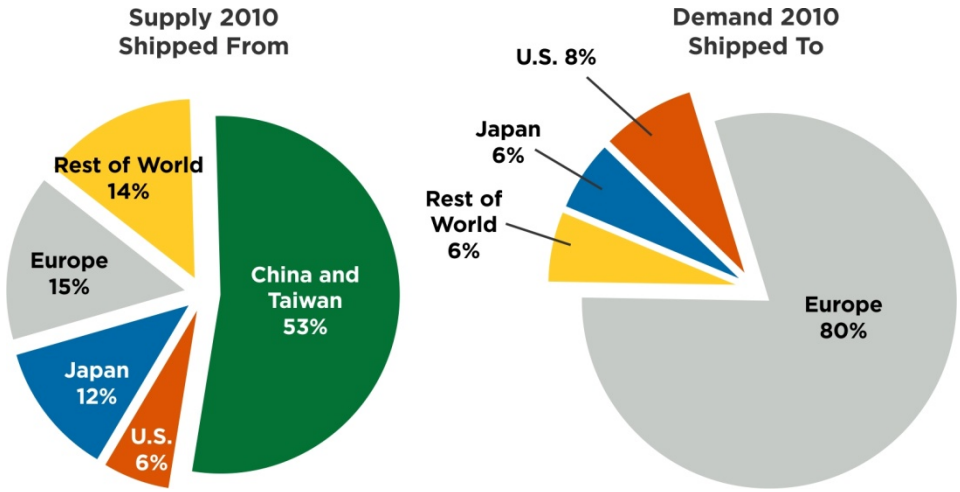
Figure 2-1. Regional PV Cell and Module Shipments, 2000–2010



Source: Mints (2011a)

Figure 2-2, which depicts global PV supply and demand in 2010, clearly shows the dominance of manufacturers in China and Taiwan. The rest of world (ROW) region includes Australia, India, the Philippines, and Malaysia.

Figure 2-2. 2010 Global PV Supply and Demand



Source: Mints (2011a) and Mints (2011b)

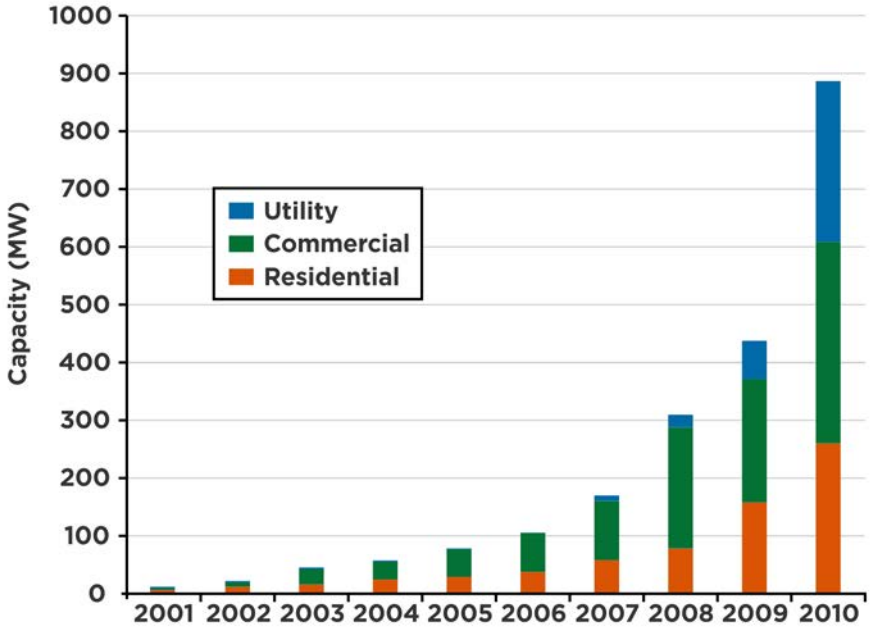
Historically, PV shipments have been dominated by crystalline-silicon technology. In 2003, the market share for crystalline-silicon PV was 95%, compared with 5% for thin-film PV. However, thin-film shipments have grown rapidly in recent years, particularly shipments of cadmium telluride (CdTe) and amorphous silicon (a-Si) technologies. At the same time, newer PV technologies—such as copper indium gallium diselenide (CIGS) and concentrating photovoltaics (CPV)—have been preparing to enter full-scale production. By the end of 2010, thin-film technology accounted for 13% of global PV shipments (3% a-Si, 8% CdTe, and 2% CIGS). The United States was responsible for 18% of global CdTe and 20% of global a-Si shipments in 2010 (Mints 2011a).

U.S. PV Demand

Despite a long history of public and private investments in PV technology, the United States remains a relatively immature PV market. In the 1980s, the U.S. and global PV demand was dominated by off-grid applications, typically very small systems with installed capacities measured in hundreds of watts. During the late 1990s, grid-connected systems—with installed capacities measured initially in kilowatts and later in megawatts—began dominating global demand. As this transition occurred, system cost declined significantly owing to a combination of research and development (R&D) advances as well as economies of scale on the production and installation sides. In the United States, the transition to a market dominated by grid-connected systems occurred slightly later, driven by state and federal incentives.

Figure 2-3 illustrates the annual growth in U.S.-installed grid-connected PV from 2001 to 2010 for residential, commercial, and utility-owned applications.[11] The entire installed PV market has grown substantially over the past decade. The utility market segment made a notable market share increase from 2009–2010, primarily the result of only 34 large (over 1 MW) installations. Off-grid PV installations—not depicted in this figure—accounted for approximately 40–60 MW in 2010 (IREC

Figure 2-3. U.S. Annual Installed Grid-Connected PV Capacity by Market, 2001–2010



Source: IREC (2011)

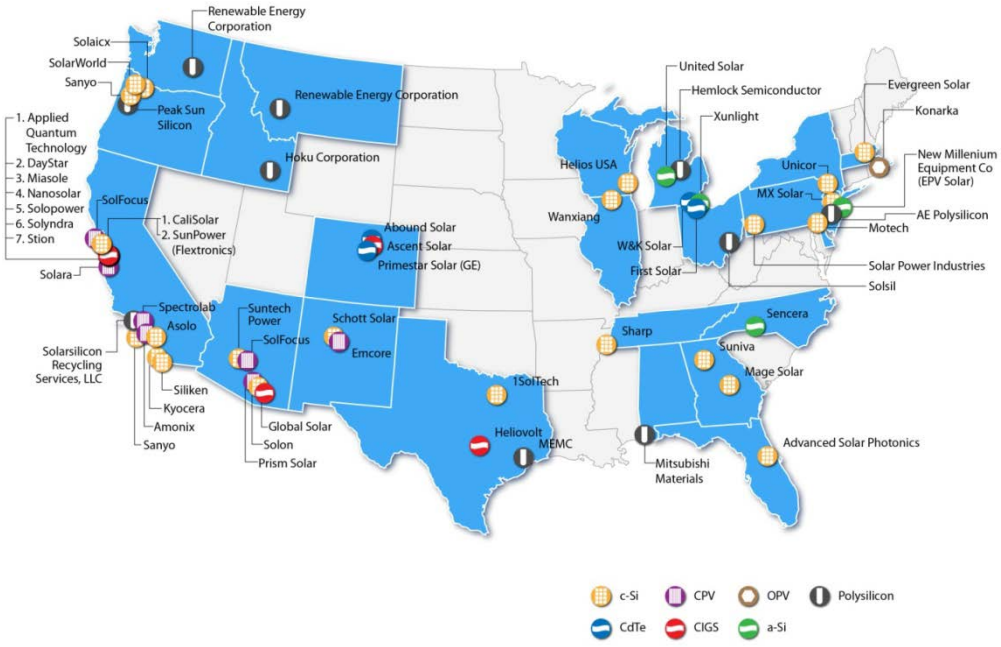
2011).
As of 2010, California was by far the strongest U.S. PV market. The California Solar Initiative, enacted in December 2005, provided the long-term market stability critical for encouraging new entrants on the production and installation sides. California continues to encourage solar and other renewable energy technologies through innovative policies, including a strong renewable portfolio standard (RPS), a diverse portfolio of incentives, and utility involvement. Other U.S. markets that have grown significantly during the past few years are Arizona, Colorado, New Mexico, New Jersey, New York, and Nevada.

U.S. PV Manufacturing

Recent federal and state incentives have encouraged manufacturers to expand PV production in the United States. Figure 2-4 shows the location and technology of

[11] The residential and commercial data generally represent installations where electricity is used on-site, whereas the utility data represent installations that generate electricity sent to the bulk grid. Commercial data capture government, non-profit, and other non-residential installations. The owner of the installation for any of the three market segments could be either the site owner or a third party.

Figure 2-4. U.S. PV Cell, Module, Wafer, and Polysilicon Manufacturing Facilities, July 2011



Sources: SEIA and GTM Research (2011a), Mehta (2009), Bradford (2008), BNEF (2009)

U.S. PV manufacturing facilities as of July 2011.[12] The figure shows that 59 PV facilities in 22 states were in operation in mid-2011.

These facilities produce crystalline-silicon, CPV, and thin-film technologies such as a-Si, CdTe, CIGS, and organic photovoltaics (OPV), as well as polysilicon and wafers for use in crystalline-silicon PV. In 2010, U.S. cell production was about 1,100 MW or 5% of global production, and module production was about 1,200 MW or 6% of global production (SEIA and GTM Research 2011b). The United States produced 42,561 metric tons (MT) of polysilicon in 2010, approximately 30% of global supply. The median estimate of total polysilicon produced in 2010 was 148,750 MT, of which about 81% (or 120,400 MT) was produced for the solar industry. In addition to these numbers, scrap polysilicon from the electronics industry has always supplied the solar industry with varying amounts of the material. The total 2010 production of polysilicon represented an estimated 60% increase over 2009 production.

The discrepancy between U.S. polysilicon production versus module production is due in part to polysilicon production being very capital intensive and complex, requiring technological sophistication, whereas module production is labor intensive, benefiting countries with low-cost labor. In addition, shipping costs of

[12] An attempt was made to only include all manufacturing plant locations with at least 5 MW of production capacity as of July 2011. However, the constantly changing landscape for PV component manufacturing and diversity of players in the solar manufacturing industry make it difficult to have a comprehensive list at any point in time. This list is not an exception, and should not be viewed as absolute.

polysilicon are minimal, so plant location near the end customer is not a key factor, whereas modules are more expensive to ship, benefitting countries in Europe where the largest end markets are located.

2.1.2 Concentrating Solar Power

The market for CSP has surged in recent years, especially in Spain and the United States. Trough systems dominate global CSP installations, but other technologies are gaining market share.

Global CSP Installations

Luz, a California-based company, first commercialized CSP in the 1980s with the Solar Energy Generating Systems (SEGS), 354 MW of parabolic trough plants in the Mojave Desert of southern California. The next CSP plant to come online in the United States was the Arizona Public Service (APS) Saguaro 1-MW parabolic trough plant, installed in Red Rock, Arizona, in 2005. Another 64 MW of CSP capacity were added in 2007 when the Nevada Solar One parabolic trough plant was installed in Boulder City, Nevada. At the end of 2008, 430 MW of grid-tied CSP capacity were in commercial operation worldwide, more than 95% of which was in the southwestern United States.

By December 2010, global CSP capacity increased to about 1,300 MW. Most of the capacity additions during 2009–2010 were in Spain, and at the end of 2010, Spain accounted for about 57% of all global CSP capacity. Parabolic trough technology accounted for about 96% of global CSP capacity at the end of 2010; tower technology accounted for 3%. Table 2-1 lists commercial and grid-tied demonstration CSP plants (with capacities of 1 MW or greater) installed worldwide as of December 2010. The Andasol 1 and Andasol 2 plants shown in the table are the first commercial CSP plants to feature thermal storage, using a two-tank molten salt system to store up to 7.5 hours of peak-load energy (Solar Millennium 2010).

Table 2-1. Commercial and Grid-Tied Demonstration CSP Plants (≥ 1 MW_{AC} capacity) Installed Worldwide as of December 2010

Plant Name	Location	Technology Type	Year Installed	Capacity (MW_{AC})
SEGS I – IX	California, U.S.	Trough	1985–1990	354
Inditep	Spain	Trough	2005	1.2*
APS Saguaro	Arizona, U.S.	Trough	2006	1
Nevada Solar One	Nevada, U.S.	Trough	2007	64
PS10	Spain	Tower	2007	11
Kimberlina	California, U.S.	Compact linear Fresnel reflector (CLFR)	2008	7*
Andasol 1	Spain	Trough w/thermal storage	2008	50
Liddell	Australia	CLFR	2008	3
Sierra Sun Tower	California, U.S.	Tower	2009	5*
Holaniku	Hawaii, U.S.	Trough	2009	2*
Stadtwerke Julich	Germany	Tower	2009	1.5*

Plant Name	Location	Technology Type	Year Installed	Capacity (MW_{AC})
Puerto Errado 1	Spain	Linear Fresnel	2009	1.4*
Puertollano Ibersol	Spain	Trough	2009	50
La Risca	Spain	Trough	2009	50
PS20	Spain	Tower	2009	20
Holaniku	Hawaii, U.S.	Trough	2009	2
Maricopa Solar	Arizona, U.S.	Dish	2010	1.5*
IEECAS Badaling	China	Tower	2010	1.5*
Cameo	Colorado, U.S.	Trough	2010	1*
Casa del Ángel Termosolar	Spain	Stirling	2010	1*
Himin Yanqing	China	Tower	2010	1*
Martin	Florida, U.S.	Trough	2010	75
Andasol 2	Spain	Trough w/thermal storage	2010	50
Extresol 1	Spain	Trough w/thermal storage	2010	50
Solnova 1	Spain	Trough	2010	50
Solnova 3	Spain	Trough	2010	50
Solnova 4	Spain	Trough	2010	50
La Florida	Spain	Trough	2010	50
Majadas	Spain	Trough	2010	50
La Dehesa	Spain	Trough w/thermal storage	2010	50
Palma Del Rio II	Spain	Trough	2010	50
Extresol-2	Spain	Trough w/thermal storage	2010	50
Manchasol-1	Spain	Trough w/thermal storage	2010	50
Ain Beni Mathar	Morocco	Trough	2010	20
Al Kuraymat	Egypt	Trough	2010	20
Archimede	Italy	Trough	2010	5

*Denotes grid-tied demonstration plant

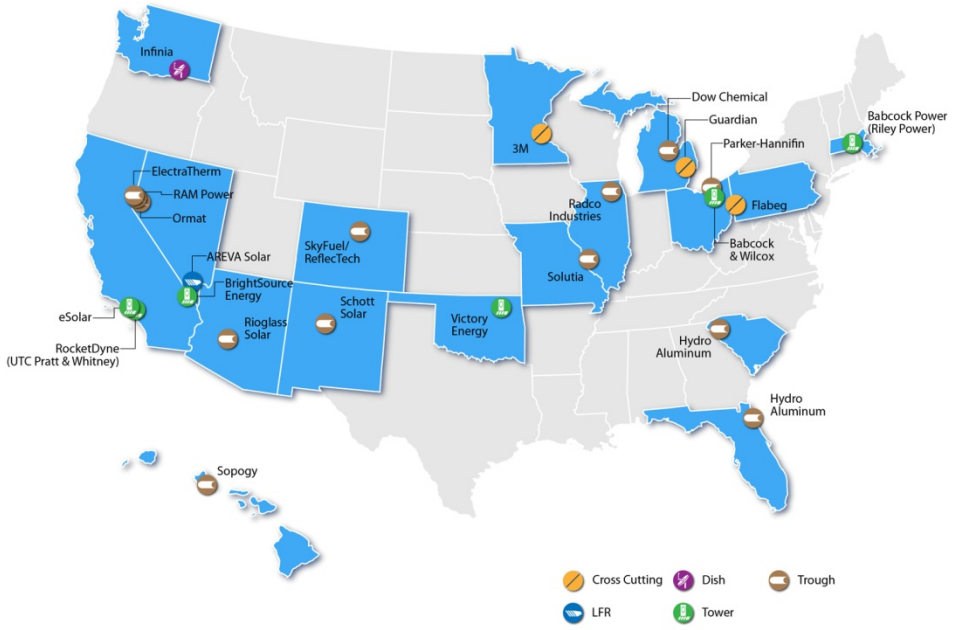
Sources: Abengoa Solar (2011), Acciona Energy (2008), Ausra (2009), BrightSource Energy (2008), Emerson Process Management (2009), eSolar (2009), Grama et al. (2008), Solar Millennium (2010), Sopogy (2009), Tessera Solar (2010), Protermosolar (2011), NREL (2011a), Renovalia Energy (2010), EIA (2010a), SEIA-GTM (2011b), BNEF (2011), NextEra Energy (2011), Areva Solar (2010)

U.S. CSP Manufacturing

Figure 2-5 shows U.S. component manufacturing facilities for CSP technologies including parabolic troughs, power towers, linear Fresnel reflectors, and dish/engine systems. A total of 24 manufacturing facilities that produce CSP components—possibly among other products—were in operation by mid-2011.[13] CSP

[13] An attempt was made to only include all manufacturing plant locations with at least 5 MW of production capacity as of July 2011. However, the constantly changing landscape for CSP component manufacturing and diversity of players in the solar manufacturing industry make it difficult to have a comprehensive list at any point in time. This list is not an exception, and should not be viewed as absolute.

Figure 2-5. U.S. CSP Component Manufacturing Facilities, July 2011



Sources: SEIA and GTM Research (2011a), BNEF (2009), DOE (2010)

components—many of which cut across technologies—include mirrors, reflectors, collector structures, heat-transfer fluids and salts, turbines, and controls. The expectation of strong CSP installation growth has resulted in CSP component production facilities being established by specialized manufacturers and large industrial conglomerates.

2.1.3 Solar Industry Employment

This section discusses the existing types and levels of employment in the solar industry for PV and CSP.

The PV and CSP industries include a variety of jobs across their supply chains and in support roles. In measuring economic impact, jobs can be divided among three categories: direct, indirect, and induced jobs. Direct jobs accomplish final production along the solar industry supply chains, e.g., manufacturing, installation, and R&D. Indirect jobs are in industries that support the solar industry, e.g., glass, steel, and office-equipment industries. Induced jobs result from the economic activity stimulated by the solar industry, e.g., jobs related to people buying more goods and services in a region that hosts a manufacturing plant or project under construction.

It is most feasible to quantify direct and indirect jobs resulting from solar industry growth. The range of direct and indirect solar jobs includes the following:

- *Manufacturing:* Technology research, engineering, raw materials production, assembly line, quality control, shipping, and marketing
- *Project planning:* Mechanical, electrical, and structural engineers, energy transmission engineers, architects, project developers, land brokers, contract personnel, environmental consultants, utility procurement staff, local permitting officials, lenders, and investors
- *Installation:* Construction managers, installers, pipefitters, electricians, plumbers, laborers, and truck drivers
- *Operations, maintenance, and ownership:* System monitors, field technicians, warranty servicing, and accounting
- *Decommissioning and disposal:* Demolition, transportation, and recycling
- *Education and training:* Professors, instructors, and administrators
- *Policy, program administration, research, and advocacy:* Energy officials, utility program administrators, government-relations staff, trade associations, market analysts, non-profits, and media.

There were an estimated 51,000 full-time-equivalent PV- and CSP-related jobs in 2010, about 90% of which were related to PV and 10% to CSP. See Chapter 3 for employment details and projections through 2050.

The distributed energy model afforded by solar technologies is a key factor influencing solar employment characteristics. The multiplicity of small- and mid-sized solar energy systems yields more installation and operations jobs compared to common central station energy technologies, per energy unit [e.g., megawatt-hours (MWh)] produced. These jobs are more widely distributed in communities across the nation, including rural locations. This enables communities to "in-source" energy production, expanding local economies and providing jobs that cannot be moved offshore (Wei et al. 2010).

2.1.4 Hedging Against Energy Price Increases

Solar energy technologies enable users to reduce their exposure to future increases in the cost of energy because these systems do not face variable fuel costs. This is an attractive attribute of solar energy technologies. In particular, the potential impact of increased solar market penetration on natural gas use and pricing is important (this is discussed in more detail in Chapter 3). Natural gas is currently a key determinant of electricity, heating, and cooling costs in the United States. Natural gas accounts for roughly 20% of U.S. electricity generation; however, because natural-gas generation plants are usually the last power source to be activated to meet a given load, it is a key determinant in setting the wholesale market price of electricity throughout much of the country. Solar energy technologies provide potential price-hedging benefits to individual consumers, by substituting a fixed cost in place of a potentially volatile fuel cost, and the broader public, by displacing demand for natural gas.

2.2 Solar Resource Availability and Technical Potential

The U.S. solar resource is enormous. In fact, the amount of solar energy falling on the United States in 1 hour of noontime summer sun is about equal to the annual U.S. electricity demand. Moreover, as shown in Figure 2-6 and discussed below, every region of the contiguous United States has a good solar resource.

The ability to exploit the available solar resource varies by technology. Solar energy contains a direct component, i.e., light from the solar disk that has not been scattered by the atmosphere, and an indirect or diffuse component, i.e., light that has been scattered by the atmosphere. Only the direct solar component can be focused effectively by mirrors or lenses such as those used by CPV and CSP systems. The direct component typically accounts for 60%–80% of surface solar insolation in clear-sky conditions and decreases with increasing relative humidity, cloud cover, and atmospheric aerosols, e.g., due to dust and urban pollution. This section describes the technical potential for PV and CSP market growth in the context of the exploitable U.S. solar resource.

2.2.1 Photovoltaics

Flat-plate PV can take advantage of direct and indirect insolation, so PV modules need not directly face and track incident radiation. This gives PV systems a broad geographical application.

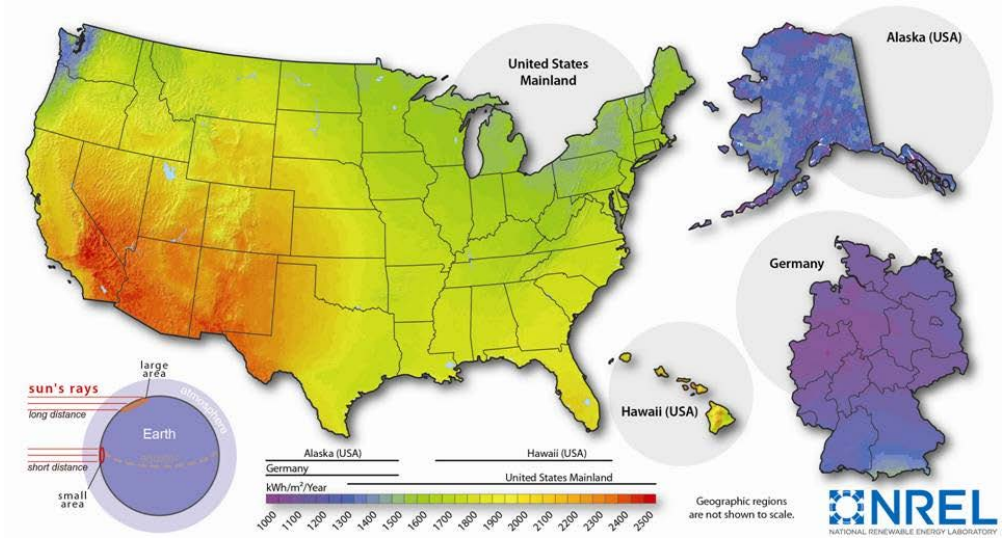
Figure 2-6 illustrates the solar resource in the United States and Germany for a flat-plate PV collector tilted south at latitude. Solar resources across the United States are mostly good to excellent at about 1,000–2,500 kilowatt-hours (kWh)/square meter (m^2)/year. The Southwest is at the top of this range, while only Alaska and part of Washington are at the low end. The range for the 48 contiguous states is about 1,350–2,500 kWh/m^2/year. Nationwide, solar resource levels vary by about a factor of two, which is considered relatively homogeneous compared with other renewable energy resources.

The U.S. solar resource is much higher than Germany's, and the southwestern United States has a better resource than southern Spain. Germany's solar resource has about the same range as Alaska's (1,000–1,500 kWh/m^2/year), but more of Germany's resource is at the lower end of the range. Spain's solar resource ranges from about 1,300–2,000 kWh/m^2/year, among the best in Europe.

The total U.S. land area suitable for PV is significant and will not limit PV deployment. For example, one estimate suggested that the land area required to supply all end-use electricity in the United States using PV is about 5,500,000 hectares (ha) (13,600,000 acres), which is equivalent to 0.6% of the country's land area or about 22% of the "urban area" footprint (Denholm and Margolis 2008a).[14] See Chapter 7 for calculations of PV land use and electricity generation under the SunShot scenario. In addition to siting PV on greenfields, there are many opportunities for installing PV on underused real estate such as parking structures,

[14] This calculation is based on deployment/land in all 50 states.

Figure 2-6. PV Solar Resource: United States and Germany



Source: NREL (2011b)

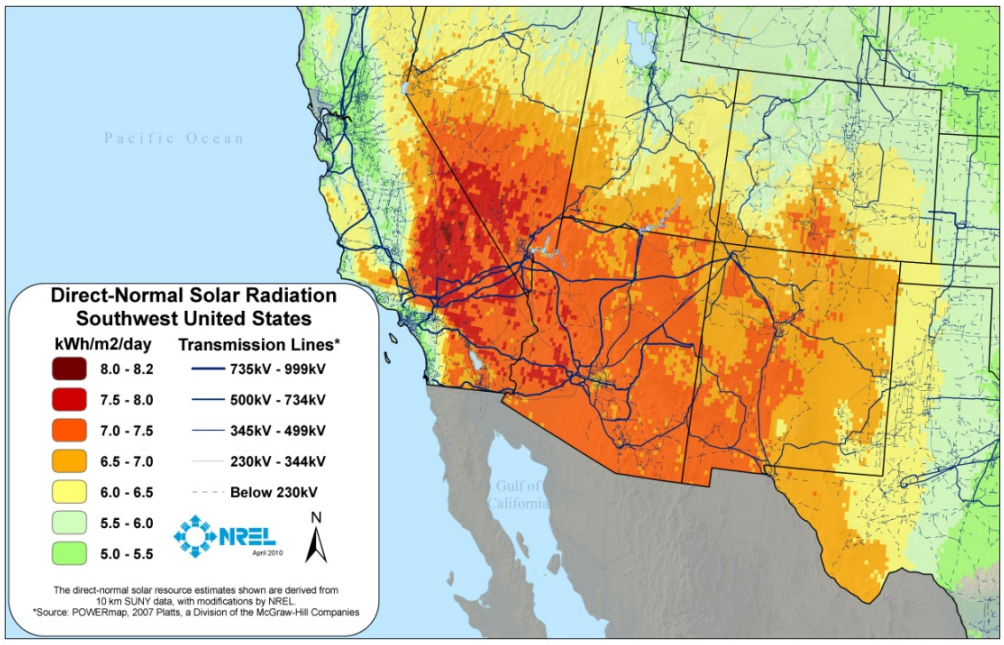
awnings, airports, freeway margins, and farmland set-asides. PV can also be located on rooftops, where it will have essentially no land-use impacts. A recent estimate of the total roof area suitable for PV in the United States is about 6 billion m^2, even after eliminating 35%–80% of roof space to account for panel shading (e.g., by trees) and suboptimal roof orientations; with current PV performance, this area has the potential for more than 600 GW of capacity (Denholm and Margolis 2008b).

2.2.2 Concentrating Solar Power

The geographic area most suitable for CSP is smaller than that for PV because CSP can exploit only direct-normal irradiance (DNI), i.e., light that can be focused effectively by mirrors or lenses. Globally, the most suitable sites for CSP plants are arid lands within 35° north and south of the equator. In the United States, the best location for CSP is the Southwest, which has some of the best solar resources in the world. Figure 2-7 shows the DNI resource in the Southwest; red indicates the most intense solar resource, and green indicates the least intense.

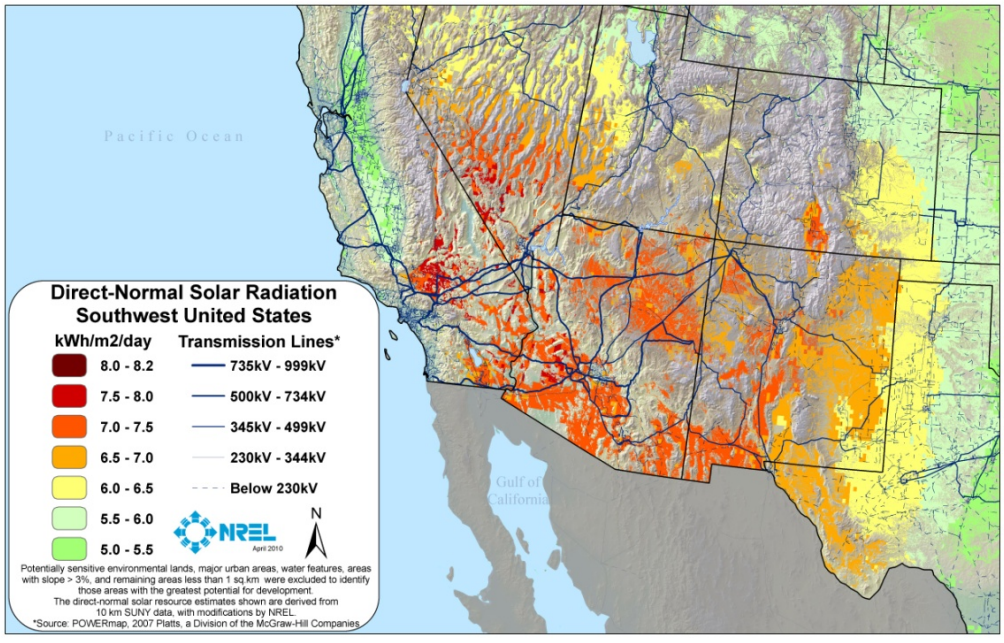
A strong solar resource is only one criterion for the effective deployment of large solar power stations. The land must also be relatively flat, unoccupied, and suitable for development. NREL has performed various assessments of the Southwest to estimate the quantity of land suitable for solar power stations and the amount of energy that might be produced. Figure 2-8 shows locations in the Southwest with characteristics ideal for CSP systems, including DNI greater than 6.0 kWh/m^2/day (2,200 kWh/m^2/year) and a land slope of less than 1°. In addition, land-use filters exclude bodies of water, urban areas, national parks and preserves, wilderness areas, and wildlife refuges. Because the economics of utility-scale solar facilities favor large size, land areas smaller than 1 square kilometer (km^2) are also excluded (Mehos et al. 2009).

Figure 2-7. DNI Resource in the U.S. Southwest



kV: kilovolts
Source: Mehos and Kearney (2007)

Figure 2-8. DNI Resource in the U.S. Southwest, Filtered by Resource, Topography, and Land Use



Sources: Mehos et al. (2009), Turchi (2009)

After implementing the appropriate insolation, slope, and land-use filters, 22,593,000 ha (55,800,000 acres) are available in the seven states considered to be most CSP compatible: Arizona, California, Colorado, Nevada, New Mexico, Texas, and Utah (Table 2-2). This relatively small land area amounts to nearly 7,500 GW of resource potential and more than 17.5 million gigawatt-hours (GWh) of annual generating capacity, assuming a capacity factor of 27% (Mehos et al. 2009, Turchi 2009). The potential generating capacity exceeds the total U.S. electric grid capacity by a factor of more than six, while the potential energy production exceeds U.S. demand by a factor of more than four (EIA 2010b, EIA 2010c).

Table 2-2. Ideal CSP Resource Potential and Land Area in Seven Southwestern States

State	Available Area (ha)	Capacity (GW)	Annual Electricity[a] (GWh)
Arizona	3,525,700	1,162	2,748,000
California	1,626,000	536	1,267,000
Colorado	1,614,100	532	1,258,000
Nevada	2,872,300	946	2,238,000
New Mexico	5,272,200	1,737	4,108,000
Texas	1,650,800	544	1,286,000
Utah	6,031,600	1,987	4,700,000
Total CSP Resource	**22,593,000**	**7,444**	**17,605,000**

[a] Annual electricity production was estimated using an average capacity factor of 27%, although actual values would depend on technology and level of thermal energy storage deployed.

Sources: Mehos et al. (2009), Turchi (2009)

A value of 3 ha/MW (7.5 acres/MW) was used to determine capacity per unit of land area. This value represents an estimated average for different CSP technologies, and actual values will depend on the specific technology used, location, and system efficiency. CSP systems with thermal storage will have a higher land use per unit of capacity due to a larger collector area needed for generating excess thermal energy. However, because the storage also results in a higher capacity factor, these effects offset each other in the calculation of annual energy production. See Chapter 7 for calculations of CSP land use and electricity generation under the SunShot scenario.

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3. Analysis of PV and CSP Growth in the SunShot Scenario

3.1 Introduction

The *SunShot Vision Study* explores the potential impact of achieving the U.S. Department of Energy's (DOE's) SunShot Initiative price targets on photovoltaics (PV) and concentrating solar power (CSP) deployment in the United States through 2050. The modeling scenarios are not predictions of the future; rather, they represent internally consistent model results based on a specific set of assumptions. The model scenarios are used to explore and quantify the costs, challenges, and benefits of reaching high levels of solar penetration. The analysis provides insights that could assist research, development, and demonstration (RD&D) portfolio managers and policy makers in designing programs aimed at achieving the SunShot targets and increasing opportunities for the United States to reap economic benefits from PV and CSP technology advancement.

In this chapter, Section 3.2 describes the SunShot scenario and the reference scenario against which it is compared, including the analysis models used, major assumptions, projected deployment of PV and CSP resources, evolution of the U.S. electric sector, transmission requirements and electrical energy flows, and operational feasibility. Section 3.3 evaluates the impact of the SunShot scenario's projected solar deployment, including electric-sector costs, carbon emissions, and solar sector employment.

3.2 SunShot Growth Scenario

Section 3.2.1 describes the models used to analyze the SunShot growth scenario. Section 3.2.2 describes the SunShot scenario assumptions and total solar deployment results. Sections 3.2.3–3.2.6 present the results of the analysis in terms of generation and capacity mix, regional deployment, transmission requirements, and operational impacts.

3.2.1 Analysis Models

Several modeling tools were used for the analysis. The Regional Energy Deployment System (ReEDS) model (Short et al. 2011), developed at the National Renewable Energy Laboratory (NREL), is a linear-optimization, capacity-expansion model that simulates the least-cost deployment and dispatch of generation resources. ReEDS was used to explore the evolution of the U.S. electric sector in meeting the

SunShot targets, and to calculate the additional transmission capacity and reserve capacity required to meet customer demand and maintain grid reliability. ReEDS determines the geographical deployment of PV, CSP, and other generation technologies based on a number of factors: regional solar resource quality, future technology and fuel price projections, future U.S. electricity demand projections, impacts of variability in renewable generation, transmission requirements, and reserve requirements. ReEDS does not take into account potential distribution side impacts and issues. Model methodology and assumptions are described in detail in Appendix A.

The Solar Deployment System (SolarDS) model (Denholm et al. 2009)—also developed at NREL—was used to simulate PV adoption in residential and commercial rooftop PV markets based on regional solar insolation, retail electricity rates, and market diffusion characteristics. SolarDS simulates regional PV economics at high spatial resolution using hourly PV generation profiles from hundreds of solar resource regions, combined with state-based retail electricity rate distributions compiled from more than 1,000 utilities. PV economics are used to project PV adoption rates using market adoption and diffusion characteristics, and the resulting adoption rates are combined with a residential and commercial building stock database to calculate market size. Utility concerns such as voltage regulation, unintentional islanding, coordinated protection, and so on, are not considered as part of the SolarDS model.

Lastly, GridView—a production-cost model frequently used by electric service providers to schedule and dispatch generation resources—was used to verify the real-world operability of the SunShot scenario.

3.2.2 SunShot Scenario Assumptions and Total Solar Deployment Projections

Table 3-1 shows price and performance characteristics used to model the SunShot and reference scenarios. The SunShot price targets were set so that PV- and CSP-generated electricity would become competitive with conventionally generated electricity without subsidies by 2020. In the SunShot scenario, utility-scale PV is assumed to achieve $1.00/watt (W) installed system prices by 2020, and prices are assumed to follow close to a linear trajectory from today's price to $1.00/W.[15] Rooftop PV is assumed to reach $1.25/W (commercial) and $1.50/W (residential) installed system prices. This is also consistent with the higher supply chain and installation costs and margins for smaller distributed PV systems. CSP is assumed to reach $3.60/W installed prices for systems with 14 hours of thermal energy storage and a 67% capacity factor (CF). The reference PV and CSP prices listed in Table 3-1 were developed by Black & Veatch (forthcoming) to support various DOE electricity generation capacity expansion studies, except for the 2010 reference PV prices, which are the approximate benchmark PV prices established in Chapter 4. The reference CSP prices refer to systems with 6 hours of thermal energy storage. However, the ReEDS model optimally deploys CSP thermal storage resources based on system economics; see Appendix A for details.

[15] Note that throughout this report all "$/W" units refer to 2010 U.S. dollars per peak watt-direct current (DC) for PV and 2010 U.S. dollars per watt-alternating current (AC) for CSP, unless specified otherwise.

Table 3-1. Projected PV and CSP Installed System Prices and Performance (2010 U.S. Dollars/W)[a]

	Utility PV		Residential Rooftop PV		Commercial Rooftop PV		CSP					
	SunShot	Ref.	SunShot	Ref.	SunShot	Ref.	SunShot			Ref.		
	$/W$_{DC}$	$/W$_{DC}$	$/W$_{DC}$	$/W$_{DC}$	$/W$_{DC}$	$/W$_{DC}$	$/W$_{AC}$	hours storage[b]	CF (%)	$/W$_{AC}$	hours storage[b]	CF (%)
2010	4.00	4.00	6.00	6.00	5.00	5.00	7.20	6	43	7.20	6	43
2020	1.00	2.51	1.50	3.78	1.25	3.36	3.60	14	67	6.64	6	43
2030	1.00	2.31	1.50	3.32	1.25	2.98	3.60	14	67	5.40	6	43
2040	1.00	2.16	1.50	3.13	1.25	2.79	3.60	14	67	4.78	6	43
2050	1.00	2.03	1.50	2.96	1.25	2.64	3.60	14	67	4.78	6	43

[a] All reference (Ref.) prices in this table are from Black & Veatch (forthcoming) except for the 2010 PV prices, which are the approximate benchmark PV prices established in Chapter 4. The SunShot prices are the benchmarks and SunShot Initiative targets discussed in Chapters 4 and 5 except for the 2010 CSP SunShot price, which is from Black & Veatch (Chapter 5 does not establish a 2010 benchmark price for CSP with 6 hours of storage). The CSP prices are based on a project's "overnight installed cost," which is the total direct and indirect costs that would be incurred if the project was built in an instant, void of any additional costs for financing the construction period.
[b] The number of hours of thermal energy storage for CSP is optimized in the ReEDS model, and is slightly different than the numbers in this table due to restrictions on the solar multiple within ReEDS (see Appendix A).

Table 3-2 summarizes the results of the SunShot scenario analysis, including the cumulative installed capacity, energy generation, and fraction of electricity demand[16] met by solar generation in 2030 and 2050. In the SunShot scenario, solar generation meets about 14% of U.S. electricity demand by 2030 (11% PV, 3% CSP) and 27% of demand by 2050 (19% PV, 8% CSP). About two-thirds of PV generation is from utility-scale ground-mounted systems,[17] and the remainder is from rooftop PV systems. These results are sensitive to technology prices and other assumptions. Appendix C discusses the sensitivity of the SunShot scenario results to the projected cost of solar technologies and the projected cost of non-solar renewable technologies. Additional sensitivity analysis will be published in supplementary technical reports.

Note that all results in this report refer to the contiguous United States (excluding Alaska and Hawaii) unless otherwise noted. For example, solar technologies are projected to meet about 14% of contiguous U.S. electricity demand by 2030 and 27% by 2050.

These SunShot scenario results are not a prediction of the future. Rather, they represent a possible growth trajectory for the U.S. electric sector if the envisioned price and performance improvements are achieved. Modeled deployment is highly dependent on several assumptions, including projections of future technology and fuel prices, electricity demand, retirement schedules for existing generation resources, transmission expansion costs, and several others, all characterized within

[16] The scenarios represent end-use electricity demand generated by the electric power sector; they do not include onsite industrial generation or onsite co-generation of heat and electricity.
[17] Utility-scale PV systems are represented in ReEDS by both central and distributed systems. See Appendix A for descriptions of these types of utility-scale systems. Distributed systems represent ~1–20 MW plants located within distribution networks, while central systems represent ~100-MW plants located outside of distribution networks. Both systems assume 1-axis tracking.

Additional Key Model Assumptions Used in the SunShot and Reference Scenarios[a]

- Electricity demand projections are based on the EIA (2010) reference scenario through 2035 and extrapolated through 2050. Electricity demand increases about 20% by 2030 and 40% by 2050.
- Capital cost projections for all energy technologies other than PV and CSP are based on an engineering analysis by Black & Veatch (forthcoming).
    - Capital costs for coal, gas, or nuclear generation technologies are assumed to stay fixed through 2050, but coal and gas achieve 10%–20% performance improvements by 2030.
    - Non-solar renewable technologies are assumed to achieve moderate price and performance improvements.
    - Geothermal is projected to achieve a 17% price reduction by 2050.
    - Onshore wind has fixed prices through 2050 but about a 10% increase in performance by shifting to taller towers.
    - Offshore wind is projected to achieve a 20% price reduction by 2050 in addition to a performance improvement similar to onshore wind.
    - Biopower is projected to achieve a small price reduction on the order of a few percent and performance improvements of about 25% by 2050.
- Future coal and natural gas fuel prices and price elasticities are based on EIA (2010) through 2035 and extrapolated based on electric sector fuel use through 2050. Coal prices stay fixed through 2030 and then increase by about 5% from 2030 to 2050. Natural gas prices increase by about 50% by 2030, and 95% by 2050.
- Retail electricity rate projections (used to model rooftop PV) are based on the EIA (2010) reference scenario and extrapolated through 2050. Residential rates are assumed to increase by 0%–1.5% annually, depending on region. Commercial rates are assumed to increase by 0%–1% annually, depending on region.
- No carbon tax or emissions prices are assumed. However, a 6% investment risk was added to the required rate of return for new coal investments to characterize uncertainty over future carbon policy[b] (Barbose et al. 2008).

[a] Modeling assumptions are described in further detail in Appendix A.

[b] The 6% investment risk is higher than the base case assumption used by many electric utilities for capacity expansion planning, but is representative of the middle to lower range of carbon sensitivities used by many utilities to develop capacity expansion plans (Barbose et al. 2008). Carbon prices were used to estimate equivalent investment risk adders based on system financing assumptions in Chapter 8.

Table 3-2. Solar Deployment in the SunShot Scenario[18]

	2030			2050		
	Capacity [gigawatts (GW)]	Energy [terawatt-hours (TWh)][a]	Fraction of Electric-Sector Demand (%)	Capacity (GW)	Energy (TWh)[a]	Fraction of Electric-Sector Demand (%)
Total Solar	**329**	**642**	**13.8**	**714**	**1,448**	**26.9**
Total PV	**302**	**505**	**10.8**	**632**	**1,036**	**19.3**
Rooftop PV	121	164	3.5	240	318	5.9
Utility PV[b]	181	341	7.3	391	718	13.4
Total CSP	**28**	**137**	**3.0**	**83**	**412**	**7.7**
Electricity Demand[c]	-	**4,421**	-	**-**	**5,103**	**-**

Components do not always add up to totals because of rounding.

[a] The capacity-expansion models (ReEDS and SolarDS) place solar technologies in locations where they are most economic, leading to capacity factors of about 15% for rooftop PV, 23% for utility-scale PV (1-axis tracking systems), 60% for CSP (ReEDS primarily builds CSP systems with several hours of storage), and 41% for wind.

[b] Utility PV includes central and distributed utility-scale PV systems. See Appendix A for descriptions of these types of utility-scale systems.

[c] Electricity demand is based on projections of electricity sales through 2035 from *Annual Energy Outlook 2010* (EIA 2010); extrapolated through 2050.

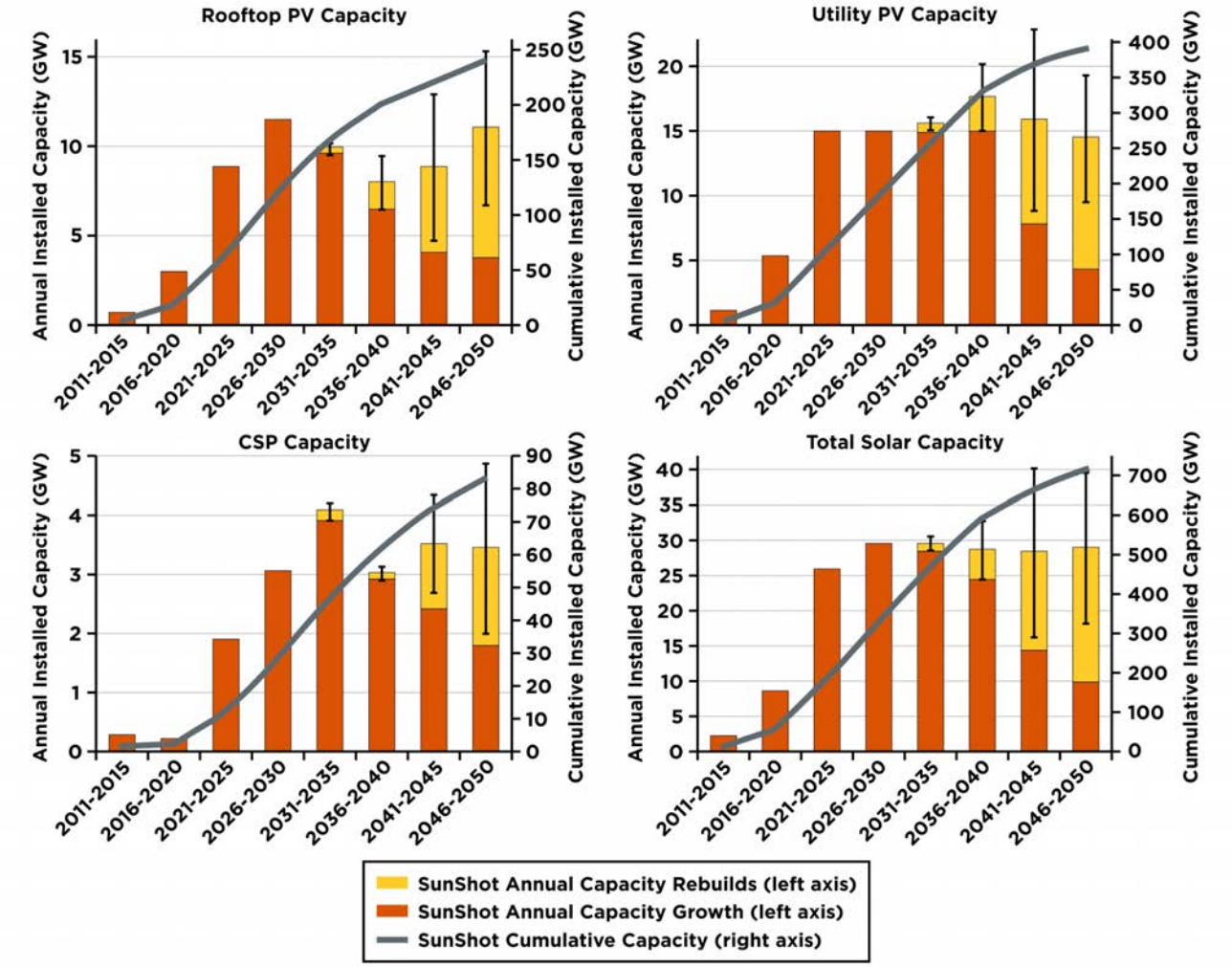
the modeling framework. Key model assumptions are listed in the sidebar, and a detailed description of the modeling methodology and assumptions is included in Appendix A.

Figure 3-1 shows annual and cumulative installed solar capacity for the SunShot scenario, and a range of annual installed capacities required to meet both the solar market growth and end-of-life replacements or retrofits. Market evolution for utility-scale PV and CSP is based on the economic optimization determined by the ReEDS model, with constraints to limit growth in annual installed capacity to no more than double in each 2-year model period, and to limit U.S. demand so it does not exceed 15 GW per year of annual installations. These constraints were added to avoid boom-bust cycles in supply-demand, i.e., where demand rises to a very high level for a few model periods and then collapses. The constraints could also be interpreted as representing the fact that manufacturers would consider longer-term market sustainability before developing manufacturing capacity and that market distribution and installation infrastructure takes time to develop.[19] Figure 3-1 shows that the utility-scale PV market is constrained by these growth rates before 2030, but that this constraint does not significantly decrease total market size in later study years. Rooftop PV markets were simulated using the SolarDS model, and these capacity additions were added into the ReEDS model.

[18] Totals may differ from components due to rounding.

[19] Unconstrained growth in electric-sector demand models frequently produces shorter-term growth peaks for individual technologies like PV, followed by several years of decreased demand. Constraints were added on annual growth rates to decrease these oscillations in PV manufacturing and labor markets to better represent the fact that market participants will temper growth based on market foresight.

Figure 3-1. Annual and Cumulative Installed Capacity for Rooftop PV, Utility-Scale PV, CSP, and All Solar Technologies



End-of-life PV and CSP system and component replacements (rebuilds) are included in Figure 3-1 to show the potential size of future solar markets. Annual solar rebuilds are approximated by the gray bars, which represent the average of rebuilds calculated using a range of system lifetimes from 20 to 30 years (the range is represented by the black error bars).

PV markets show peak growth trends during 2020–2040. CSP markets show peak growth trends during 2025–2040. The distribution of annual installations combine to form an S-shaped diffusion curve in cumulative installed capacity, for all solar technologies. Including rebuilds, the modeled U.S. PV market stabilizes at about 25–30 GW/year (yr), and the U.S. CSP market stabilizes at about 3–4 GW/yr of new capacity additions and plant retrofits.

3.2.3 Generation and Capacity Mix

Figure 3-2 shows the mix of electricity generated by each technology in the SunShot and reference scenarios.[20] In the SunShot scenario, solar generation primarily displaces natural gas and coal generation relative to the reference scenario. Before 2030, solar generation primarily offsets natural gas generation. This is because midday solar generation corresponds well with times of peak midday electricity demand, and solar electricity frequently offsets more expensive peaking generation resources, such as natural gas generators. However, once a large amount of solar generation has been added to the system (14% of demand by 2030), the "net load" of the system, defined as electricity demand minus solar and wind generation, shifts from midday to evening. Once this happens, solar generation offsets the new buildout of coal capacity seen in the reference scenario, and solar significantly offsets coal use after 2030. Additional natural gas is built to satisfy the evening peak in net load, and CSP resources are deployed with several hours of storage representing a dispatchable solar generation resource.

Figure 3-2. Evolution of Electricity Generation in the SunShot and Reference Scenarios ("Other" Includes Biomass and Geothermal Technologies)

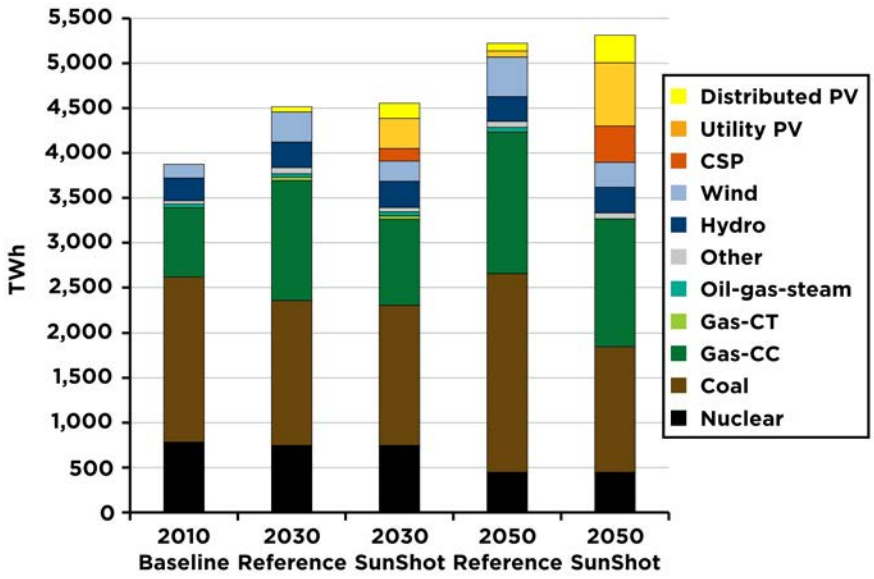


Figure 3-3 shows the avoided use of coal and natural gas fuel in the SunShot scenario relative to the reference scenario. Solar generation displaces about 2.6 quadrillion British thermal units (Quads) of natural gas and 0.4 Quads of coal per year by 2030. In 2050, solar generation displaces the use of 1.5 Quads of natural gas and 7.3 Quads of coal per year. This corresponds to a fuel savings of about $34 billion per year by 2030 and $41 billion per year by 2050.

Figure 3-4 shows the evolution of electricity generation capacity in the SunShot and reference scenarios. The electricity generation capacity deployed in ReEDS ensures

[20] The projected mix of generating technologies is sensitive to technology prices and various other assumptions. See Appendix C for additional information about sensitivities.

Figure 3-3. Annual Avoided Fuel Use in the SunShot Scenario

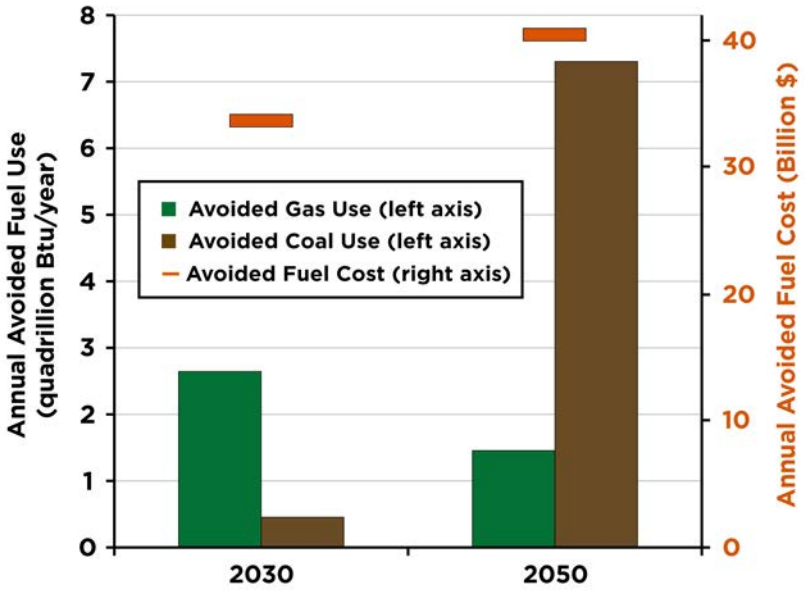
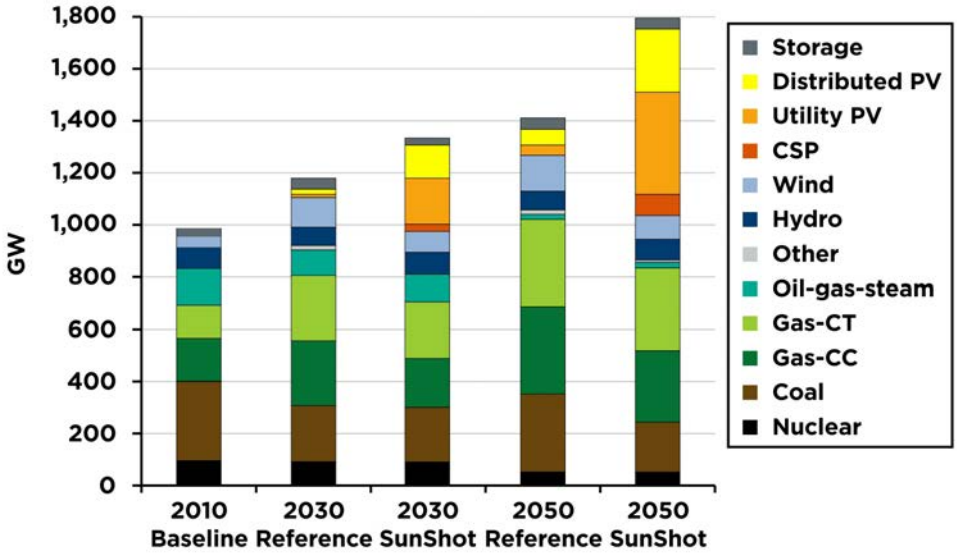


Figure 3-4. Evolution of Electricity-Generation Capacity in the SunShot and Reference Scenarios ("Other" Includes Biomass and Geothermal Technologies)



that peak electricity demands are met, and that additional resources provide operating and planning reserves to cover unexpected plant outages, load fluctuations, and variability in wind and PV generation. Both electricity demand and reserve requirements are time-dependent and specific to each region depending on the historical development of generation capacity.[21]

[21] Additional detail on reserve requirements can be found in Appendix A, along with specific reserve requirements of the SunShot scenario. Note that, in addition to generating capacity, ReEDS also includes interruptible load resources as operating reserves.

The SunShot scenario shows significantly more generation capacity than the reference scenario, reflecting the lower solar capacity factors relative to conventional technologies, and the additional need for reserve capacity. Although more generation capacity is built, the overall system costs are less (see Section 3.3.1) because of the annual fuel savings (Figure 3-3). The increased capacity is particularly pronounced in 2050 relative to 2030 because coal units are typically built to provide baseload with high capacity factors. The SunShot scenario shows a similar buildout of gas-combustion turbine (gas-CT) and gas-combined cycle (gas-CC) capacity as the reference scenario, suggesting that the increase in reserve requirements from the wide-scale deployment of solar resources is roughly offset by the reduction in midday peak demand from the coincidence of solar generation and peak load.

Storage technologies see modest growth in the SunShot scenario. Storage capacity starts at about 20 gigawatts (GW) in 2010, and grows to 29 GW by 2030 and 38 GW by 2050. Storage technologies[22] provide several benefits to the system, including shifting demand, reducing curtailment,[23] and providing capacity resources for operational reserves and regulation. These benefits result in a 50% increase in storage resources by 2030, and a doubling in storage resources by 2050, but not wide-scale deployment in the SunShot scenario. Additionally, interruptible load resources[24] can be developed in the ReEDS model to provide operating reserves, and these resources grow from 13 GW in 2010 to 48 GW by 2050 in the reference scenario and 93 GW by 2050 in the SunShot scenario.

Essentially, the flexibility needed to integrate the levels of PV electricity envisioned in the SunShot scenario is derived largely from fast-ramping generation resources (including existing generators) and the development of demand response resources, as opposed to a large amount of dedicated storage capacity. This is in part due to the fact that CSP is projected to be built with significant amounts of thermal storage, which can be used to provide fast ramping and load shifting. In the SunShot scenario, ReEDS primarily deploys CSP systems with more than 10 hours of storage, and this is a relatively inexpensive method for energy storage relative to other electricity storage options. However, ReEDS does not identify the potential value and opportunities of many storage devices. In particular, it does not evaluate opportunities to relieve local transmission or distribution (T&D) congestion, the value of T&D deferral, or benefits of decreased distribution losses. ReEDS also does not explicitly model storage technologies designed to provide short-term ancillary services such as flywheels. Thus, the modeling assumptions inherently undervalue certain storage devices, and deployment of these technologies is likely underestimated in the SunShot scenario.

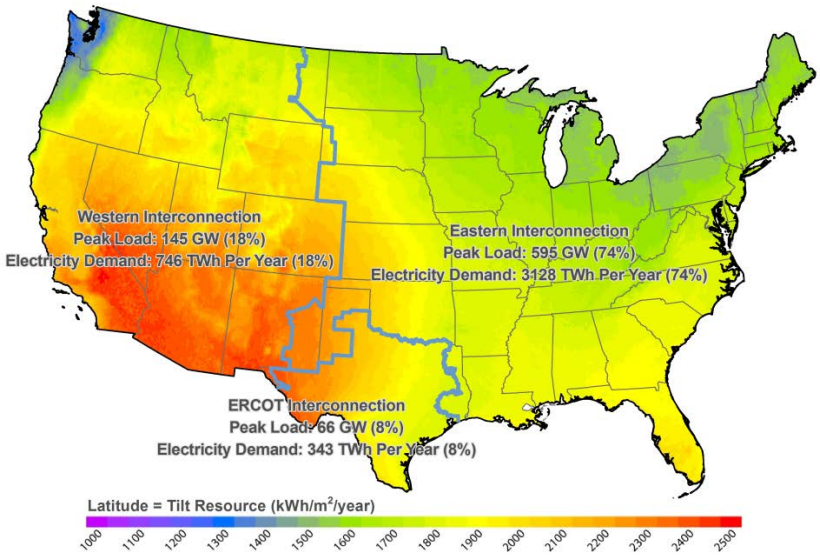
[22] Storage technologies in ReEDS include pumped-hydropower, compressed-air energy storage (CAES), and batteries. Storage technologies in ReEDS are discussed in Appendix A, along with cost and performance assumptions.
[23] Curtailments of variable renewable generation are calculated statistically in ReEDS. See Appendix A for a more detailed description.
[24] Interruptible load represents demand entities that utilities can partially control under contract; its treatment in ReEDS is described in Appendix A.

3.2.4 Regional Deployment

Solar energy contains a direct component (light from the solar disk that has not been scattered by the atmosphere) and a diffuse component (light that has been scattered by the atmosphere). The direct solar component is commonly referred to as direct-normal irradiance (DNI) and is important for concentrating solar applications because only the DNI component of solar radiation can be focused effectively by mirrors or lenses. DNI typically accounts for 60%–80% of surface solar insolation[25] in clear-sky conditions and decreases with increasing relative humidity, cloud cover, and atmospheric aerosols (e.g., dust, and urban pollution). Solar technologies that do not concentrate sunlight, such as most PV applications, can use both the direct and diffuse components of solar radiation and can be economically deployed over a wider range of locations and conditions than concentrating technologies that depend on high DNI.

The U.S. solar resource has significant geographic variation, as shown in Figure 3-5. The southwestern United States has both a high DNI fraction and generally high total solar radiation, leading to higher PV capacity factors than elsewhere in the country. For example, a 1-axis tracking PV module installed near Los Angeles will generate about 23% more electricity than the same module installed near New York City.[26]

Figure 3-5. Global Horizontal Solar Resource (South Facing, Tilted at Latitude) with Electricity Use Statistics by Interconnection



Source: NREL

[25] Insolation is a measure of solar radiation energy received on a given surface area in a given time.
[26] PV generation profiles were calculated using version 2011.8.30 of the System Advisor Model (SAM). www.nrel.gov/analysis/sam. Accessed September 2011.

Electricity demand and wholesale electricity prices also have significant geographic variation. Figure 3-5 shows the peak electricity demand (power) and the annual electricity demand (energy) for the three U.S. electric interconnections.[27] The Western Interconnection represents about 18% of peak and annual demand, the Electric Reliability Council of Texas (ERCOT) Interconnection represents 8% of demand, and the Eastern Interconnection represents 74% of demand. Solar deployment can be more economic in regions with access to better solar resources, and the SunShot scenario leads to higher relative solar generation fractions in the Western and ERCOT Interconnections than in the Eastern Interconnection, particularly for CSP resources. However, since total electricity demand is higher in the Eastern Interconnection, the total amount of PV installed there is higher than in the other interconnections.

Figure 3-6 shows the distribution of PV and CSP deployed in the SunShot scenario. PV is widely deployed in all U.S. states. Rooftop PV markets in particular develop in all U.S. states, while utility-scale PV is predominantly deployed in southern states, reflecting the combination of good solar resources and the general correspondence of PV output with peak afternoon summer air-conditioning load. On a capacity basis, the largest PV markets are in California, Texas, and Florida, reflecting the relatively good solar resource, and relatively high electricity demand. CSP is primarily deployed in the arid southwestern United States, where DNI is highest. The primary CSP markets are in California, Arizona, and Texas, reflecting the high DNI resource and access to load centers in southern California and eastern Texas.

Figure 3-7 shows the fraction of end-use electricity demand satisfied by solar and wind resources within each interconnection in 2030 and 2050. In 2030, solar is preferentially deployed in the Western Interconnection (meeting 31% of annual electricity demand) and the ERCOT Interconnection (14% of demand). PV satisfies about 9% of electricity demand in the Eastern Interconnection, and CSP supplies a small fraction of demand. There are good wind resources in each interconnection, and about 6% of electricity demand is met with wind in each interconnection. However, since CSP is built with several hours of storage, making it a dispatchable resource, the variable renewable energy (PV and wind) fraction is less stratified between interconnections, represented by 22% of electricity demand in the Western Interconnection, and 20% and 13% of electricity demand in the Eastern and ERCOT Interconnections, respectively.

By 2050, solar generation reaches 56% of demand in the Western Interconnection, 28% in the ERCOT Interconnection, and 18% in the Eastern Interconnection. CSP provides the largest share of solar generation in the Western Interconnection, and the resulting variable renewable generation (PV and wind) is similarly less stratified across interconnections (29%, 27%, and 23% in the Western, ERCOT, and Eastern Interconnections). At these levels of regional market penetration, system operation is

[27] The electric system for the continental United States comprises three largely independent grids or "interconnections": the Western, Eastern, and ERCOT (sometimes referred to as Texas) Interconnections. Although the Western and Eastern Interconnections technically reach north of the U.S. border into Canada, only the U.S. regions of those interconnections are accounted for in the analysis for this report.

Figure 3-6. Cumulative Installed PV and CSP Capacity in the SunShot Scenario in 2030 and 2050

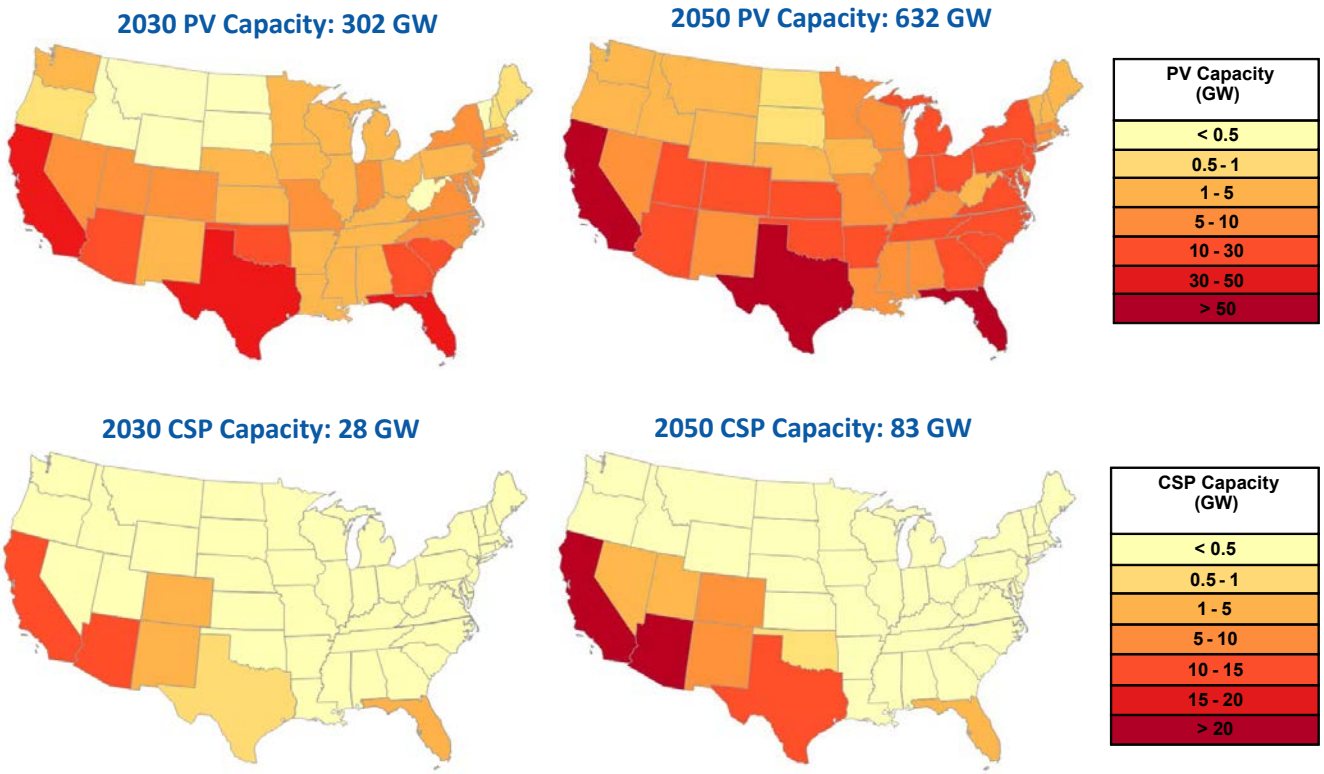
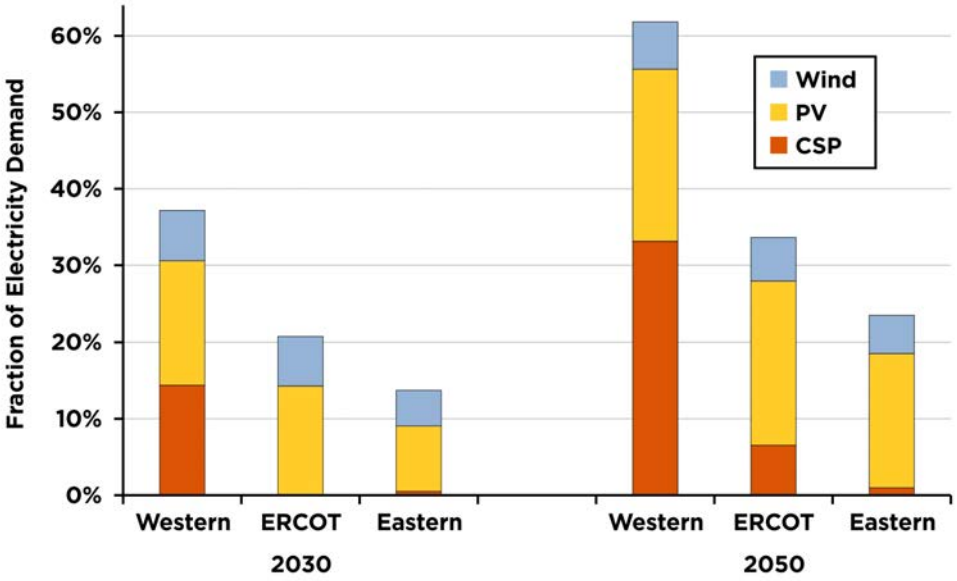


Figure 3-7. Fractions of Electricity Demand Met by CSP, PV, and Wind in Each Interconnection for the SunShot Scenario



clearly a concern. However, CSP with storage can be operated as a dispatchable resource to help integrate variable renewable resources. Grid operability is discussed in Section 3.2.6.

Although solar resources are preferentially deployed in the Western and ERCOT Interconnections, seen by the higher fraction of electricity demand met by solar resources, the larger population and electricity demand in the Eastern Interconnection leads to significantly higher PV capacity additions there than in the Western and ERCOT Interconnections combined. Table 3-3 summarizes the PV and CSP capacity built by interconnection in the SunShot scenario for 2030 and 2050. The majority of PV capacity is installed in the Eastern Interconnection (63% by 2030, 70% by 2050), and the majority of CSP capacity is installed in the Western Interconnection (87% by 2030, 81% by 2050).

Table 3-3. Solar Deployment by Interconnection in the SunShot Scenario

Interconnection	2030		2050	
	PV	CSP	PV	CSP
Eastern	190 GW (63%)	3 GW (12%)	442 GW (70%)	9 GW (11%)
ERCOT	32 GW (11%)	<1 GW (1%)	59 GW (9%)	7 GW (9%)
Western	79 GW (26%)	24 GW (87%)	130 GW (21%)	67 GW (81%)
Total	302 GW	28 GW	632 GW	83 GW

3.2.5 Transmission Requirements

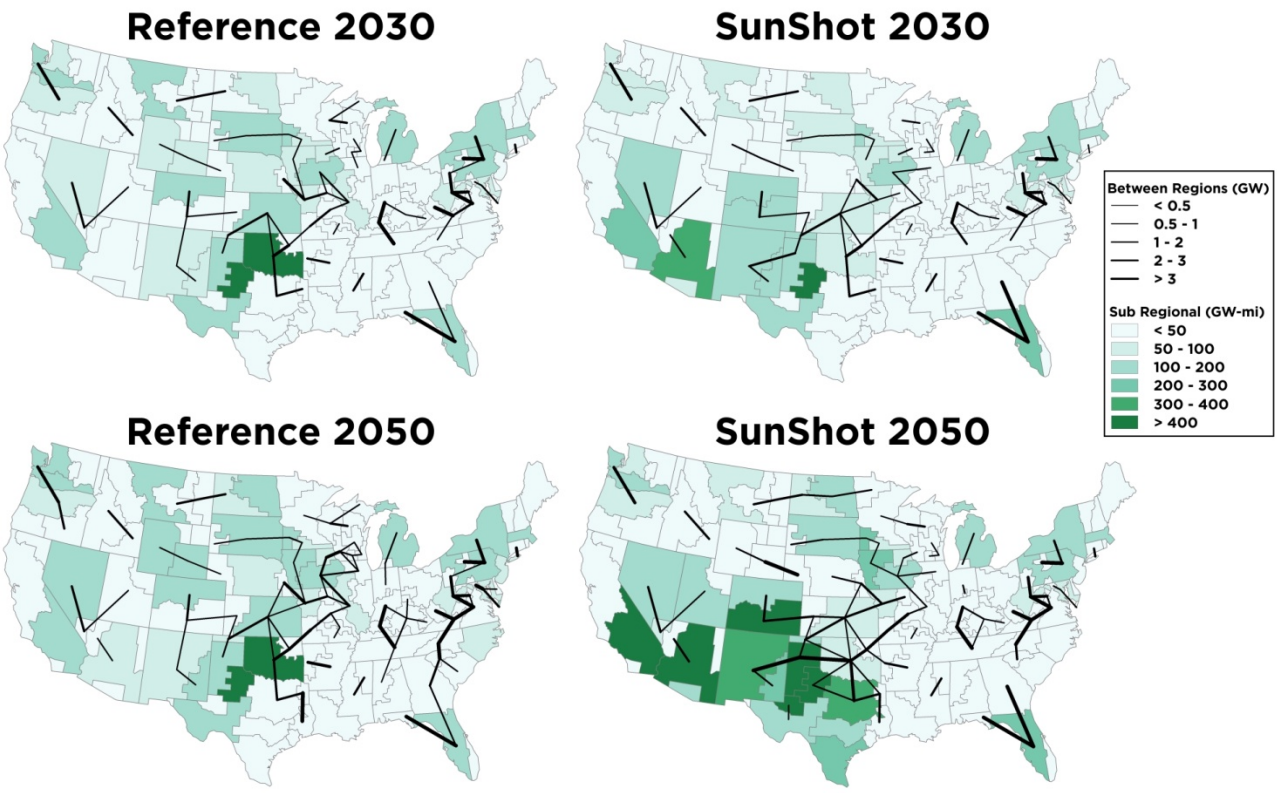
U.S. transmission resources are projected to increase in both the reference and SunShot scenarios. In the reference scenario, growing electricity demand met primarily by new conventional and wind resources necessitates expanded transmission. In the SunShot scenario, transmission is similarly expanded to serve growing demand, but is built out differently in order to develop solar resources.

Figure 3-8 shows the transmission expansion for the SunShot and reference scenarios by 2030 and 2050 as modeled using ReEDS. Transmission expansion includes capacity additions within each region to connect CSP and wind resources to the existing transmission network, and capacity built between regions to enhance the existing transmission network. The transmission infrastructure and cost required to connect utility-scale PV to the grid is assumed to be similar to that for conventional generation since PV resources can frequently be sited near load centers or existing transmission lines. Interregional transmission is expanded in ReEDS to connect different power control areas (PCAs)[28] and is primarily built to connect remote solar and wind resources to load centers. Existing interregional transmission is characterized using the historical transmission development in the United States. A detailed description of the transmission assumptions and model characterization is included in Appendix A.

Transmission expansion is highest in the southwest United States in the SunShot scenario, to connect CSP resources to load centers. Similar cross-interconnection lines are built to connect the Western and Eastern Interconnections in the western plains states in both the reference and SunShot scenarios. These are likely built to

[28] Though existing Balancing Authority (BA) area boundaries are considered in the design of the power control areas (PCAs), the PCA boundaries are generally not aligned with the boundaries of real BA areas. In ReEDS, PCAs are the regional level at which demand requirements are satisfied. See Chapter 6 and Appendix A for a more detailed description of BA areas.

Figure 3-8. Transmission Capacity Additions (Intraregional Capacity Expansion Shown by Color, Interregional Expansion Shown by Lines)



support wind development in both scenarios, and to increase power flow between interconnections. The reference scenario shows more transmission buildout in several midwest and plains states to accommodate increased wind development. Modeled transmission expansion is somewhat limited in parts of the Eastern Interconnection since transmission expansion is assumed to cost more (up to four times) than in other regions because of siting and regulatory challenges. Florida is an exception, and sees significant transmission expansion to meet growing demand and integrate some CSP capacity.

In the reference scenario, transmission capacity is expanded 15% from 2010 to 2030, growing from about 88,000 gigawatt-miles (GW-mi)[29] to 102,000 GW-mi in the model representation. This 15% growth supports a 21% assumed increase in U.S. electricity demand, and provides transmission for developing wind resources in the reference scenario. The SunShot scenario shows 13% transmission capacity expansion during this same period, growing to about 100,000 GW-mi. Less transmission expansion is projected in the SunShot scenario than in the reference scenario because a significant amount of utility-scale PV capacity is developed near

[29] Modeled transmission infrastructure is summarized here using the unit gigawatt-mile (GW-mi), which represents a transmission line that is rated to carry 1 GW of power over a distance of 1 mile. Model representation of transmission resources is more detailed than this summary metric, as described in Appendix A, and this simplifying measure is primarily used for reporting existing transmission resources, and the expansion of these resources within the modeling framework.

load centers and near existing underutilized[30] transmission infrastructure. By 2050, the reference scenario shows a 25% increase in transmission capacity relative to 2010 levels, reaching about 110,000 GW-mi, to meet the 40% increase in U.S. electricity demand. The SunShot scenario shows a 32% increase in transmission capacity by 2050, reaching about 117,000 GW-mi. Additional transmission is built in the SunShot scenario by 2050 primarily to connect remote CSP resources to load centers. The growth in transmission capacity is projected to be less than the increase in U.S. electricity demand in all scenarios.[31]

The projected cost of expanding transmission in the SunShot and reference scenarios is low compared to the overall cost of generating electricity. The discounted cost of expanding transmission capacity from 2010 to 2050 is about $60 billion (2010 dollars) in both scenarios. The discounted cost[32] for the SunShot scenario is approximately the same as for the reference scenario, even though more transmission capacity is built, because this additional capacity is developed later in the study period whereas the reference scenario develops more transmission capacity earlier in the period. The $60 billion transmission investment required in both scenarios is spread out over 40 years, representing about 2% of the total electric-sector costs (see Section 3.3.1). This level of investment is within the historical range of U.S. transmission expenditures by investor-owned utilities, which was $2–$9 billion per year between 1995 and 2008 (Pfeifenberger et al. 2009).

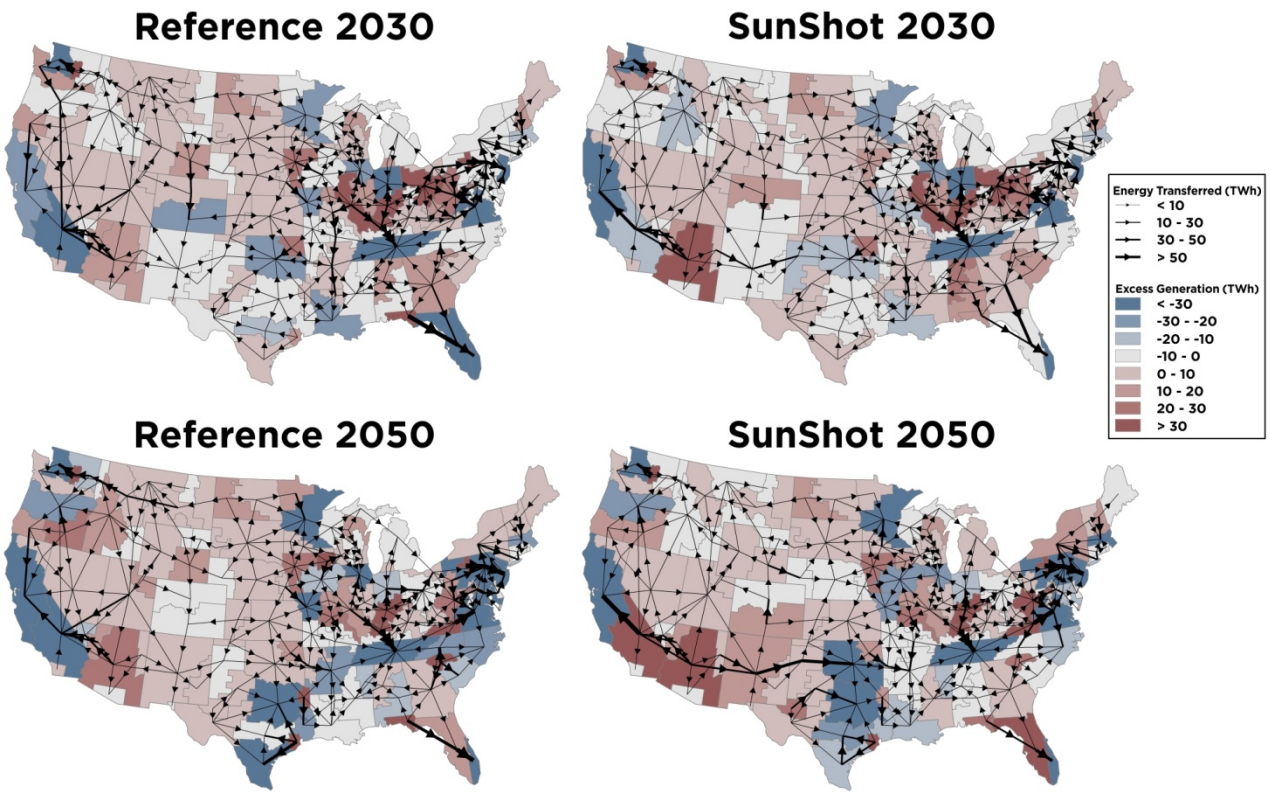
Figure 3-9 shows the mean regional energy imports, exports, and interregional energy transmission for the SunShot and reference scenarios. Regions that generate more electricity from all sources than local demand are shown in red, and importing regions are shown in blue. The mean geographic structure of electricity exporting and importing regions is similar in the reference and SunShot scenarios. The main difference is that in the SunShot scenario, the southwestern United States becomes a significant electricity exporting region by 2050 because of CSP deployment. CSP electricity is primarily exported into West Coast electricity markets. Florida also generates significantly more electricity in the SunShot scenario relative to the reference scenario, primarily because of regional PV deployment. While there are several regional differences in electricity generation and interregional transport between the reference and SunShot scenarios, these are generally small or localized. This suggests that, while there are a few regional differences, the SunShot scenario does not fundamentally change where electricity is generated and transported, which is consistent with the relatively low amount of transmission expansion required in the SunShot scenario relative to the reference scenario (Figure 3-8).

[30] As existing electricity generation capacity is retired during the study period, some transmission capacity resources become underutilized, representing an opportunity for developing solar resources to take advantage of excess transmission capacity.

[31] The ReEDS model likely underestimates transmission requirements for several reasons, including: 1) the model does not characterize the potential need for developing new intraregional transmission capacity beyond what is required to connect generation resources to the existing grid, 2) the modeling framework assumes generation resources can be developed incrementally, at any size, relieving the need for transmission to multiple destinations from a large new power plant, 3) the model does not include a detailed treatment of siting restrictions for conventional and renewable generation resources. Model transmission assumptions are described in more detail in Appendix A.

[32] Transmission costs include grid-interconnection fees (for conventional and renewable resources) in addition to building and maintaining transmission lines.

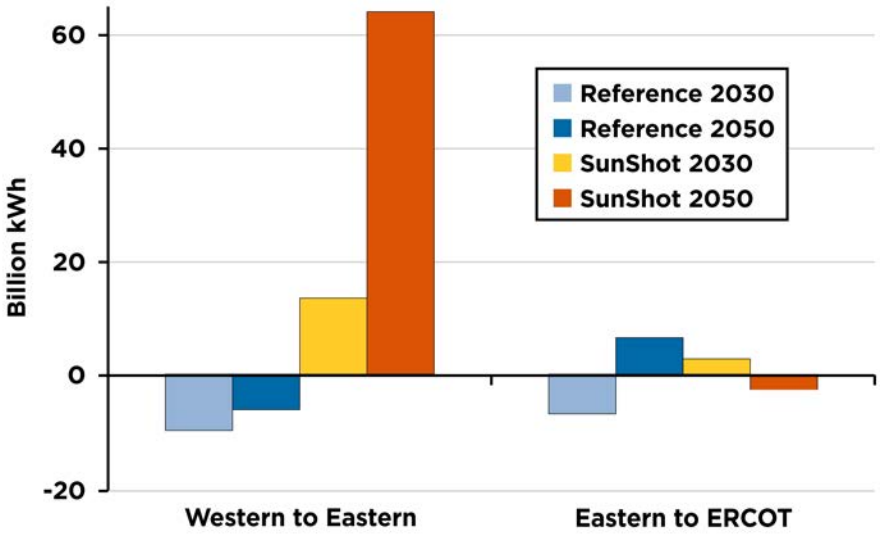
Figure 3-9. Mean Transmitted Energy Showing Net Exporting (Red) and Net Importing (Blue) Regions and Interregional Energy Transmission (Arrows)



Most regions in the Western Interconnection are net exporters in the SunShot scenario, with surplus electricity transmitted to the Eastern Interconnection (Figure 3-10). Net annual exports from the Western to the Eastern Interconnection reach about 14 terawatt-hours (TWh) per year by 2030, or about 2% of the electricity demand in the Western Interconnection. By 2050, the net energy exported from the Western to the Eastern Interconnection increases to about 64 TWh each year, or about 7% of the Western Interconnection's annual electricity demand. In the reference scenario, the Western Interconnection is a small net importer of electricity from the Eastern Interconnection, primarily wind electricity sited in the plains states. All other energy transfers between interconnections are small in comparison to exports out of the Western Interconnection in the SunShot scenario.

To facilitate energy transfer between interconnections, the transmission capacity crossing interconnection boundaries is expanded. In 2010, only a few gigawatts of transmission capacity link the Eastern Interconnection with the Western and ERCOT Interconnections. In the SunShot scenario, the Eastern and Western Interconnections are linked by 7 GW of transmission capacity by 2030 and 18 GW by 2050. The Eastern and ERCOT Interconnections are linked by 4 GW of transmission capacity by 2030 and 5 GW by 2050. The Western and ERCOT Interconnections currently do not have transmission capacity linking each other, and building of this transfer capacity was not simulated because of the small geographic boundary shared by these interconnections, in a location that is far from load centers.

Figure 3-10. Net Energy Transmitted Between Interconnections (Negative Values Represent Imported Energy, Positive Values Represent Exported Energy)



While the increase in transmission capacity and net energy exports between interconnections represents a significant expansion of existing resources and energy transfer, the required growth represents more of an economic and policy challenge in developing new direct current (DC) interconnection capacity than a technical barrier to increasing the amount of electricity transferred between interconnections. This is discussed in detail in Chapter 6.

3.2.6 Operational Impacts

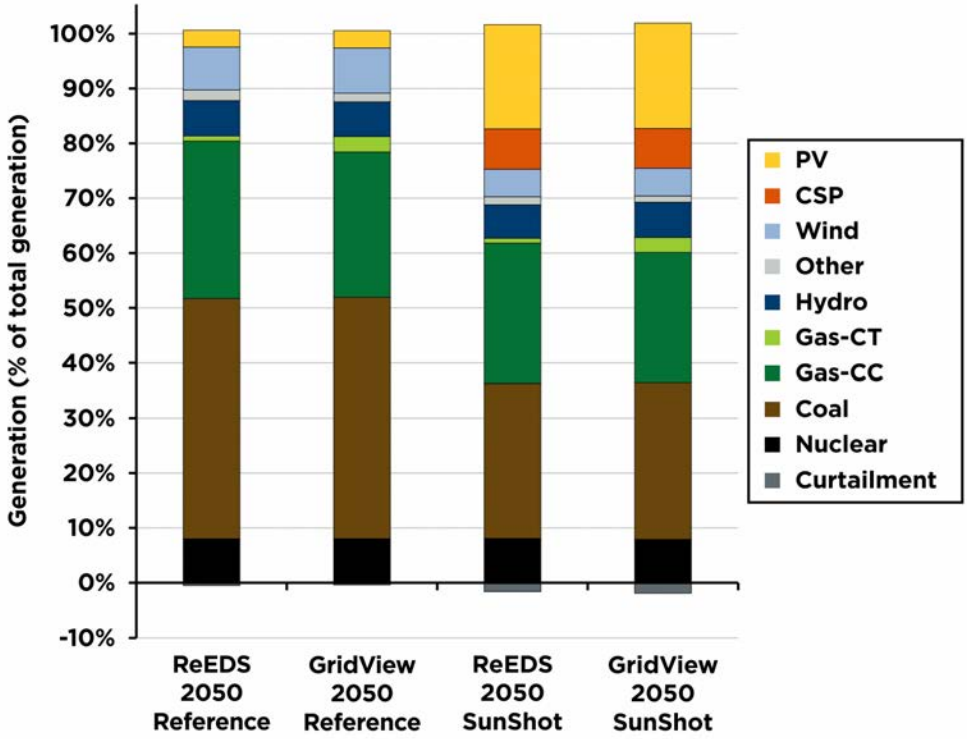
The ReEDS model, used to develop and evaluate the SunShot scenario, uses a reduced-form dispatch and transmission model that cannot completely capture many of the integration and transmission challenges explored in the SunShot scenario. GridView[33] was used to check the basic operability of the SunShot scenario in 2050, including analysis of transmission-flow constraints. In particular, ReEDS and GridView were compared with regard to how they dispatch generation resources, transmit and curtail electricity, and analyze electric-sector fuel use and emissions. In general, the GridView analysis helped confirm that the ReEDS dispatch method produces comparable results to a more detailed dispatch model.

The ReEDS-based SunShot and reference scenarios were imported into GridView, including the generator fleet, transmission network, and DC ties between the three interconnections. The transmission capacity built in ReEDS was augmented across some interfaces because GridView models more congestion compared to ReEDS due to parallel-flow constraints not considered in ReEDS. This led to additional transmission capacity equivalent to 12% of 2010 interzonal transmission capacity in the SunShot scenario, compared to an 11% addition in the reference scenario.

[33] GridView is one of several commercially available utility simulation tools that combines security-constrained unit commitment, economic dispatch, and optimal power flow to optimally dispatch a power plant fleet and provide reliable electricity at the lowest cost. GridView is described in further detail in Appendix A.

The GridView simulations confirm the basic hourly operational feasibility of the SunShot scenario developed in ReEDS. Electricity demand and operating reserves are completely served in all areas during every hour of the year. Also, electric-sector operating parameters—primarily fuel use and generation mix—are very similar in ReEDS and GridView (Figure 3-11). In the GridView simulation, coal provides 44% of generation in the reference scenario and 28% of generation in the SunShot scenario—compared with 43% and 28% in ReEDS. GridView dispatches natural gas units to generate 29% of electricity demand in the reference scenario and 26% in the SunShot scenario—compared to 30% and 26% in ReEDS. GridView projects that each megawatt-hour (MWh) of solar energy produced would displace a mix of 0.64 MWh from coal units and 0.16 MWh from gas units based on the available gas and coal generators projected by ReEDS. The remaining 0.20 MWh would be displaced wind generation or curtailment.

Figure 3-11. Comparison of the National Generation Mix Simulated in GridView and ReEDS for the Reference and SunShot Scenarios, 2050

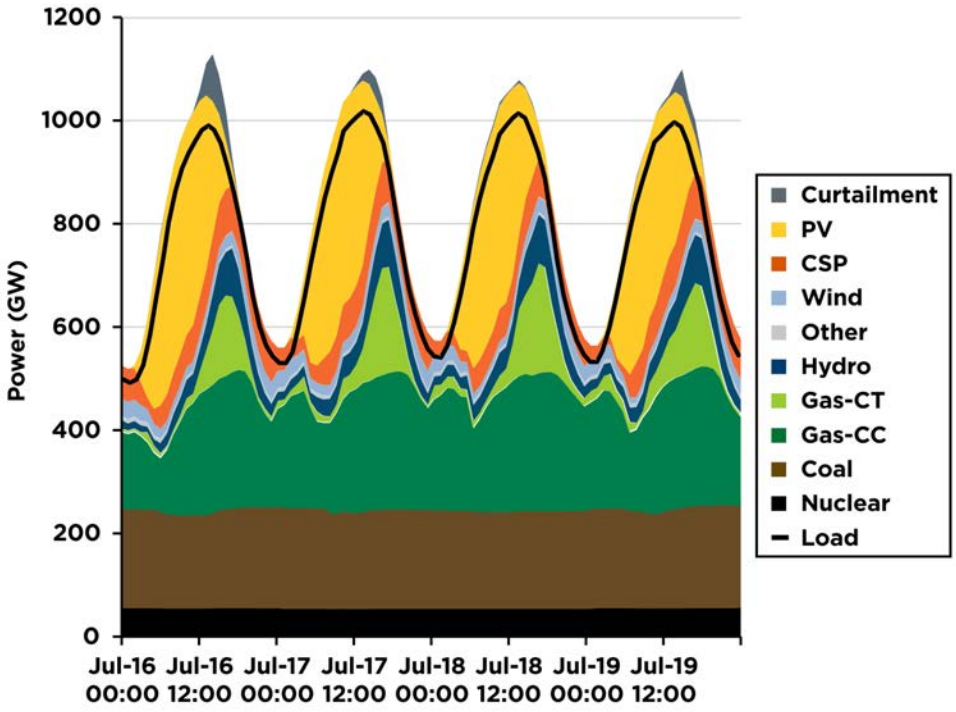


The hourly GridView modeling shows that the SunShot scenario introduces operational challenges and that some solar energy is curtailed, particularly during periods of peak solar output and low demand. The GridView simulation of the SunShot scenario shows 90 TWh of curtailment in 2050, representing 1.8% of the demand and 5.3% of wind and solar generation; ReEDS simulates 80 TWh, representing 1.6% of demand and 4.6% of wind and solar generation. In the reference scenario, GridView curtails 1 TWh of wind and solar energy, while ReEDS curtails 17 TWh of wind energy. The differences in simulated curtailment are primarily caused by the different treatment of transmission in each model (see Appendix A).

Although the annual curtailment estimates are relatively modest, curtailment can be significant during some periods. Fifty-five percent of curtailment occurs between April and June, mostly during mid-day. During this spring period, solar, wind, and hydroelectric generation are all at or near their peak output, while demand is still low compared with the overall summer peak. Curtailment could be reduced by adding transmission capacity, to send excess electricity to areas with unmet demand, or by utilizing energy storage. However, the ReEDS model does not build large amounts of storage capacity or additional transmission capacity because the added cost of investing in these resources is higher than the benefit of reducing curtailment during a relatively small number of hours. Eighty-two percent of the curtailment occurs in the Western Interconnection, which is due to limited transmission capacity to the major load centers in the eastern United States.

Figure 3-12 shows the hourly dispatch from GridView for the entire United States during a typical 4-day summer period in the SunShot scenario in 2050. Electricity load is shown by a black line—the difference between generation and load is due to transmission losses—and curtailment is shown by the grey above the load line. Although most summer days show little or no curtailment, some days, such as July 16, representing a Sunday, show significant curtailment during midday because of the combination of higher solar output and lower demand. CSP units with thermal storage generate at more than half capacity during all hours and generate near peak capacity during the evening after PV generation has decreased but load is still high. The peak net load (load minus wind and PV) shifts from approximately 3 or 4 p.m. local time for a given electric power system with insignificant PV penetration to approximately sunset in the SunShot scenario. This is true during all seasons in most

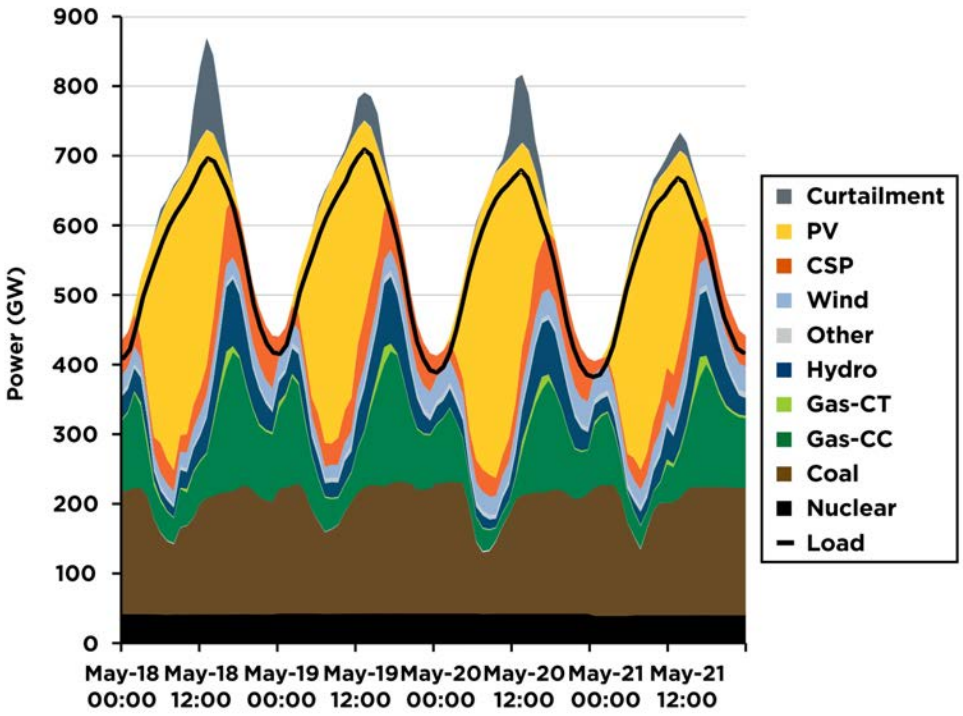
Figure 3-12. GridView-Simulated National Mean Dispatch Stack During 4 Days in Summer for the SunShot Scenario in 2050



areas in the SunShot scenario. During these evening hours, the remaining thermal generators ramp to provide additional energy. The flexibility of CSP generators allows them to produce electricity at maximum capacity during the evening peak in net load.

Figure 3-13 shows the hourly dispatch for a typical 4-day period during May for the SunShot scenario in 2050. During spring, peak electricity demand is up to 40% lower than the summer peak, and renewable generation is high. Any generation resource with no marginal production cost, such as wind, PV, CSP, hydropower, and geothermal, could be curtailed without changing the overall production cost. This curtailment is dominated by curtailment in the Western Interconnection, and is primarily attributed to CSP in GridView. The CSP capacities described in the SunShot growth trajectories represent systems with up to 12 hours of storage and an average solar multiple of 2.6.[34] For the SunShot scenario in 2050, the 81 GW of installed CSP capacity with storage represents approximately 210 GW of instantaneous power from the solar field. The curtailment of more than 100 GW on May 20 represents times when CSP thermal storage capacity is "full," and excess power from the solar field is curtailed. Although curtailment in the Western Interconnection is significant, the amount of curtailment in the ERCOT and Eastern Interconnections during this period is small.

Figure 3-13. GridView-Simulated National Mean Dispatch Stack During 4 Days in Spring for the SunShot Scenario in 2050



[34] The solar multiple is the ratio of the peak thermal power generated by the solar field to the power required to operate the thermal generator at peak capacity. A solar multiple greater than one represents a system with increased solar collector area, and the additional thermal energy can be used to increase system capacity factors by running the generator at peak load for more hours each year.

Several modeling assumptions affect the amount of curtailed solar and wind energy. For example, GridView uses a conservative estimate of the ability to redispatch hydropower. Although there are significant limitations related to real-world dispatch of hydro resources, there may be additional flexibility to reschedule these resources to reduce curtailment.

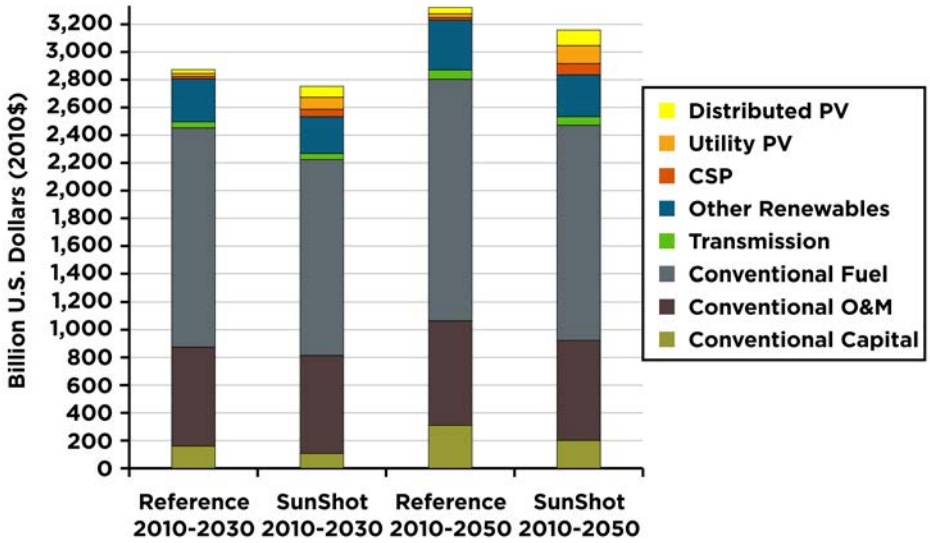
3.3 Costs and Benefits

Achieving the SunShot price targets has the potential to reduce electric-sector costs and retail electricity prices, reduce greenhouse gas (GHG) emissions, and create a robust solar sector based on increasing solar employment. These impacts are discussed below. Additional environmental and financial impacts are discussed in Chapters 7 and 8, respectively.

3.3.1 Costs

Direct electric-sector costs include the cost of investing in renewable and conventional generation capacity as well as costs for operation and maintenance (O&M), fuel, and expanding transmission capacity. Figure 3-14 shows the electric-sector costs for the reference and SunShot scenarios, calculated using 2010 U.S. dollars adjusted with a 7% real discount rate.[35] The PV and CSP installed prices are based on SunShot price targets and the financing assumptions outlined in Table 8-1 of Chapter 8. The costs shown in Figure 3-14 represent the cost of expanding generation and transmission capacity for the years shown plus operating the systems (incurring fuel and O&M costs) for an additional 20 years. Thus, the "2010-2030" costs include the cost of building and operating the generation capacity/transmission during 2010-2030 plus operating it during 2030-2050. The "2010-2050" costs

Figure 3-14. Direct Electric-Sector Costs for the Reference and SunShot Scenarios



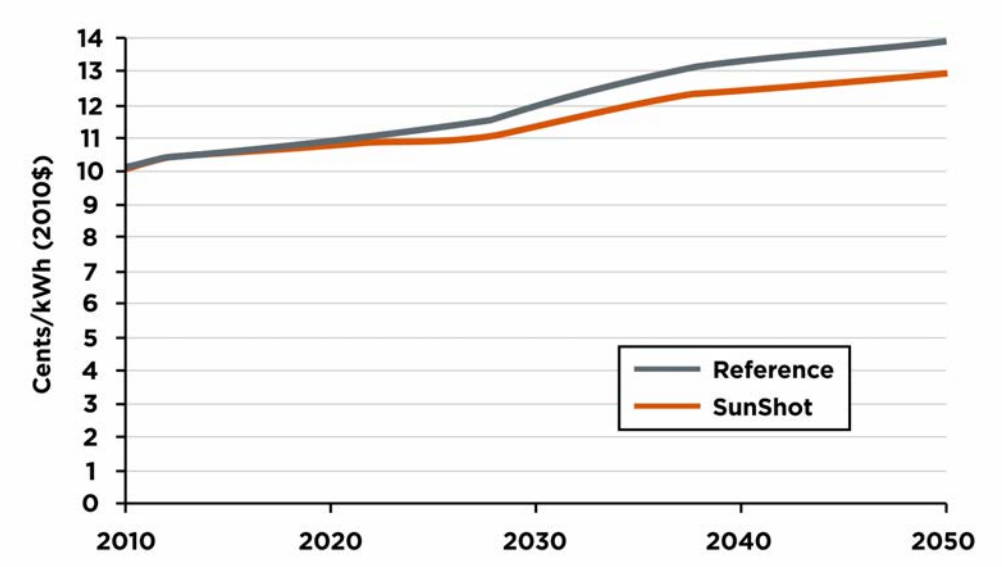
[35] See Chapter 8 for a detailed discussion of electric-sector costs and discounting.

include the cost of building and operating the generation capacity/transmission during 2010-2050 plus operating it during 2050-2070. The costs in Figure 3-14 do not account for incentives, such as the federal investment tax credit (ITC), but they do include rooftop PV installations that will be financed by end users. Because of this, the direct costs incurred by electric service providers for the solar technologies in the SunShot scenario are less than those shown in Figure 3-14. However, electric-sector costs do not include the cost of upgrading and maintaining the distribution system, which could add significant cost to the reference and SunShot scenarios (see Chapter 6).

In the SunShot scenario, the cost of developing solar resources is more than offset by annual fuel savings and reduced capital and O&M expenditures from other technologies. Based on *AEO 2010* (EIA 2010), projected fuel prices that are adjusted for higher or lower fuel demand within each scenario, annual fuel savings in the SunShot scenario reach $34 billion by 2030 and $41 billion by 2050, relative to the reference scenario. For both scenarios, transmission costs are significantly less than the costs of investing in new generation capacity, O&M, and fuel.

Figure 3-15 shows mean retail electricity rates (2010 dollars) charged to end users through 2050. Mean U.S. retail rates are about 5% lower in the SunShot scenario by 2030 and 7% lower by 2050 relative to the reference scenario. This corresponds to a 0.6 cents/kilowatt-hour (kWh) reduction in retail rates by 2030 in the SunShot scenario and 0.9 cents/kWh reduction by 2050 relative to the reference scenario. The lower costs in the SunShot scenario result in about a $6 savings per household, per month by 2030, and about a $9 savings per household, per month by 2050.[36] Real electricity rates increase by about 40% in the reference scenario based on the assumed increase in real natural gas and coal prices in *AEO 2010*. Across all market sectors, the lower electricity prices in the SunShot scenario translate into about $30 billion in annual cost savings by 2030 and $50 billion in annual savings by 2050.

Figure 3-15. Average U.S. Retail Electricity Rates in the SunShot and Reference Scenarios



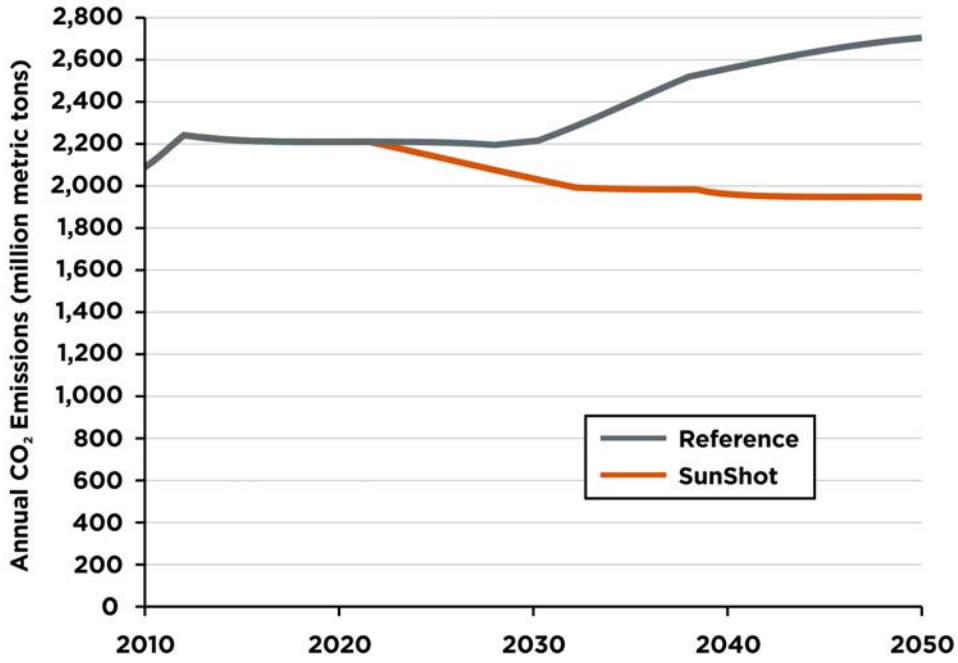
[36] Assuming average household electricity use of about 12,000 kilowatt-hours (kWh) per year, calculated using energy use and household growth statistics from *AEO 2010* (EIA 2010).

Retail electricity rates include the cost of generation, transmission, and distribution. The costs of generation and transmission are captured in the ReEDS model. Distribution costs are based on average historical costs for the entire U.S. electric-power sector, which is assumed to remain regulated. End-use rooftop PV investments do not significantly impact wholesale electricity rates.[37]

3.3.2 Carbon Emissions

Achieving the SunShot price targets could significantly reduce U.S. electric-sector carbon emissions. Figure 3-16 shows electric-sector carbon dioxide (CO_2) emissions for the reference and SunShot scenarios. In the reference scenario, electric-sector emissions increase by 6% from 2010 to 2030, caused by the 21% increase in electricity demand that is partially offset by increasing wind generation and a higher fraction of natural gas generation. Emissions in the SunShot scenario decrease by 3% from 2010 to 2030, where solar generation more than offsets emissions from demand growth. In 2030, emissions in the SunShot scenario are 8% lower than the reference scenario. Emissions in the reference and SunShot scenarios increase briefly after 2010, reflecting increased demand and higher natural gas fuel prices during the recovery from the current economic downturn.

Figure 3-16. Annual Electric-Sector CO_2 Emissions in the SunShot and Reference Scenarios



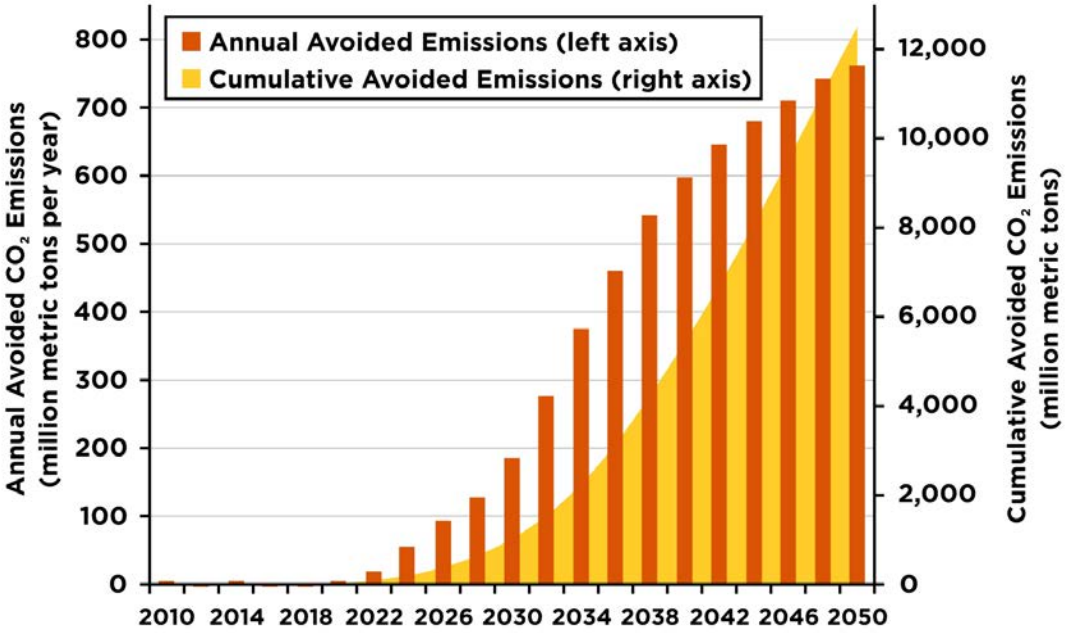
By 2050, CO_2 emissions in the reference scenario increase 29% beyond 2010 levels, due in large part to the expansion of new coal capacity and generation between 2030

[37] End-use distributed photovoltaic (PV) investments are similar to energy-efficiency investments in that customers spend money to reduce the amount of electricity they purchase from the utility. While the customer, not the utility, pays for this investment, it can affect utility rates by reducing daytime demand in load centers. This impact of rooftop PV on mean wholesale electricity rates is characterized in the modeling framework; however, the costs and benefits of integrating PV on distribution networks are not characterized.

and 2050. By offsetting this expansion of new coal capacity, the SunShot scenario achieves a significant reduction in CO_2 emissions. Emissions in the SunShot scenario decrease by 7% from 2010 to 2050, and 2050 emissions in the SunShot scenario are 28% below 2050 emissions in the reference scenario.

Figure 3-17 shows annual and cumulative CO_2 emissions reductions from the SunShot scenario relative to the reference scenario. The cumulative avoided emissions by 2030 and by 2050 would total about 900 and 12,500 million metric tons (MMT) of CO_2, respectively. However, the PV and CSP systems deployed in the SunShot scenario will continue to operate beyond 2050, leading to even greater emissions reductions. If the electric-power sector developed in the SunShot scenario was operated through 2070, the cumulative avoided emissions would be about 27,700 MMT of CO_2.

Figure 3-17. Annual and Cumulative Electric-Sector Emissions Reductions in the SunShot Scenario Relative to the Reference Scenario



3.3.3 EMPLOYMENT

As the U.S. solar industry expands under the SunShot scenario, additional skilled workers will be needed to design, manufacture, distribute, install, and maintain solar systems. Estimating SunShot employment impacts requires accounting for two classes of jobs: 1) manufacturing/distribution and installation jobs for PV and CSP, based on annual production and installation demand and, 2) operations and maintenance jobs for PV and CSP, based on the cumulative deployed solar capacity. SunShot employment estimates are based on gross job creation.[38] Several assumptions are necessary to estimate job growth, including the increase in domestic manufacturing capacity to meet solar market demand, the impact of automation on

[38] Gross job estimates represent jobs that are directly tied to solar markets, whereas a net jobs estimate would account for the potential displacement of jobs in other sectors, such as coal or natural gas industries.

manufacturing labor intensities, and the increase in labor productivity due to streamlining solar manufacturing and installation methods.[39] SunShot job estimates were developed by establishing the current job intensity for PV and CSP, and then accounting for improved labor productivity as solar price and performance improvements are achieved. For this analysis, a full-time equivalent (FTE) job is defined as 2,000 hours per year of employment, which could represent a single full-time employee or several part-time employees.

PV job intensities for 2010 were estimated based on the Solar Foundation's National Solar Jobs Census, which included about 2,500 interviews with employers in each major sector of the solar value chain across solar technologies (Solar Foundation 2010). The study estimated 93,500 direct and indirect U.S. workers with greater than 50% focus on solar in four major market industry sectors: installation, wholesale trade, manufacturing, and utilities. Accounting for the fact that not all of these employees work full time on solar, this level of employment translates into roughly 60,000–70,000 FTE jobs. These FTEs include both direct and indirect jobs; however, induced impacts were not part of the study. Based on the data gathered in this study, PV workers outnumber those focused on solar thermal technologies by about 2.5 to 1 (with many companies engaged in both PV and solar thermal). Thus, of the total estimated FTE jobs, the PV workforce was approximately 40,000–50,000 FTEs, as of the July/August 2010 time frame during which the data were gathered. These were split almost equally between PV manufacturing/distribution and installation. Table 3-4 uses the mid-point of this range (45,000 FTEs) as the 2010 benchmark for estimating jobs per megawatt (MW) in PV manufacturing, distribution, and installation.

Based on an estimated 0.9 GW of U.S. PV installations in 2010, the resulting job intensities were roughly 25 jobs per megawatt in manufacturing/distribution and 25 jobs per megawatt in installation. The operation and maintenance job intensity for PV in 2010 was estimated at 0.5 jobs per MW. These 2010 U.S. PV job intensity estimates are considerably higher than one would expect in an efficient manufacturing/distribution supply chain and installation infrastructure. The fact that they are relatively high is not surprising given that the U.S. PV industry in 2010 was in a scale-up phase, where a significant fraction of FTE jobs were likely focused on business development, research and development (R&D), regulatory issues, and production scale-up.

[39] A number of other factors can create variability in published job estimates, including the following: data collection and analysis methods, types of jobs being considered, types of occupations being considered, variation in estimates of capacity being installed, types of industry subsectors included, variation in metrics or units being used, and variation in the time periods being considered.

Table 3-4. Solar Industry Jobs Supported in the SunShot Scenario

	2010	2030	2050
PV Employment			
Jobs index[a]	1	0.2	0.2
Annual installed PV capacity (GW)	0.9	25	30
Cumulative installed PV capacity (GW)	2.5	302	631
PV manufacturing and distribution jobs/MW	25	5	5
PV installation jobs/MW	25	5	5
PV O&M jobs per MW	0.5	0.1	0.1
PV manufacturing and distribution jobs[b]	22,500	125,000	150,000
PV installation jobs[b]	22,500	125,000	150,000
PV O&M jobs[c]	1,250	30,100	63,100
Total PV industry jobs[e]	46,000	280,000	363,000
CSP Employment			
Jobs index[d]	1	0.33	0.33
Annual installed CSP capacity (GW)	0.1	4	4
Cumulative installed CSP capacity (GW)	0.5	28	83
CSP manufacturing and distribution jobs/MW	25	8.3	8.3
CSP installation jobs/MW	15	5	5
CSP O&M jobs per MW	1	0.33	0.33
CSP manufacturing and distribution jobs[b]	2,500	33,300	33,300
CSP installation jobs[b]	1,500	20,000	20,000
CSP O&M jobs[c]	500	9,300	27,700
Total CSP industry jobs[e]	4,500	63,000	81,000
Total Solar Industry Employment[e]	**51,000**	**343,000**	**444,000**

[a] The PV jobs index is based on the decline in PV prices in residential, commercial, and utility-scale markets (Chapter 4) and improved labor productivity as PV markets mature.
[b] The manufacturing and installation jobs are proportional to the annual installed capacity (i.e., equal to the annual installed capacity × manufacturing/installation jobs per MW).
[c] The O&M jobs are proportional to the cumulative installed capacity (i.e., equal to the cumulative installed capacity × O&M jobs per MW).
[d] The CSP jobs index is based on the declining cost of CSP-generated electricity (Chapter 5). The move to increasing levels of thermal storage means that CSP costs—and employment intensities—are not expected to decline as rapidly as PV costs.
[e] These include direct and indirect (e.g., supply chain) jobs supported as a result of increased solar-industry activity. These do not include induced jobs. Some categories may not add exactly due to rounding errors, and jobs numbers should be interpreted as rough estimates.

CSP job intensities for 2010 were based roughly on McCrone et al. (2009), with job intensities adjusted slightly upward to account for labor inefficiencies during industry scale-up. As with PV, a significant fraction of U.S. CSP full-time equivalent jobs in 2010 were likely focused on business development, R&D, regulatory issues, and production scale-up. CSP job intensities were estimated at 25 jobs per MW in manufacturing/distribution and 15 jobs per MW in installation. The operation and maintenance job intensity for CSP in 2010 was estimated at one job per MW. This represented about 4,500 FTE CSP jobs in the United States in 2010.

The 2010 labor intensities represent market dynamics for current PV and CSP prices. These labor intensities will need to decrease significantly as solar markets mature and prices decrease in the SunShot scenario. The PV job intensities are assumed to decrease by a factor of five by 2020, corresponding to both a decrease in PV prices and an increase in PV supply chain and installation efficiencies as PV markets mature. The CSP job intensities are assumed to decrease by a factor of three by 2020, based on the combination of CSP price reductions and the transition from plants that have historically been built with little or no thermal storage to building plants with several hours of storage.[40]

Through 2010, U.S. solar technology production has been more than sufficient to meet U.S. demand. Given that an important component of the SunShot Initiative is enabling and encouraging the scale-up of the U.S. solar industry, it is assumed here that U.S. solar demand will continue to be met largely by domestic solar manufacturing, distribution, and installation.

Table 3-4 summarizes SunShot solar employment projections for 2030 and 2050. Under the SunShot scenario, gross solar jobs could increase from roughly 51,000 FTE jobs in 2010 to 340,000 FTE jobs in 2030 and to 440,000 FTE jobs in 2050. This could support about 290,000 new jobs by 2030, and 390,000 new jobs by 2050. About 80% of solar jobs are estimated to be produced by PV market growth, and about 20% from CSP market growth.

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[40] The factor of three intensity reduction is based on decreasing CSP levelized cost of energy (LCOE) from about 18 cents/kilowatt-hour (kWh) currently to around 6 cents/kWh in the SunShot scenario. The price of energy is a better proxy for basing job intensity than capacity costs for CSP because there is a large range in the amount of thermal storage capacity both in the historical labor data and in model projections.

Solar Foundation. (2010). *National Solar Jobs Census 2010*. Washington, DC: The Solar Foundation.

U.S. Energy Information Administration, EIA. (2010). *Annual Energy Outlook 2010*. Report No. DOE/EIA-0383 (2010). Washington, DC: U.S. EIA.

4. Photovoltaics: Technologies, Cost, and Performance

4.1 INTRODUCTION

Photovoltaic (PV) technologies currently supply only a small fraction of U.S. energy needs, largely because PV-generated electricity historically has cost more than electricity from conventional sources. Achieving the SunShot Initiative's PV cost-reduction targets—reducing the price of PV systems by about 75% by 2020—is projected to make PV competitive with conventional sources on a levelized cost of energy (LCOE) basis. Achieving this electricity price parity is projected to result in large-scale U.S. deployment of PV technologies, which would meet 11% of contiguous U.S. electricity demand in 2030 and 19% in 2050 (see Chapter 3 for detailed analysis of the SunShot scenario).

Over the past several decades, PV manufacturing costs and sales prices have dropped dramatically while experience accumulated by solar manufacturers and developers, utilities, and regulatory bodies has shortened the time and expense required to install a fully operating PV system. These gains have come partly through research, development, and demonstration (RD&D) and partly through market stimulation. Best-in-class installed PV prices in late 2010 were about $3/watt (W)[41] for utility-scale systems, with an average of about $3.80/W (Goodrich et al. 2010), and prices continue to decline following the global trend of continuous price and performance improvements.

Bringing PV prices down even further and more rapidly, to the SunShot levels, will require a combination of evolutionary and revolutionary technological improvements, in conjunction with, and in support of, substantial market and manufacturing scale-up. Concerted RD&D efforts are needed to create breakthrough technologies and processes that drastically reduce PV module, power electronics, and balance-of-systems (BOS) costs. This will also include a close collaboration with the private sector to ensure that new PV technologies are deployed commercially and installed in a cost-effective manner.

This chapter evaluates the current price and performance of PV technologies. Price projections representing incremental/evolutionary technological improvements are compared with the SunShot price projections. This analysis indicates that achieving the SunShot price-reduction targets will require going beyond evolutionary changes

[41] Note: all "$/W" units refer to 2010 U.S. dollars per peak watt-direct current (DC), unless specified.

to PV technologies; revolutionary steps forward are needed to achieve the SunShot targets.

The availability of key PV materials and the required scale-up of PV manufacturing capacity are also evaluated. Increased production and improved utilization of PV materials should enable the PV growth projected under the SunShot scenario. Rapid PV manufacturing capacity scale-up is possible and should not constrain SunShot levels of PV growth.

4.2 TODAY'S PV TECHNOLOGY

Current PV technology is the result of decades of performance and price improvements. This section describes the components that make up a PV system, the types of PV module technologies, and the history and current status of PV prices and performance.

4.2.1 COMPONENTS OF A PV SYSTEM

For the purpose of characterizing costs, PV systems can be classified into three subsystems: PV modules, power electronics, and BOS.

PV modules are made up of interconnected PV cells that convert sunlight directly into electricity. PV cells are fabricated from semiconductor materials that enable photons from sunlight to "knock" electrons out of a molecular lattice, leaving a freed electron and "hole" pair that diffuse in an electric field to separate contacts, generating direct-current (DC) electricity. This "photoelectric effect" has most commonly been generated with materials such as crystalline silicon (c-Si) and a range of thin-film semiconductors, which are described in the next subsection (Luque and Hegedus 2003).

The great majority of electrical applications require alternating-current (AC) electricity. For these applications, power electronics are required to convert and condition the DC electricity generated by the PV module into AC electricity suitable for customer use or transmission; most importantly, an inverter converts DC to AC, and a transformer steps the electricity up to the appropriate voltage. BOS comprises the remaining components and procedures required to produce a complete PV system, including mounting and wiring hardware, land, installation, and permitting fees.

4.2.2 PV MODULE TECHNOLOGIES

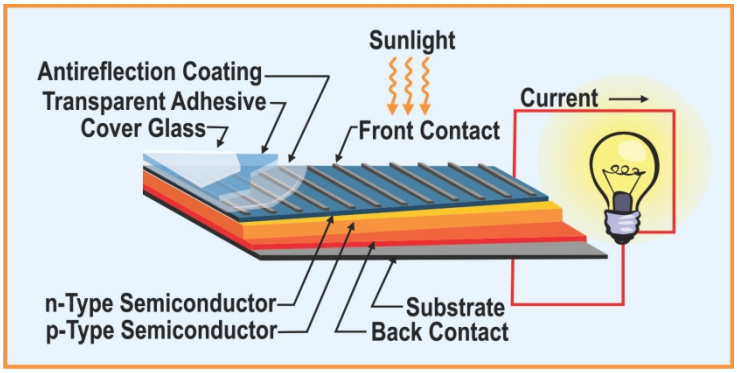
Several c-Si and thin-film PV technologies have been demonstrated commercially on a large scale. In addition, several emerging PV technologies may be technically and economically competitive in the future. This subsection briefly describes these types of PV module technologies. Efficiency is one important characteristic described in this subsection. The efficiency of a solar cell or module is the percentage of the sun's energy striking the cell or module that is converted into electricity.

Crystalline Silicon

Crystalline silicon technologies constitute about 85% of the current PV market (Mints 2011). This technology has a long history of reliable performance; c-Si modules have demonstrated operational lifetimes of more than 25 years (Jordan and Kurtz 2011).

There are two general types of crystalline, or wafer-based, silicon PV: monocrystalline and multicrystalline. Monocrystalline semiconductor wafers are cut from single-crystal silicon ingots. Multicrystalline semiconductor wafers are cut from directionally solidified blocks or grown in thin sheets. Monocrystalline ingots are more difficult, energy intensive, and expensive to grow than simple blocks of multicrystalline silicon. However, monocrystalline silicon produces higher-efficiency cells. For both types, the silicon is processed to create an internal electric field, and positive and negative electrical connections are added to wafers to form a cell (Figure 4-1). Standard cell processes are used to complete the circuit for both mono- and multicrystalline cells, and multiple cells are linked and encapsulated to form modules.

Figure 4-1. Basic Components of a c-Si PV Cell



Source: NREL

The rated DC efficiencies of standard c-Si PV modules are about 14%–16%. A number of new or non-standard cell architectures—such as back-contact cells—are growing in importance because they offer the potential for significantly higher efficiency. Non-standard cell architectures tend to use high-quality monocrystalline wafers and more sophisticated processing to achieve module efficiencies of about 17%–21%.

Thin Film

Thin-film PV cells consist of a semiconductor layer a few microns (μm) thick, which is about 100 times thinner than current c-Si cells. Most thin films are direct bandgap semiconductors, which means they are able to absorb the energy contained in sunlight with a much thinner layer than indirect bandgap semiconductors such as traditional c-Si PV. The most common thin-film semiconductor materials are cadmium telluride (CdTe), amorphous silicon (a-Si), and alloys of copper indium gallium diselenide (CIGS). The semiconductor layer is typically deposited on a substrate or superstrate inside a vacuum chamber. A number of companies are pursuing lower-cost, non-vacuum approaches for manufacturing thin-film

technologies. Glass is a common substrate/superstrate, but thin films can also be deposited on flexible substrates/superstrates such as metal, which allows for the potential for flexible lightweight solar modules. Thin films are very sensitive to water vapor and thus have traditionally been encapsulated behind glass to maintain performance. Eliminating the need for glass through the use of "ultra barrier" flexible glass replacement materials is an important next step in thin film development.

Thin-film modules have lower DC efficiencies than c-Si modules: about 9%–12% for CdTe, 6%–9% for a-Si, and 8%–14% for CIGS. CdTe-based PV has experienced significantly higher market growth during the last decade than the other thin-film PV technologies primarily due to the success of First Solar, which utilizes CdTe technology.

Concentrating PV

Concentrating photovoltaics (CPV) technologies use mirrors or lenses to concentrate sunlight 2–1,200 times onto high-efficiency silicon or multijunction (MJ) PV cells. CPV uses concentrating optics made out of inexpensive materials such as glass, steel, and plastic to focus sunlight onto a relatively small semiconductor area. This approach offers several significant benefits. First, it minimizes the amount of active semiconductor material (the material that converts sunlight into electricity) needed to produce a given amount of electricity. On an area basis, the active semiconductor material is the most complex and expensive component of many PV modules; this is particularly true for MJ cells. MJ cells are capable of much higher efficiencies than single junction silicon or thin-film cells. This is because each junction of a MJ cell is designed to collect a different part of the solar spectrum: MJ cells are typically a stack of three different cells on top of one another. This higher efficiency comes at an increase in manufacturing cost, and thus MJ devices are too expensive to use in terrestrial applications without concentration. The downside to CPV, especially for higher concentration levels, is that, in order to maintain the concentration of sunlight on the cell, the module must accurately track the sun throughout the day. Tracking results in a more complex and expensive installation. Recent improvements to MJ PV cells have produced cell efficiencies of 43.5% in the laboratory. Use of CPV systems for utility-scale electricity generation has been growing.

Emerging PV Options

A number of other PV technologies—frequently referred to as third-generation PV—are being developed. Dye-sensitized solar cells use dye molecules absorbed onto a nanostructured substrate and immersed in a liquid or gel electrolyte to absorb solar radiation and have demonstrated laboratory efficiencies as high as 11.1%. Organic PV (OPV) solar cells, based on polymers or small molecules with semiconductor properties, have demonstrated laboratory cell efficiencies above 8%; organic modules have the potential for low-cost manufacturing using existing printing and lamination technologies (Shaheen et al. 2005). Quantum dots—nanospheres with physical properties similar to both bulk semiconductors and discrete molecules—have the potential to achieve higher efficiencies through multiple exciton generation, but they have not yet been used to produce efficient PV cells.

There are significant challenges to the commercialization of solution-processed organic solar cells, dye-sensitized cells with certain electrolytes, and quantum dots due to the stability of the materials against oxygen and water ingress. This limits the lifetime of these devices to anywhere from a few hundred hours to 2 years. This issue is being addressed through efforts to develop improved, yet cost-effective, encapsulants. In addition, organic and dye-sensitized solar cells use dyes that have been shown to degrade when put in direct sunlight for long periods of time, a significant issue to have in a solar cell. Further research and development (R&D) is needed to improve the viability of these materials.

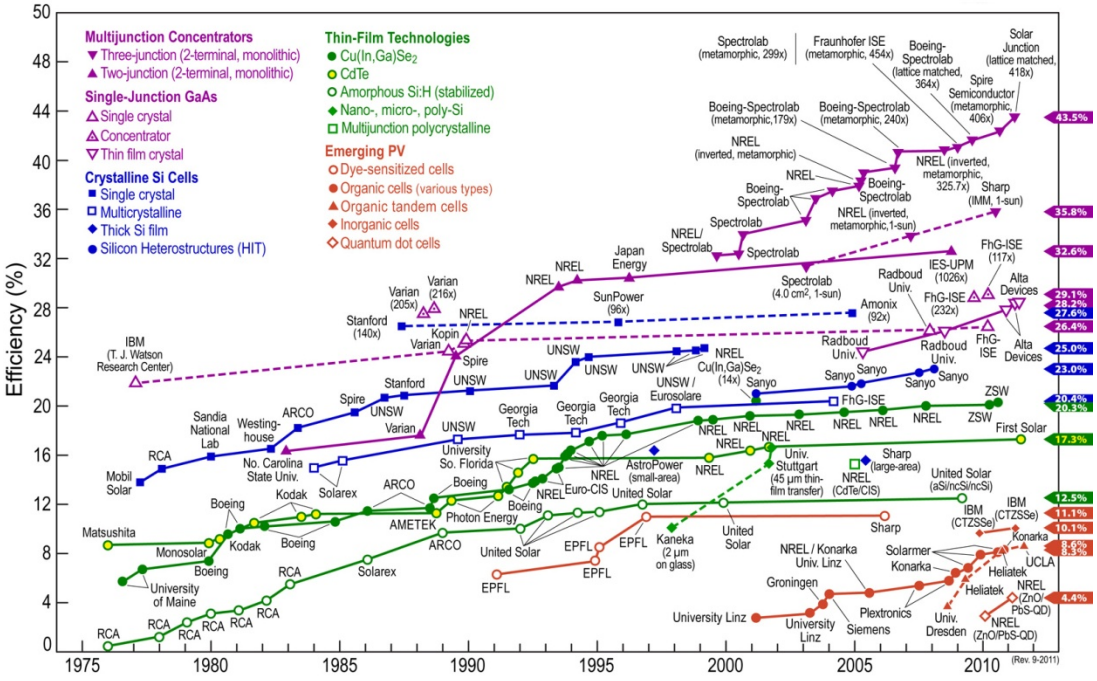
4.2.3 PV Performance and Price

The performance of PV technologies has improved substantially, while PV manufacturing costs have declined during the past several decades due to a combination of technological innovation, improved manufacturing processes, and growing PV markets. All of these factors have contributed to a downward trend in PV prices.

PV Efficiency

Figure 4-2 shows the increase in laboratory best-cell efficiencies by PV technology over the past few decades. These are laboratory prototype cells, developed through successful R&D. A number of challenges—such as simplifying or modifying cell properties to improve manufacturability and economics—must be overcome before laboratory cell innovations lead to improvements in commercial products. Some cell

Figure 4-2. Laboratory Best-Cell Efficiencies for Various PV Technologies



Source: NREL (2011)

efficiency improvements are simply too expensive to implement at the commercial scale. Further challenges are encountered as small cells are linked together (e.g., c-Si or flexible thin film on metal substrate) or made in much larger areas (e.g., thin films) and then encapsulated to form commercial modules. Commercial module efficiencies typically track best-cell efficiency improvements, with a time and performance lag.

PV Module Prices

Photovoltaic modules have followed a well-documented historical trend of price decline. Since 1976, global module prices declined about 20% on average for every doubling of cumulative global production, resulting in a price decline of roughly 95%—from about $60/W to about $2/W—between 1976 and 2010 (Figure 4-3).

Historic PV module prices stem from a long-term trend of continued technology and manufacturing improvements, along with shorter-term trends driven by supply and demand dynamics. As the industry has matured over the long term, factories have increased in scale and efficiency. During 1980–2001, cost reductions related to increasing plant size, often called economies of scale, had the single greatest impact of any factor on PV module prices (Nemet 2006). As the annual production capacity of manufacturers grew from hundreds of kilowatts (kW) to hundreds of megawatts (MW), economies of scale were realized in purchasing raw materials and equipment. Companies also adopted leaner process control techniques found in more mature, analogous sectors such as semiconductors.

As an example of shorter-term price variations, PV module prices rose from 2005–2008, reflecting both a supply-constrained market and high polysilicon feedstock prices. The resulting high market prices led to a global expansion of polysilicon feedstock supplies, which increased PV manufacturing capacity. These market forces brought module prices back to the long-term trend line by 2010 (Figure 4-3).

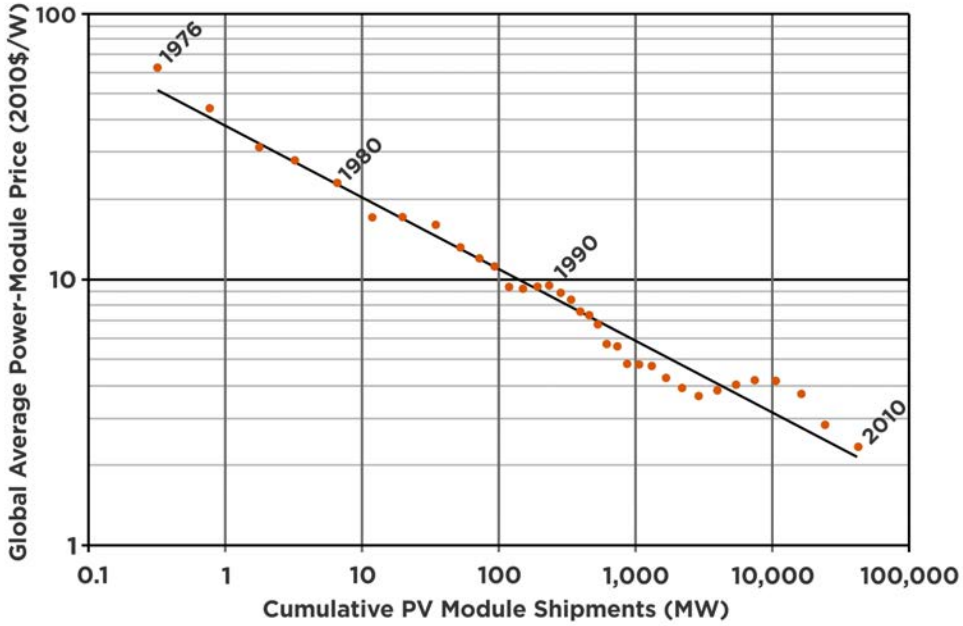
Module production costs vary by technology and manufacturer. For example, cost leaders for mono- and multicrystalline silicon modules have cited costs as low as $1.10/W (Trina Solar 2010), but this manufacturing cost is not representative of all manufacturing processes, products, and financial assumptions. Typical module prices in 2010 ranged from about $1.5–$2/W (Mints 2011).

PV modules achieved significant price and performance improvements in 2011, relative to the benchmarked 2010 numbers in Figure 4-3. PV module prices trended toward $1.5/W for several technologies in the first half of 2011 (First Solar 2011a, UBS 2011). Also, both thin-film and c-Si PV technologies achieved modest efficiency gains (First Solar 2011a, SunPower 2011).

PV System Prices

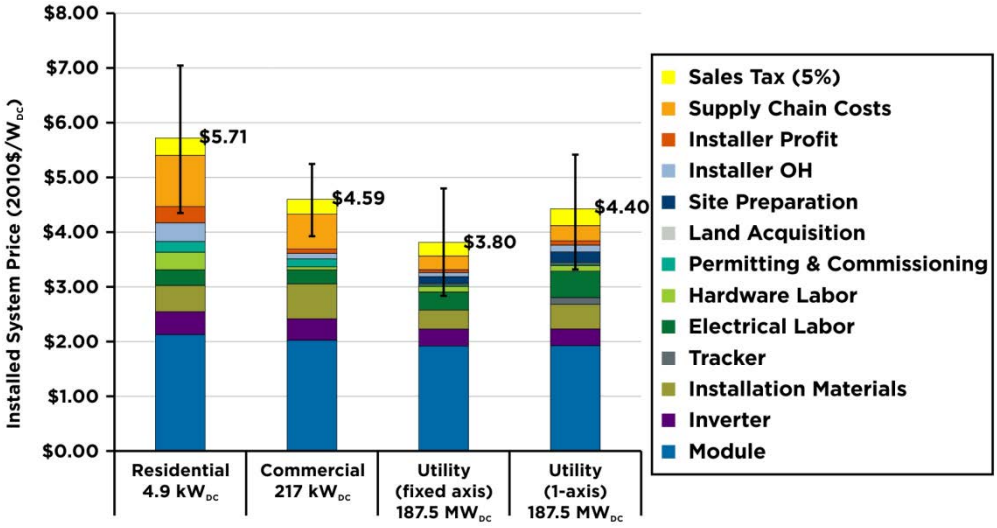
Installed PV system prices include the price of the module and power electronics and the BOS costs. Figure 4-4 shows benchmarked installed PV system prices in 2010, assuming typical monocrystalline silicon PV module prices and efficiencies for each of the key PV market segments: residential, commercial, and utility-scale installations. Residential systems have the highest installed system prices, at roughly $6/W in 2010. This is because of their small size (typically 3–5 kW), fragmented

Figure 4-3. Decline in Factory-Gate PV Module Prices with Increasing Cumulative Module Shipments



Sources: Mints (2011), Mints (2006), Strategies Unlimited (2003)

Figure 4-4. Benchmarked 2010 Installed PV System Prices with Uncertainty Ranges for Multiple Sectors and System Configurations with Three Standard Deviation Confidence Intervals Based on Monte Carlo Analysis[42]



Source: Goodrich et al. (2012)

[42] For all market segments, the uncertainty analysis considers a range of module assumptions based on c-Si technologies (standard c-Si up to super monocrystalline-based products), including market-appropriate module sizes. In the case of "utility fixed axis" only, modules based on cadmium telluride were also considered.

distribution channels, and high customer acquisition and installation costs. Residential PV modules typically pass through multiple distributors between the factory gate and local installers, each of which adds a price markup.

Commercial systems, such as those on the flat roofs of big-box retail stores, can be tens of kilowatts to multiple megawatts in size. Even though they are much larger than residential systems, they are not typically large enough to attain all economies of scale in purchasing components and installation labor. As shown in Figure 4-4, the installed price of a commercial system in 2010 was roughly $5/W, about 20% lower than for a residential system. While commercial systems typically cost more than utility-scale systems, a growing number of commercial systems are being developed by third-party installers using power purchase agreements (PPAs). These third-party installers are frequently able to achieve significant economies of scale in component purchasing and can finance, permit, and build commercial projects more quickly than larger utility projects.

Utility-scale PV systems typically have the lowest installed price: roughly $4/W in 2010. These systems are large enough to realize significant economies of scale in component purchasing and installation labor, significantly reducing installed system prices. Many module manufacturers act as the engineering, procurement, and construction (EPC) firm for large-scale utility installations, achieving an improvement in supply chain costs over traditional third-party installers.

4.2.4 Levelized Cost of Energy

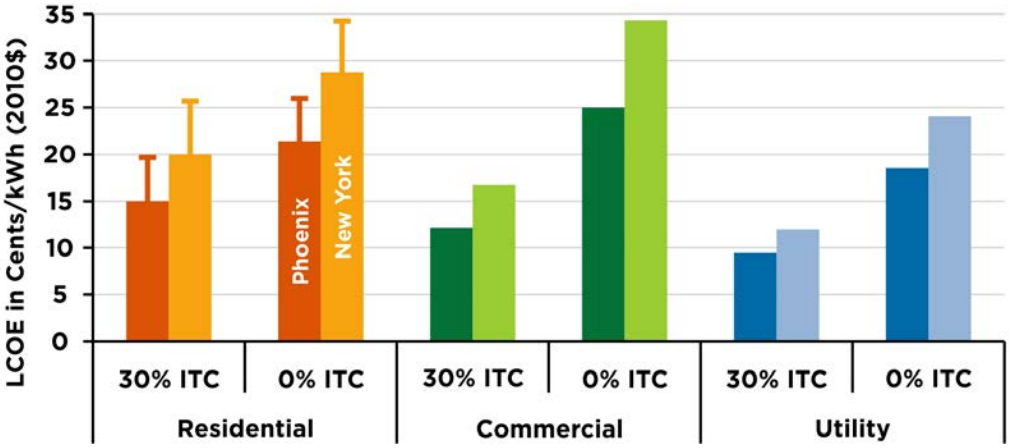
LCOE is the ratio of an electricity-generation system's costs—installed cost plus lifetime operation and maintenance (O&M) costs—to the electricity generated by the system over its operational lifetime, given in units of cents/kilowatt-hour (kWh). The calculation of LCOE is highly sensitive to installed system cost, O&M costs, local solar resource and climate, PV panel orientation, financing terms, system lifetime, taxation, and policy. Thus, PV LCOE estimates vary widely depending on the assumptions made when assigning values to these variables.

Figure 4-5 shows the LCOE for residential, commercial, and utility-scale (1-axis tracking) PV systems as benchmarked above, i.e., priced at roughly $6/W, $5/W, and $4/W, respectively. Because local solar resource is such an important factor, LCOE is calculated in two locations: Phoenix and New York City. Figure 4-5 shows the LCOEs both with and without the 30% federal investment tax credit (ITC). With the ITC, LCOE ranges from $0.15–$0.20/kWh for residential systems, $0.12–$0.17/kWh for commercial systems, and $0.9–$0.12/kWh for utility systems. Without the ITC, LCOE ranges from $0.22–$0.28/kWh for residential systems, $0.25–$0.34/kWh for commercial systems, and $0.18–$0.24/kWh for utility-scale systems.

The LCOEs in Figure 4-5 were calculated using monocrystalline silicon PV performance characteristics[43] and the standard financing assumptions provided in Table 8-1 in Chapter 8. Residential systems are assumed to be fixed tilt and south facing, commercial systems are assumed to be a mix of flat mount and fixed tilt, and

[43] Several PV performance characteristics, such as the temperature sensitivity of cell efficiency, vary across technologies. These differences lead to annual output changes that can affect annualized LCOEs.

Figure 4-5. LCOE for PV Systems in Phoenix (left bars) and New York City (right bars) in 2010, with and without the Federal Investment Tax Credit



Note: For residential systems, mortgage financing is shown on the main bars, and cash purchase is represented by the high error bars.

utility systems are assumed to use 1-axis tracking. Residential and commercial systems are assumed to be owned by the site host, and utility systems are assumed to be owned by an independent power producer (IPP) or investor-owned utility (IOU) that pays taxes on electricity revenues. Even though the installed price of commercial systems is lower than the price of residential systems, the LCOEs are comparable due to multiple factors including higher cost of capital for commercial systems, different performance characteristics, and different tax impacts. Table 4-1 lists other important assumptions used in the LCOE calculations.

4.3 Overview of Strategies for Reducing PV System Prices

The SunShot targets require that the following installed PV system price reductions be achieved by 2020, relative to benchmarked 2010 installed system prices:

- Residential system prices reduced from $6/W to $1.50/W
- Commercial system prices reduced from $5/W to $1.25/W
- Utility-scale system prices reduced from $4/W to $1.00/W.

Figure 4-6 shows the SunShot targets broken out by subsystem prices. The per-watt price of a PV system is directly proportional to the total installed system price and inversely proportional to the system efficiency:

$$\frac{\$}{W} \propto \frac{\text{Total installed system price (\$)}}{\text{System efficiency (\%)}}$$

Table 4-1. Assumptions for LCOE Calculations

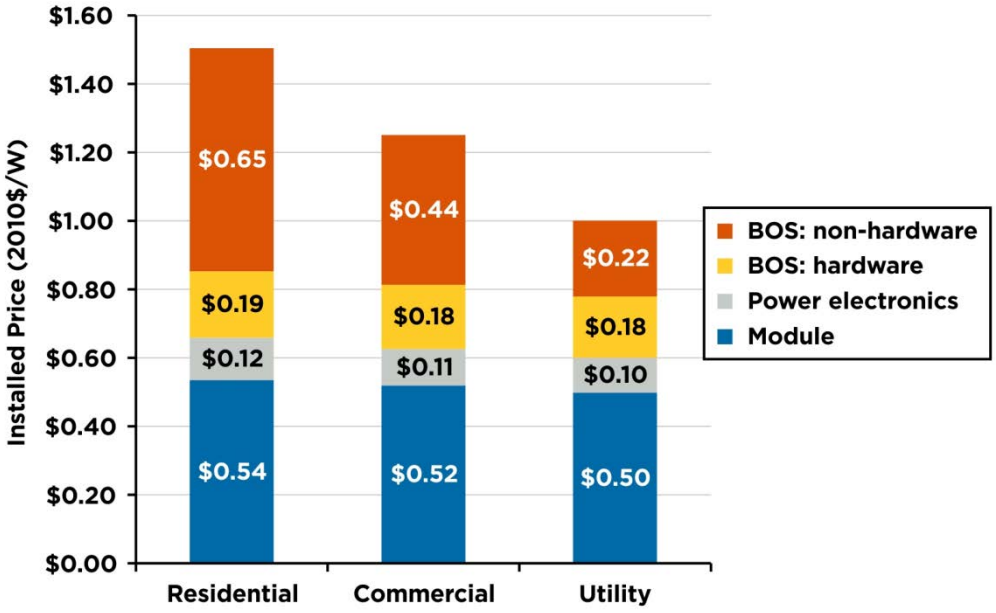
PV Performance and O&M Costs (2010$)	Residential		Commercial		Utility	
	2010	SunShot	2010	SunShot	2010	SunShot
	Actual	Proj.	Actual	Proj.	Actual	Proj.
System Lifetime (Years)	30	30	30	30	30	30
Annual Degradation (%)	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Inverter Replacement Price ($/W, at time of replacement)	$0.25	$0.12	$0.20	$0.11	$0.17	$0.10
Inverter Replacement Labor[a] ($/inverter, at time of replacement)	$600	$600	$3,000	$3,000	$1,000	$1,000
Inverter Lifetime (Years)	10	20	15	20	15	20
O&M Expenses ($/kW-yr)	$32.8	$10.0	$23.5[d]	$7.5	19.93[e]	$6.5
Pre-Inverter Derate[b] (%)	90.0%	93.0%	90.5%	93.5%	90.5%	93.5%
Inverter Efficiency[c] (%)	94.0%	97.0%	95.0%	98.0%	96.0%	98.0%
System Size (kW-DC)	5.0	7.5	200	300	20,000	30,000

[a] Residential and commercial values for inverter replacement labor costs are based on a 2009 estimate from Standard Solar. Estimates of residential and commercial values for inverter replacement labor costs are also provided by Standard Solar. The utility value is discounted from commercial inverter replacement labor costs due to ground, rather than rooftop, location.
[b] Includes losses in wiring, soiling, connections, and system mismatch.
[c] 2010 inverter efficiencies for residential, commercial, and utility systems are based on data from the California Energy Commission, available at www.gosolarcalifornia.org/equipment/inverters.php.
[d] Based on LBNL (Lawrence Berkeley National Laboratory) (2009). Internal survey of commercial rooftop O&M costs.
[e] Based on average O&M costs at Arizona Public Service's 1-axis tracking PV installations, available at www.resourcesaver.org/ewebeditpro/items/O63F5452.pdf.

Thus, the per-watt PV system price can be reduced by reducing the total installed system price or increasing system efficiency. The total installed system price can be reduced by reducing the price of one or more of the three PV subsystems: PV modules, power electronics, and BOS. System efficiency can be increased by increasing the sunlight-to-electricity efficiency of the PV modules and/or increasing the electrical efficiency of the integrated PV system (including power electronics and wiring losses).

Total installed system price and efficiency are interrelated. For example, high-efficiency PV modules might cost more than lower-efficiency PV modules on a per-watt basis. However, their higher efficiency might reduce non-module costs, e.g., per-watt power electronics and BOS prices could be lower because the amount of

Figure 4-6. Estimated Subsystem Prices Needed to Achieve 2020 SunShot Targets



equipment, labor, and land required per watt of installed capacity is lower with higher-efficiency modules. It is important to consider these tradeoffs and to understand that there are a number of potential PV system pathways (e.g., low-cost, low-efficiency modules versus higher-cost, high-efficiency modules) for reducing total installed PV system prices. The following sections explore the methods for reducing total installed system price and increasing system efficiency via improvements to PV modules, power electronics, and BOS.

4.4 Reducing PV Module Prices

As Figure 4-4 shows, benchmark 2010 PV module prices were about $2.00/W. As Figure 4-6 shows, the SunShot targets for PV module prices are $0.50/W for utility systems, $0.52/W for commercial systems, and $0.54/W for residential systems. Module prices can be reduced by reducing module material, manufacturing, and shipping costs and by increasing module efficiency. This section explores these approaches.

4.4.1 Reducing PV Module Material, Manufacturing, and Shipping Costs

Substantial PV system price reductions have been achieved over the past several decades via reductions in material, manufacturing, and shipping costs. These approaches are discussed below, including historical improvements and potential pathways to the improvements needed to achieve the SunShot targets.

Reducing Material Costs

There are a number of ways to reduce material costs in support of the SunShot targets. The active semiconductor material is a complex and expensive component of most PV modules, accounting for about 60% of c-Si module cost and 8%–22% of CdTe and CIGS module cost (Goodrich et al. 2011a, Woodhouse et al. 2011). The cost of polysilicon for c-Si modules could be reduced by making thinner wafers, minimizing polysilicon losses during the wafering process, improving polysilicon scrap recycling capabilities and costs, and introducing low-cost polysilicon feedstock-purification methods. Replacing c-Si with thin-film and CPV technologies is potentially another way to reduce semiconductor material costs. However, although CPV and thin films use less semiconductor material per watt than c-Si, the materials used can be rare and expensive. Using these materials more efficiently or identifying substitutes that are less expensive, earth-abundant, and non-toxic or recyclable could reduce semiconductor material costs in these technologies.

It will also be important to ensure that the supply of PV feedstock materials remains sufficient to meet demand, since supply constraints can significantly increase feedstock prices. For example, when demand for polysilicon outpaced supply in 2007 and 2008, polysilicon contract prices increased from about $50–$60/kilogram (kg) up to $150/kg, and spot market prices peaked above $500/kg (Mehta 2010).

The front and back cell contacts are another important cost component in c-Si PV modules. PV manufacturers strive to design cells that balance the cost of these materials with their effect on module performance.

Module-encapsulation materials—such as front and back glass, adhesives to bind the layers and the cells, edge seals, and frames—can add considerable cost to PV modules (Mehta and Bradford 2009) and dominate the material costs of many thin-film modules. Cost reductions may be possible via depositing semiconductor material on substrates that are lighter and cheaper than glass and replacing traditional framing material and encapsulation glass with flexible ultra barrier encapsulation material. Again, manufacturers must balance the benefits of using less-expensive materials against resulting effects on module performance and reliability. Other materials to be considered are those used in edge seals, mounting hardware, cell interconnections, bus bars, and junction boxes.

Manufacturers may also be able to reduce materials costs by becoming more vertically integrated. In particular, vertical integration can help manufacturers reduce exposure to volatile market prices and improve the efficiency of handling materials.

Improving Manufacturing Processes

PV manufacturing process improvements stem from mass-production efficiency and labor-reduction strategies analogous to those of any manufacturing operation. In addition, improved manufacturing processes can minimize the cell-to-module losses that occur during the transition from laboratory-scale PV technologies to mass-produced commercial products.

Manufacturing equipment costs, which are frequently characterized in dollars per watt of annual manufacturing capacity, can be estimated from capital expenditure (CapEx) investments, which should not be confused with the per-watt module and

system costs. New PV manufacturing facilities are being developed at costs from $1–$2/W (First Solar 2011b, Goodrich et al. 2011a, Woodhouse et al. 2011). Because equipment is depreciated over time (e.g., 7 years), the contribution of CapEx costs to module cost is about one-seventh of the per-watt CapEx costs. For example, a $1.4/W CapEx would add approximately $0.2/W to module costs. There are also additional costs related to the cost of capital for the manufacturer and equipment maintenance costs.

Several factors affect manufacturing cost structure, including speed, yield, labor, and energy prices. Increasing manufacturing speed results in higher throughput and lower capital costs per watt, but often comes as a result of a tradeoff in other categories, such as yield, cell efficiency, and materials costs. Speed can be enhanced by measures such as increasing deposition rates, increasing the width of an in-line reaction chamber, and building large furnaces that can process many substrates at once.

Increasing yield—the proportion of manufactured product that meets commercial specifications—is another way to increase throughput and reduce cost per watt. Crystalline silicon production lines typically operate at yields of at least 93%. However, yields can vary widely depending on the quality of the incoming material, such as wafers, and the desired minimum product quality, such as cell efficiency. Having a wide variation in cell efficiencies would create unacceptable module-stringing losses later. As polysilicon prices have dropped, the use of recycled silicon in casting operations has diminished, increasing the overall quality of materials on the market. The point in the manufacturing process at which defective parts are identified is also critical. Bad parts that are not identified until the end of a process increase costs more than those identified at the beginning or middle of the manufacturing process.

Reducing labor and energy-use requirements also reduces manufacturing costs. Labor costs frequently depend on the maturity of the manufacturing approach and local labor rates. Labor costs are expected to decline as PV matures and manufacturing plants become larger and more automated. Energy use can be reduced by implementing several strategies, including faster processing techniques, lower-temperature processes, and replacing vacuum with non-vacuum processes where possible. Past improvements of this sort have lowered the PV energy payback periods—the length of time the system must operate to match the energy used to make it—to 1–3 years, which has important policy implications. See the discussion of greenhouse gas (GHG) emissions in Chapter 7.

To reach the SunShot price targets, new technologies likely will need to be developed and brought quickly to commercial maturity. Moving technological innovations from the laboratory to commercial production quickly and efficiently will be critical. Potential manufacturing strategies for achieving the SunShot targets include increasing manufacturing throughput, using roll-to-roll thin-film module manufacturing, using high-frequency plasma deposition for thin films, and using atmospheric-pressure liquid washing. Another strategy is to reduce the cost of fabrication equipment and facilities to achieve a CapEx of $0.7/W of annual manufacturing capacity, or lower.

Reducing Module Shipping Costs

The PV industry relies on a global supply chain. As the industry matures, the economies-of-scale advantages captured by large suppliers likely will increase the average distance that a PV product travels from manufacturer to installer. Sea-transport (container) rates are currently at historic lows, and the cost of shipping modules by sea is about $0.05–$0.06/W (Goodrich et al. 2011a), adding 5%–10% to module costs. As module costs decrease, shipping costs for some types of module manufacturing could become a more significant factor and may lead to disaggregated manufacturing models, with separate cell manufacturing and module assembly facilities, for example.

Many PV components—including polysilicon, wafers, and cells—can be shipped cheaply due to their low weight and volume and high value. In fact, cells can often be shipped by air to module manufacturing facilities. The glass content of both thin-film and c-Si modules adds the most to shipping costs, because glass is dense and tends to fill a shipping container based on weight rather than volume. Lower-efficiency modules have more glass per watt—and thus cost more to ship—per unit of power.

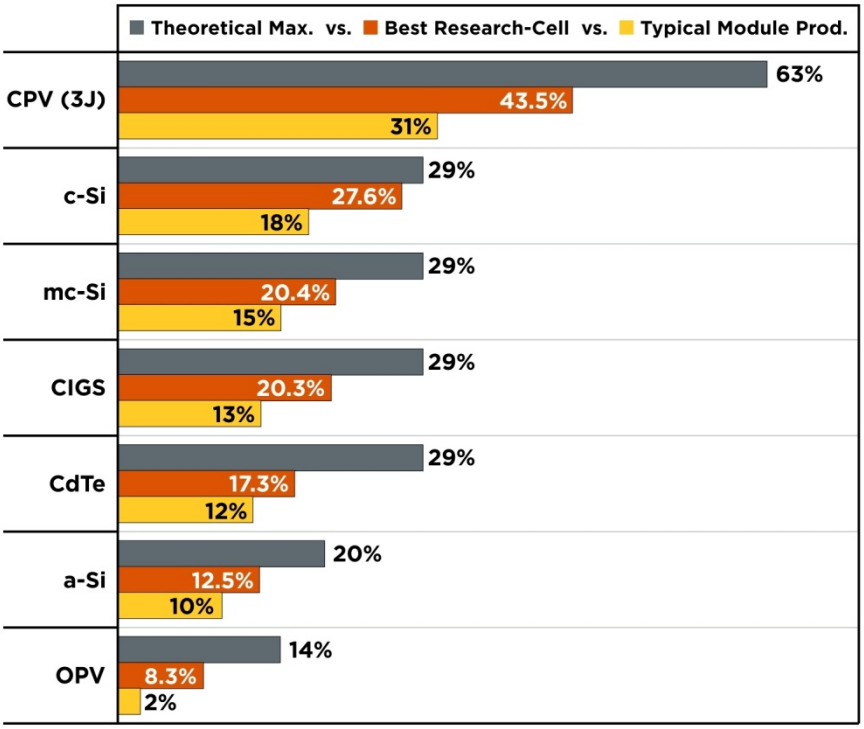
Crystalline silicon module manufacturers frequently have a disaggregated supply chain, where wafers, cells, and modules are manufactured by different companies in different locations. Thin-film manufacturers typically have an aggregated supply chain that is inherent to their device design, where there are no intermediate products. This can be an advantage for reducing c-Si shipping costs: wafer and cell manufacturing can be located in low-cost regions, and module-manufacturing facilities can be sited near end-use markets. This reduces the need to ship glass and encapsulation materials over long distances.

4.4.2 Increasing PV Module Efficiency

Increasing module efficiency is the other major strategy for reducing per-watt module price. Consistent improvements in PV cell efficiency have been realized for virtually every PV technology (Figure 4-2), and module efficiency has followed this trend, albeit with a time and performance lag. This trend is projected to continue, owing to R&D improvements that produce higher best-cell efficiencies and manufacturing technology improvements that advance commercial modules toward best-cell efficiencies. As single-junction PV technologies approach the theoretical (Shockley-Queisser) efficiency limit for their respective semiconductor materials, the extent to which further cost reduction may be attributable to efficiency gains will be reduced, and more substantial cost reductions will need to be realized via other avenues. Nevertheless, as shown in Figure 4-7, there is still significant room for efficiency improvements for many PV technologies.

Module efficiencies greater than 25% (with much of this efficiency maintained for a 30-year module lifetime) may be required to achieve the SunShot PV system price-reduction targets. Multi-year, even multi-decade, R&D programs—such as the U.S. Department of Energy (DOE) Thin Film PV Partnership, which drove several of the improvements shown in Figure 4-2—have improved the industry's understanding of PV technologies and helped develop this knowledge into commercial products. Additional R&D efforts will be required to increase laboratory PV efficiency and to

Figure 4-7. Closing the Gap: Production, Laboratory, andTheoretical (Maximum) PV Module Efficiencies



Source: NREL

transition high-efficiency laboratory technologies to large-scale commercial production.

R&D must support the many stages leading to commercialization: proof of concept, prototype development, product and process development, demonstration-system deployment, and commercialization/scale-up. A substantial base of scientific knowledge exists for c-Si PV technologies, largely owing to integrated circuit R&D, but such a base is still being developed for other leading PV technologies. This current advantage for c-Si PV is true for materials, interfaces, processes for making and altering PV devices, advanced PV device layers, device scale-up from square inches to square meters, and process scale-up to square miles of annual output at high yield. Additional challenges include maintaining or improving device efficiency, device stability, and process stability. Several key R&D issues are discussed below.

Interfaces

Many of the most critical issues of PV device performance and reliability occur at interfaces such as the device junction, back contact, front contact, and between various additional layers that modify device behavior, such as light and carrier reflectors. Examples of critical interface challenges include the following:

- Recombination of free carriers within the junction region of high-efficiency PV devices

- Poor, non-ohmic contacting and instability to high-work-function, resistive p-type material such as CdTe
- The physics, chemistry, and stability of grain boundaries in multicrystalline semiconductors
- The adherence and lifetime of semiconductor/encapsulant and thermal interface materials
- The numerous interfaces resulting from the use of different materials that respond to different parts of the spectrum in multijunction cells.

There is a need for increasing the fundamental knowledge around the interfaces of a PV device. Although most work to date has been empirical, there is an opportunity to use more sophisticated R&D tools and expertise to better understand the optical, electrical, mechanical, and chemical properties of these interfaces.

Performance of Large-Area PV

Sophisticated computational models, tools, and analysis could assist in the correlation of processing parameters with fundamental device physics to accelerate research and commercial product development. One opportunity for existing silicon- and thin-film-based modules is the further exploration of material parameter space for optimizing electronic and optical properties. Another is the development and employment of *in situ* process controls and in-line metrology and diagnostics for improved manufacturing yield.

Degradation Science

An improved understanding of degradation mechanisms in devices and protective materials would allow for further improvements that can increase module lifetimes and further reduce PV LCOE. It is important to increase understanding in the following areas:

- Photochemical degradation
- Dielectric breakdown
- Leakage current in the presence of water and oxygen
- Impurity diffusion processes in semiconductors and through interfaces, especially in large-area devices (which have inevitable compositional variations in all dimensions).

Well-designed stress tests are needed to define and test degradation mechanisms, as are parallel accelerated lifetime models that correlate these new tests with actual outdoor performance through many decades. Also, better qualification tests would standardize PV performance metrics and drive reliability improvements.

The above list is not all inclusive, and there are several technology-specific R&D challenges. For example, thermal management of CPV devices will be important for optimizing performance and durability under the high-operating temperatures common with concentrating solar devices.

Long-Term, High-Potential R&D

R&D funding for universities, companies, and national laboratories to explore non-traditional, high-potential PV technologies promotes innovation and the development and expansion of future PV technology. This R&D funding also expands the pool of scientists and engineers with PV expertise, of which there is a critical shortage.

The PV research community is exploring a portfolio of promising new materials in the category of abundant, non-toxic, easily processed inorganic semiconductors for direct-bandgap thin-film cells. Wadia et al. (2009) highlighted these novel R&D efforts. Subsequent to this study, there has been renewed interest among the basic science community in exploring underdeveloped materials for PV such as metal oxides and metal sulfides for new PV absorbers. Such long-term efforts build on lessons learned from developing the existing, successful direct-bandgap inorganic thin films and could open up new avenues for low cost while avoiding issues of toxic materials and material availability.

Beyond new materials, there are new PV device concepts that could reduce costs. Examples include organic, nanostructured, and dye-sensitized cells, which are in early stages of commercial development (see Section 4.2.2). They offer the potential for lower module costs through use of less-expensive materials and simpler processing. However, there have been challenges in attaining high efficiency and long-term reliability with the materials that have been used to date.

4.5 Reducing Power Electronics Costs

Power electronics include inverters, which convert DC electricity produced by the PV module into AC electricity used by the grid, and transformers, which step the electricity up to the appropriate voltage. These are often combined into a single integrated device and referred to as the inverter.

As Figure 4-4 shows, benchmark 2010 inverter prices were about $0.20/W–$0.30/W for utility systems and about $0.40/W for residential and commercial systems. As Figure 4-6 shows, the SunShot targets for power electronics prices are $0.10/W for utility systems, $0.11/W for commercial systems, and 0.12/W for residential systems. Power electronics prices can be reduced via exploiting economies of scale, developing advanced components, improving reliability, and enabling smart grid integration. Specific power electronics strategies that may be needed to achieve the SunShot targets include the following:

- Solving fundamental power electronics problems at the component level that can be leveraged by advances across multiple industries.
- Reducing the cost of advanced components (e.g., silicon carbide and gallium nitride), which will reduce the size and cost of the magnetic materials (and other components) traditionally used in power electronic inverters and converters.
- Addressing reliability failures due to the thermal cycling of materials with different coefficients of thermal expansion.

- Developing technologies that allow high penetrations of solar technologies onto the grid (e.g., reactive power, energy storage, and advanced functionalities).
- Developing PV system technologies that reduce overall BOS costs (e.g., high-voltage systems).
- Developing technologies that harvest more energy from the sun (e.g., maximum power point tracking and micro-inverters).
- Integrating micro-inverters into modules, reducing installation effort and achieving further cost reductions through mass production.

4.6 Reducing Balance-of-Systems Costs

BOS comprises the non-module, non-power electronics components and procedures required to produce a complete PV system. "Hard" BOS elements include support structures (including trackers), mounting hardware, wiring, monitoring equipment, shipping, and land. "Soft" BOS elements include system design and engineering, customer and site acquisition, installation, permitting, interconnection and inspection, financing, contracting, market-regulatory barriers, and operation and maintenance.

As Figure 4-4 shows, benchmark 2010 BOS prices were about $2.00/W for utility systems, about $2.40/W for commercial systems, and about $3.00/W for residential systems. As Figure 4-6 shows, the SunShot targets for BOS prices are $0.40/W for utility systems, $0.62/W for commercial systems, and $0.84/W for residential systems. BOS prices can vary substantially based on the size and type of PV system, its location, and profit margins. Specific BOS strategies that may be needed to achieve the SunShot targets include the following:

- Hard BOS
  - Improve supply chains for BOS components
  - Develop high-voltage systems
  - Develop racking systems that enhance energy production or require less robust engineering
  - Integrate racking and mounting components in modules
  - Develop innovative materials (e.g., steel or aluminum alloys designed specifically for solar industry applications) for applications such as lightweight, modular mounting frames
  - Create standard packaged system designs
  - Develop building-integrated PV (BIPV) to replace traditional roofing and building facade materials.
- Soft BOS
  - Identify strategies for streamlining permitting and interconnection processes and disseminate best practices to a broad set of jurisdictions
  - Develop improved software design tools and databases
  - Address a wide range of policy and regulatory barriers, as well as utility business and operational challenges
  - Streamline installation practices through improved workforce development and training, including both installers and code officials

- Expand access to a range of business models and financing approaches
- Develop best practices for considering solar access and PV installations in height restrictions, subdivision regulations, new construction guidelines, and aesthetic and design requirements
- Reduce supply chain margins (profit and overhead charged by suppliers, manufacturers, distributors, and retailers); this is likely to occur as the PV industry becomes more mature.

4.7 SunShot versus Evolutionary-Roadmap PV System Price Projections

Before the SunShot Initiative was launched, modeling was performed to project the effect of aggressive—but incremental/evolutionary—PV system improvements to today's dominant PV technologies: c-Si and CdTe. This section compares the PV price projections from this evolutionary roadmap with the more aggressive SunShot price targets.

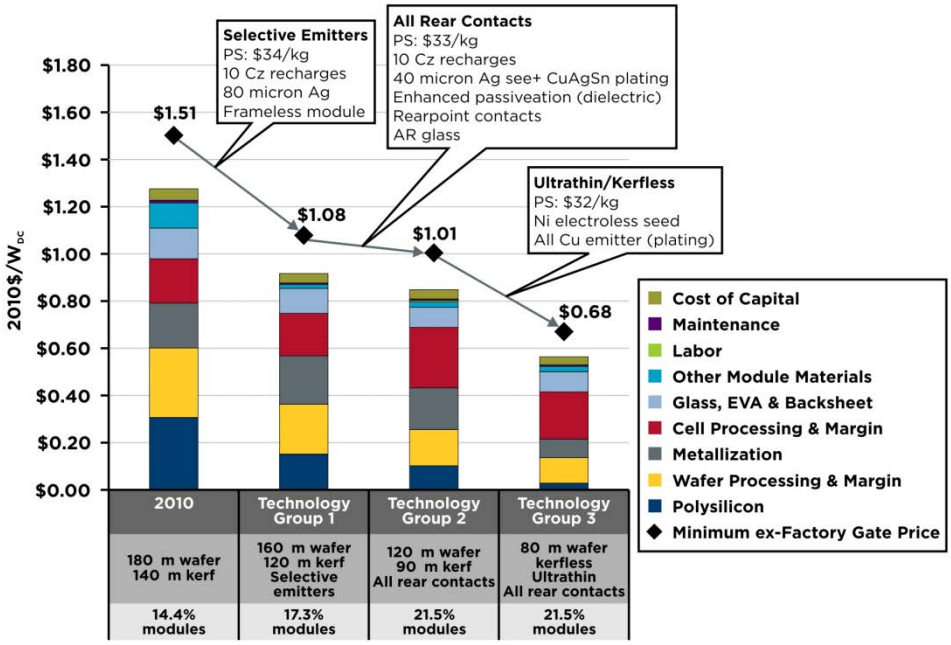
To develop the evolutionary roadmap, NREL created detailed models, in collaboration with industry stakeholders, to quantify residential and commercial distributed (residential and commercial rooftop) and utility-scale (ground-mounted) PV installation prices. Because the results of these models were validated against industry input for current installation prices, the models could be used to estimate future installed system prices. Forecast system prices considered a range of assumptions, including a range of inverter (0%–66%), installation materials (0%–50%), and installation labor (0%–50%) cost or content reductions. Further, in the case of residential and commercial rooftop installations, it was assumed that, over time, competition and industry growth would reduce installer overhead and margins for all sectors to ranges typical of a mature electrical contractor service business (i.e., 16% for residential and 10% for commercial).

Projected PV module price reductions were a primary part of the evolutionary roadmap modeling effort. Figure 4-8 shows a modeled pathway to c-Si module cost reductions. The modeling showed that evolutionary improvements could lead to industry median c-Si modules with an ex-factory gate price of about $1.01/W by 2020 ("Technology Group 2" in Figure 4-8) (Goodrich et al. 2011a). Importantly, it was estimated that this price could be achieved along with a substantial increase in median production module efficiency, to 21.5%—equivalent to a production cell efficiency of approximately 24%. Increasing module efficiency reduces many system costs.

Figure 4-9 shows the system-level results of the evolutionary roadmap modeling. The projected PV system prices are based on forecasted lower cost limits and upper efficiency limits for c-Si and CdTe modules, as well as the range of non-module cost improvements discussed above. The 2010 benchmarks and SunShot PV system price targets are also plotted on Figure 4-9 for comparison.[44]

[44] The official SunShot price targets are $1.5/W for residential systems, $1.25/W for commercial systems, and $1/W for utility-scale fixed-mount systems. Tracking PV systems could have slightly higher costs and still reach comparable LCOEs. As discussed in Chapter 3, $1/W tracking PV systems were modeled for the SunShot scenario, but this is not to imply that 1-axis tracking systems will dominate all markets; the types of mounting/tracking technologies deployed likely will vary regionally.

Figure 4-8. Evolutionary Module Manufacturing Cost Reduction Opportunities C-Si PV



PS: polysilicon
Ag: silver
Cz: Czochralski
Cu: copper
Sn: tin
AR: anti-reflection
EVA: ethylene vinyl acetate

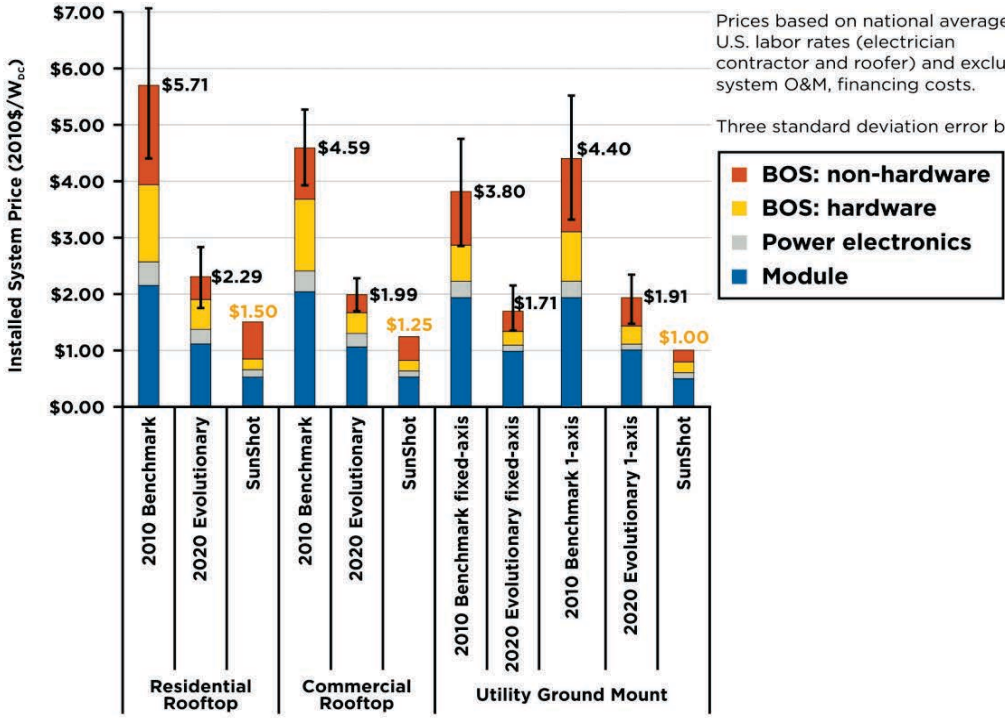
Source: Goodrich et al. (2011a)

Under the evolutionary roadmap assumptions, the installed price of utility-scale PV systems could reach about $1.70–$1.90/W by 2020.[45] Although CdTe has a steeper module price-reduction trajectory and lower estimated module average selling-price limit, CdTe systems have higher non-module costs relative to c-Si owing to lower module efficiency and smaller module size. Residential and commercial installed system prices are projected to reach about $2.30/W and $2.00/W, respectively, by 2020. All of these projected prices are well above the SunShot targets. Even assuming a more optimistic evolutionary module price reduction ($0.68/W, "Technology Group 3" in Figure 4-8), the evolutionary system prices would still be well above the SunShot targets.

The key insight gained through this analysis is that evolutionary change is not likely to be sufficient to reach the SunShot price-reduction targets via today's dominant technologies (single-junction c-Si and CdTe). Instead, reducing the installed price of PV systems by roughly 75% likely will require significant technological improvements, such as, through the acceleration of innovative technologies into the

[45] See Appendix C for several sensitivity analyses which explore deployment projections based on different cost assumptions for solar and other technologies.

Figure 4-9. Installed PV System Prices: 2010 Benchmark, Projected 2020 Evolutionary, and 2020 SunShot Target[46]



Source: Goodrich et al. (2012)

marketplace and the pursuit of more radical change by developing new, R&D-driven PV technologies.

For example, multi-junction device architectures theoretically could achieve much higher efficiencies than single-junction c-Si and CdTe; however, to be viable in the marketplace, they would need to do so at a competitive cost structure. Alternative module configurations, such as flexible encapsulation of thin films, could also offer pathways to the SunShot price-reduction targets. Such pathways are important to consider because they leverage the experience of researchers and manufacturers gained over each technology's long history. The actual technological pathways to revolutionary PV improvement are not known today—continued R&D and sustained focus on meeting the price-reduction targets will be necessary to identify and realize these pathways.

[46] For all market segments, the uncertainty analysis considers a range of module assumptions based on c-Si technologies (standard c-Si up to super monocrystalline-based products), including market-appropriate module sizes. In the case of "utility fixed axis" only, modules based on CdTe were also considered.

4.8 SUNSHOT LCOE PROJECTIONS

Figure 4-10 shows the LCOEs resulting from achieving the SunShot installed PV system prices. These LCOEs are calculated using assumptions about O&M expenses, inverter efficiencies, and derate factors (due to losses in wiring, diodes, or shading) as provided in Table 4-1. Moreover, Figure 4-10 represents LCOEs with no ITC and no state, utility, or local incentives. The financing assumptions are the same as those listed in Table 8-1 in Chapter 8. Finally, three locations—Phoenix, Kansas City, and New York City—and a number of system orientations are used to represent a range of PV LCOEs.

Figure 4-10. SunShot PV LCOEs by Year and Market Segment[47,48]

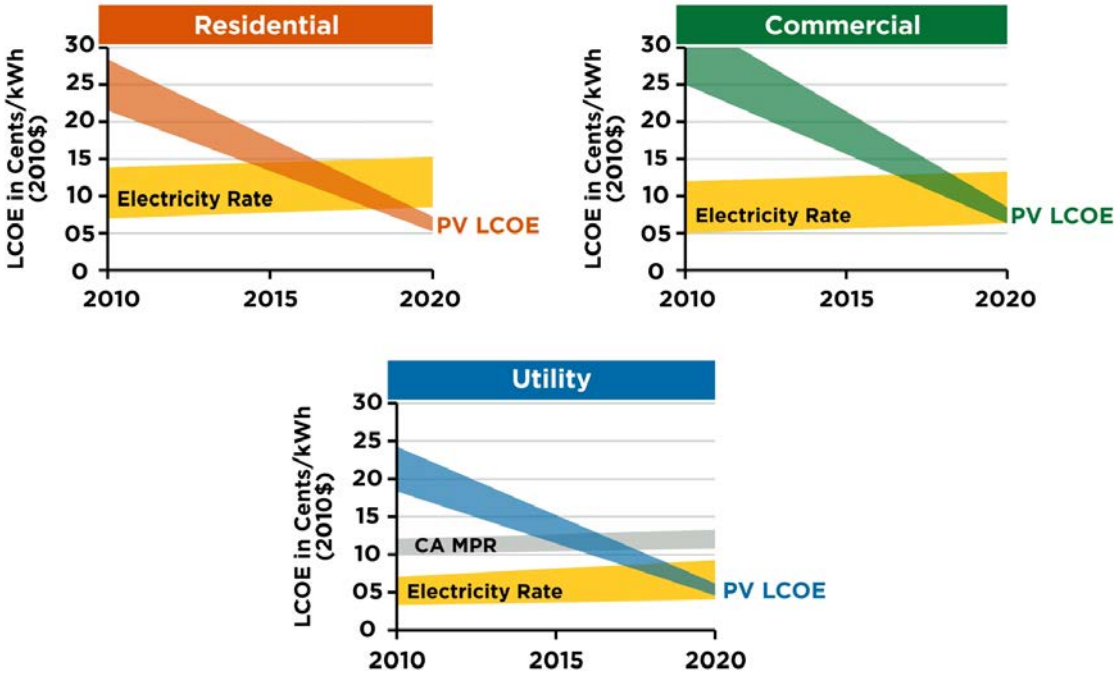


Figure 4-10 shows that, assuming the SunShot targets are met by 2020, residential PV is projected to be increasingly competitive with residential electricity rates, commercial PV is projected to be increasingly competitive with commercial electricity rates, and utility-scale PV is projected to be increasingly competitive with wholesale electricity rates. Utility-scale PV LCOEs become competitive with California's Market Price Referent (MPR), which is used as a benchmark to assess the value of renewable generation in California (CPUC 2011), by 2015 at higher

[47] Note that commercial systems assume site-host ownership, in contrast to utility systems, which are owned by IPPs or IOUs and pay taxes on electricity revenue. However, the apparent tax advantage of site ownership is reduced by the fact that for-profit commercial entities may deduct electricity expenses from their taxable income. Thus, the LCOE of a site-owned commercial system must be compared to the after-tax commercial electricity rate.

[48] The electricity-rate range represents one standard deviation below and above the mean U.S. electricity prices for the respective market segment, including residential, commercial, and utility. The California Market Price Referent (MPR) is in real terms and includes adjustments by utility for the time of delivery profile of solar.

costs than those targeted in the SunShot scenario. This illustrates that, while achieving SunShot price targets will allow PV to compete broadly with conventional generation in several U.S. markets, PV will become competitive in some markets more quickly and at higher prices.

4.9 Materials and Manufacturing Resources

The SunShot scenario reaches 302 gigawatts (GW) of cumulative PV capacity by 2030 and 632 GW by 2050. To achieve this, annual U.S. PV installations will stabilize at about 25–30 GW per year (see Chapter 3). Satisfying these high levels of demand will increase the PV industry's raw materials requirements significantly and require rapid expansion of manufacturing capacity. Essential raw materials include polysilicon feedstocks for c-Si PV technologies and relatively rare elements for several thin-film and CPV technologies. This section evaluates the materials and manufacturing challenges to meeting SunShot PV demand.

4.9.1 Raw Materials Requirements

Raw material availability can become a concern when there is a supply/demand mismatch or a material shortage. These two conditions are discussed below.

Supply/Demand Mismatch

A supply/demand mismatch is a temporary market imbalance resulting in a shortage of available material due to a lack of exploration, extraction, or refining efforts—even when the basic accessibility of the underlying material is presumably not a problem. An example of this type of mismatch in the PV sector is the recent shortage of polysilicon feedstock, which occurred because demand for polysilicon-based modules rose more rapidly than polysilicon production capacity.

Although the polysilicon shortage has dissipated over the past few years, it is useful to examine its causes. The delay between perceiving the opportunity and increasing polysilicon production resulted from the time and expense required to build, start up, and qualify a new polysilicon plant. From initiating plant construction to beginning qualified production, it takes 2–3 years and costs hundreds of millions of dollars. This constraint on response time was further exacerbated by the lack of vertical integration within the industry as cell manufacturers had to wait for producers to respond to the market signals of increased demand. Lower capital-cost processes such as the use of thinner silicon wafers and less-refined, solar-grade silicon could help mitigate this type of imbalance in the future (provided that the most successful cell architectures will still not require the higher-quality material and that the yield losses from thinner wafers are still acceptable).

Such a temporary supply/demand mismatch is familiar to other industries and is likely to remain a part of the PV landscape as it evolves. Better planning can help to minimize these types of disruptions but cannot eliminate them completely in the future.

Material Shortage

A more serious challenge is a fundamental shortage of raw material availability. For example, a shortage can occur when not enough material is being mined, when material cannot be economically mined at prices the PV industry can support, or when competing uses can afford higher prices for the material. Prices can rise significantly long before supply is truly exhausted, which incentivizes the exploration and development of new supply and helps balance demand for each technology.

There are five main ways that material constraints can be mitigated:

- Increase ore extraction and refining—both the amount and material extraction efficiency
- Increase PV efficiency
- Reduce the thickness of semiconductor layers in PV devices
- Improve process utilization and in-process recycling
- Recycle semiconductor materials at the end of module life.

Crystalline silicon feedstocks are virtually unlimited. However, silver, which is currently used for contacts, has some limitation. If different contact materials are used, such as nickel-copper (which is currently under development), the c-Si supply is virtually unconstrained. The glass, steel, and aluminum used as encapsulation and support structures are not subject to rigid supply constraints, but their costs will be tied to changing commodity prices.

Material shortages are a concern for several semiconductor materials used in some thin-film, concentrating, and emerging PV technologies: tellurium in CdTe; indium, selenium, and gallium used in CIGS; indium, germanium, and gallium used in some III-V multijunction cells; and ruthenium, sometimes used in dye-sensitized PV cells. Conductive materials may also be a concern in the longer term, including molybdenum used for CIGS PV contacts. Of these, the primary concerns are the tellurium supply for CdTe and the indium supply for CIGS; thus, this discussion focuses on these two materials.

In its *Critical Materials Strategy*, DOE (2010) estimated current (2010) and projected (2015) supplies of several materials, including tellurium and indium. It estimates 2010 tellurium production at 500 metric tons (MT)/yr and projects it to rise to 1,220 MT/yr in 2015 based on assumptions about increased production from copper anode slimes. It also estimates that global tellurium production could increase four-fold by 2020 due to increased production from copper anode slimes, assuming copper refiners do not move away from electrolytic processing (to promote larger tellurium supplies, the PV industry could incentivize an increased use of electrolytic copper refining). Copper production historically has grown by about 3% per year (ICSG 2006) and is, with planned new capacity additions, projected to grow around 4.5% per year from 2011–2014 (Edelstein 2011). According to Ojebuoboh (2008), the efficiency of tellurium extraction from copper could increase substantially, although the impact on tellurium prices is unknown. Mining of tellurium ores and recovery of tellurium from gold concentrates are additional potential tellurium sources (DOE 2010, Green 2009). The cost of

alternative tellurium sources and extraction techniques is not well known. However, the cost of recovering any element is inversely proportional to its concentration (Green 2009). Therefore, tellurium costs are likely to increase if the industry shifts to these new sources.

Indium is a relatively rare coproduct of zinc refining. Nearly all of the indium supply is used in thin-film coatings, such as in the production of indium tin oxide for flat-panel liquid-crystal displays, which could present a challenge to the PV industry because other uses could potentially accommodate a higher indium price. The *Critical Materials Strategy* estimates the 2010 indium supply at 1,345 MT/year (yr) (480 MT virgin and 865 MT reclaimed) (DOE 2010). It estimates 2015 indium supplies could increase to 1,612 MT/yr based on increased recovery from additional zinc production and recycling.

CPV modules frequently use indium and gallium but do not face the same resource limitations as flat-plate PV technologies. Optical concentration reduces the amount of semiconductor material required by a factor nearly equivalent to the concentration ratio.

Table 4-2 summarizes how reduced material requirements and increased tellurium and indium availability could increase potential PV production capacity for CdTe and CIGS PV technologies.[49] Under the SunShot scenario, annual U.S. PV installations could reach 27 GW/yr by 2030. If global PV penetration roughly follows SunShot-like trajectories, global PV demand could reach well over 100 GW/yr by 2030. Table 4-2 shows that, at current material requirements and availability, the ability of tellurium- and indium-dependent PV technologies alone to meet projected U.S. and global demand would be limited. However, with reduced materials requirements, even current tellurium and indium availability could enable these technologies to play a substantial role in satisfying projected demand, and the projected increase in tellurium and indium availability is substantial even in the 2015 time frame. Availability could increase even further by the time annual U.S. SunShot demand is in the 20–30 GW/yr range and global demand is on the order of 100 GW/yr. Of course, competing uses of these materials will reduce the amounts available for PV. See DOE (2010) for long-term tellurium and indium demand scenarios and additional discussion about materials availability.

4.9.2 Manufacturing Scale-Up

The PV industry is currently expanding its manufacturing capacity to meet growing demand. This has been helped, in large part, by new market entrants bringing manufacturing and supply chain management experience from other successful industries, including computers, semiconductors, and liquid crystal displays. The expansion has also been aided by improved manufacturing throughput, based on technology improvements and efficiency gains. The annual production capacity of PV manufacturing lines has typically increased by an order of magnitude over the last decade, from tens to hundreds of megawatts per year.

[49] Because of the success of cadmium telluride (CdTe) in the marketplace, the amount of CdTe production potential has been examined by a number of investigators (Green 2006, Green 2009, Feltrin and Freundlich 2007, Ojebuoboh 2008, Fthenakis 2009).

Table 4-2. Potential Annual PV Capacity Supply Based on Current and Potential PV Material Requirements and Material Availability

Material	PV Type	Material Requirement (MT/GW)[a]	Material Availability (MT/yr)[b]	Potential PV Capacity (GW/yr)
Current (2010) Material Requirements and Current (2010) Material Availability				
Tellurium	CdTe	60–90	500	**6–8**
Indium	CIGS	52	1,345	**26**
Reduced (Future) Material Requirements and Current (2010) Material Availability				
Tellurium	CdTe	19	500	**26**
Indium	CIGS	5	1,345	**270**
Reduced (Future) Material Requirements and Increased (2015) Material Availability				
Tellurium	CdTe	19	1,220	**64**
Indium	CIGS	5	1,612	**320**

[a] The reduced material requirement estimates listed here are not projected to a specific year, e.g., not to 2015. Rather, they represent estimates of practical minimum limits on tellurium and indium requirements for CdTe and CIGS PV technologies. Accelerated R&D may reduce the time required to reach these levels.

Current CdTe production module efficiencies have been demonstrated to be as high as 11.7% (First Solar 2011a), with CdTe layers that are 2–3 µm thick (Green 2011). Process materials use is about 90% for current CdTe module production techniques (with in-process recycling), which implies tellurium requirements of about 7–10 grams (g)/m^2 and, correspondingly, 60–90 MT/GW of tellurium. According to Woodhouse et al. (2011), if R&D-driven improvements could increase CdTe efficiency to 18% and decrease layer thickness to about 1 µm—roughly the amount of semiconductor thickness needed to efficiently fully absorb the solar spectrum (without significant drops in photocurrent)—tellurium requirements could drop to 19 MT/GW.

The CIGS indium requirements are from Goodrich et al. (2011b). The 2010 CIGS (coevaporation technique) indium requirement of 52 MT/GW is based on current estimates of material yield losses, 10% module efficiency, and a 1.5-µm absorber. The reduced CIGS indium requirement of 5 MT/GW includes estimated material yield losses, 20.8% module efficiency, a 1.0-µm absorber, and a high gallium-to-indium ratio.

[b] Current/2010 and increased/2015 material availability are from DOE (2010); although this report does not project longer-term tellurium and indium availability, availability may be higher beyond 2015. The large projected increase in tellurium availability between 2010 and 2015 is based, in part, on assumptions about greatly increasing the rate of tellurium recovery from copper refining; the added cost of this increased recovery rate is unknown, thus it is unknown whether the process will prove economically viable.

The need to scale up PV manufacturing capacity will not limit PV deployment under the SunShot scenario. For example, global PV manufacturing capacity has grown from 1.4 GW/yr in 2004 to 22.5 GW/yr by the end of 2010 (Mints 2011). Given that U.S. PV manufacturing capacity at the end of 2010 was 1.4 GW/yr, expanding U.S. PV production to 27 GW/yr over the next 20 years under the SunShot scenario is very realistic. The capital equipment and land costs required to build a 1-GW/yr PV manufacturing facility has been estimated at $1–$3 billion for c-Si (Mehta and Bradford 2009), and has been reported to be as low as $0.64/W for CdTe (First Solar 2010). Thus, the cost of building new PV manufacturing capacity should not limit SunShot-scale deployment.

That said, supply chain planning and clear market signals are needed to enable the required scale-up. For an "emerging" technology such as PV, strong and consistent government policy support can help to create initial demand. Prospective PV investors and manufacturers must see a clear market-growth pathway before committing the substantial resources needed to scale up production capacity and output.

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5. Concentrating Solar Power: Technologies, Cost, and Performance

5.1 INTRODUCTION

At the end of 2010, about 1,300 megawatts (MW) of concentrating solar power[50] (CSP) capacity was in operation worldwide, with 512 MW in the United States. More than half of the U.S. capacity was built in southern California in the 1980s. More recently, there has been increased interest in CSP technologies as a result of greater demand for renewable energy, government-supported research and development (R&D), and improved economics through policy initiatives. In the past few years, multiple utility-scale plants have been built, and almost 12 gigawatts (GW) of capacity were under construction or under contract worldwide during 2010. Of this total, almost 10 GW represented CSP plants with signed power purchase agreements (PPAs) under development in the U.S. Southwest (SEIA 2010).

CSP is composed of a diverse mix of technologies, at different stages of maturity, which convert sunlight into thermal energy and then use this thermal energy to generate electricity. A key characteristic of CSP is its built-in thermal inertia, which can provide stability in plant output during slight changes in solar radiation, such as when a cloud passes overhead. Because CSP uses thermal energy, it can also incorporate thermal energy storage (TES), fossil-fuel backup/hybridization, or both for higher levels of stability and dispatchability and increased duration of energy output. These attributes allow CSP plants to obtain capacity credits similar to those for fossil-fuel power systems and provide a firm energy resource that improves grid operations.

This chapter evaluates the current cost, performance, and potential of several CSP technologies. A detailed discussion of the opportunities for potential cost reductions to existing and emerging CSP technologies is provided. Key challenges to achieving the level of CSP growth envisioned in the SunShot scenario are evaluated, including potential materials-supply constraints as well as manufacturing scale-up issues. This analysis makes it clear that continued CSP technology advances and cost reductions, through both continued R&D investments and increased deployment activities, will be necessary for achieving the SunShot scenario. In particular, CSP's ability to provide firm, dispatchable power generation will play a critical role in enabling the U.S. electricity generation system to operate safely and reliably under the SunShot scenario's levels of solar technology deployment.

[50] CSP may also be called concentrating solar thermal power or solar thermal electric power.

5.2 TODAY'S CSP TECHNOLOGY

There are four demonstrated types of CSP systems: parabolic trough, linear Fresnel, power tower (also called central receiver), and dish/engine. All of these technologies involve converting sunlight into thermal energy for use in a heat-driven engine. The first three have been demonstrated in hybrid configurations with fossil-fuel technologies and/or adapted to use TES. These options provide operating flexibility and greater reliability. TES and hybridization are expected to play increasingly important roles as renewable energy contributions to the electric grid increase.

5.2.1 TECHNOLOGY TYPES

Parabolic Trough

Parabolic trough systems are currently the most proven CSP technology owing to a commercial operating history starting in 1984, with the Solar Energy Generating Systems (SEGS) plants in the Mojave Desert of California, and continuing with Nevada Solar One (Figure 5-1) and several recent commercial trough plants in Spain.

Figure 5-1. Example of a Parabolic Trough Plant



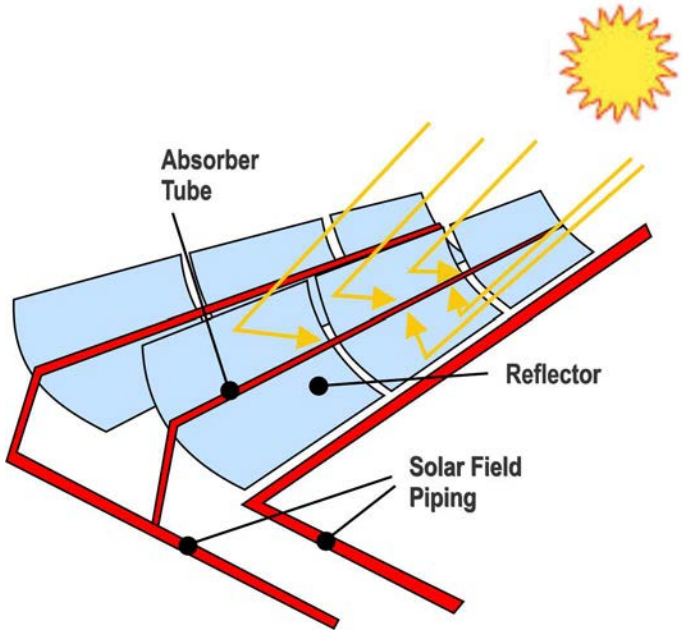
Source: EPRI (2010)

Parabolic trough power plants consist of large fields of mirrored parabolic trough collectors, a heat-transfer fluid (HTF)/steam-generation system, a power system such as a Rankine steam turbine/generator, and optional TES and/or fossil-fuel-fired backup systems. The use of TES results in both dispatchable generation and higher annual generation per unit of capacity, although the larger collector field and storage system lead to a higher upfront capital investment. Trough solar fields can also be deployed with fossil-fueled power plants to augment the steam cycle, improving performance by lowering the heat rate of the plant and either increasing power output or displacing fossil-fuel consumption.

The solar field is made up of large modular arrays of 1-axis[51] tracking solar collectors arranged in parallel rows, usually aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the direct-beam solar radiation onto a linear receiver (absorber tube) located at the focal line of the parabola (Figure 5-2). The collectors track the sun from east to west during the day, with the incident radiation continuously focused onto the linear receiver, within which an HTF is heated to approximately 390ºC.[52]

[51] Note that 1-axis tracking may also be referred to as "single-axis" tracking.
[52] To convert temperature to Fahrenheit, multiply the Celsius value by 1.8 and then add 32 degrees.

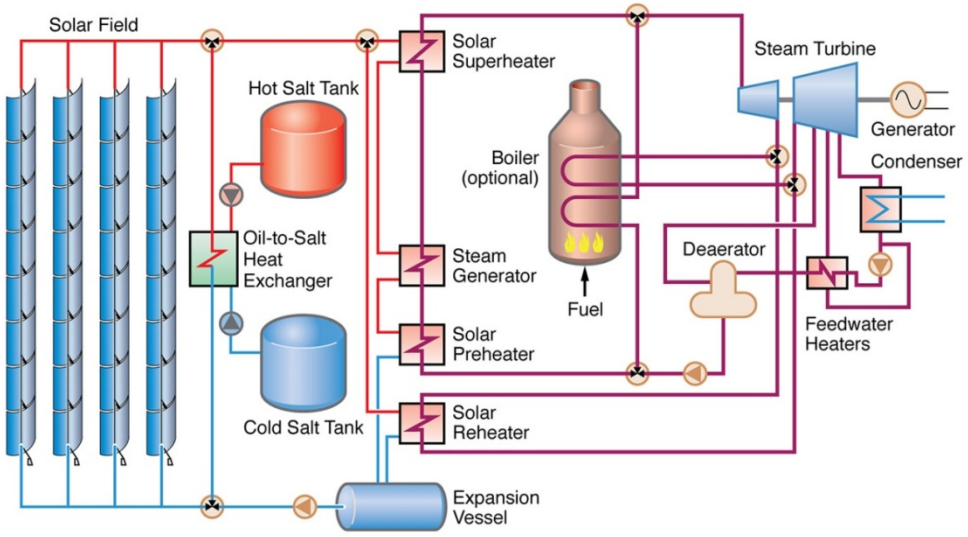
Figure 5-2. Parabolic Trough Field Components



Source: NREL

After circulation through the receivers, the HTF flows through a heat exchanger to generate high-pressure superheated steam (typically 100 bar at 370ºC). The superheated steam is fed to a conventional reheat steam turbine/generator to produce electricity. The spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feed-water pumps to be transformed back into steam. Wet, dry, or hybrid cooling towers can be used for heat rejection from the condenser; the selection will influence water use, cycle performance, and cost (see the water discussion in Chapter 7). Figure 5-3 shows a trough plant with a fossil-fuel-fired backup boiler and TES.

Figure 5-3. Trough Plant Operation with Fossil-Fuel-Fired Backup System



Source: EPRI (2010)

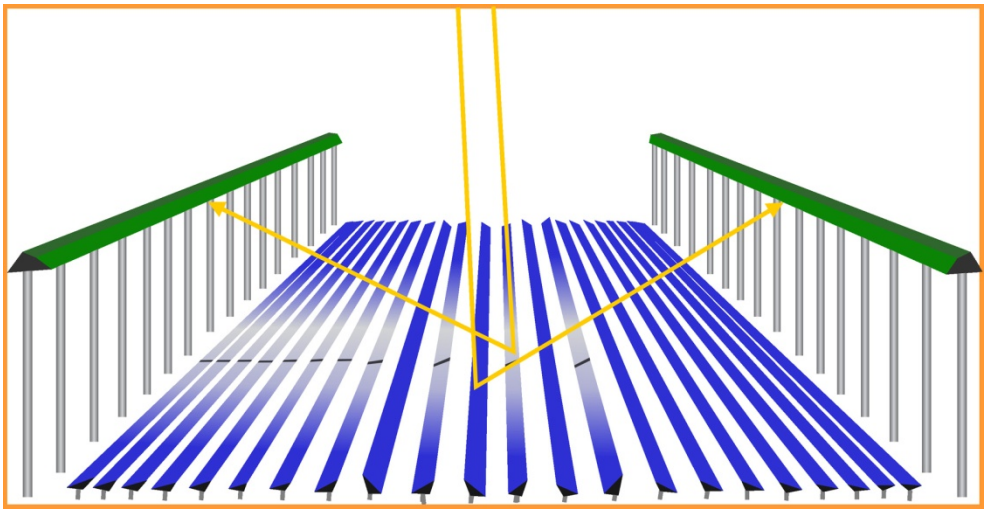
The current design-point solar-to-electric efficiency—the net efficiency in the ideal case when the sun is directly overhead—for a parabolic trough plant ranges from 24%–26%, and the overall annual average conversion efficiency is about 13%–15%. The design-point values represent an ideal case that is useful for comparing between different components, such as two different receiver designs. This metric is also used for evaluating photovoltaic (PV) panels. The annual average efficiency provides a better assessment of actual operation.

Linear Fresnel

Linear Fresnel reflectors (LFRs) approximate the parabolic shape of a traditional trough collector with long, ground-level rows of flat or slightly curved reflectors that reflect the solar rays up onto an overhead linear receiver. Flat reflectors and fixed receivers lead to lower capital costs relative to a traditional trough-based plant, but LFR plants are less efficient on a solar-to-electricity basis. Recently, superheated steam at about 380°C has been demonstrated in an LFR plant, and there are proposals for producing steam at 450°C; higher operating temperatures enable higher efficiency. Because LFRs are in the demonstration phase of development, their relative energy cost compared with parabolic troughs remains to be established.

Compact LFR technology uses a design with two parallel receivers for each row of reflectors (Figure 5-4). This configuration minimizes blocking of adjacent reflectors and reduces required land area. Another advantage is that, depending on the position of the sun, the reflectors can be alternated to point at different receivers, thus improving optical efficiency.

Figure 5-4. Compact Linear Fresnel Reflector Field



Source: NREL

Power Tower

Power towers (also called central receivers) are in the demonstration to early-commercialization stage of development. Because of their higher operating temperatures, power towers have the potential to achieve higher efficiency and lower-cost TES compared with current trough technology.

Power towers use heliostats—reflectors that rotate about both the azimuth and elevation axes—to reflect sunlight onto a central receiver. A large power tower plant can require from several thousand to more than one-hundred thousand heliostats, each under computer control. Because they typically constitute about 50% of the plant cost, it is important to optimize heliostat design. Heliostat size, weight, manufacturing volume, and performance are important design variables, and developers have selected different approaches to minimize cost. Some heliostat technology can be installed on relatively uneven land, with 5% or more slope, thereby reducing site-preparation costs for new projects. Figure 5-5 shows an example of a heliostat array and receiver.

Figure 5-5. Example of a Power Tower and Heliostat Array



Source: BrightSource (2010)

The two principal power tower technology concepts currently being pursued by developers are defined by the HTF in the receiver: steam or molten salt. Both concepts have unique operating characteristics, which are detailed below.

In direct-steam power towers, heliostats reflect sunlight onto a receiver on a tower, which is similar to a boiler in a conventional coal-fired power plant. The feed water, pumped from the power block, is evaporated and superheated in the receiver to produce steam, which feeds a turbine generator to generate electricity. Current steam conditions for direct-steam generation towers range from saturated steam at 250°C to superheated steam at over 550°C. Several characteristics of direct-steam power towers make them attractive: their straightforward design; use of conventional boiler technology, materials, and manufacturing techniques; high thermodynamic efficiency; and low parasitic power consumption. Short-duration direct-steam/water storage has been demonstrated at the 20-MW PS20 tower in Spain. Like many CSP technologies, steam towers can be hybridized with natural gas to provide additional operating flexibility and enhanced dispatchability. Figure 5-6 shows two examples of direct-steam receivers in operation.

Figure 5-6. Examples of Direct Steam Receivers in Operation



Source: eSolar (2010) (left) and BrightSource (2010) (right)

In a molten-salt power tower, salt at about 290°C is pumped from a cold storage tank to a receiver, where concentrated sunlight from the heliostat field heats the salt to about 565°C. The salt is typically a blend of sodium and potassium nitrate, which are ingredients sold commercially as fertilizer. The hot salt is held in a storage tank, and when electric power generation is required, hot salt is pumped to the steam generator, which produces high-pressure steam at nominal conditions of 100–150 bar and up to 540°C. The now-cooler salt from the steam generator is returned to the cold salt storage tank to complete the cycle. Owing to the negligible vapor pressure of the salt, both storage tanks are at atmospheric pressure. The steam is converted to electrical energy in a conventional steam turbine/generator. By placing the storage between the receiver and the steam generator, solar energy collection is decoupled from electricity generation. Thus, passing clouds that temporarily reduce direct-normal irradiance (DNI) do not affect turbine output. In addition, the TES could be less than half the cost of salt TES in trough plants because the larger temperature range across the storage system enables more energy to be stored per mass of salt. The combination of salt density, salt-specific heat, and temperature difference between the two tanks allows economic storage capacities of up to 15 hours of turbine operation at full load. Such a plant could run 24 hours per day, 7 days per week in the summer and part-load in the winter to achieve a 70% solar-only annual capacity factor. The Gemasolar plant in Spain is designed for such performance. Figure 5-7 shows a 43-MW thermal (MW_t) receiver at the 10-MW Solar Two central receiver demonstration project, which was completed in 1995 in Barstow, California.

The annual average solar-to-electric conversion efficiency of a power tower is about 14%–18%, with direct-steam towers slightly higher than molten-salt towers. The design-point efficiency is about 20%–24%. As discussed for troughs, annual average efficiency represents overall real-world performance, whereas design-point values are useful for comparing the performance of individual components. The choice of wet, dry, or hybrid cooling towers can influence water use, cycle performance, and cost (see Chapter 7).

Dish/Engine

Figure 5-7. Example of a Molten-Salt Receiver



Source: Sandia National Laboratories (2010)

Dish/engine CSP technology uses a collection of reflectors assembled in the shape of a parabolic dish to concentrate sunlight onto a receiver cavity at the focal point of the dish. Within the receiver, the heater head collects this solar energy, running an engine-driven generator to produce electricity. Similar to heliostats, all dishes rotate along two axes to track the sun for optimum capture of solar radiation. There are currently three major types of engines used at the core of dish/engine technology: kinematic Stirling engines, free-piston Stirling engines, and Brayton turbine-alternator based engines. Dishes have also been proposed with air receivers that feed hot air to a steam generator. Both kinematic and free-piston Stirling engines harness the thermodynamic Stirling cycle to convert solar thermal energy into electricity by using a working fluid, such as hydrogen or helium. Brayton systems use turbine-alternator engines with compressed hot air to produce electricity. Current dish/Stirling systems generate 3–30 kilowatts (kW) of electricity, depending on the size of the dish and the heat engine used. The first dish/Stirling commercial demonstration began operation in January 2010. Dish/Brayton systems have been proposed at sizes up to 200 kW.

Some dish/engine technology can be installed on relatively uneven land—with 5% or more slope—thereby reducing the cost of site preparation for new projects. Dish/engine systems are cooled by closed-loop systems (similar to an automobile engine), which, combined with the lack of a steam cycle, endow them with the lowest water use per megawatt-hour (MWh) among all the CSP technologies. As a modular technology, dish/engine systems are built to scale to meet the needs of each individual project site, potentially satisfying loads from kilowatts to gigawatts. This scalability makes dish/engine technology applicable for both distributed and utility-scale generation. Dish/Stirling systems have demonstrated the highest recorded CSP design-point solar-to-electric efficiency (31.4%) and have an estimated annual conversion efficiency in the low 20% range. Two types of dish/engine systems are shown in Figure 5-8.

5.2.2 Cost and Performance

The current performance and cost of CSP plants varies by technology, configuration, solar resource, and financing parameters. However, it is possible to evaluate different plant designs and technologies in terms of a single index: the levelized cost of energy (LCOE). LCOE takes into account the available solar resource, upfront capital investment, plant capacity factor, operation and maintenance (O&M) costs, and financing parameters. LCOE is generally expressed in terms of cents per kilowatt-hour (kWh). Alternatively, the cost of a CSP plant can be expressed in terms of dollars per watt (W) or, more commonly, dollars per kilowatt. LCOE takes

Figure 5-8. Examples of Dish/Engine Systems



Sources: Stirling Energy Systems (SES) (2010) (left) and Infinia (2010) (right)

capacity factor and O&M costs into account, but dollars per kilowatt does not. For example, a 100-MW CSP plant can be built with TES and additional collector area to increase its capacity factor. This hypothetical design might generate 100% more energy per year and have a 60% higher installed cost than an alternative design without TES and additional collector area; such a plant would have a higher installed dollars-per-kilowatt cost but a lower LCOE than the alternative-design plant.

Assuming fixed financial inputs, the LCOE of a CSP plant can be reduced in two ways: 1) by lowering capital or O&M costs, and 2) by increasing annual performance. The capital equipment for a CSP plant involves solar components (e.g., solar collector field, heat-transfer piping, and TES system) and more-or-less conventional thermodynamic power-cycle components (e.g., pump, turbine, and generator). The O&M cost per megawatt-hour, of which staff is the largest contributor, decreases with an increase in plant size or co-location of multiple units at one site. Decreasing capital and operating costs can be achieved by technology advances and increased manufacturing volume and supply chain efficiency.

The performance of a CSP plant is characterized by its annual solar-to-electric conversion efficiency. This metric includes all of the energy losses that affect the annual electricity produced by the plant, including optical, thermal, and electrical parasitic losses, as well as forced and planned outages for maintenance. Although higher efficiency often costs more up front, it may more than pay for itself over the operating life of the plant. Also, plants with higher efficiency require less land to produce a given amount of electricity. In other cases, a slightly lower overall efficiency may be advantageous. For example, if the marginal cost of a heliostat is less than the return in revenue it provides, it may be worth adding heliostats—increasing the capacity factor, but lowering the efficiency, of the plant. Capacity factor is defined as the ratio of actual annual generation to the amount of generation had the plant operated at its nameplate capacity for the entire year. Capacity factors vary greatly between different locations, technologies, and plant configurations; for example, plants with TES achieve higher capacity factors because their power block can have more hours of operation. CSP plants with TES are likely to be more cost effective in the future as compared to plants without TES, because while the

addition of low-cost TES does increase capital costs, it has the potential to reduce the LCOE.

One of the most recent utility-scale CSP plants built in the United States is the Nevada Solar One parabolic trough plant, which came on line in 2007 at a reported cost of about $4,100/kW ($266 million cost, nominal 64-MW capacity). Several similar-size trough plants have been built in Spain, including the Andasol plants that include TES; however, those project costs have not been disclosed. The estimated direct capital costs for building a CSP plant today are about $4,000–$8,500/kW. The upper end of the range reflects plants with TES, whereas the lower end includes no-TES troughs, direct-steam generation towers, and dish/engine systems (see Section 5.3.6 for more information). Plant capacity factors extend from 20%–28% for plants with no TES and 40%–50% for plants with 6–7.5 hours of TES. Larger amounts of TES and higher capacity factors are technically viable but subject to project economics. The LCOE varies greatly depending on the location, ownership, values of key financing terms, available financial incentives, and other factors. For locations in the southwestern United States, the LCOE is currently in the 12–18 cents/kWh range with a 30% investment tax credit (ITC).

5.3 Projected Technology and Cost Improvements to Existing and Emerging CSP Technologies

Anticipated reductions in the delivered cost of electricity from CSP plants will occur primarily from decreasing the upfront investment cost and improving performance. Reduced capital cost will be a consequence of manufacturing and installation scale-up as well as technology advancements through R&D aimed at cost reduction and performance improvements. A number of component- and system-level advancements are currently being pursued, which generally can be classified into five sub-systems: solar field, HTF, TES, cooling technology, and power block. Each of these sub-systems is discussed below, followed by a detailed discussion of current and projected cost improvements by sub-system.

5.3.1 Solar Field

The solar collector field (materials plus labor) represents the single largest capital investment in a CSP plant and thus represents the greatest potential for LCOE reduction among capital equipment costs. The key to reducing solar field costs is reducing the cost of the collector support structure, reflectors, and receivers.

The support structure must support the weight of the reflectors and have sufficient strength to keep the reflectors aligned, even during high-wind conditions. Survival wind loads (the maximum wind loads that structures must withstand), which vary by location, tend to drive the overall design of the collector. The support structures must also have sufficient torsional rigidity to minimize twisting. For the collectors, developers are working to reduce the amount of material and labor necessary to provide accurate optical performance. The choice of material also plays an important role in structural design: steel is stronger and stiffer than aluminum, but aluminum is lightweight, corrosion resistant, and more easily processed. Advanced collector

designs that use integrated structural reflectors reduce the installation cost of both the structure and reflectors by making assembly of the solar field easier and faster. For troughs, several advanced frame designs are being evaluated, such as space frame, torque tube, and monocoque. Troughs are generally moving toward larger-aperture collectors to reduce total costs for piping, receivers, drives, and controls. For towers, heliostat sizes from 1–130 square meters (m^2) are being used. In addition, improvements in other collector components—such as drives, controls, and foundations —are needed to reduce the support structure cost further.

The optical performance of reflectors is also critical to minimizing LCOE, because it has an approximately one-to-one ratio with LCOE—i.e., a 1% increase in reflectance will cause a 1% reduction in LCOE. For CSP reflectors, it is important for the reflective surface to not only be highly reflective, but also to be highly specular; in other words, the reflector must not only reflect the sunlight, but also reflect it into a narrow cone angle that intercepts the receiver. Currently, most CSP plants use 4-millimeter (mm) second-surface silvered glass reflectors, and current glass reflectors have proven field performance and reflectivity values of about 93.5%. Costs may be reduced by moving from these heavy glass reflectors to lightweight thin glass, polymeric film, or coated aluminum reflectors. Figure 5-9 shows a recently installed parabolic trough system operating at SEGS-II as an example of a large-aperture trough that uses a silvered polymer reflector. Compared with glass reflectors, thin-film reflectors have the potential to provide a lightweight, high-reflectance, low-cost alternative, while also allowing a greater degree of design freedom and reduced breakability. Advanced reflectors are being developed to increase reflectivity to 95% or higher, but time is required to prove their long-term durability. Reflector coatings are being explored to increase durability and to reduce the amount of water used for cleaning.

Figure 5-9. Parabolic Trough Undergoing Testing in Southern California



Source: SkyFuel (2010)

Receivers have optical and thermal performance characteristics. The optical efficiency is a measure of the percentage of incoming DNI that is absorbed by the receiver, whereas the thermal efficiency is the proportion of energy absorbed by the

receiver that is transferred to the HTF. Current solar selective coatings for receiver surfaces display high absorptivity of short-wave radiation (sunlight), but a challenge is to reduce the emissivity of long-wave radiation (infrared) while maintaining high absorptivity at high temperatures. Selective coatings for vacuum-jacketed trough receivers are fairly advanced, but tower receivers would benefit from new selective coatings that can withstand their higher temperatures and are resistant to oxidation.

For trough receivers in particular, receiver tubes in the field have exhibited a problem of hydrogen permeation from the HTF into the vacuum space, resulting in greatly increased heat loss. Solutions being studied to solve this problem include adjusting the amount and location of hydrogen getters, centrally removing the hydrogen, using an inert gas to block the motion of hydrogen, and deploying HTFs that do not generate hydrogen.

5.3.2 Heat-Transfer Fluid

A major focus of improved CSP performance is achieving higher operating temperatures to take advantage of increased thermal-to-electric conversion efficiencies and—for systems with TES—lower TES cost.

For commercial parabolic trough systems, the maximum operating temperature is limited by the HTF, currently a synthetic oil with a maximum operating temperature of approximately 390°C. Other limitations of this HTF include the cost of the fluid and the need for heat-exchange equipment to transfer thermal energy to the power cycle or storage system. Several parabolic trough companies are experimenting with alternative HTFs that would allow operation at much higher temperatures. Examples of HTFs currently under investigation include molten salts, water for direct-steam generation, organic silicones, ionic liquids, and polyaromatic napthalenes. In addition, researchers are investigating the incorporation of nanoparticles into many of these fluids to improve their heat capacity, heat-transfer rate, and/or thermal stability at high temperatures.

The maximum practical concentration ratio possible coupled with the lowest practical heat loss from the receiver tubes suggest an upper temperature limit of approximately 500°C for parabolic trough systems. Water/steam and molten-salt HTFs can be used at this temperature; however, there are concerns with the freezing temperature of molten salts as well as a need for salt-compatible components, such as flex-joints and valves. The salt currently used in tower projects and TES systems is a 40/60-weight-percent blend of potassium nitrate and sodium nitrate, which starts melting at 220°C. A small demonstration trough plant in Sicily is also currently running with this salt HTF. A shift to molten-salt HTFs running at 500°C is predicted to significantly reduce trough plant costs, primarily by improving thermal conversion efficiency, reducing TES costs, and reducing HTF system cost (piping, insulation, and fluid) (Turchi et al. 2010a). For this reason, considerable R&D efforts are underway to find lower-melting-point salts that are more attractive for use in commercial parabolic trough plants. However, lowering the melting point of salts typically requires the incorporation of more expensive salt components and hardware, and these tradeoffs must be weighed carefully. Efforts to address material compatibility are also underway, including new packing materials for ball joints and testing of both piping components and instrumentation. Direct-steam troughs have

also been proposed and tested, but no commercial plants have yet been built owing to the greater control complexity of these systems.

In contrast to parabolic trough systems, molten salt and direct steam are currently used as the HTFs in power tower systems operating at temperatures near 565°C. This is possible because of the considerably smaller amount of piping required for the HTF in a tower system. Owing to higher concentration ratios associated with tower systems as compared with parabolic troughs, operating temperatures of 1,000°C or higher may be feasible, depending on the medium used for the HTF. Research efforts are investigating systems and materials capable of operating at these elevated temperatures. Systems that operate at moderately higher temperatures (600°C–700°C) may allow molten-salt and steam towers to adapt and use commercial supercritical steam turbines (as opposed to the current subcritical Rankine cycles).

The choice of HTF greatly influences whether a particular design can be integrated with TES. For example, although small amounts of steam can be stored in steam accumulators, such designs are not economically feasible at higher storage capacities. Steam-compatible options such as phase-change storage show promise but have yet to be demonstrated beyond pilot scale. Alternatively, molten-salt receivers can efficiently store the high-temperature salt HTF directly in tanks at a relatively low cost. Potential storage options are discussed in greater detail in the following section.

5.3.3 Thermal Energy Storage

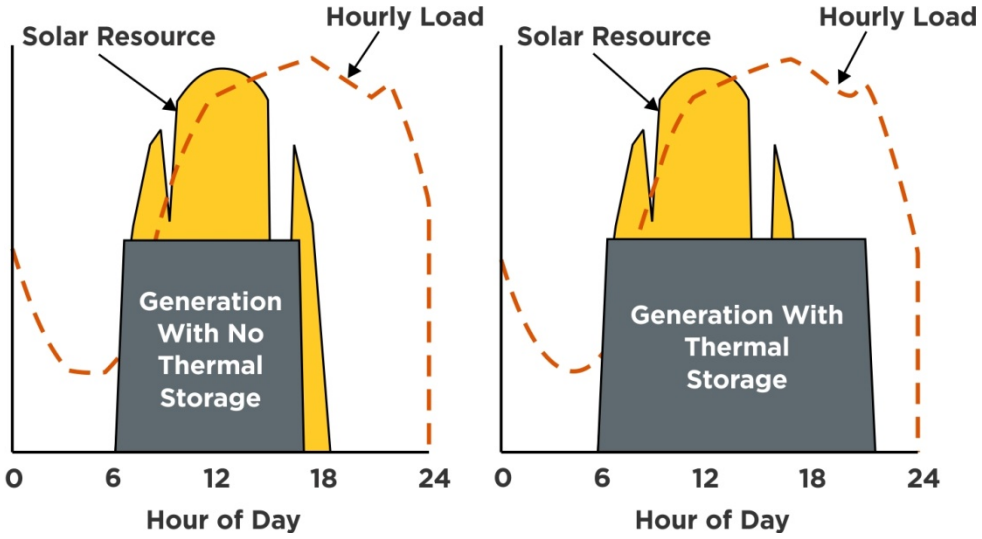
A very important characteristic of CSP technologies is their ability to dispatch power beyond the daytime sun hours by incorporating TES systems. During summer months, for example, plants typically operate for up to 10 hours per day at full-rated electric output without TES. However, full-load generation hours can be added or shifted if TES is available, allowing for greater utilization of the power block and potentially reducing LCOE. Incorporating TES normally is accompanied by increasing the size of the collector area to produce excess thermal energy during the day that can be put into the TES system for later use. An alternative to TES that does not require collector-area expansion is to configure the systems as hybrid plants, i.e., provide a secondary backup system to supplement the solar output during periods of low solar irradiance. Use of natural gas is typical, but the use of renewable fuels such as biomass is also possible. Hybrid plants provide good dispatchability at relatively low cost and risk, albeit with a diluted solar contribution.

Large-scale TES systems have only recently appeared in commercial CSP plants. Plants with TES typically have collector fields that are much larger than the minimum size required to operate the power cycle at full load. The ratio of the collector-field thermal power to the power required to operate the power cycle at full load is termed the “solar multiple.” For example, a system with a solar multiple of 1.0 means that the solar field delivers exactly the amount of energy required for the generator to produce the maximum rated power, or “nameplate capacity,” for the plant’s turbine at a defined insolation value—e.g., solar noon on the summer solstice. At all other times, the solar field would be delivering less power than required to run the turbine at maximum capacity. Even plants without explicit TES are designed with an oversized solar collector field (i.e., with a solar multiple greater

than one) so that they can operate the turbine at its maximum power capacity (design point) for more hours of the year. The plant may need to reduce collection of some solar energy during summer afternoons, but the larger solar field allows for full-load operation for more total hours throughout the year. If TES is included, any excess heat from the collector field is sent to the TES system. When power is needed, the heat is extracted from the TES system and sent to the steam cycle. An example of a commercial plant with storage is Andasol 1 in Spain, which incorporates a two-tank molten-salt system. The 50-MW plant uses 28,500 metric tons (MT) of nitrate salts, offering a storage capacity of 1,000 MW_t, equivalent to about 7.5 hours of power production. The salt temperature ranges from 292°C in the cold tank to 386°C in the hot tank.

Additional capital investment is required to expand the collector area and add storage tanks so that a CSP plant may incorporate TES; however, these costs are offset by increasing the operational hours of the power block. If solar field and TES costs are low enough, the net effect is a decrease in LCOE. In addition, TES provides greater operating flexibility and enhances dispatchability, which provides additional value to the utility. Figure 5-10 shows how CSP plants with TES can tailor their output to match load curves, thereby maximizing value to the utility and revenue to the owner. TES allows CSP plants to extend and/or shift energy generation to coincide with peak load demands. The only current commercial TES option for parabolic trough, linear Fresnel, and power tower systems uses molten nitrate salt as the storage medium in a two-tank, sensible heat system. Two-tank, sensible heat TES tends to be highly efficient in both energy (energy stored is recovered) and exergy (energy stored is recovered at nearly the same temperature); roundtrip energy efficiencies of up to 98% were reported for the storage system at the Solar Two power tower demonstration (Pacheco 2002). The major limitation to two-tank, sensible TES is the amount of storage media required, especially at the lower operating temperatures used by current trough technology.

Figure 5-10. Thermal Storage and Utility Demand



Source: NREL

To reduce the cost of TES, industry and the U.S. Department of Energy (DOE) have made considerable investments in improvements and alternatives to two-tank, sensible TES. Examples of research topics include the following:

- Low-melting-point salt mixtures, which are identical to research efforts in HTFs
- Solid-media storage, such as graphite, concrete, or ceramics
- Phase-change material (PCM) systems, in which a solid, such as metal or salt, is melted, capturing a considerable amount of energy in the latent heat of the material
- Single-tank thermoclines, in which hot and cold molten salt are stored in one tank and separated by the difference in density between the hot and cold salt
- Thermochemical storage, in which energy is captured using a chemical reaction and, when needed, released by reversing the reaction
- Specially engineered additive materials such as dispersed nanoparticles within salts to increase heat capacity.

These TES options must be compatible with the corresponding HTF, because the most economical TES option is largely contingent on the HTF being used.

For most TES systems, the operational temperature range has an effect on the cost of storage. For example, molten-salt power tower plants can operate at higher temperatures and therefore can reduce the amount of salt required for TES by approximately a factor of three, for a given storage capacity, relative to a current parabolic trough plant.[53] This significant reduction in storage-material mass and the associated reduction in costs make it possible to economically add higher TES capacities. Longer-duration storage (~12 hours) makes near-baseload operation possible. However, at least for the near term, most troughs and towers likely will be built with low levels (6 hours or less) of storage owing to time-of-delivery rate schedules that pay more for peak-power electricity delivery. For example, the Nevada Solar One plant does not have a TES system, although it does provide about 30 minutes of storage via the extra HTF capacity held in the expansion tank.

The storage methods described above are largely focused on TES for parabolic trough, linear Fresnel, and power tower systems. The modular nature of dish/engine systems make them less suitable for large, centralized TES systems. However, several methods for incorporating better dispatchability into dish/engine technologies are being explored, including TES using PCMs and hybrid systems using fossil fuels to augment power production, similar to hybrid options in other CSP systems.

Although delivered cost of electricity, as measured by LCOE, is the most important cost metric for CSP, it does not fully capture the value of CSP as a dispatchable power source. Adding storage to a CSP plant adds value by decreasing variability, increasing predictability, and providing firm capacity during peak load when it is most valuable. CSP plants with TES can bid into ancillary services and capacity

[53] The mass of salt required is inversely proportional to the temperature differential in the storage system; thus, a tower operating from 290°C–565°C requires approximately three times less storage salt than a trough system operating from 300°C–390°C.

markets, where they exist, to realize additional revenue. Even in the absence of explicit markets, the greater capacity value of CSP with TES is recognized in resource planning, where CSP can be given additional consideration due to its dispatchability. This can be observed in the discussion about system dispatch in Section 3.2.6, where CSP is used to follow the significant variability of net load. This ability will become increasingly important to system planners and operators as they seek to maintain the reliability of the bulk power system while integrating large amounts of variable generation such as PV and wind.

5.3.4 Cooling Technology

All CSP systems require cooling, but they differ in their selection of cooling technology. Dish/engine systems are inherently air cooled, whereas trough, Fresnel, and power tower technologies can use wet, dry, or hybrid (a combination of wet and dry) cooling. The selection of cooling technology depends on economics, water availability, and policy. If available, wet cooling is often preferred and provides the lowest cost; however, some CSP developers have voluntarily opted for dry cooling to reduce water consumption. Chapter 7 provides additional discussion on the water use of CSP and other electricity-generating technologies.

CSP facilities need to be built in areas of high DNI, which generally translates into arid, desert areas where water is a scarce resource, making water use a major concern for CSP plants. A typical trough or power tower plant that employs wet cooling can consume 750–1,020 gallons of water to produce 1 MWh of solar electricity (see Chapter 7, Table 7-3). Several strategies can reduce the freshwater consumption of CSP plants: using dry cooling, using degraded water sources, capturing water that would otherwise be lost, and increasing thermal conversion efficiencies. Dry and hybrid cooling systems are commercial technologies that have the potential to reduce CSP water consumption by 40%–97%, depending on the generating technology and project location (see Chapter 7).

Compared with wet cooling, dry and hybrid cooling systems have a higher equipment cost and, depending on design, may have a performance penalty. Various studies have sought to define the cost and performance effects of dry cooling to minimize the impact on LCOE. For example, a recent analysis estimated that switching to dry cooling would raise the LCOE of a trough plant by 3%–8%, depending on location and plant design (Turchi et al. 2010b). The performance and cost penalty for power tower systems should be lower, because CSP technologies operating at higher temperatures experience smaller penalties as a result of using dry or hybrid cooling systems. Nevertheless, the importance of this issue may warrant additional research on indirect air cooling or other aspects to improve efficiencies and reduce costs for dry cooling. Examples of R&D efforts to reduce water use for wet or hybrid cooling include recovering water that is evaporated in cooling towers or using non-traditional sources for cooling water, such as treated saline groundwater, reclaimed water, or water produced from oil and gas extraction.

The effect of cooling technology on CSP system cost and performance varies by technology, location, and climate. Cooler climates make dry cooling more attractive, whereas the performance penalty is greatest for lower-temperature CSP systems in hot climates. Lastly, using TES systems enables some electricity production to be

shifted to cooler evening hours, which offsets some of the penalties associated with dry or hybrid cooling systems (Sioshansi and Denholm 2010).

5.3.5 Power Block and Other Cost-Reduction Potential

The current CSP power block for trough, Fresnel, and power tower systems uses many conventional steam Rankine cycle components. It consists of a steam generator that feeds a subcritical Rankine cycle with reheat. The main cost-reduction potential in the current power block is correlated to increased size. For example, the SEGS units in California were built in the 1980s over a period of 7 years, with an increase in size from 14 to 80 MW. The recent Nevada Solar One plant is 64 MW, and several announced CSP plants exceed 200 MW. Increasing the size of the power block results in improved cycle efficiency and lower amortized O&M costs. Sargent & Lundy (2003) report a scaling factor of 0.7 for the power block, indicating that a doubling of gross turbine capacity results in only a 62% increase in power block cost (i.e., $2^{0.7} = 1.62$). However, some developers prefer to use multiple, smaller turbines within a single plant because this can yield higher annual availability. For the long term, alternative power cycles—such as supercritical steam, supercritical carbon dioxide (CO_2) Brayton, and air Brayton—are being investigated, which offer the potential to increase the efficiency and/or decrease the cost of the power block.

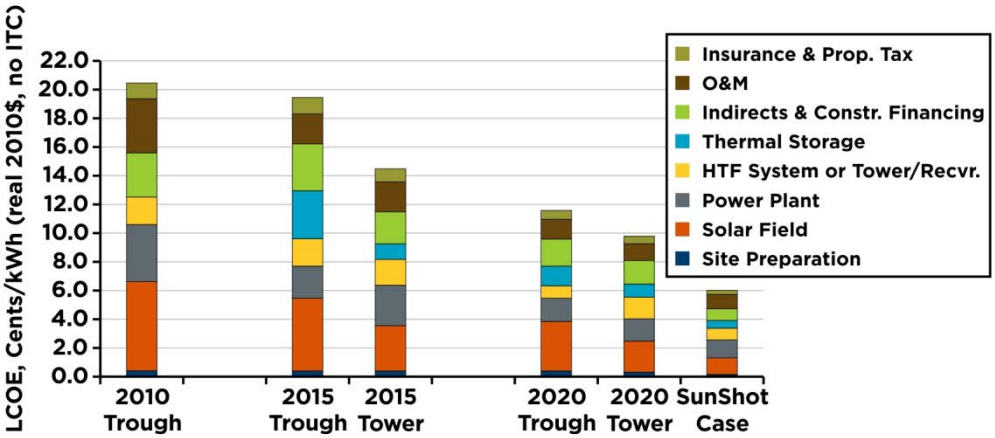
The next generation power cycle is likely the supercritical steam Rankine cycle, because this cycle readily exists at commercial utility-scale fossil plants. However, existing systems are 400 MW electric (MW_e) or larger and may need to be scaled down to better accommodate CSP systems. Operating at temperatures above 650°C may require advanced cycles such as supercritical CO_2 Brayton or air Brayton, which could provide high thermodynamic efficiencies compared with a traditional Rankine cycle. Commercial natural gas Brayton cycles currently exist; however, supercritical-CO_2 and air-Brayton systems do not currently exist beyond the pilot and demonstration scale, respectively. Research efforts are underway to better understand the feasibility of using Brayton cycles for CSP applications.

As unit size increases, the per-megawatt-hour costs for balance of plant and O&M staffing decrease. For plants with multiple units, there is a cost reduction associated with shared infrastructure, such as substations and buildings, and O&M staffing (KJC Operating Co. 1994, Sargent & Lundy 2003). The average O&M cost for CSP is currently about 2.9 cents/kWh and drops to about 1.0 cent/kWh by 2020 in the SunShot target case defined below (Figure 5-11). The main drivers behind the O&M cost reduction are the increase in capacity factor and larger plant sizes. Potential areas for automation, such as reflector cleaning, are also being considered.

Parasitic power consumption can account for 10%–15% of gross turbine output in a CSP plant. Much of this consumption is due to pumping losses, and various options—including pressure-drop reduction, head-recovery, and joint minimization—are being explored to reduce this impact.

A promising low-cost market-entry strategy is augmentation of existing fossil-fired plants with CSP systems. Adding a solar component to an existing fossil-fired plant holds several distinct advantages, including reduction in capital and O&M costs through the use of existing power block hardware and O&M crews, respectively. Such projects have lower risk than stand-alone solar plants and benefit from existing

Figure 5-11. Current and Projected Costs for CSP Trough and Tower Technologies, per Table 5-1



grid connections and inherent fossil backup. A joint study by the National Renewable Energy Laboratory (NREL) and the Electric Power Research Institute (EPRI) suggested that 10–20 GW of solar capacity could be added in the United States through solar augmentation of existing fossil plants (Turchi 2011).

5.3.6 Summary of Technology Improvements and Cost-Reduction Potential

In 2009, the DOE CSP subprogram set a goal to reduce the LCOE of CSP technology to 9 cents/kWh or less by 2020. In pursuit of this goal, two multi-year planning exercises—a parabolic trough roadmap and power tower roadmap—were initiated with representatives from the CSP industry, NREL, and Sandia National Laboratories (Kutscher et al. 2010, Kolb et al. 2011). The purpose of these documents was to describe the current technology, the technology improvement opportunities (TIOs) that exist, and the specific activities needed to advance CSP technology.

In 2011, DOE officially unveiled the SunShot Initiative, an aggressive R&D plan to make large-scale solar energy systems cost competitive without subsidies by the end of the decade. The SunShot Initiative takes a systems-level approach to revolutionary, disruptive (as opposed to incremental) technological advancements in the field of solar energy. The overarching goal of the SunShot Initiative is reaching cost parity with baseload energy rates, estimated to be 6 cents/kWh without subsidies, which would pave the way for rapid and large-scale adoption of solar electricity across the United States.

The SunShot Initiative's target for CSP is 6 cents/kWh or less. Although many of the TIOs identified in the roadmaps are applicable to the SunShot cost-reduction target, it is clear that an "extra step" is necessary to move from the roadmap goals to the SunShot targets. In other words, although the roadmaps laid out pathways to next-generation CSP technologies, SunShot requires even more advanced CSP technological breakthroughs.

Estimated current costs and projected future costs for roadmap and SunShot scenarios are presented in Table 5-1 and Figure 5-11. Current CSP costs are largely based on parabolic trough technology, which is the most mature CSP technology. Trough plants without TES are benchmarked by Nevada Solar One, whereas the Andasol plants in Spain represent the state-of-the-art for plants with TES.

Table 5-1 outlines representative cases for current and future CSP technology costs based on the DOE roadmap exercises. A SunShot target case, outlined later in this section, is also shown. The LCOE estimates for the different cases are presented in Figure 5-11. These values are based on the financial assumptions described in Chapter 8. No ITC is applied when calculating these LCOEs. Both the current and projected LCOE estimates for CSP technologies shown in Figure 5-11 are based on values shown in Table 5-1. The contingency percentage shown in Table 5-1 has been added to each direct cost category.

In Table 5-1 and Figure 5-11, 2010 costs are estimated based on a 100-MW parabolic trough plant with no TES, while the 2015 costs are based on a 250-MW parabolic trough plant with 6 hours of TES and a 100-MW molten-salt power tower plant with 6 hours of TES.[54] Both 2015 configurations are representative of current projects with existing PPAs. After 2015, salt-HTF trough and tower systems are assumed to be proven technologies with expanding deployment that leads to reduced costs via learning and manufacturing volume.

Future Parabolic Troughs

The 2020 trough roadmap case is based on a 250-MW molten-salt HTF trough at a field temperature of 500°C, similar to the configuration being tested by Enel at the 5-MW Archimede demonstration in Sicily. The higher temperature improves power-cycle efficiency and dramatically lowers TES cost. Direct storage of the molten-salt HTF in a thermocline system is assumed, and no adjustment in the performance of the TES system is applied, which assumes improvement in the ability to maintain a sharply stratified thermocline and/or sliding pressure turbine operation with minimal efficiency impacts, as has been suggested by Kolb (2010). Advanced collector designs, employing novel reflector materials and larger-aperture troughs, account for the reduced solar field cost. Operating experience and manufacturing volume are also assumed to lower O&M and capital costs. The major challenge for this case is successful deployment of salt-HTF systems for troughs.

Future Power Towers

The 2020 tower roadmap case is based on a 150-MW molten-salt HTF tower with a supercritical steam power cycle at 650°C. A slight power block cost increase is included based on the current ratio of subcritical-steam to supercritical-steam power blocks for coal plants.

[54] Although the 2015 power tower analysis presented in Table 5-1 and Figure 5-11 is based on a molten-salt power tower with several hours of TES, the predicted LCOEs for steam and molten-salt power tower technologies are nearly identical. Modeling a steam tower system with little to no storage results in an LCOE prediction within 1 cent/kWh of the 2015 tower values. In addition, much of the cost-reduction potential identified for molten-salt towers also applies to steam towers.

Table 5-1. Current and Projected Costs and Performance Estimates for CSP Trough and Tower Technologies (Analysis with System Advisor Model Version 2010-11-09)

Case	2010 Trough	2015 Trough Roadmap	2015 Tower Roadmap	2020 Trough Roadmap	2020 Tower Roadmap	2020 SunShot Target
Design Assumptions						
Technology	Oil-HTF trough	Oil-HTF trough	Salt tower	Salt-HTF trough	Salt tower	Supercrit. CO_2 combined cycle tower
Solar Multiple	1.3	2.0	1.8	2.8	2.8	2.7
TES (hours)	-	6	6	12	14	14
Plant Capacity (MW, net)	100	250	100	250	150	200
Power Cycle Gross Efficiency	0.377	0.356	0.416	0.397	0.470	0.550
Cooling Method	wet	dry	dry	dry	dry	dry
Cost Assumptions						
Site Preparation ($/m^2)	20	20	20	20	20	10
Solar Field ($/m^2)	295	245	165	190	120	75
Power Plant ($/kW)	940	875	1,140	875	1,050	880
HTF Sys or Tower/Rcvr ($/m^2 or $/$kW_{th}$)	90	90	180	50	170	110
Thermal Storage ($/$kWh_{th}$)	-	80	30	25	20	15
Contingency	10%	10%	10%	10%	10%	10%
Indirect (% of direct costs + contingency)	17.6%	17.6%	17.6%	17.6%	17.6%	13%
Interest during Construction (% of overnight installed cost)	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
O&M ($/kW-yr)	70	60	65	50	50	40
Performance and Cost						
Capacity Factor	25.3%	42.2%	43.1%	59.1%	66.4%	66.6%
Total Overnight Installed Cost ($/kW)[a]	4,250	7,420	5,600	6,160	6,070	3,560
Total Installed Cost ($/kW)[a]	4,500	7,870	5,940	6,530	6,430	3,770
LCOE (cents/kWh, real) [SunShot financial assumptions]	20.4	19.4	14.4	11.6	9.8	6.0

Costs for trough and tower systems are based on analyses made in 2009 and 2010 dollars. No adjustments were made to these costs—net changes in labor and commodity prices for the period are assumed to be within the error of the analysis.

[a] A project's "overnight installed cost" is the total direct and indirect costs that would be incurred if the project was built in an instant, that is, there are no additional costs for financing the construction period. A project's "total installed cost" is its overnight installed cost plus any financial costs incurred to cover payments made during the period between the start of construction and plant commissioning.

Direct storage of the molten-salt HTF in a thermocline system is assumed, and, as with troughs, no adjustment in performance of the TES system is applied. System availability increases and O&M cost reductions are due to increased operating experience. Improved heliostat designs, along with manufacturing experience and scale, account for the reduced solar field cost. The major challenge for this case is scale-down of supercritical steam turbomachinery from the 400-MW or larger scale currently deployed for coal plants to the 150-MW size proposed for CSP.

SunShot Options

The 2020 SunShot case requires more aggressive advances in performance improvements and cost reductions than assumed by the roadmap cases. SunShot-level cost reductions likely include an increase in system efficiency by moving to higher-temperature operation (i.e., maximizing power-cycle efficiency) without sacrificing efficiency elsewhere in the system (i.e., minimizing optical and thermal efficiency losses). Likewise, reducing the cost of the solar field and developing high-temperature TES compatible with high-efficiency, high-temperature power cycles are critical to driving costs down further.

Reaching the SunShot cost target of 6 cents/kWh will require improvements to all subsystems within a CSP plant. The primary source of efficiency gains is the development and implementation of advanced power cycles, with the leading candidates for CSP applications being supercritical-CO_2 Brayton and air-Brayton power cycles. Although there are multiple potential pathways to reaching SunShot targets, the 2020 SunShot case presented in Table 5-1 is based on a 200-MW power tower utilizing a supercritical-CO_2-Brayton power cycle. Power towers may have the highest potential for achieving the SunShot target due to their combination of high optical concentration, high temperature, ease of TES integration, and ability to scale over a wide range of capacities. The development of these new CSP power blocks will require detailed modeling of power systems, followed by the development and testing of new turbomachinery, instrumentation, and heat exchanger designs. The 2020 SunShot case shown in Table 5-1 and Figure 5-11 assumes the deployment of a supercritical-CO_2 power cycle combined with a Rankine bottom cycle. A high-temperature salt serves as receiver HTF, and TES is provided by direct storage of the HTF in a thermocline. Fourteen hours of storage was selected as a value that minimizes LCOE for the assumed case conditions. Supercritical CO_2 power cycles are under development by a variety of academic, laboratory, and industry players for application to solar, advanced fossil, and other energy applications (Rochau 2011). Such a design offers the potential of high overall system efficiency while running at temperatures several hundred degrees lower than required for air-Brayton cycles, thereby lessening materials and thermal loss concerns.

Regardless of the power-cycle design, achieving the SunShot target will require significant reductions in collector costs while minimizing optical efficiency losses. It is essential to remove material weight from the solar field while maintaining adequate wind-load rigidity and optical accuracy. The primary cost components of heliostats include the reflector module, support structure and pylon, drive systems, wiring, and manufacturing infrastructure, all of which will need to be addressed. Proposed improvements include polymeric or thin-glass reflectors, anti-soiling coatings to maintain reflectivity while decreasing O&M costs, novel structures with

significantly reduced material content, low-cost drives with wireless field controls, and highly automated manufacturing and installation procedures.

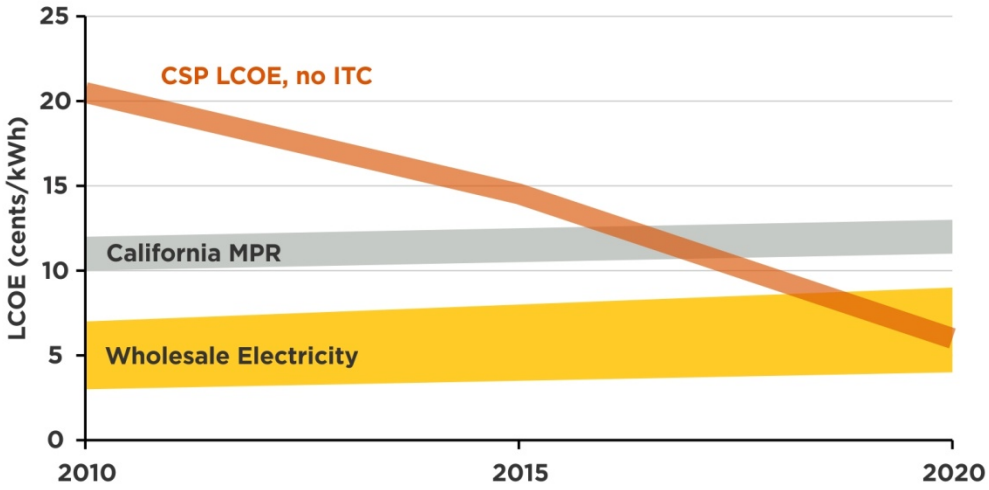
The development and testing of new solar receiver designs and materials will be necessary to accommodate the deployment of advanced, high-temperature power cycles. Air-Brayton systems running at temperatures of 1,000°C and higher may require volumetric receivers or designs with secondary concentrators; such designs are currently being investigated as part of the European Solugas project. Although supercritical-CO_2 systems will run at lower temperatures (600°C–800°C), they will still require the determination of compatible materials and receiver designs for high-pressure CO_2 systems. Selective receiver tube surface coatings that maintain high absorptivity while minimizing emissivity and are stable at high temperatures in air are needed for new receiver designs. Initial research suggests that candidate materials may be found among those originally investigated for trough receiver coatings.

Lastly, as temperatures are increased and new HTFs are deployed, TES systems will need to advance to maintain the relatively high efficiency and low cost of current CSP TES systems. Supercritical steam and CO_2 are compatible with thermocline and two-tank storage concepts, but salts with stability and low corrosivity at the proposed higher temperatures may be required. Air-Brayton cycles in particular would benefit from low-cost solid-phase storage media or other novel TES concepts. Although the SunShot case presented in Table 5-1 and Figure 5-11 assumes a supercritical-CO_2 combined cycle with salt storage, alternative approaches are being considered and may prove a better fit.

The combined effect of lower capital costs, improved performance, and learning should lead to a rapid drop in LCOE by the end of the decade. Figure 5-12 shows the calculated decrease in LCOE if the CSP industry achieves the SunShot cost and performance targets presented above. The LCOE estimates in Figure 5-12 are based on the financial assumptions listed in Table 8-1 of Chapter 8, which are applied to both CSP and utility PV cases. In the near term, CSP with a 30% ITC is competitive with the solar-weighted California Market Price Referent (MPR). The California MPR represents the market price of electricity in California and is used as a benchmark to assess the above-market costs of renewable portfolio standard (RPS) contracts in California (CA PUC 2009). Solar weighting refers to the time-of-delivery credit applied to solar generation due to its good coincidence with peak load. When the 30% ITC expires at the end of 2016, CSP is projected to remain competitive with the California MPR. The LCOE projections shown in Figure 5-12 do not include any ITC, even though current U.S. law maintains a 10% ITC after 2016. This choice is made to be consistent with the SunShot Initiative's goal of making large-scale solar energy systems cost competitive without subsidies by the end of the decade.

Finally, although installed cost and LCOE are dominant metrics, they are not the sole criteria for technology selection. For example, CSP with TES is recognized to achieve close to 100% capacity value—much higher than wind or PV systems (Lew 2010). This dispatchability provides greater grid stability, especially as renewable generation penetration increases. As one example of this value, Arizona Public Service applied up to a 3 cents/kWh of credit to CSP for operational and capacity credit (APS 2009).

Figure 5-12. Projected SunShot CSP LCOE (2010 U.S. Dollars, Real) versus Future Market Prices



5.4 Materials and Manufacturing Requirements

The long-term availability of materials and manufacturing capacity is critical for increased deployment of CSP plants. The analysis here focuses on the most important raw materials needed for the SunShot scenario: aluminum, steel, glass, HTF, and molten salt. In general, these materials are not subject to rigid supply limits, but they are affected by changes in commodity prices. Manufacturing and supply chain issues are also considered.

5.4.1 Materials

Table 5-2 provides the construction material breakdown for a 100-MW parabolic trough plant with 6 hours of TES and a solar multiple of 2.2, i.e., for 2010 technology design and performance characteristics as adapted from Burkhardt et al. (2010), which assumes a 103-MW plant with 6.3 hours of TES. The estimates shown in Table 5-2 do not include commonly available construction materials such as gravel, asphalt, and various plastics, which may be used in significant volumes in CSP plants but generally are not subject to supply constraints. The baseline plant depicted in Table 5-2 generates approximately 426,000 MWh of net energy per year.

Table 5-3 uses the data in Table 5-2 to provide a preliminary estimate of the annual material requirements for CSP assuming the SunShot targets are met. The SunShot scenario assumes peak annual U.S. CSP installations of 4 GW. Similar to the baseline plant shown in Table 5-2, in order to be conservative, a 100-MW trough plant capacity is assumed, although the solar multiple and hours of TES have been increased to 2.8 and 12, respectively. In addition, material requirements have been adjusted to account for the estimated efficiency improvements in the SunShot case. Whereas Table 5-2 is for a parabolic trough plant, Table 5-3 assumes a mix of CSP technologies. This scenario assumes that the transition to next-generation CSP technologies includes higher-temperature operation and a transition away from synthetic oil as an HTF.

Table 5-2. Construction Materials for Nominal 100-MW Parabolic Trough Plant with 6 Hours of TES

Material	Trough Plant Subsystem (MT)				
	Solar Field	HTF System	Power Block	Thermal Storage	Total
Aluminum	16	51	18	0	86
Other Non-Ferrous Metal	68	6	66	2	142
Steel and Iron	17,556	3,346	2,277	3,654	26,833
Glass	10,971	-	11	0	10,982
Concrete	27,184	5,709	18,738	9,339	60,970
Synthetic Oil	0	4,146	0	0	4,146
Nitrate Salts	0	0	0	57,328	57,328

Source: Adapted from Burkhardt et al. (2010)

Table 5-3. Projected Annual Material Requirements for CSP Assuming Maximum SunShot (4 GW/year) U.S. Deployment

Scenario	Material Requirements (MT)				
	Glass	Aluminum	Steel and Iron	Synthetic Oil	Molten Salt
SunShot	360,000	2,700	840,000	—	1,000,000

Glass for CSP reflectors is manufactured via a float glass process. Global production of common float glass in 2007 was approximately 44 million MT, while global production capacity was estimated at 65 million MT (AGC Flat Glass 2010). U.S. production of float glass in 2007 was approximately 5.5 million MT, with additional available capacity of approximately 0.5 million MT (Headley 2008). Based on this standard float glass capacity, the glass requirements in the SunShot case correspond to approximately 7% of 2007 U.S. production or less than 1% of 2007 global production. However, CSP plants use low-iron glass, which is produced through a similar process as common float glass, but with specific feedstock sand and rigorous contamination requirements. Current production of low-iron glass is limited by relatively low demand, which in turn leads to reduced production runs and increased cost. Increased demand for low-iron glass would result in the operation of dedicated production lines and reduced costs.

Although glass is clearly not a constraint on increased CSP deployment, it is possible that non-glass reflectors—such as reflective films laminated onto aluminum sheets—may be used in commercial CSP facilities as the technology continues to mature. If all CSP were to use non-glass films as reflectors, approximately 40 million m^2 of reflecting material would be required on an annual basis. This volume is roughly half of the current production volume of solar-control window film (which requires a similar production process) of approximately 80 million m^2 annually.

The SunShot scenario relies primarily on steel for the solar field structures, with additional steel needed for HTF piping, molten-salt storage tanks, heat exchangers,

and the power block. The peak steel requirement in the SunShot scenario is less than 1 million MT/year, or approximately 1% of the 84 million MT of U.S. steel production in 2008 (Fenton 2010).

Aluminum can serve as a replacement material for a significant fraction of the structural steel in CSP plants and can also be used as the reflector material in CSP plants using thin-film reflectors. Each MW of solar collector field using aluminum-based structures would require approximately 50 MT of aluminum with a solar multiple of two. An additional 22–29 MT/MW would be required for plants using coated aluminum or thin-film laminated reflectors. A deployment scenario including a shift to aluminum would reduce steel requirements in Table 5-3 by approximately 50%; however, it would also require approximately 300,000 MT of aluminum per year for SunShot scenario deployment. Aluminum production in the United States in 2008 was approximately 2.4 million MT, with another 4.1 million MT imported (Fenton 2010). Thus, a deployment scenario including a shift to aluminum could require up to 5% of current annual U.S. aluminum use.

The current HTF for existing parabolic trough systems consists of a eutectic mixture of diphenyl oxide and biphenyl. This fluid type is widely used in large volumes in the global chemical industry, and there appears to be no supply constraints. Regardless, the SunShot scenario assumes a shift away from synthetic oil as an HTF to other materials that can operate at higher temperatures, such as molten salt.

Molten salt is currently used as the TES medium in most CSP storage system designs and as the HTF in salt-receiver power towers. Much of the world's nitrate salts are derived from deposits in the Atacama region of Chile. Proven reserves are 29.4 million MT, although this figure is based on exploration of only 16% of total reserves (SQM 2009). Burkhardt et al. (2010) estimate that the nitrate salt requirement for a thermocline storage system is approximately 32% of the two-tank system assumed in Table 5-2 and that higher-temperature TES would reduce this requirement even further. As a result, Table 5-3 assumes a MT/MW nitrate salt requirement equal to approximately 22% of the requirement in Table 5-2. For SunShot scenario total deployment levels, the cumulative required salt is roughly two-thirds of proven Chilean reserves. Although alternative salts for storage and/or HTFs could be used, the use of nitrate salts is still feasible. If nitrates remain the salt of choice, it is possible that increased CSP deployment would require expansion of nitrate salt production, possibly including synthetic production via the Haber-Bosch process, which is used worldwide for fertilizer production.

5.4.2 Manufacturing and Supply Chain

The CSP supply chain is overwhelmingly domestic, from materials to manufacturing. Most, if not all, materials necessary to build a CSP plant can be found in the United States. However, substantial increases in the manufacturing capacity of CSP components will be required to achieve the SunShot scenario. CSP plants require a number of components; some are similar to other industrial components and others are unique to the industry. In addition to the structural and reflector components, CSP plants require manufacturing of receiver components and the power block.

Reflectors are manufactured from readily available materials. The current manufacturing capacity is consistent with the requirements for facilities under construction or scheduled for construction in the near term. It takes approximately 1 year to construct a glass reflector manufacturing line. Therefore, as the demand for reflectors increases, the reflector industry should be able to ramp up production quickly enough to meet demand. As a result, the availability of reflectors should not be a bottleneck to achieving the SunShot scenario.

Receiver tubes for parabolic troughs and linear Fresnel plants are fabricated from readily available materials such as glass tubing, stainless-steel tubing, and steel bellows. Although the materials are basic, manufacturing high-quality receivers does require expertise and specialized processes. This could create short-term constraints on scaling-up manufacturing of receivers. The current manufacturing capacity, however, is adequate to meet the demands for facilities currently under construction and scheduled for construction in the near term. Experience with current manufacturers of receiver tubes shows that significant manufacturing lines can be brought to production in approximately 1–2 years.

Power tower receivers are similar in design to standard industrial boiler equipment. All developed countries and many developing countries have boiler manufacturing capabilities and are capable of fabricating components such as steam boilers and pressure vessels. Boilers and turbines to be used in CSP plants will replace similar products that would have been manufactured for fossil-fuel power systems. The manufacturing capability that exists to build conventional fossil-fuel boilers can be readily adapted to fabricate multiple gigawatts per year of steam or molten-salt receivers. A good example of this adaptation is the steam receivers fabricated for the Sierra Sun Tower in Lancaster, California. These receivers were manufactured by two separate conventional boiler shops in the United States without significant changes to the shop floor or development of new manufacturing techniques.

In a dish/engine system, the receiver and power block subsystems are well integrated into a single unit. Dish/Stirling engines use materials and manufacturing processes common to the automotive industry that allow for efficient mass production.

For parabolic trough, power tower, and linear Fresnel systems, the current power block is very similar to those used in conventional fossil-fired plants, thus, manufacturing capabilities for these power blocks and other system components are available worldwide. The development of new turbomachinery—such as that required for new supercritical-CO_2 or air-Brayton solar turbines—will also use materials and manufacturing processes common to the existing gas and steam turbine industries.

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6. Integration of Solar into the U.S. Electric Power System

6.1 INTRODUCTION

The *SunShot Vision Study* lays out a scenario in which solar energy technologies satisfy a significant fraction of U.S. electricity demand. The contribution of solar energy in this scenario is projected to be 14% and 27% of total contiguous U.S. electric demand by 2030 and 2050, respectively, which introduces several integration challenges.

The first challenge is to ensure that the system can operate reliably with increased variability and uncertainty. Unlike the hydropower and thermal generation sources that currently provide most of the nation's electricity, PV generation in particular has limited dispatchability. Another challenge is planning for and building the new transmission facilities that will be required to access high-quality solar resources. A third major challenge involves evaluating and addressing the impacts of distributed solar generation on electricity distribution systems, most of which were not designed to accommodate generation at the point of use. Previous work on solar integration, along with substantial work on wind integration, reveals several potential solutions for these challenges to widespread deployment of solar-powered generation technologies.

This chapter gives an overview of the major integration challenges along with potential solutions needed to achieve the SunShot scenario. Section 6.2 describes the operation of the electric power system and the important role of reliability standards in ensuring adequate balancing of generation and demand. It then discusses the characteristics of the solar resource and generation technologies, including variability, uncertainty, and capacity value. Section 6.2 also addresses the integration of solar into power system operations and planning, including lessons learned in this and other studies (DOE 2008) to maximize the role of solar energy and minimize integration costs. In addition, it discusses the specific role of markets in providing flexibility and incentivizing efficient use of generation and demand resources. Section 6.3 discusses the feasibility of developing the transmission infrastructure required to accommodate increased development of solar power installations and to connect high-quality solar resource regions to load centers. This section highlights the importance of developing models and performance standards to ensure the reliable operation of the transmission system with significant levels of solar energy. Section 6.4 covers the feasibility of integrating significant levels of

solar energy into the existing and future distribution grid, which will include improved monitoring, information exchange, and control at the distribution level.

6.2 Planning and Operation of Electric Power Systems with Solar Electric Generation

The electric power system has developed historically with thermal power plants as the main source of generation. Nearly 90% of the installed generation capacity in the United States is composed of dispatchable natural gas, coal, and nuclear power resources. Incorporating a large fraction of electricity from photovoltaic (PV) and concentrating solar power (CSP) systems will require changes to many of the practices and policies that are designed for dispatchable thermal plants. The variability and uncertainty associated with solar generation requires new sophistication of real-time operations and planning practices. Maintaining reliability and the most economic dispatch will undoubtedly require new strategies to manage the grid. The need to evolve new grid operating paradigms becomes even more significant considering the likely deployment of both solar and other variable generation sources such as wind.

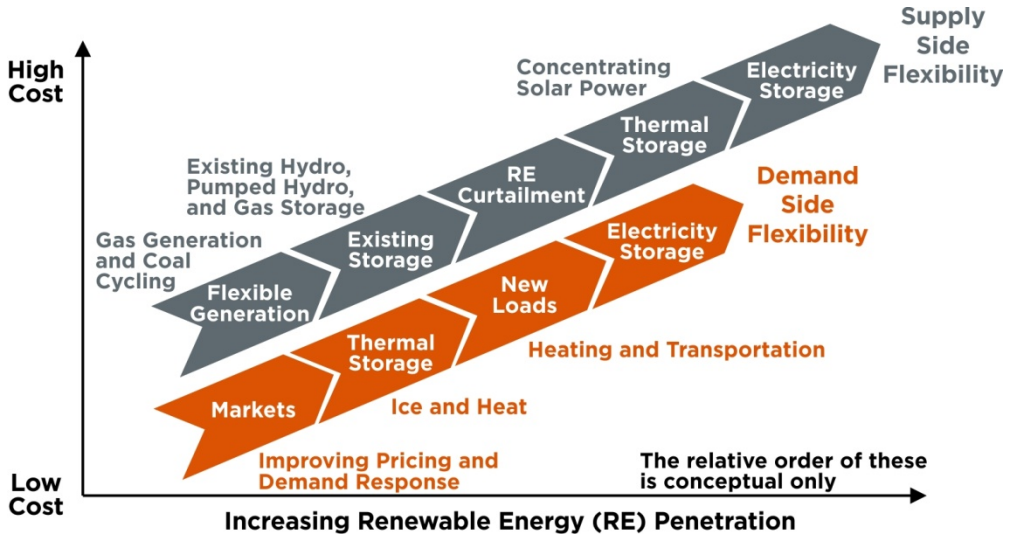
Studies of increased levels of solar and wind generation show that the variability and uncertainty associated with weather-dependent resources can be managed with increased operating reserves, increased access to flexibility in conventional generation plants, demand response and storage, better cooperation among adjacent electrical operating areas, and incorporation of solar and wind generation forecasting into system operations. The set of technologies and mechanisms enabling greater penetration of solar energy can be described in terms of a flexibility supply curve that can provide responsive energy over various timescales. Figure 6-1 provides a conceptual flexibility supply curve that summarizes the options for incorporating variable generation. The optimal mix of these technologies has yet to be determined, but several sources of flexibility will likely be required for the most cost-effective integration of solar at high penetrations.

6.2.1 Power System Design, Planning, and Operations

Power systems are planned and operated to meet established performance and reliability standards. System operators work with existing system assets—generation, network, and responsive demand—to maintain safe and reliable system operation in real time and in compliance with established standards. As the standards generally do not dictate how they must be met, different system planning and operations practices have evolved to meet system performance and reliability targets while minimizing costs. An effective way to reduce the operating cost of producing electricity and increasing reliability of supply is to aggregate a large number of different generation resources and loads. This type of aggregation relies on a dynamic transmission and distribution network and associated communication and control infrastructure.

Continually balancing generation and load, even with a degree of uncertainty and unpredictability in both load and generation, is among the primary requirements for operating the power system reliably. Balancing Authorities (BAs) accomplish this

Figure 6-1. Options for Increasing Power System Flexibility to Accommodate Renewables

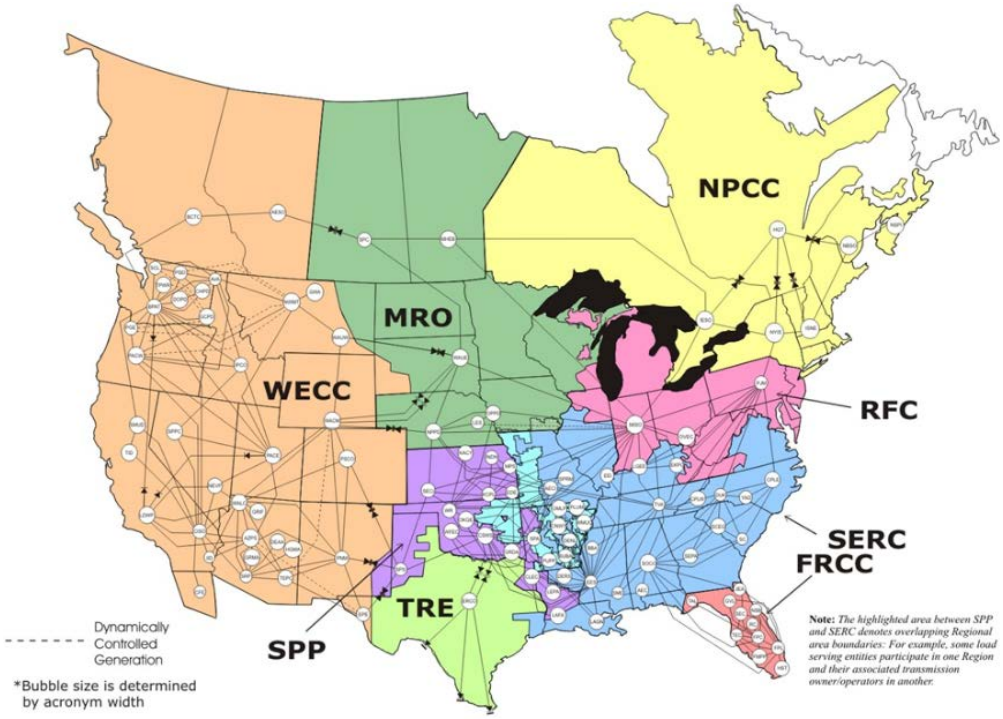


Source: Denholm (2008)

by scheduling, dispatching, and controlling generation and by facilitating exchange of electricity with other BAs. The map depicted in Figure 6-2 identifies the eight regional entities[55] and well over 100 BAs that coordinate the supply of electricity within the bulk power system. Each BA is responsible for balancing energy supply with demand and maintaining reliable service in an assigned BA area (NERC 2008). The interchange of power among BA areas must be scheduled and managed to avoid exceeding the capacity of transmission interties. Because load forecasts are imperfect and generation cannot respond instantaneously, it is neither possible nor required to match perfectly at all times the actual interchange to the desired or scheduled interchange across BA area boundaries. To balance changes in load and generation that occur over a short time frame—from seconds to minutes—automated systems continually adjust the output of generators that are able to ramp up and down relatively quickly. This class of operating reserves is required to address regulation (the ability to respond to small, random fluctuations around normal load), load-forecasting errors (the ability to respond to a greater or less than predicted change in demand), and contingencies (the ability to respond to a major contingency such as an unscheduled power plant or transmission line outage) (NERC 2008). Over periods on the order of tens of minutes to hours, operators optimally readjust the output of online generators in a least-cost order, taking into account short-term forecasts and system constraints. Over longer periods, spanning hours to days, operators commit least-cost generators so they are available for dispatch during real-time operations. Unit commitment takes into consideration, among other

[55] The North American Electric Reliability Corporation (NERC) works with eight regional entities to improve the reliability of the bulk power system, accounting for most of the electricity supplied in the United States, Canada, and a portion of Mexico. The entities responsible for regions in the Eastern Interconnection include: Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council (NPCC); Reliability First Corporation (RFC); SERC Reliability Corporation (SERC); and Southwest Power Pool, RE (SPP). The Electric Reliability Council of Texas (ERCOT) Interconnection is covered by the Texas Reliability Entity (TRE) and the Western Interconnection by the Western Electricity Coordinating Council (WECC).

Figure 6-2. Regions and Balancing Authorities in North America



Source: NERC (2011)

factors, forecast demand, generation availability, and operating constraints of individual generators.

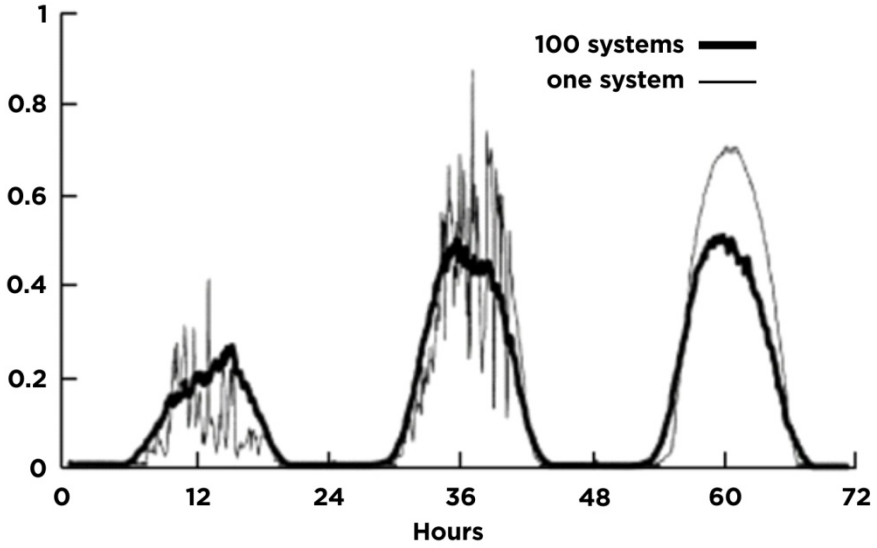
System planners are responsible for ensuring that the assets are adequate for the reliable operation of the system. Complex models and operational experience are used to evaluate the adequacy of the transmission and generation infrastructure. One measure of adequacy is the ability of the system to serve load with a certain level of reliability (measured by the effective load-carrying capability of the generation fleet). Power systems must also be able to operate reliably under abnormal conditions; that is, they should be sufficiently robust to recover from significant contingencies, such as the unplanned loss of a large generator or a large transmission line. System planners design upgrades and operating procedures to ensure that minimum margins of transmission and generation capacity can be maintained at all times.

6.2.2 Solar Resource and Technology Characteristics Relevant to Grid Integration

Solar electricity has unique attributes relative to conventional generation that need to be accounted for to reach high penetrations in the electric power system. The primary characteristics of solar generation relevant to system operation and planning are variability (and associated uncertainty) and capacity value. Although significant measurement data are not available for analysis of variability, some general characteristics of the solar resource are known.

With respect to power-system operations, the most relevant characteristics of solar generation are the output variability and rate of change—ramping—over different time periods, and the predictability of these ramping events. Figure 6-3 illustrates the high degree of variability and high ramp rates that can occur in a single PV plant over a short time frame—from seconds to minutes—resulting from passing clouds. Figure 6-3 also shows that the aggregate of multiple solar plants over a wide geographical area, but within a single BA area, has far less variability and smaller short-term ramp rates relative to the amount of PV deployed. This demonstrates the value of geographic diversity in mitigating short-term variability (Mills and Wiser 2010).

Figure 6-3. Solar Variability: 100 Small PV Systems Throughout Germany, June 1995



Source: Wiemken et al. (2001)

The variability and predictability of the aggregated solar electric generation in a system depends on the degree of correlation of cloud-induced variability between solar plants. The correlation between solar plants, in turn, depends on the locations of solar plants and the regional characteristics of cloud patterns. Generally, the variability of solar plants that are farther apart are less correlated, and variability over shorter time periods—minutes—is less correlated than variability over longer time periods, such as multiple hours (Murata et al. 2009). The decrease in correlation with distance leads to much less relative variability, i.e., a smoothing effect. Consequently, forecast accuracy improves as the number of solar plants aggregated over larger areas increases.

Unlike PV systems, most CSP plant designs have inherent thermal inertia that greatly reduces or eliminates short-term variability. Parabolic trough plants using oil as the heat-transfer fluid and modern direct-steam systems with integrated steam storage vessels can typically operate in a predictable manner with no solar input for a period of about one-half hour (Steinmann and Eck 2006). Dish/engine CSP plants have less thermal inertia than the other CSP technologies, and thus the output of these plants can vary much more with passing clouds.

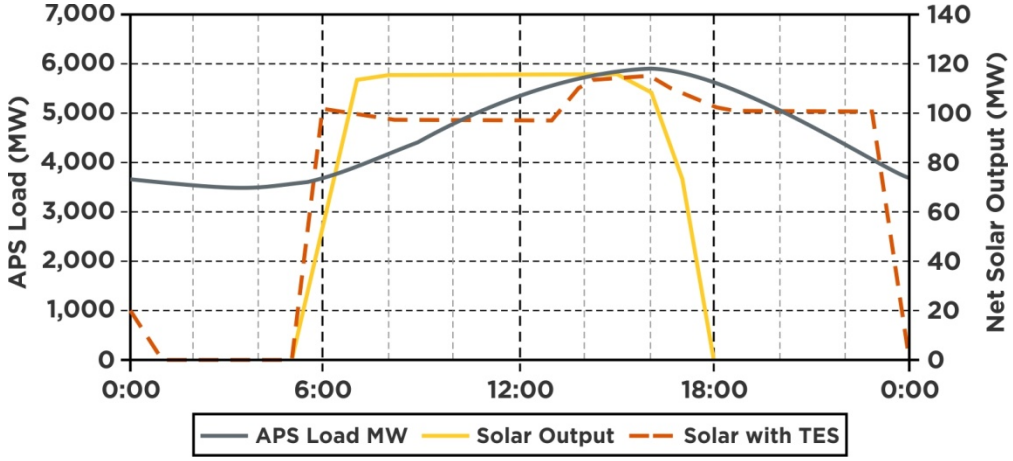
Some CSP plants are designed with several hours of thermal energy storage (TES), allowing them to generate electricity even during periods with low or zero solar input. This provides operating flexibility and the ability to shift solar generation into the evening hours or other periods to better match the load profile and provide more value to the grid. The additional capital costs for multi-hour thermal storage must be justified by the reduced levelized cost and/or increased value of energy delivered by the plant (Sioshansi and Denholm 2010). A number of cost projections indicate that the addition of thermal storage will reduce the levelized cost of solar energy for parabolic trough plants (DOE and EPRI 1997, Sargent & Lundy 2003, Stoddard et al. 2006). Thermal storage with molten-salt power tower plants is projected to produce even more pronounced reductions in the levelized cost of energy (LCOE) relative to power towers without storage.

With the exception of dish/engine plants, existing CSP plant designs can also be augmented readily with fossil-fueled generation, providing either short- or long-term dispatchable output in the absence of solar input. The Solar Energy Generating Systems (SEGS) plants in southern California, for example, include natural gas fuel augmentation. The reverse is also true; in some cases, fossil steam-cycle generation plants have been augmented with CSP, e.g., the Florida Power & Light Company (FPL) Martin Next Generation Solar facility (FPL 2010). This approach could result in lower CSP cost by using generation components already in place.

With respect to system planning, the most relevant characteristic of solar is the correlation of solar power with periods of high electricity demand and, therefore, high system risk. The correlation between solar resources and high demand affects the capacity value that can be assigned to solar generation for the purposes of generation resource planning. The capacity value assigned to the generation resource indicates the fraction of its nameplate capacity that contributes to the overall capability of the system to reliably meet demand. The capacity value of new solar plants is expected to be greatest where electricity load and solar production are strongly correlated. Electricity demand in most of the United States, and particularly in the Southwest, is the greatest during summer afternoons when solar insolation is also generally high. Figure 6-4 illustrates the coincidence of electricity load and modeled solar output for a CSP plant with no storage or with 6 hours of thermal storage. In Figure 6-5, PV acts to reduce the peak demand during the summer, reducing not only the fuel used, but also potentially the need to construct new generation capacity. PV plants would be slightly less correlated with load because their output tapers off in the evening when demand is highest.

As suggested in Figure 6-4, the incorporation of on-site energy storage and the amount of such storage greatly increases the probability that solar generation will be available when the system is most in need of that generation. A detailed probability analysis of the capacity value for CSP with 6 hours of thermal storage in the western states found capacity values of 90%–95% (GE Energy 2010), which is similar to conventional power plants, at a 3.5% energy penetration level. At higher penetrations, the larger amount of storage deployed (up to 14 hours) should maintain very high capacity values. A more detailed discussion of the capacity value of CSP plants with thermal energy storage is provided by Madaeni et al. (2011).

Figure 6-4. Southwestern Utility Load and CSP Generation Profile Illustrating That Thermal Energy Storage Can Increase the Coincidence of High Load Periods and Solar Plant Output



APS: Arizona Public Service
Source: Price et al. (2007)

For solar generation without storage or fossil-fuel augmentation, either PV or CSP, the capacity value depends much more heavily on the correlation between system peak load and solar insolation. A variety of methods and technologies has been used to estimate the capacity value of PV, and they result in a wide range of estimates. The *Western Wind and Solar Integration Study*, which used a traditional loss of load probability technique, found a 27%–38% capacity value for PV—based on the direct current (DC) rating—in the U.S. Southwest for penetration levels up to 1.5% by energy (GE Energy 2010). Xcel Energy's Public Service of Colorado used a similar technique at a penetration level of 1.4% by capacity and found a 53%–70% capacity value for PV and 66%–83% for CSP without storage (Xcel Energy 2009). Other studies have estimated the effective capacity of PV plants in the Southwest greater than 60% and sometimes greater than 80% of the nameplate capacity of the solar plant (Hoff et al. 2008, Perez et al. 2006). In other parts of the United States, these studies have found capacity values greater than 50% for many regions, but lower value in others such as 30% for parts of the Pacific Northwest, where peak electricity demand occurs during winter evenings.

It is misleading to compare capacity value results directly because of the differences in methodologies, technologies, orientation, load shapes, and penetration levels. For example, the Xcel study compared PV to a natural gas plant, and the *Western Wind and Solar Integration Study* compared PV to a perfect plant (Xcel Energy 2009, GE Energy 2010). The high capacity values (60%–80%) from the Perez et al. (2006) study are for two-axis tracking PV systems. It is also important to note that most of these high capacity values occur at relatively low penetration, below 5%, and the capacity value drops significantly as penetration of PV increases. Hoff et al. (2008) show an example of a Southwest utility where the capacity value of PV decreases from about 80% to about 60% as the nameplate capacity of PV increases from 1% of the peak load to 20% of the peak load. The reason for this decline in reliability

contribution is that, as solar output increases, the times of peak net electricity demand will increasingly occur when solar output is low.

6.2.3 System Operations with Solar and Lessons Learned

Utility operators are already accustomed to dealing with variability in the load. Accommodating the variability in the net load—load minus solar (and wind) generation—is possible with approaches similar to those used currently. Because wind generation has characteristics that are similar to solar generation, the large body of experience with wind integration can provide valuable insights regarding costs of solar integration, as well as the changes to operations and markets needed to facilitate large-scale integration of solar generation. This includes significant international experience in locations such as Germany and Spain where penetration of wind energy exceeds that in the United States.

The wind-integration studies find modest cost impacts (Gross et al. 2007, Smith et al. 2007), and a summary of wind-integration costs in the United States shows the expected range to be between $5 and $10/megawatt-hour (MWh) for penetrations up to 30% on a capacity basis, i.e., about 20% on a generation basis (Wiser and Bolinger 2009). The modest cost impacts of wind integration have been based on exploitation of low-cost options for flexibility to balance the system. For example, full utilization of the existing flexibility in the utility's dispatchable fleet or existing storage systems can help accommodate the increased variability and uncertainty. At higher penetrations, when these low-cost options have been fully tapped, integration costs are expected to rise.

A few studies have quantified specific aspects of solar-integration costs. EnerNex Corp. (2009) evaluated the costs of managing day-ahead forecast errors for up to 800 megawatts (MW) of solar in the Public Service of Colorado system. The cost of the day-ahead forecast error with 200 MW of PV, 200 MW of CSP with 4 hours of thermal storage, and 400 MW of CSP without thermal storage was between $4 and $7/MWh, depending on assumptions about natural gas prices. More detailed studies are needed to develop integration cost estimates for solar generation scenarios.

The existing power system evolved over a long history with dispatchable generation with controllable and largely predictable output. Operational strategies and tools, market structures, and system planning were developed for a dispatchable generation paradigm. Significant institutional and physical steps need to be undertaken to transform the existing power system to one that is planned with and integrates high levels of variable and uncertain resources. A "one size fits all" solution does not exist for solar electric integration, but in general, more flexible markets and operational practices can significantly reduce the cost of solar integration and can allow for cost-effective deployment of higher penetration levels. Based on U.S. and international experience (DeCesaro et al. 2009, Ackermann et al. 2009, Milligan et al. 2009a, EnerNex Corp. 2010, GE Energy 2010, Smith et al. 2007), several key conclusions have emerged, which are listed here and described in greater detail below:

- Managing the net load economically and reliably will require flexibility in conventional generation.

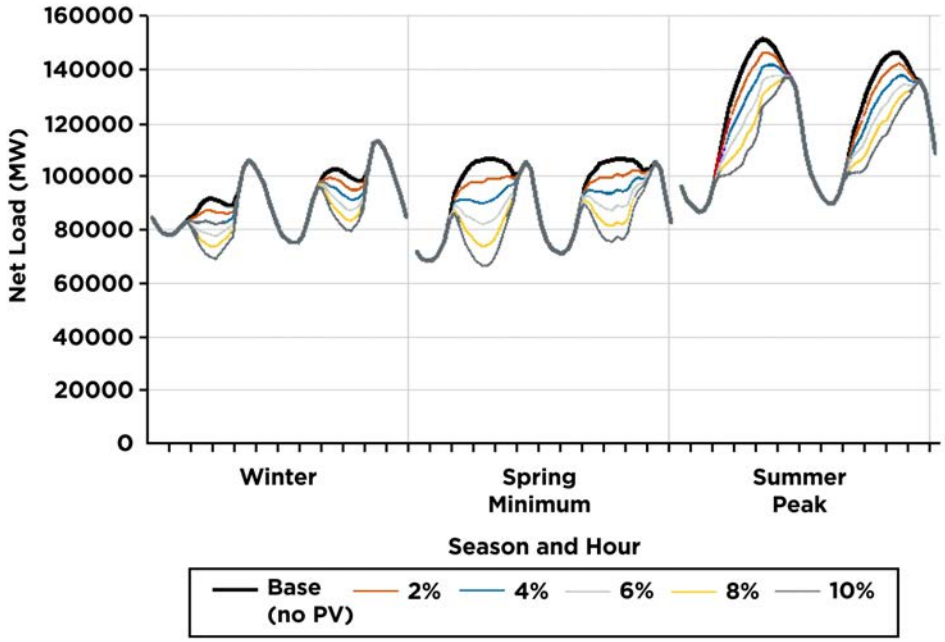
- Aggregation over greater load and generation sources provides opportunities to handle the additional variability and uncertainty of solar generation more efficiently.
- Power system operations must be focused on managing the net variability of aggregated load *and* generation, not the variability of individual plants.
- Increased reserves may be required to manage the additional net variability and uncertainty.
- Better integration of solar forecasting into scheduling and dispatch helps reduce integration costs.
- Shorter-term scheduling can decrease reserve requirements and integration costs.
- Full participation of load as a controllable resource is a cost-effective way to increase system flexibility.
- New mechanisms are needed to incorporate distributed energy resource (DER) assets efficiently.
- Different generation mixes and sources of flexibility will provide the lowest overall cost of energy.

Managing the net load economically and reliably will require flexibility in conventional generation. Increased flexibility of the conventional generation fleet will be required to accommodate large penetrations of solar energy. Even at lower penetration levels, increased penetration of solar without storage can lead to a net load shape that requires thermal generation units to ramp more than they would without the solar. Additional start-ups and shut-downs, part-load operation, and ramping will be required from the conventional units to maintain the supply/demand balance (Goransson and Johnsson 2009).

This additional flexibility comes with some cost and may increase plant operation and maintenance costs (Troy et al. 2010). Figure 6-5 shows the new load shapes with several penetrations of PV in the Western Interconnection territory. Following the net load will require more flexible generation units and may increase generation costs. This may also require increased use of natural gas storage to increase the use of flexible gas turbines and decrease contractual penalties for forecast errors in natural gas use (Zavadil 2006). At higher penetration, energy prices may fall toward zero when minimum generation limits on thermal plants are reached. In an inflexible system, this would lead to curtailment of solar and an increase in the relative cost of energy from PV (Denholm and Margolis 2007). Proper market incentives, as discussed in the next section, can ensure that the ability of a generator to provide flexibility is made available to the system operator.

Aggregation over greater load and generation sources provides opportunities to handle the additional variability and uncertainty of solar generation more efficiently. Aggregation can be in the form of larger BA Areas or through cooperation among BAs, allowing for greater ability to share supply and demand resources. This simultaneously gives access to more responsive resources and reduces net variability, providing several benefits. First, aggregation of dispersed solar resources and load mitigates the net load variability because short-term variability is largely uncorrelated for solar systems at multiple locations. The larger

Figure 6-5. Seasonal Average Load Net PV Generation Shape for Several PV Penetration Scenarios in the Western Interconnection



Source: Denholm et al. (2008)

the region over which the solar plants and load are aggregated, the lower the variability will be. Second, increased BA Area size allows operators to access a larger pool of reserves, reducing the proportional cost of managing the variability. Aggregation of resources and load can be accomplished by physically increasing the size of BA Areas. In several regions with restructured electricity markets, such as PJM Interconnection LLC (PJM) and the Midwest Independent Transmission System Operator (Midwest ISO or MISO), BA Area consolidation has taken place in recent years (see Figure 6-2). In locations without structured wholesale markets—such as the Southwest, Northwest, and Southeast—effective cooperation among BAs can still provide substantial opportunities for resource sharing and lower integration costs for variable generation. Dynamic scheduling of variable generation and sharing of contingency reserves, as well as regulating reserves, are examples of effective collaboration among BA Areas that increase flexibility and reduce cost of integrating variable generation, without physical consolidation of BA Areas.

Power system operations must be focused on managing the net variability of aggregated load and generation, not the variability of individual plants. It is neither efficient nor necessary to manage PV plant variability on a project-by-project basis by trying to create firm power from PV output. There will be times when PV moves in the same direction as load, or when down-ramps in one plant are offset by up-ramps in other plants in the same BA Area. Firming up PV output on a project-by-project basis would unnecessarily increase cost and result in suboptimal use of power system assets. Any local impacts on the transmission or sub-transmission system of variability from PV plants potentially could be mitigated through systems-level changes rather than addressed on a project-by-project basis.

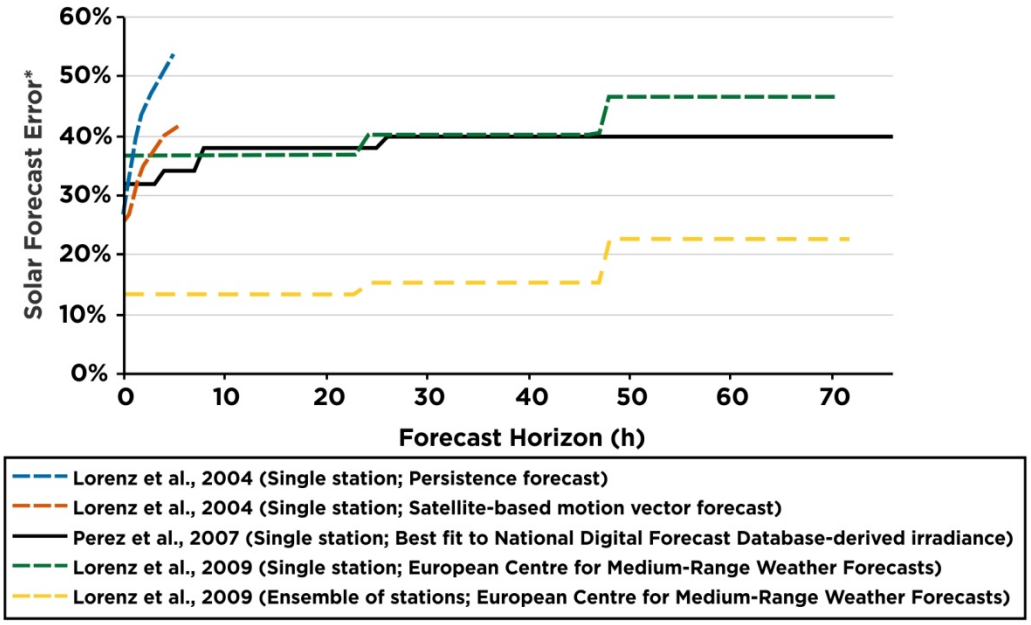
Increased reserves may be required to manage the additional net variability and uncertainty. Greater solar penetration will increase the ramping rate of the net load due to the morning and afternoon PV ramping, as well as short-term fluctuations due to clouds. This may require an increased need for fast response generation and reserves. The actual amount of increased ramping and regulation reserves has yet to be extensively studied and quantified, especially considering the effects of widely distributed PV and the lack of spatially diverse sub-hourly solar radiation data. However, based on operational studies with wind, it is anticipated that solar-generation variability aggregated over a wide geographical region will reduce the impact of variability and reduce the relative increase in operating reserves requirements (EnerNex Corp 2010, GE Energy 2010). Detailed analysis, however, is required to determine specific requirements on factors such as location, penetration level, and balance of generation. Forecasts of weather events that may result in large changes in solar generation locally—if it is a large plant—or over a large region would be valuable. With advance warning, operators can temporarily increase ramping reserves, and thus reduce the cost of solar variability and uncertainty without compromising overall system reliability. Finally, a forecast that alerts operators to potentially faster fluctuations caused by fast-moving clouds could be useful so that sufficient regulating reserves can be available or variable generation plants can be controlled to given set points. Similar actions are already taken by system operators for forecasted lightning storms, which increase the risk of transmission line outages (Alvarado and Oren 2002, NERC 2009). Some aspects of solar integration may be easier than wind integration because the clear-sky output is predictable, and reserves will likely need to be held only in proportion to the clear-sky output.

Better integration of solar forecasting into scheduling and dispatch helps reduce integration costs. Integration of solar forecasting into operations on a day-ahead, hour-ahead, and real-time basis improves operational efficiency and reduces integration costs. When good day-ahead and short-term forecasts are available and are fully used, operators can optimize dispatch strategies. Forecasts for both energy production and variability—ramping events and higher frequency fluctuations—should be taken into account during system operations. Inclusion of state-of-the-art wind forecasts has been shown to dramatically reduce scheduling costs relative to not taking such forecasts into account (Smith et al. 2007, GE Energy 2010). Similarly, operational decisions based on an understanding that forecasts are imperfect allow for more conservative and overall lower-cost scheduling decisions (Tuohy et al. 2009). Full integration of solar forecasts into dispatch and scheduling decisions may require operator training and new decision-support tools. Additional research and development is needed in this area.

Shorter-term scheduling can decrease reserve requirements and integration costs. Reserve requirements can be reduced by making unit-commitment decisions closer to the real time. Currently, many utilities make their unit-commitment decisions the morning before the day being planned, pursuant to long-standing regional guidelines. Forecasted information that feeds into this process is based on meteorological data that is 24–48 hours ahead of the hour being planned, and thus is likely to have a higher forecast error than forecasts made closer to real time (Lorenz et al. 2004, Perez et al. 2007, Lorenz et al. 2009, GE Energy 2010). Rolling unit-commitment approaches or moving unit-commitment decisions closer to real time should result in decreased forecast error between load and generation and reduced

requirements for expensive short-term reserve capacity. Figure 6-6 illustrates the magnitude of solar forecasting errors for forecast horizons up to 76 hours using different forecasting methods. All methods are more accurate over shorter forecast horizons. In addition, the bottom line in Figure 6-6 shows that forecasting the aggregate output of multiple sites is much more accurate than forecasting the output of an individual site.

Figure 6-6. Solar Forecast Error for Different Forecast Horizons and Different Prediction Methods



*Relative Root Sq. Mean Error of Global Solar Insolation Forecast

Likewise, sub-hourly system dispatch can also reduce integration costs. This includes sub-hourly scheduling of all balancing resources such as generators and voluntary responsive loads and sub-hourly scheduling of interchanges between BAs. Without sub-hourly scheduling, expensive regulating generators must account for all the sub-hourly variability of the solar instead of the less-expensive load following generators.

Full participation of load as a controllable resource is a cost-effective way to increase system flexibility. It may be less costly for load to respond to system needs by shifting or curtailing consumption than to increase reserve requirements or procure additional flexible generation. ERCOT's Loads acting as a Resource (LaaR) program is a good example of load participation to increase flexibility. The LaaR program is able to curtail load during those specific hours when additional reserves would be necessary, achieving the same objective as deploying operating reserves for 8,760 hours of the year (Ela and Kirby 2008). Expanding this type of load-participation arrangement could decrease the costs of solar integration.

New mechanisms are needed to incorporate DER assets efficiently. Because of their small size, customer-owned PV installations are typically not incorporated into system operations and markets. As future "smart grid" concepts and technologies are implemented on the distribution system, it will become increasingly feasible to

integrate DERs into grid planning and operations. Better visibility of DERs from the utility control room, coupled with inverter technology that can be responsive to system needs via operator commands and price signals, would enable DERs to participate in energy and capacity markets and help support system reliability. To accommodate high penetration at the distribution level, technical changes to the distribution circuit devices may be needed to make them more responsive to the impacts of variable resources (for additional discussion of this topic see Section 6.4).

Different generation mixes and sources of flexibility will provide the lowest overall cost of energy. Adding a large amount of solar generation to the power system can have a significant impact on generation planning assumptions. Adding solar to the existing mix of generation will displace energy from plants with higher operating costs (Denholm et al. 2008). As the penetration of solar expands, however, solar will increasingly displace lower cost generation, and the value of additional solar to the generation mix will start to decline. In the long run, however, the generation mix with significant solar will begin to look different than the current generation mix. Adding solar will, in the long run, influence the "balance of system" mix, likely toward less baseload capacity and more flexible generation capacity than a similar system without solar (Lamont 2008). The set of technologies and mechanisms enabling greater penetration of solar energy can be described in terms of a flexibility supply curve that can provide responsive energy over various timescales. Figure 6-1 provides a conceptual flexibility supply curve that summarizes the options for incorporating variable generation. The optimal mix of these technologies has yet to be determined, but many sources of flexibility will be required for the most cost-effective integration of solar at high penetration.

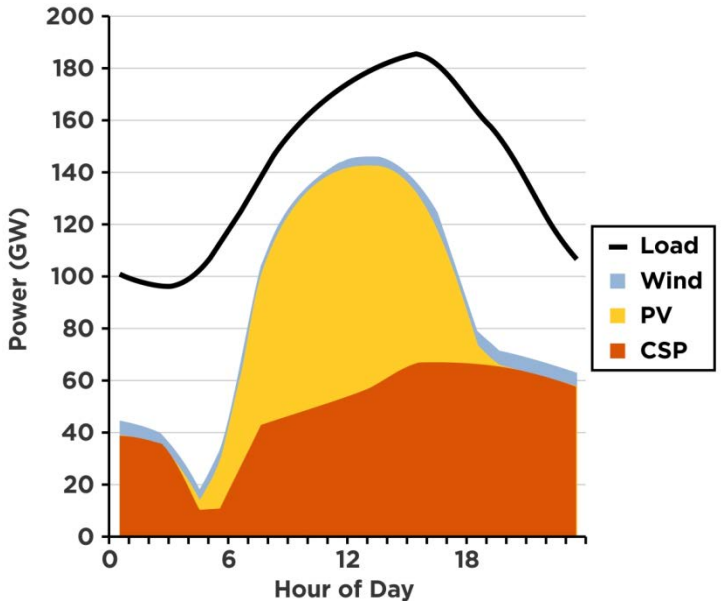
6.2.4 Operational Feasibility of the SunShot Scenario

In the SunShot scenario, the most challenging region of the country in terms of electric system operation would likely be the Western Interconnection. The SunShot scenario envisions meeting 31% of the Western Interconnection's demand with solar (and 6% from wind) in 2030. This increases to 56% of demand from solar by 2050. The operational feasibility of the SunShot scenario was modeled using GridView, in particular, to investigate the flexibility required to balance hourly supply and demand for the system as envisioned in 2050. GridView simulations indicate that hourly load could be met at all locations throughout the year. Flexibility in these simulations was provided by CSP with thermal storage, hydropower and pumped hydro storage, transmission capacity and power exchanges between the Western Interconnection and the other interconnections, curtailment, demand response, and the fleet of existing and new fossil-fueled generators. While this type of modeling validates the ability to operate the electric system on an hourly basis, in order to evaluate the complete operational feasibility of the SunShot scenario, additional modeling of sub-hourly balancing, system stability, and voltage stability would be required.

The biggest challenge with the SunShot scenario from a systems operation perspective is integrating variable generation, including PV and wind. By 2050, 29% of the electricity demand in the Western Interconnection is met with wind and PV generation, and 33% is met with CSP. CSP is deployed with up to 12 hours of thermal storage and provides dispatchable energy. As a result, the fraction of demand met by variable sources (29%) is similar to previous studies modeling

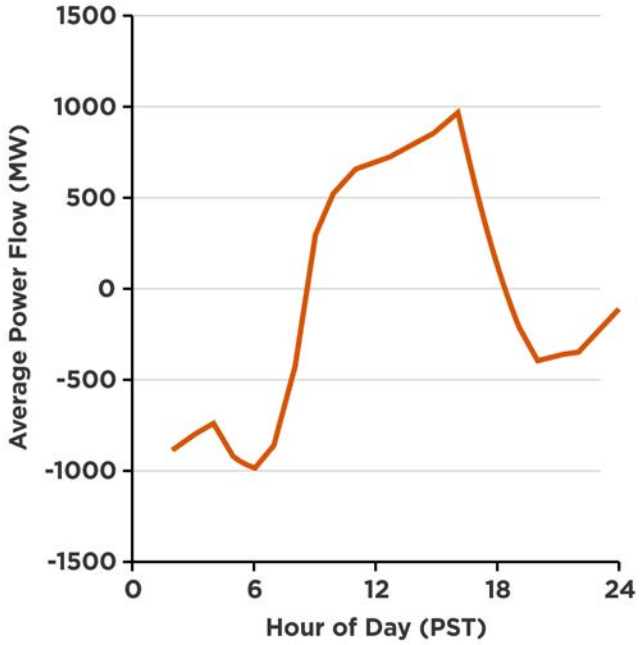
renewable penetration in the western United States, including the *Western Wind and Solar Integration Study* (GE Energy 2010) and the ongoing assessment of the California independent system operator (ISO) 33% renewable portfolio standard (CPUC 2008). Figure 6-7 shows the GridView average diurnal dispatch of CSP generators with thermal storage during July, along with PV output, wind output, and load in the Western Interconnection. During this time of the year, CSP in the Western Interconnection coupled with 12 hours of storage allows most CSP generators to operate 24 hours per day. CSP generators also typically generate at close to 100% of their capacity during the evening hours, i.e., after PV has stopped producing electricity, but the load is still relatively high.

Figure 6-7. Average Hourly Dispatch in the Western Interconnection during July



Another major source of flexibility in the SunShot scenario is the ability to exchange energy with other interconnections. The Western Interconnection currently has very limited transmission capacity to other interconnections [less than 2 gigawatts (GW)]. To accommodate solar penetration levels in the West, the SunShot scenario develops a total of 18 GW of transfer capacity on DC connections between the Western Interconnection and the Eastern Interconnection. Although the Western Interconnection does export more than it imports, the transfer capacity is not used simply to export excess solar electricity. The interties are used to import and export electricity to optimize the total system production cost, which adds additional flexibility to the system. Figure 6-8 is an example of the average annual diurnal profile of the AC-DC-AC interconnection between Wyoming (in the Western Interconnection) and South Dakota (in the Eastern Interconnection) modeled in the SunShot scenario in 2050. Power exchange along this line is usually near the capacity of the line, yet the direction of power flow changes twice per day on most days.

Figure 6-8. Annual Hourly Power Flow from Wyoming (Western Interconnection) to South Dakota (Eastern Interconnection), SunShot Scenario, 2050



There are several other major sources of flexibility that could facilitate penetration levels discussed here. Hydro generators, including pumped hydro storage, are flexible and have inherent storage capabilities. Existing and new fossil-fuel generators can also provide flexibility. Although coal and natural gas combined cycle (gas-CC) units are relatively expensive to start, they can be ramped and operated at part-load to allow for changes in generation. This may, however, have implications for nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions (Mills et al. 2009) and long-term maintenance costs (Agan et al. 2008). Natural gas combustion turbines (gas-CT) are more flexible and can be cycled regularly to help provide generation for relatively short periods. Interruptible loads can also be a cost-effective solution for providing operating reserves. Finally, curtailment of wind and solar generation can provide flexibility to the system.

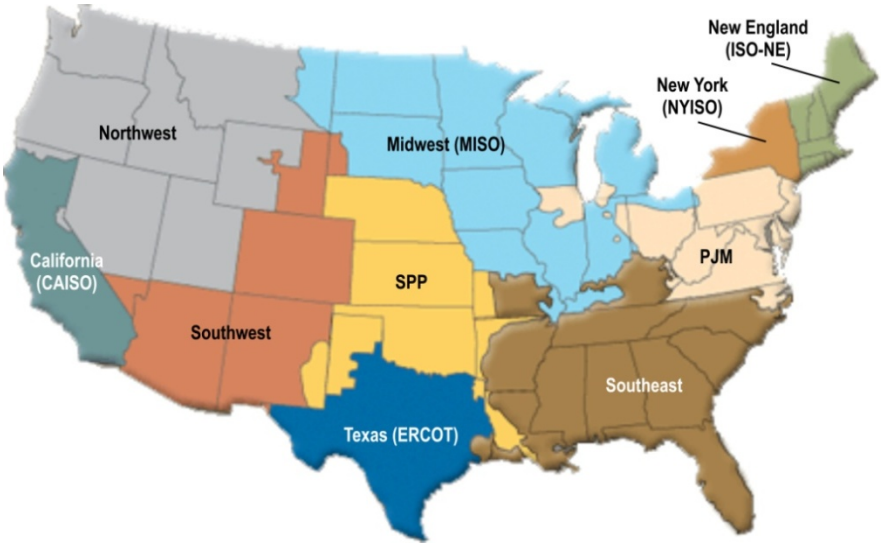
The ability to curtail generation can be used by the system operator to reduce system ramp rates or avoid transmission congestion or minimum generation problems. A generator that is curtailing energy may also be able to use that capacity to provide operating reserves (Miller et al. 2010). The GridView simulations indicate that by using a combination of CSP with thermal storage, other generation technologies, transmission, and curtailment, the SunShot scenario can feasibly balance supply and demand on seasonal and hourly time scales.

6.2.5 The Role of Energy Markets

Market structures have an important role in the integration of solar generation, and nearly all the factors discussed in Section 6.2.3 are affected by the design and implementation of markets. Markets provide a mechanism for buying and selling electric power to meet the system load and maintain an acceptable level of

reliability. In the United States, electricity market structures vary widely by region (Figure 6-9). Some markets, such as the MISO, PJM, New York Independent System Operator (NYISO), Independent System Operator-New England (ISO-NE), ERCOT, California Independent System Operator (CAISO), and increasingly the SPP, are integrated, flexible, and efficient. Some of them offer a wide variety of energy as well as capacity and ancillary services products that can be accessed day-ahead, hour-ahead, or in some cases, on a sub-hourly basis. In other areas such as the Southwest, Southeast, and Northwest, however, electricity markets are less flexible and require BAs to rely more heavily on bilateral transactions to access electricity and capacity resources that are not under their direct control. However, it is possible that areas without electricity markets could develop cooperative agreements that would provide some of the benefits of markets (Milligan et al. 2009b).

Figure 6-9. Electricity Markets in the United States



Source: FERC (2010)

Market characteristics, including size, sub-hourly interval, and product options and rules, can significantly affect how effectively and economically system operations are able to use the flexibility that is physically available to deal with increasing levels of solar generation. Whether operating in a large liquid market or in a regulated utility with limited resource access, the market features listed here and described following the list can help enable more efficient integration of solar generation:

- Markets that are more flexible, larger, and more diverse provide opportunities for the integration of solar generation at a lower cost.
- Market flexibility, such as shorter transaction closure intervals, can significantly lower the cost of solar integration.
- Market-based incentives can produce optimal solutions to uncertainty and variability and maximize system flexibility.

Markets that are more flexible, larger, and more diverse provide opportunities for the integration of solar generation at a lower cost. Larger, more flexible markets

tend to be more adaptable to changes in system requirements, such as the need for additional generation flexibility to handle increased levels of variability. Such markets provide a mechanism to access the flexibility that is physically available from all generators in the area and all responsive loads. The larger the market is, the larger the pool of generators and responsive load and the smaller the relative variability of aggregated load. Larger markets also have the advantage of more geographic diversity of solar resources, as discussed earlier. The results of numerous wind-integration studies and actual experience have shown that, for the same level of penetration, integration cost is significantly lower in markets such as the MISO compared to a smaller BA Area without the ability to exchange resources across a larger area (Milligan et al. 2009b). This conclusion will almost certainly hold for solar generation as well.

Market flexibility, such as shorter transaction closure intervals, can significantly lower the cost of solar integration. A key measure of flexibility is how often system operators can interact with the market to optimize operating cost. For example, markets that allow for faster transactions—scheduling power exchanges every 5 or 10 minutes as opposed to 1 hour—reduce requirements for regulation, which is the most expensive ancillary service.

Market-based incentives can produce optimal solutions to uncertainty and variability and maximize system flexibility. Efficient market structures can incentivize the most cost-effective technical alternatives to deal with variability at the system level. This includes flexible generation, storage, better forecasting, and full participation of load as a resource. Some electricity markets do not include capacity or ancillary services options. Real-time prices for ancillary services should provide sufficient incentive for the right amount and type of generation capacity and responsive load needed to maintain system reliability. Studies have shown that the existing generating fleet is capable of providing a large amount of flexibility; however, much of that capability is not tapped due to a lack of appropriate market incentives or prices for flexibility services (Kirby and Milligan 2005). Markets can also be designed to deal with transmission congestion through mechanisms such as location marginal pricing (LMP). Flexible generation that has shorter commitment times—the time required to start and begin delivering energy—and lower cycling costs will be more valuable in an environment with high solar and/or wind penetration. Markets can be structured to motivate new capacity entrants to be more flexible, for example, by providing the amount of expected variable generation to help inform conventional generation owners/investors of future opportunities for flexible generation response.

6.3 Feasibility of the New Transmission Infrastructure Required for the SunShot Scenario

Both the SunShot and reference scenarios require significant transmission expansion. In the reference scenario, transmission is expanded primarily to enable new conventional and wind resources to meet growing electricity demand. In the SunShot scenario, transmission is expanded at a similar level, but in different locations in order to develop solar as well as wind and conventional resources. In the

SunShot scenario, concentration of large-scale CSP and central utility-scale PV would occur in some areas such as the Southwest where solar electricity can be generated at a significantly lower cost based on the higher-quality solar resources in the region. Additional transmission capacity will be needed to deliver solar-generated electricity from these areas to load centers—for more information, see Chapter 3. Transmission development represents a major challenge based on cost, cost allocation, permitting, and the long time frames involved. Major transmission lines typically take 7–10 years to plan, permit, and construct. Therefore, it is important that large-scale deployment of renewable generation be considered proactively as part of the regional transmission planning process. Furthermore, because only 1–2 years of transmission-project time lines are devoted to construction, there could be opportunities to reduce transmission development timescales. In particular, new frameworks to address transmission siting and cost allocation could facilitate the transmission development needed for solar.

Several challenges are associated with integrating solar energy into the United States transmission system. There is a clear need to develop or improve planning models and methodologies to represent solar generation properly in grid-planning and interconnection studies. Another challenge is the need to develop, improve, or adapt performance and interconnection standards to ensure that solar generation can be integrated reliably and cost effectively into the transmission system. Perhaps the most difficult challenges will be the permitting and financing of the new transmission infrastructure required to move large amounts of solar generation, as discussed in Chapters 7 and 8, respectively. This section discusses the technical issues and solutions associated with the integration of SunShot-level solar generation onto the grid.

6.3.1 Methodologies for Transmission Planning

Transmission planning is a complex process whereby system planners identify system-expansion requirements to meet future needs. The process is driven by predictions of load growth and generation patterns that are informed by decades of accumulated experience. There is a growing trend toward regional transmission planning to capture the benefits of obtaining least-cost renewable energy, increasing reliability through diversification of the resource areas employed, and decreasing the need for ramping/ancillary services when balancing occurs over larger areas. As the penetration level of solar and other variable sources of generation increases, the analysis techniques and study approaches employed in transmission planning must become more sophisticated. Below are some examples.

- Regional planning studies are conducted on a limited set of scenarios that represent peak and off-peak conditions during different seasons of the year. For the most part, the generation pattern assumed for each load scenario can be inferred based on the use of dispatchable generators. The accelerated introduction of large amounts of solar as well as other sources of variable generation, primarily wind, will give rise to a wider range of operating conditions that need to be considered in the transmission planning process.
- Large and potentially frequent changes in generation are possible with PV and CSP without storage. As the amount of solar generation increases relative to the strength of the local transmission system, additional reactive power support may be needed to maintain voltage levels and system

stability. However, variability scenarios are not typically considered as part of transmission-planning and interconnection studies.

- The existing grid relies, in part, on the mechanical inertia of large generators. The inherent inertia of the collective synchronous generators in an interconnected system provides frequency stability that helps the system withstand severe disturbances. Certain solar-generation technologies, such as PV and dish/engine CSP systems, have no effective inertia and provide relatively low short-circuit currents during faults. Inverter-based wind generation exhibits similar behavior unless specifically designed to provide an inertial response. Technically, displacing a significant amount of conventional generation with solar generation that has no mechanical inertia has the potential to affect the dynamic performance of the interconnection negatively. This characteristic must be taken into account in the design of control and protection systems. That said, tower and trough CSP plants use synchronous generators that provide inertia in the same manner as conventional generators, thus minimizing the potential for additional challenges.

None of the issues discussed above constitute insurmountable challenges to achieving significant penetration levels of solar energy. However, new approaches are needed to integrate solar into the grid. Three issues have been identified as requirements for improving the integration of solar into the U.S. transmission system. These issues are listed here and described in greater detail below.

- New and improved models of solar-generation technologies will be needed.
- Interconnection procedures and requirements will need to evolve.
- Solar systems will need to be integrated into utility operations via supervisory control and data acquisition (SCADA) systems.

New and improved models of solar-generation technologies will be needed. Adequate solar-generation electrical models for transmission-planning and interconnection studies are indispensable to achieving high solar penetration levels. Transmission-planning and interconnection studies consist mainly of power flow, dynamics, and short-circuit simulations that take into account the effect of a large number of system components. Because trough and tower CSP technologies employ conventional generators, well-established electrical models can be used to represent these types of systems. However, PV and dish/engine technologies require different types of dynamic and short-circuit models that still need to be developed or improved. PV systems are inverter-based generators, which are fundamentally different from conventional generators. Inverters exhibit a very quick electrical response, which results from fast switching capability and lack of mechanical inertia. Unlike conventional generators, inverters are able to quickly control current with little or no oscillatory behavior following system disturbances. Dish/engine systems are induction generators driven by low-inertia reciprocating engines. Models that represent this behavior and these characteristics need to be developed or improved. Models also need to be validated and supported by the various industry-standard simulation software platforms and be readily shared among multiple system planning entities and consultants. For example, the Western Electricity Coordinating Council (WECC) initiated an effort to develop models for solar generation, following a similar effort for wind generation that started in 2006.

Interconnection procedures and requirements will need to evolve. In addition to the new models needed, interconnection requirements for solar and other variable-generation resources, both distribution-connected and transmission-connected, must continue to evolve to adequately cover solar-generation technologies. At the transmission level, existing interconnection procedures can be applied to solar-generation technologies that use conventional generators, such as CSP troughs and towers, but are not adequate to address PV and dish/engine systems.

The North American Electric Reliability Corporation (NERC) has already identified several gaps in the standards related to transmission planning and operations with high levels of solar and wind generation (NERC 2009). One of them is the need to reconcile key aspects of the standards that apply to distribution-connected generation. Distribution-level connected solar systems typically are required to follow the Institute of Electrical and Electronics Engineers (IEEE) 1547 interconnection standard. The existing IEEE 1547 requirements carry the implicit risk that a large amount of distribution-connected PV generation may trip as a result of transmission system disturbances if voltage and frequency levels fall outside narrow windows. A recent study performed by General Electric (GE) as part of the U.S. Department of Energy's (DOE) Renewable Systems Integration (RSI) study effort shows that, in high-penetration scenarios, PV inverter tripping caused by transmission disturbances can exacerbate voltage instability in load centers (Achilles et al. 2008). As solar penetration increases, voltage tolerance or low voltage ride-through (LVRT) will start to be required, as it is required for wind generation today. In high-penetration scenarios, solar plants should also provide reactive support of a character similar to conventional power plants. In Europe, several jurisdictions have adopted new voltage and frequency standards that add LVRT and reactive support for PV generation connected to the high- and medium-voltage networks (Troester 2009).

Future standards for solar generation should also address power control and frequency support. All solar-generation technologies could be designed to limit power output, control ramps to some extent, and even contribute to frequency support. This capability would essentially mimic the behavior found in rotating machines. For PV and dish/engine systems, power control and frequency support functionality could be achieved by curtailing some amount of solar power, although the costs of this approach would need to be compared to the value of curtailed energy.

Because PV systems are inverter based, evolutionary changes in capabilities could take place relatively quickly. Wind turbines, which use the same type of inverter technology as PV systems, have rapidly evolved over the last 5 years to meet rather stringent voltage ride-through requirements and are able to support advanced active and reactive power-management options. It is expected that PV inverters will be able to adapt rapidly to expected changes in performance standards or grid codes.

Solar systems will need to be integrated into utility operations via SCADA systems. For full integration into utility operations, centralized solar plants, and, increasingly, distribution-connected PV plants, should be integrated into a utility's SCADA systems. This integration not only provides visibility to system operators, but also allows solar systems to participate in energy and ancillary services markets. During periods of system stress or reliability risk, SCADA integration would allow system

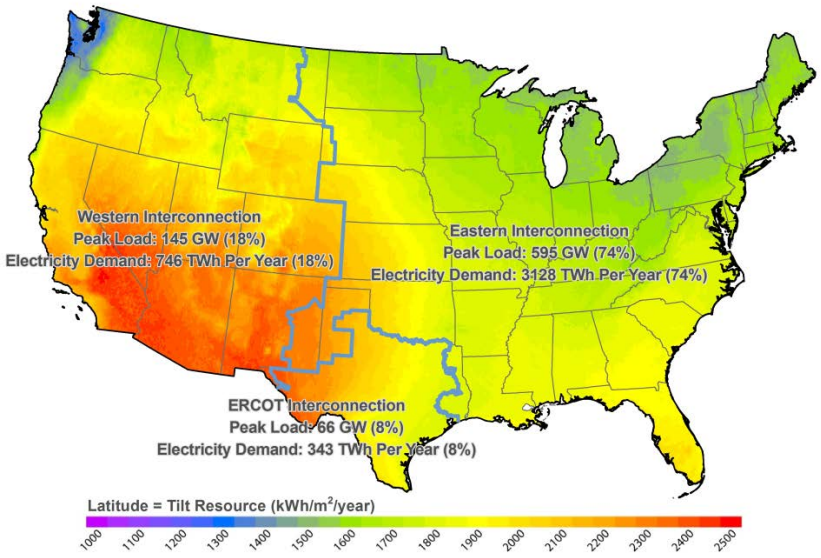
operators to request dynamic voltage support, frequency support, and power management from solar plants, assuming the plants have the capability to do so. Integration of distributed solar installations into SCADA is significantly more challenging than integrating centralized solar installations, because the distributed plants could be deployed in extremely large numbers. Aggregation of these distributed systems is a promising approach to integrating with utilities' SCADA systems.

6.3.2 Transmission Capacity Needs to Facilitate Solar Growth Scenario

The need for new transmission for a high solar-penetration scenario will be driven primarily by the location of new solar plants and the availability of existing transmission capacity. The economics of exploiting high-quality solar resources may be favorable, even if long transmission lines are required to deliver the power, because the lower cost of electricity from these remote sources could offset the capital cost of additional infrastructure to deliver the power to demand centers. In other cases, however, it may be preferable to place new facilities closer to areas of high population density. These tradeoffs will be a central concern when considering the balance between centralized and distributed solar electricity deployment.

It is expected that a large fraction of the infrastructure additions to carry power from high-quality solar resources to nearby load centers are, in the near term, likely to be built in the Southwest. This is especially true for transmission to access CSP capacity. Figure 6-10 shows the solar insolation for a south-facing latitude-tilt array along with electricity capacity and demand statistics for the three large power system interconnections in the United States. As shown in the figure, the locations

Figure 6-10. Global Horizontal Solar Resource (South Facing, Tilted at Latitude) with Electricity Use Statistics by Interconnection



Source: NREL

with the highest insolation are concentrated in southwestern states such as Arizona, New Mexico, California, and Nevada. The concentration of resources in the southwestern states is even more pronounced for direct-normal irradiance (DNI) with two-axis tracking, such as, for CSP and concentrating photovoltaic (CPV) technologies.

Although CSP and central utility-scale PV deployment in the SunShot scenario is concentrated in the Southwest, there are notable exceptions where they are deployed in areas with lower insolation, like Florida, to access greater load-density regions.

PV deployment in the SunShot scenario is highly concentrated in the Western Interconnection in the early years of the analysis. Later deployment, benefiting from continued technology cost reductions, has a broader geographic scope; however, it is clear that the western United States faces the more significant integration challenge in these scenarios (see Chapter 3). This deployment trajectory for CSP and PV, coupled with the fact that the Western Interconnection accounts for less than one-fifth of the national electrical load, results in very high solar penetrations in the Western Interconnection. By 2050 in the SunShot scenario, the solar penetration in the Western Interconnection is 56% on an energy basis. While this is a very high level of solar penetration, as discussed in Section 6.2.4, GridView simulations indicate that through a combination of CSP with thermal storage, other generation technologies, transmission, and curtailment, it would be feasible to balance supply and demand on seasonal and hourly timescales.

Significant transfer capacity between the interconnections, in addition to long-distance transmission lines, is required to accommodate the large solar deployment in the western United States. Increased transfer capability between the three electrical interconnections (Eastern, Western, and ERCOT) could facilitate integration of larger quantities of solar. The SunShot scenario shows this type of transfer capacity increasing substantially (with a total of 18 GW between the Eastern and Western Interconnections and 5 GW between the Eastern and ERCOT Interconnections by 2050). The SunShot scenario also requires substantial transmission system additions within the interconnections.

The low capacity factors for solar electric systems raise asset utilization concerns for transmission systems. Several methods can be employed to enhance line-load factors or otherwise address these issues. In particular, where night-peaking wind is prevalent, such resources can provide a suitable complement to the day-peak output characteristics of solar electricity. Fast-ramping, dispatchable generating capacity, such as from gas-CT or energy storage, can also provide balancing capacity for solar (NERC 2009). Other tools to maximize the use of new and existing lines for variable energy resources include dynamic line rating and conditional firm service agreements (WIRES 2008). However, in the case of solar, the applicability of these tools will be limited because peak solar output will occur during the hottest times of the day when line ratings are at their minimum, system load is highest, and available transfer capacity (ATC) is most scarce.

Based on the vast size of high-quality solar resource areas and economies of scale for transmission, the optimal scale of transmission to access a given resource is often much larger than is required for any individual facility. The mismatch of individual project size and scale of transmission creates complications for system planning and

transmission cost allocation. Lines built for each individual plant in a resource area would be much more expensive than bundling multiple projects together on a single transmission line. Furthermore, the time required to develop new transmission (about 7–10 years) is often much longer than the 1–3 years that are typically needed to develop individual solar projects. It will be increasingly important to meet these challenges with multi-regional system planning to exploit the economies of scale and reduced land use—right-of-way width per unit of capacity—that higher-voltage lines offer. If long-distance power transfer (greater than 500 miles) becomes necessary, high-voltage direct current (HVDC) lines offer lower losses and further reduced rights-of-way widths (Bahrman and Johnson 2007).

Integrating large quantities of solar electricity into the power system will require substantial additional transmission infrastructure to deliver the power from the point of generation to where it is needed. The concentration of the highest-quality solar resources poses significant integration challenges in the West. Targeted transmission development, however, can help address these issues and, in many cases, BA Area transfer capacity will be most critical. Finally, as PV system costs continue to come down, the viability of solar will be less dependent on solar resource strength, potentially broadening the geographic distribution of PV development.

6.4 Feasibility of the New Distribution Infrastructure Required for the SunShot Scenario

In the SunShot scenario, 121 GW and 240 GW of rooftop PV will be installed by 2030 and 2050, respectively. In addition, a significant fraction of utility-scale PV is expected to be connected to the distribution system. The main difference between transmission and distribution system planning is that generation, except for emergency backup power, rarely has been connected at the distribution level, and even more rarely has been part of dispatch and control for load balancing. Distribution feeders are typically designed to manage one-way power flows from the transmission system to the customer.

The benefits of siting generation near loads include reducing line losses, increasing reliability due to fuel diversity, increasing access to an emergency backup supply for consumers, and potentially deferring equipment upgrades. However, adding significant quantities of generation to the distribution system presents several challenges. At high levels of PV penetration on distribution lines, the distribution system will be required to manage two-way power flow. Significant penetration of PV or any other form of DER sited on distribution lines will require modifications to standards, practices, and equipment to manage two-way power flow safely and cost effectively while maintaining the same level of power quality for customers. In particular, equipment upgrades and advanced communication and monitoring equipment may be required to accommodate high levels of power exported from the distribution system to other parts of the grid and avoid interference with the operation of local-protection-system and voltage-control devices.

6.4.1 Integrating Solar with the Distribution System

Interconnection of PV with the distribution system requires the involvement of the utility, which must approve interconnection of the electricity source, as well as building inspectors who are responsible for the safety of the installation. Processing the paperwork required by the utility or building departments is typically handled by the solar installer and can be time consuming. As the number of distributed PV installations increases, it will be important for utilities and building departments to be able to handle the high number of applications. With greater penetration of PV, improvements in inverter technologies, and increasing comfort with the technology on the part of developers, utilities, and building departments, interconnection processes are being streamlined in many states to allow expedited treatment for PV systems smaller than 25 kilowatts (kW) that are connected to the distribution system. Currently, most utilities will allow up to 15% capacity penetration (rated output divided by peak load) per circuit of the DER to be connected to the grid using a simplified interconnection process. Once that threshold has been reached, a detailed, costly interconnection requirements study is usually mandatory before interconnecting. The 15% penetration level at which a detailed interconnection study is required may be a barrier for large deployments on the distribution system. As more real-world experience is gained, it is possible the level at which in-depth interconnection studies are required could rise above 15% penetration, and/or gradations could occur where studies at lower penetrations are not as in-depth as studies for higher penetration levels. The impact of high penetrations of PV on distribution circuits and the conditions under which issues occur is an important area of research.

There are several technical concerns for integrating solar on distribution systems. In most cases, the magnitude of the influence of DERs on the distribution system depends on the size, nature, and operation of the generation system as well the characteristics of the distribution system. At low penetration levels, the existing standards are adequate to address the technical concerns. For example, the industry standard IEEE 1547 “IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems,” applies to any distributed energy resource up to 10 mega-volt amperes, or MVA (roughly equivalent to megawatts), in nameplate capacity connected through to a single point of common coupling (PCC), and includes requirements for connecting PV systems deployed on the distribution system. Most PV inverters are designed and tested to this standard, which prevents PV and other distributed generation from controlling voltage and requires them to disconnect from the utility when voltage or frequency fall outside a narrow operating range.

An important limitation of IEEE 1547 is that it provides neither the guidance nor technical specifications for protection requirements that might be needed for aggregated DERs along a supply feeder or in a network, but is only applicable to the single PCC between the DER and the utility. This limitation should be kept in mind when considering potential impacts of high penetration of PV on the distribution system—for some cases, the high-penetration scenarios will need to be studied further. Prior studies have shown virtually no impacts at low (5%) penetration levels on a capacity basis, and possible system instability at higher (20%) penetrations on a capacity basis, when the DER follows the requirements of IEEE 1547 (Achilles et al. 2008, Liu and Bebic 2008). As penetration levels of distributed PV increase,

interconnection standards will need to be updated to ensure the safety and reliability of distribution systems.

As the penetration levels of DERs increase and their role in grid operations and the grid's dependence on DER capacity and energy increases, it may be useful to define different rules for different levels of PV involvement in the operation of an electric distribution system. As shown in Table 6-1, three different levels are used to illustrate this point. The actual penetration values that constitute low, medium, and high penetration will vary depending on distribution circuit and PV system characteristics. The main point is that different penetration levels will, by practical necessity, lead to different roles and operating requirements.

Table 6-1. Grid-Penetration Scenarios and Impacts

Penetration Level	Impacts on Power System and Standards Defining Role and Operating Rules for Distributed PV
Low	• No impact on normal feeder or grid operation. • Current interconnection standards are sufficient.
Medium	• Distributed PV affects feeder voltage, may need to widen voltage trip limit, adjust circuit voltage regulation, and adapt circuit-protection settings. • Under-frequency tripping needs to be widened to coordinate with load-shedding schemes. • Evolve interconnection standards to consider feeder-level interactions.
High	• PV systems affect utility feeder and grid balancing (transmission system) and will need to be integrated with both planning and operations. • Ramp rates may be controlled at the PV system level. • Update interconnection standards to integrate PV for voltage and energy support, allowing voltage regulation, low-voltage ride-through, and enhanced anti-islanding schemes.

Source: Key et al. (2003)

It is clear that at the higher penetration levels, standards may need to be changed or requirements expanded to address changing requirements for interaction with PV systems. Issues of concern include steady-state voltage regulation, voltage flicker, harmonics, unintentional islanding, and protection design and coordination. These are discussed in detail below.

Steady-state voltage regulation. Steady-state voltage is the voltage of the power system over a sustained period, usually defined as anywhere from about 1–3 minutes or longer in duration. Utilities require generation on the distribution system to be operated in a manner that does not cause the voltage regulation to go outside the applicable limits. In addition, operation of the DER may not cause interference with the normal operation of the utility's voltage regulation equipment. Because DERs raise voltage levels when they inject power into the grid, they may cause high-voltage conditions at high penetration levels. A solution to increased voltage levels at high penetrations would be to allow the PV inverters to have the ability to regulate voltage at the local level. Because voltage regulation has historically been done by the utility, proper coordination with existing voltage-regulation schemes would be necessary. If the operation of the voltage regulation on the distribution circuits is not

coordinated, there may be additional costs associated with wear and tear on transformer tap changers and power-factor management devices.

Voltage flicker. Voltage flicker is a sudden change in voltage that occurs in seconds or fractions of a second that can cause objectionable changes in the visible output of lighting systems. The PV inverter standards and designs can evolve to help mitigate any potential voltage-flicker issues that might emerge as penetration increases.

Harmonics. Harmonics are distortions in the regular 60-hertz (Hz) sine wave in North American power systems. Too much harmonic distortion can cause adverse operation of customer and utility equipment. Improvements over the last 10 years in the quality of inverter output have drastically reduced issues with PV system harmonics. The existing standards including requirements for the amount of harmonics that inverters can produce are likely adequate for high penetration of distribution-system-connected PV. Inverters could be designed to cancel harmonics at local loads and provide a benefit to the utility.

Unintentional islanding. Utilities are regularly required to isolate a section of the power system by disconnecting the section with network protectors or switches. Unintentional islands can be established when a section of the grid is isolated from the substation supply while the load continues to be maintained by an energy source within the isolated section. Unintentional islands pose a threat to proper utility system operation for a number of reasons:

- The upstream utility system might attempt to reclose into the island unsynchronized with voltage, frequency, and/or power factor, which can damage switchgear, power-generation equipment, and customer equipment.
- An unintentional island can increase public exposure to unsafe, energized downed conductors.
- Line crews working on power restoration following storms or other events may encounter unintentional energized islands, making their job more hazardous and slowing down the power-restoration process.
- Unintentional islands do not usually have their generators set up with the proper controls to maintain voltage and frequency conditions adequate to the customer loads.
- Unintentional islands can increase the likelihood of dangerous spikes or surges in the system.

Because of the possibility of unintentional islands, the IEEE 1547 standard and utility interconnection guidelines require DER systems connecting to the network to disconnect from the utility grid in the event that the network voltage or frequency goes outside of predefined limits. Certified inverters do this by employing an active anti-islanding scheme. As a result, unintentional islands are not currently considered a significant concern at low-penetration levels. Under high-penetration levels, however, current anti-islanding techniques may not adequately detect island formation and cease to energize the utility within a suitable amount of time. Furthermore, current anti-islanding techniques require DER systems to drop offline rather than ride through temporary faults, contributing to voltage drop or frequency problems. Large amounts of DERs could be prone to tripping during severe transmission-system disturbances that typically affect a wide geographical area. A

recent study shows that, in high-penetration scenarios, PV inverter tripping caused by transmission disturbances can exacerbate voltage instability in load centers (Achilles et al. 2008).

Protection design and coordination. Utility protection systems are designed to reduce the impact of faults that can be caused by lightning or other problems on the utility system. All power-generation equipment should meet the applicable surge-voltage withstand and insulation ratings found in current standards. PV systems also need to coordinate with the protection systems employed on distribution circuits. Typically, a distribution system will employ a protection scheme that consists of fuses, circuit breakers, reclosers, and sectionalizers that are coordinated to operate with a protective relay scheme. Adding additional sources of power to the distribution circuit will affect the coordination of these devices. PV inverters contribute relatively small levels of short-circuit current. This can have potential benefits, or cause issues, depending on distribution circuit characteristics (Keller and Kroposki 2010).

6.4.2 Integrating Distributed Resources at the System Level

Incorporating distributed energy resources requires ensuring their safe and reliable operation on the distribution network. However, as discussed in Section 6.2, maximizing their usefulness to the grid as a whole will require new methods to communicate with and control resources at the grid system level. A variety of strategies can be employed to incorporate high-penetration PV as a safe and reliable energy resource for the grid and reduce concerns of distribution system integration.

Managing energy supply from the distribution system, rather than the transmission system, requires a new strategy for system design, planning, and operations. New models of the PV systems will be needed to evaluate the potential impacts of DERs and ensure proper system protection. These models will need to be able to simulate the full range of steady-state and dynamic conditions encountered in the operation of the power system. As the penetration of DERs increases and the necessary technology is developed, it is anticipated that the distribution system will evolve to accommodate two-way power flows and will take full advantage of the benefits of DERs.

Integrating large numbers of DERs into utility SCADA systems from a systems-operation perspective is needed. Based on their larger size, distributed utility-scale PV plants can be integrated into utility SCADA systems more easily than customer-owned PV and other DERs. As smart grid concepts are implemented on the distribution system, it will become increasingly feasible to integrate distributed PV into grid operations. Managing large amounts of data from multiple DER and demand side management (DSM) sites will add complexity, along with cyber security concerns. All of these data will also need to be time synchronized for proposer coordination. Better visibility of distributed PV system output from the control room, coupled with PV inverter technology that can be responsive to system needs via operator commands and price signals, would enable distributed PV to participate in energy and capacity markets and help support system reliability.

Emerging communication and control technologies make it feasible for DERs to be aggregated into “virtual power plants.” Combining solar with demand response

creates a compelling reliability product, but this concept is in its infancy. All of these changes will add complexity to the operations of the distribution system. Rules and performance standards for such a product need to be established, and system operators need to be assured that the resource will be available before they can plan to it and operate with it. Markets and systems operations should evolve guided by the expectation that DERs will play a part. Changes to the regulatory environment may be needed to allow DERs to participate fully in markets and ancillary services.

Updating interconnection standards is also an important aspect to handling increasing DER penetrations. One example is changes to existing interconnection standards, such as IEEE 1547, to permit active voltage regulation, and possibly new anti-islanding techniques that can be used. Communication capability could be added to the PV inverter to allow the distribution system to signal the inverter to dispatch power and loads to optimize power flow to the utility. Such communication could be in the form of time-of-use rates and demand charges or could be real-time pricing via smart-metering technology. Communications between the PV inverter and distribution-system protection equipment, utility control room, and customer or utility storage systems are expected to help overcome variability and power-export concerns.

Benefits of such interactivity would include allowing PV systems to stay connected and ride through during temporary faults as needed. Utilities could command an inverter to ride through voltage sag, rather than having a large number of inverters go offline while leaving the loads online. Interactive control would also enable the distribution system to direct the inverter to go offline when there is a fault, rather than relying on multiple inverters, each supplying power to the grid, to detect a fault or islanding condition independently.

Combining energy storage with solar energy systems can also address some of the issues associated with solar energy integration. A relatively small amount of energy storage can be used to minimize the rate of change of system output to the grid to avoid demand charges. Storage on a distribution feeder could also be used to avoid reverse power flows at the substation. Much more storage would be required to provide significant capability for energy shifting or off-grid operation.

A variety of research and development activities can help with integrating high penetrations of DERs at the distribution level. These include the development of advanced inverter and control technologies, advanced distribution voltage and reactive power management, aggregation of distributed resources systems, and integration of PV systems with local load control and energy management.

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7. Solar Power Environmental Impacts and Siting Challenges

7.1 INTRODUCTION

All energy-generating technologies, including solar technologies, affect the environment in many ways. However, the potential of solar technologies to reduce greenhouse gas (GHG) emissions and other environmental impacts of energy generation compared with other generating technologies is among the most important reasons for widespread solar use. This chapter discusses the potential environmental impacts of achieving the SunShot scenario (Section 7.2), with comparisons to other generating technologies and land uses whenever possible, as well as the challenges associated with siting utility-scale (Section 7.3) and distributed (Section 7.4) solar technologies.

Environmental Benefits and Impacts

Solar energy reduces GHG emissions compared with most other sources of energy. Compared with the reference scenario, the SunShot scenario is estimated to reduce electric-sector operational carbon dioxide (CO_2) emissions by 181 million metric tons (MMT) per year by 2030 (an 8% reduction), and the estimated reduction by 2050 is 760 MMT per year for the SunShot scenario (a 28% reduction). Life-cycle GHG emissions from photovoltaics (PV) and concentrating solar power (CSP) are one to two orders of magnitude lower than from natural gas and coal power plants. Replacing fossil-fuel plants with solar also can reduce emissions of mercury, nitrogen oxides (NO_x), sulfur oxides (SO_x), and particulate matter (PM).

The SunShot scenario deployment of utility-scale solar technologies will require a substantial amount of land: an estimated 370,000–1,100,000 hectares[56] (ha) in 2030 and 860,000–2,500,000 ha in 2050, concentrated in the southern United States. This is equivalent to about 0.05%–0.14% of the contiguous U.S. land area in 2030 and about 0.11%–0.33% in 2050.[57] However, solar technologies can require less land per unit of electricity produced than other energy technologies on a life-cycle basis. In addition, distributed rooftop PV requires little or no land, i.e., by utilizing rooftop space for residential and commercial installations.

[56] One hectare equals approximately 2.471 acres.
[57] All results in this report refer to the contiguous United States (excluding Alaska and Hawaii) unless otherwise noted.

Although some solar technologies consume significant amounts of water during operation, many solar configurations may reduce water consumption dramatically compared with conventional energy technologies. The largest water consumption associated with solar electricity production is for CSP wet cooling. Dry and hybrid cooling can reduce CSP water consumption substantially, although these systems can increase cost and reduce efficiency compared with wet cooling. Solar development could actually reduce water consumption if it replaces activities that have more intensive water consumption, such as irrigation-intensive agriculture.

Like all other technologies, solar technologies require proper waste management and recycling. PV is associated with a few particular waste management and recycling issues, whereas CSP shares issues with other technologies that use common materials such as concrete, glass, and steel. The technical and economic feasibility of recycling PV materials has been established, and existing recycling programs could provide models for the large-scale management of PV materials that will be required under the SunShot scenario.

The primary ecological and other land-use impacts of solar development relate to utility-scale PV and CSP sites. A wide range of habitats, plant and animal species, and cultural and economic activities could be affected by widespread solar development, particularly in the southern United States. Consultation among government and tribal agencies, property owners, and other stakeholders early in the development-planning process can help identify potential land-use conflicts, applicable regulations, and strategies for reducing the impacts of solar projects.

Siting Challenges

Siting and construction of utility-scale solar projects and associated transmission infrastructure requires extensive government and stakeholder review and approval. Potential improvements to siting processes for utility-scale projects and transmission are discussed in detail in Section 7.3. A number of initiatives have identified a large potential resource for utility-scale solar that can avoid developing the most environmentally sensitive areas while expediting development on less-sensitive areas.

Although distributed solar technologies (rooftop PV) do not face the same land-use issues as utility-scale technologies, they do face siting challenges related to their use on residential and commercial buildings, including codes and permits, zoning ordinances, and restrictive covenants. Achieving the SunShot targets will require additional streamlining of distributed solar siting requirements and processes. In particular, a unified permitting process across different regions would facilitate expansion of the distributed solar market. Establishing strong solar access and rights laws would protect the rights of consumers to install solar energy systems.

7.2 Environmental Benefits and Impacts

Solar energy provides environmental benefits compared with most other energy technologies and many other land uses. The adverse impacts of solar energy are mainly local, whereas the benefits of solar are local, regional, and global. The following environmental topics are covered in this section: GHG emissions and

global climate change, air pollutant emissions, land use, water consumption, waste management and recycling, and ecological[58] and other land-use impacts.

7.2.1 Greenhouse Gas Emissions and Global Climate Change

Global climate change, largely caused by anthropogenic GHG emissions, threatens public health, welfare, and the environment around the world (IPCC 2007). In 2009, the U.S. Environmental Protection Agency (EPA) officially recognized GHGs as a threat to the health and welfare of the American people. Increased temperatures will likely increase heat-related morbidity and mortality and the prevalence of diseases and other health threats that depend largely on local climate (EPA 2007a, USCCSP 2008). Warmer temperatures can also increase air and water pollution, which in turn can harm human health (EPA 2007a, CDC 2010, USCCSP 2008). Global warming exacerbates the problem of ground-level ozone (smog), intensifying the public health dangers associated with air-quality violations (EPA 2007b). Increased surface water evaporation could lead to more wildfires and increased dust from dry soil, both of which generate harmful PM emissions.

In 2007, all sectors of the United States emitted approximately 6,000 MMT of CO_2, the most important GHG. The electric power sector was responsible for about 40% of these emissions (EIA 2010a). The entire world emitted about 29,700 MMT of CO_2 in 2007 (EIA 2010b). The Energy Information Administration (EIA) (2010a) projects U.S. CO_2 emissions to grow to about 6,200 MMT in 2030, with the electric power sector contributing 41%. World CO_2 emissions are projected to reach 39,300 MMT in 2030 (EIA 2010b).

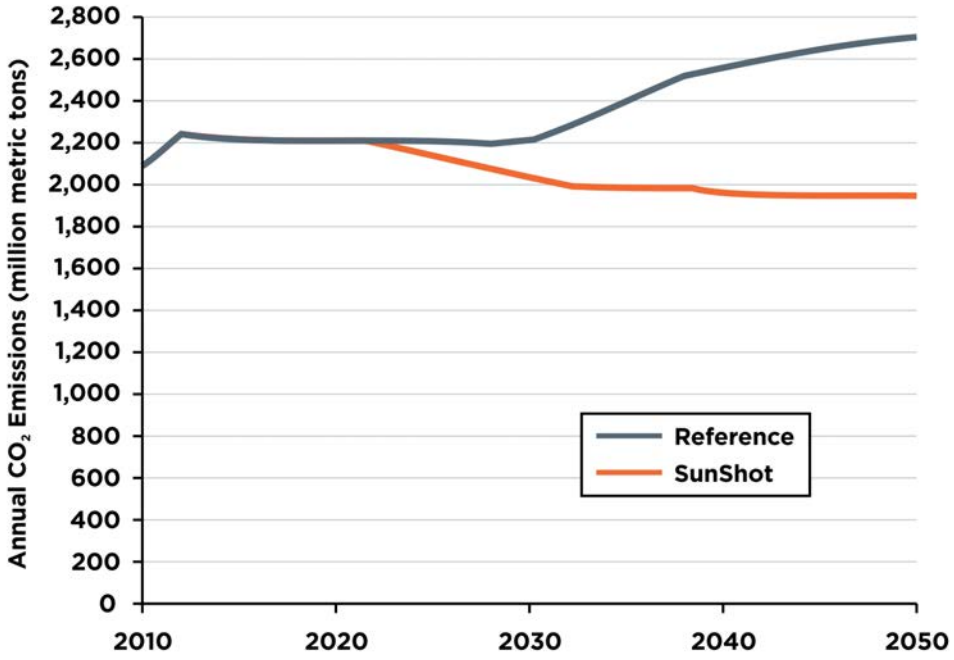
Significant reductions in U.S. GHG emissions are projected under the SunShot scenario. Combined with other efforts worldwide, these reductions have the potential to contribute significantly to the deceleration of global climate change. Figure 7-1 compares the CO_2 emissions projections, for the period 2010–2050, under the SunShot and reference scenarios. Chapter 3 describes the SunShot and reference scenarios, including descriptions of the modeled electricity capacity and generation mixes and discussion of peak and baseload power resources. Note that the CO_2 emissions shown in Figure 7-1 are operational emissions (i.e., emissions resulting directly from electricity generation); lifecycle GHG emissions are discussed later in this section.

In the reference scenario, annual electric-sector operational CO_2 emissions are estimated to increase by 123 MMT by 2030. In the SunShot scenario, annual emissions are estimated to decrease by 59 MMT by 2030—an 8% reduction compared with the reference scenario.

In the reference scenario, annual electric-sector operational CO_2 emissions are estimated to increase by 613 MMT by 2050. In the SunShot scenario, annual emissions are estimated to decrease by 146 MMT by 2050—a 28% reduction compared with the reference scenario.

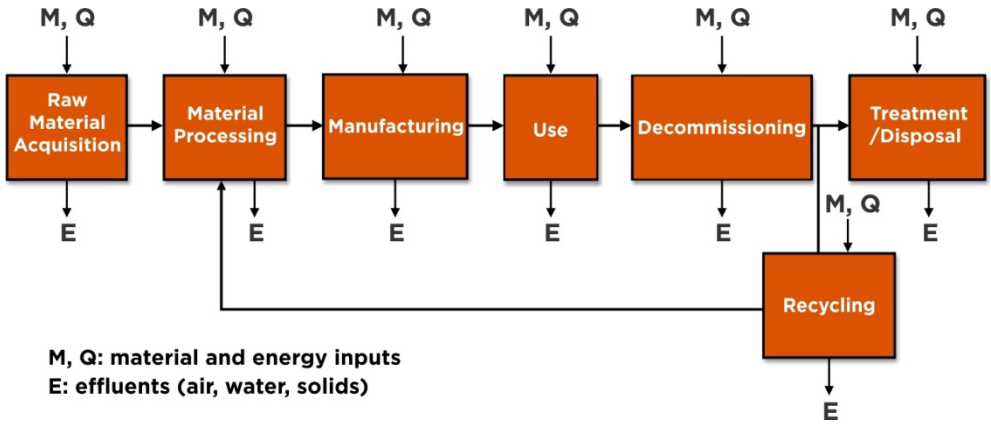
[58] Ecological impacts are defined here as “the effect that a man-caused or natural activity has on living organisms and their non-living (abiotic) environment” (EPA 2006).

Figure 7-1. Annual Electric-Sector Operational CO_2 Emissions under the SunShot and Reference Scenarios



These results are based on CO_2 emissions resulting from electricity generation only. However, electricity-generating technologies produce CO_2 and other GHG emissions during additional stages in their life cycles, such as, from raw materials extraction through end-of-life disposal and recycling (Figure 7-2). For example, the fuel for solar technologies—sunlight—generates no GHG emissions, but GHGs are generated throughout the solar technology life cycle. Similarly, GHG emissions are produced during coal mining, natural gas drilling, wind-turbine manufacturing, and so forth.

Figure 7-2. Energy, Material, and Waste Flows Across Stages of Energy Technology Life Cycles



Source: Fthenakis and Kim (2007)

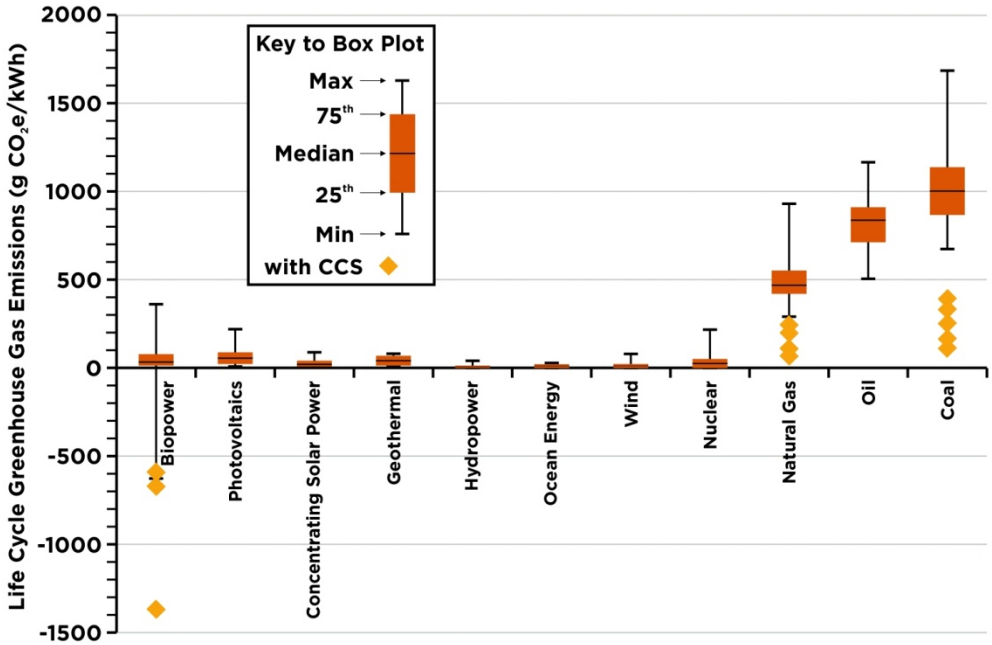
Because PV and CSP life-cycle GHG emissions are generated primarily during manufacturing processes, the rapid growth of solar technologies could lead to a

small net increase in short-term U.S. GHG emissions. However, this increase has been shown to be less than a fraction of one percent, and the lifetime GHG reductions from PV and CSP far outweigh the up-front manufacturing emissions (Drury et al. 2009).

A related concept is energy payback time, which is the time required for an energy technology to generate the amount of energy used to manufacture it. The energy payback time for PV systems is about 0.8–1.8 years at the average insolation found in the United States and southern Europe [1,700 kilowatt-hours (kWh)/square meter (m^2)/year] (Fthenakis et al. 2009a). During an expected lifetime of 30 years, PV systems produce 10–30 times the energy required for their manufacture (Fthenakis and Alsema 2006). The energy payback time for CSP systems is about 12–13 months for a plant in Daggett, California, with a direct-normal irradiance (DNI) of 2,700 kWh/m^2/year (yr) (Burkhardt et al. 2010). During an assumed lifetime of 30 years, such a CSP system would produce about 20 times the energy required for its manufacture. Solar energy payback time depends, in part, on the energy requirements associated with manufacturing specific to PV or CSP technologies and where the technologies are installed (i.e., what solar resource is available). The energy payback times of PV and CSP installations in the U.S. Southwest will be shorter than the U.S. average.

When entire technology life cycles are taken into account, the full GHG-reduction benefits of solar technologies become apparent. Figure 7-3 presents approximate

Figure 7-3. Life-Cycle GHG Emissions for Various Electricity-Producing Technologies



These estimates are based on a comprehensive review of English-language life-cycle analysis literature screened for relevance and quality. They are not directly comparable because they use different assumptions for key performance parameters, life-cycle analysis boundaries, and other methodological issues. For example, different insolation/irradiation levels are assumed in the PV and CSP analyses. However, this comparative plot clearly displays major trends based on the best available literature.

Source: Adapted from Edenhofer et al. (2011)

ranges of life-cycle GHG emissions estimates for many electricity-generating technologies. The figure is useful for comparing major trends in life-cycle GHG emissions among technologies. Importantly, there are large differences between renewable technologies and conventional fossil-fuel generation and relatively small differences among renewable technologies. The diamonds show life-cycle GHG emissions estimates for biopower, natural gas, and coal generation with carbon capture and storage (CCS). Ongoing research aims to provide more robust and consistently derived estimates of life-cycle GHG emissions for these and other electricity-generating technologies.

Solar GHG emissions depend, in part, on the specific PV or CSP technology type and where it is installed. According to Fthenakis et al. (2009a), life-cycle GHG emissions for typical PV technologies installed in the southwestern United States are approximately 13–22 grams (g) of CO_2-equivalent per kilowatt-hour (g CO_2e/kWh). For CSP, Burkhardt et al. (2010) modeled a parabolic trough plant with molten salt thermal energy storage in southern California, based on an engineering design study (Turchi 2010). They estimated life-cycle GHG emissions at 24–28 g CO_2e/kWh depending on cooling technology (wet or dry cooling) and thermal storage design (two-tank or thermocline). In contrast to PV and CSP, coal power plants emit about 700–1,700 g CO_2e/kWh, and natural gas power plants emit about 300–900 g CO_2e/kWh (Figure 7-3).

Integration of variable-generation renewable technologies can introduce inefficiencies in the electricity system because conventional-generation sources must operate at suboptimal efficiency under some conditions to maintain the system's supply-demand balance. These system inefficiencies can partially offset the GHG benefits provided by the renewable technologies, although one study suggested the efficiency penalty is relatively small for renewable penetration levels less than 35% of electricity production (GE Energy 2010). Strategies such as drawing from PV installed over a wide area (Fthenakis et al. 2009b) and using thermal storage with CSP should reduce the efficiency penalties. Additional research is needed to quantify the effects on the electricity system of integrating a high proportion of solar generation. See Chapter 6 for additional information about integrating variable-generation technologies.

7.2.2 Air Pollutant Emissions

All electricity-generating and thermal energy technologies emit pollutants during their life cycles, but solar energy technologies emit few or no pollutants during operation (Figure 7-2). Among the emissions of greatest concern for electricity generation are mercury, NO_x, SO_x, and PM.

Mercury can harm the nervous system of unborn babies and young children (EPA 2010a). Coal-burning power plants account for more than 40% of U.S. mercury emissions. Displacing coal-derived electricity using technologies such as PV and CSP would reduce mercury emissions.

NO_x contribute to health and environmental problems such as respiratory ailments, acid rain, climate change, deterioration of water quality, ground-level ozone (smog), air toxics, and PM. SO_x can aggravate respiratory illness and heart and lung disease, form PM, and cause acid rain. In the United States, electricity generation is a major

source of NO_x (motor vehicles are the largest source) and the largest source of SO_x (EPA 2010b). For technologies such as PV that produce no emissions during operation, NO_x and SO_x emission estimates depend largely on assumptions about which power sources are used to manufacture PV equipment. For CSP, sources of electric or thermal heat used to warm transfer and storage media and heat boilers at the beginning or end of the day are also factors; the amount of energy required for these purposes is highly technology dependent. For coal-burning power plants, the most important assumptions are which combustion technologies are used and which technologies are installed to reduce NO_x and SO_x emissions during operation. In general, life-cycle NO_x and SO_x emissions from PV and CSP are very small in comparison to emissions from natural gas and coal-burning power plants (National Academy of Sciences 2010a, Fthenakis et al. 2008, Viebahn et al. 2008, Pehnt 2006).

PM, particularly particles less than 2.5 microns in size ($PM_{2.5}$), causes health problems including premature death, reduced lung function, asthma, bronchitis, and cardiovascular diseases. PM also alters soil and water chemistry and upsets nutrient balances. In addition, impacts of PM emissions can occur far from their source (EPA 2008). Displacing fossil-fuel combustion with solar technologies would reduce $PM_{2.5}$ emissions drastically. The National Academy of Sciences (2010b) discusses in more detail the health and environmental impacts of emissions from coal and natural gas power plants, including emissions of mercury, NO_x, SO_x, and PM.

7.2.3 Land Use

Under the SunShot scenario, a substantial amount of PV is expected to be installed on buildings and other low-opportunity-cost areas such as parking structures, awnings, and airports. However, much of the solar deployment under the SunShot scenario would require use of land that was previously used for other applications (e.g., abandoned industrial, fallow agricultural, or former mining sites) or was previously undeveloped. The way in which solar technologies are deployed can change the nature of their impacts on the land (see Section 7.2.6).

Table 7-1 shows estimates of current direct land requirements for utility-scale solar technologies.[59] The values for land use by capacity [ha/megawatt (MW)] are based on previous estimates as well as a survey of existing or proposed utility-scale PV and CSP installations in the United States. The range in values is a function of several factors. For PV, land use is a function of module efficiency and spacing. For CSP, there is a particularly wide range of values—this is in part due to the variation in the size of the solar field (solar multiple) for a given unit of capacity enabled by the use of thermal storage. For a better comparison, the values for land use by annual electricity production [ha/terawatt-hour (TWh)] are also provided. These are based on the land-use-by-capacity values normalized to a single insolation level in the southwestern United States. Therefore, regardless of where the projects are actually located, their electricity production was calculated using this single insolation value. This single insolation value is approximately equal to the average insolation value for utility-scale PV and CSP deployments in the SunShot scenario, about 2,500 $kWh/m^2/yr$ of DNI or global horizontal insolation of about 2,100 $kWh/m^2/yr$.

[59] Here, direct land requirements are defined as the land "footprint" occupied by the solar power plant. Indirect land requirements, such as land transformation associated with the energy and materials required to construct a solar technology, are not included.

Table 7-1. Estimates of Current Direct Land Requirements for Utility-Scale Solar Technologies

	Number of Installations Evaluated	Direct Land Use by Capacity (ha/MW)[a]	Direct Land Use by Annual Electricity Production (ha/TWh)[b]
PV, fixed tilt	26	1.4–4.3	800–2,500
PV, 1-axis tracking	25	1.8–4.1	900–1,900
CSP, dish/engine	3	3.5–4.1	1,600–1,800
CSP, tower	5	1.6–6.2	700–1,800
CSP, trough	10	2.2–3.6	800–1,200

[a] Based on data from 69 existing, under-construction, and proposed U.S. utility-scale PV and CSP installations as of August 2010. The values for land use by capacity (ha/MW) are based on estimates from the actual installations. The information was collected from project developers and project websites to construct this table for the *SunShot Vision Study*.
[b] The values for land use by annual electricity production (ha/TWh) were calculated using the National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM) www.nrel.gov/analysis/sam. They are based on the average insolation value for utility-scale PV and CSP deployments in the SunShot scenario, equal to about 2,500 kWh/m^2/yr of DNI or global horizontal insolation of about 2,100 kWh/m^2/yr.

Source: Ong et al. (forthcoming)

Table 7-2 shows estimates of solar land use in 2030 and 2050 under the SunShot scenario, derived from the utility-scale solar ranges shown in Table 7-1. These ranges are wide for a variety of reasons, including those discussed above. The exact mix of solar technologies and land-use practices that will evolve through 2050 is unknown. If minimizing land use is given priority, it is likely that values at the low end of the range, or lower, would be achieved. In any case, these estimates are based on current solar technology; it is likely that land requirements per unit of capacity installed and electricity generated will generally be lower through 2050 as the efficiency and maturity of solar systems improve across technologies. See Chapters 4 and 5 for details about expected technology improvements.

Table 7-2. Estimates of Direct Solar Land Requirements in 2030 and 2050 under the SunShot Scenario

	Direct Land Use by Annual Electricity Production (ha/TWh)[a]	Solar Generation in 2030 (TWh)	Direct Solar Land Use in 2030 (ha)	Solar Generation in 2050 (TWh)	Direct Solar Land Use in 2050 (ha)
PV, Rooftop[b]	0	164	0	318	0
PV, Utility-Scale	800–2,500	341	270,000–850,000	718	570,000–1,800,000
CSP	700–1,800	137	96,000–250,000	412	290,000–740,000
Total		**642**	**370,000–1,100,000**	**1,448**	**860,000–2,500,000**

[a] These land-use ranges are from Table 7-1.
[b] Indirect land uses are not considered in these calculations. Also not considered is potential land required for another use due to rooftop PV occupying space on a structure that might otherwise accommodate that use. Rooftop PV is assumed to account for a negligible amount of direct land use.

Chapter 3 shows the regional deployment of solar technologies under the SunShot scenario, with the CSP and much of the utility-scale PV deployed in the southern United States. The highest estimate of land use for 2050 (2.5 million ha) in Table 7-2 is equivalent to less than 10% of the land area of Arizona, which covers about 30 million ha, and is similar in magnitude to the land area dedicated to golf courses (about 1 million ha) in the United States (Denholm and Margolis 2008).

These land-use estimates can also be compared with other energy-production land uses. For example, a study by Fthenakis and Kim (2009) found that, on a life-cycle electricity-output basis—including direct and indirect land transformation—utility-scale PV in the U.S. Southwest requires less land than the average U.S. power plant using surface-mined coal.

7.2.4 Water Consumption

Water consumption for solar generation varies by technology and location.[60] Table 7-3 gives estimates for solar-, wind-, fossil-fuel, and nuclear-generating technologies. Biomass and co-fired biomass power plants will have cooling/generating water consumption similar to that of comparable coal plants, but water consumption related to growing biomass fuel is highly variable (Gerbens-Leenes et al. 2009, Macknick et al. 2011). Table 7-4 shows estimated water-consumption ranges for solar deployment in 2030 and 2050 under the SunShot scenario; these values represent estimates of gross water consumption from deployed solar technologies only (i.e., they do not consider the amount of water consumption avoided owing to replacement of other electricity-generating technologies by solar). As Table 7-3 shows, many solar configurations can reduce water consumption dramatically compared with conventional technologies that use evaporative cooling systems (i.e., cooling towers). Other cooling types (e.g., once-through and pond systems) may have different water consumption and withdrawal rates, but these technologies are generally not feasible in arid regions owing to their higher withdrawal rates.

PV consumes little, if any, water during operation; some PV operators wash panels to maintain optimal performance, whereas others do not. Concentrating solar technologies, including concentrating photovoltaics (CPV) and CSP, require water for rinsing panels, mirrors, and reflectors to ensure maximum energy production. Manufacturing solar technologies also consumes water. For a trough-based CSP facility with 6 hours of two-tank indirect thermal energy storage

[60] Water consumption is defined as the amount of water that is "evaporated, transpired, incorporated into products or crops, consumed by humans or livestock, or otherwise removed from the immediate water environment" (Kenny et al. 2009). Water consumption is distinct from water withdrawal. Water withdrawal is the total amount of "water removed from the ground or diverted from a surface-water source for use" (Kenny et al. 2009), but which may be returned to the source. Both water withdrawal and consumption are important metrics, but consumption is a very useful metric for water-scarce regions, especially in the context of future resource development, because consumption effectively removes water from the system so it is not available for other uses (e.g., agriculture or drinking).

Table 7-3. Water Intensity of Electricity Generation by Fuel Source and Technology[a]

Generation Technology	Cooling System	Water Consumed for Cooling (gal/MWh)	Other Water Consumed in Generation (gal/MWh)	Water Consumed in Producing Fuel (gal/MWh)
CSP trough or tower (wet-cooled)[b]	Closed-loop cooling tower	710–960	40–60	0
CSP trough or tower (dry-cooled)[c]	Dry air cooling	0	30–80	0
CSP dish/engine[d]	Dry air cooling	0	4–6	0
PV[e]	None	0	0–5	0
Wind[f]	None	0	0	0
Pulverized coal[f,g]	Closed-loop cooling tower	360–590	60–120	5–74
Pulverized coal with CO_2 capture[f,h]	Closed-loop cooling tower	700–770	150–180	5–74
Integrated gasification combined cycle (IGCC)[f,i]	Closed-loop cooling tower	250–370	40–70	5–74
IGCC with CO_2 capture[f,j]	Closed-loop cooling tower	390–410	130–150	5–74
Natural gas combined cycle (CC)[f,k]	Closed-loop cooling tower	180–280	2	11
Nuclear[f,l]	Closed-loop cooling tower	580–850	30	45–150

[a] The table does not account for water consumption in system manufacturing or construction of any of the technologies. Water consumption for fuel extraction is considered for fossil and nuclear. All wet-cooled Rankine power cycles are assumed to use closed-loop cooling towers with four cycles of concentration and blowdown water discharge to an on-site evaporation pond. Water consumption values for wet-cooled Rankine power cycles using once-through cooling systems are not shown because their large water withdrawal requirements make them infeasible for the Southwest. Dry cooling is possible with all Rankine cycles, although it is explicitly shown for CSP only.

[b] From Cohen et al. (1999) and Viebahn et al. (2008). Other water consumed for trough and tower technologies includes water for washing mirrors and steam cycle blowdown and makeup. Mirror soiling rates/washing rates are site- and developer-specific. Towers will be at the lower end of the cooling-water range and troughs at the higher end owing to thermal efficiency differences.

[c] From Brightsource Energy (2007) and Kelly (2006). Other water consumed for trough and tower technologies includes water for washing mirrors and steam cycle blowdown and makeup. Mirror soiling rates/washing rates are site- and developer-specific. There is more uncertainty in other water consumed for dry-cooled trough/tower technologies than for wet-cooled technologies because fewer dry-cooled plants have been built.

[d] Dish/engine washing rates and other water use are not well documented and vary by site/developer. The estimate of 4–6 gal/MWh is based on Leitner (2002) and CEC (2010) as well as industry knowledge.

[e] Utility-scale PV washing rates and other water use are not well documented and vary by site/developer. The estimate of 0–5 gal/MWh is based on Aspen Environmental Group (2011a and 2011b) as well as industry knowledge.

[f] From DOE (2006).

[g] From NETL (2010) and NETL (2007). Cooling and other-generation values are for new subcritical and supercritical coal plants.

[h] From NETL (2010). Cooling and other-generation values are for new subcritical and supercritical coal plants.

[i] From NETL (2010) and NETL (2007).

[j] From NETL (2010).

[k] From EPRI (2002) and NETL (2007).

[l] From Gleick (1993) and Gerdes and Nichols (2009).

Table 7-4. U.S. Solar-Related Water Consumption for Solar Technology Deployment in 2030 and 2050 under the SunShot Scenario

	Solar Generation in 2030 (TWh)	Solar-Related Water Consumption in 2030 (billion gal)	Solar Generation in 2050 (TWh)	Solar-Related Water Consumption in 2050 (billion gal)
Rooftop PV	164	0–0.8	318	0–1.6
Utility-scale PV	341	0–1.7	718	0–3.6
CSP[a]	137	14–75	412	42–227
Total	**642**	**14–78**	**1,448**	**42–232**

[a] The CSP water-use ranges reflect the range of trough/tower water-use estimates from Table 7-3. The low number reflects trough/tower technology with 90% use of dry cooling and 10% use of wet cooling, with per-megawatt-hour consumption at the low end of the trough/tower ranges. The high number reflects trough/tower technology with 50% use of wet cooling and 50% use of dry cooling, with per-megawatt-hour consumption at the high end of the trough/tower ranges. The SunShot scenario assumes 100% dry cooling as a conservative estimate of costs, but it is likely that the mix would consist of various technologies. Thus, the values given in this table are meant to illustrate a range of possible scenarios of CSP deployment. As Table 7-3 shows, dish/engine CSP technologies use even less water than dry-cooled trough/tower technologies. Trough/tower technologies were used in these calculations because substantially more data are available for them, but, assuming dish/engine technologies meet the price and performance characteristics envisioned in the SunShot scenario, widespread deployment of these technologies could help reduce CSP-related water use.

(TES), Burkhardt et al. (2010) estimate about 120 gallons (gal)/megawatt-hour (MWh), mainly consumed in the production of solar collector assemblies, nitrate salts, and heat-transfer fluid (HTF). While water-consumption values for PV manufacturing have not been established, Fthenakis and Kim (2010) provide some information about water withdrawals related to PV manufacturing (i.e., water used in the PV manufacturing process but not entirely consumed, with some of the water processed and returned to the immediate water environment). Water consumed to extract, process, and transport fuels can be significant for fossil-fuel and nuclear technologies, but is not required for solar and wind technologies (Table 7-3).

The largest water consumption associated with solar-electricity production is for cooling CSP trough and tower plants. The amount of water a CSP system consumes for cooling depends on the technology, cooling system, location, climate, and water availability. Three types of CSP cooling systems can be deployed: wet, dry, and hybrid (combination wet/dry). Wet cooling (using cooling towers) currently offers the highest performance at the lowest overall cost (Turchi et al. 2010), but it also consumes the largest amount of water. Dry cooling cuts operational water consumption by as much as 97% compared with wet cooling, but it increases capital costs and reduces efficiency on hot days (Turchi 2010). The cost of electricity from a dry-cooled parabolic-trough plant in the Mojave Desert is about 7% higher than from a similar wet-cooled plant (DOE 2009a, Turchi 2010). Dish/engine CSP plants are dry cooled.

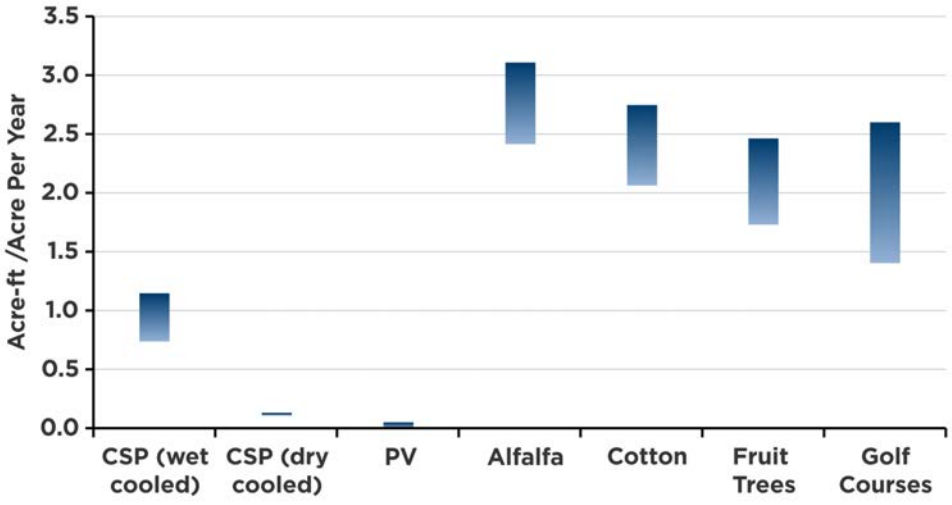
To overcome the cost and performance penalty associated with dry cooling, some developers are considering hybrid systems that employ dry cooling when temperatures are below 38°C (100°F) and wet cooling for hotter periods. Hybrid systems can consume 40%–90% less water than a wet-cooled system while maintaining 97%–99% of the performance (DOE 2009). However, hybrid systems currently have a higher life-cycle cost than wet-cooled systems (Turchi et al. 2010).

See Chapter 5 for information about CSP cooling system research and development (R&D).

In addition to consuming water for cooling, trough and tower CSP systems consume a relatively small amount of water to produce steam for electricity generation. In a typical Rankine-cycle steam turbine, water in a closed loop is heated to produce steam and spin a turbine, then cooled, re-condensed, and used again. A relatively small amount of water—compared with the water consumed in an evaporative cooling system—is drained to remove particulates and salts (a process called "blowdown") in the boiler and cooling systems. The amount of blowdown water depends on the quality of the source water; more is required when using degraded water sources. Dish/engine CSP plants with Stirling engines do not use a water-steam cycle; the movement of a gas is used to produce electricity in these systems.

The distribution of solar water consumption will not be uniform across the United States; it will be highest in the arid Southwest, where CSP deployment will be concentrated. Dry cooling is assumed for all CSP deployment in the SunShot scenario. Unless dry cooling is used, siting CSP in arid areas presents a potentially insurmountable deployment challenge because of water constraints in these areas (Carter and Campbell 2009). The West accounted for half of all U.S. population growth from 1990 to 2000, creating additional demand for water (Anderson and Woosley 2005). Water resources in arid regions may also decline with climate change, and the Southwest has experienced the most rapid warming in the United States (U.S. Global Change Research Program 2009). As shown in Figure 7-4, water consumption per unit of area for PV and CSP is less intensive than for a number of other activities. Thus, although water consumption is likely to be a contentious issue in the Southwest going forward, it is possible that solar developers will be able to obtain water rights from existing water-rights holders, sometimes resulting in less-intensive water consumption.

Figure 7-4. Water Consumption per Acre for Different Applications in the Southwest



7.2.5 Waste Management and Recycling

Like all other technologies, solar technologies require proper waste management and recycling. PV is associated with a few particular waste management and recycling issues, whereas CSP shares issues with other technologies that use common materials such as concrete, glass, and steel. Waste management and recycling issues for each technology are discussed below, with a focus on the issues surrounding PV.

PV modules contain hazardous materials [e.g., compounds of cadmium (Cd), selenium (Se), and lead (Pb)], and there are concerns about potential emissions at the end of a module's useful life. Managing the disposal and/or recycling of these materials to avoid groundwater contamination (via landfills) and air pollution (via incinerators) is an important environmental consideration.

In addition to materials contained within the completed module, a number of chemicals may be used during PV manufacturing. For crystalline silicon modules, feedstock materials are made through a purification process, the by-products of which typically include silicon tetrachloride ($SiCl_4$). To reduce costs and protect the environment, most of today's manufacturing plants use a closed-loop process that greatly minimizes waste products by converting, separating, and reusing trichlorosilane from the $SiCl_4$ by-product. Silicon nitride (SiN_4) is used as an antireflective-coating material and is generally deposited via chemical vapor deposition. This process requires the safe handling and management of pyrophoric silane gas—i.e., gas that can ignite spontaneously when exposed to air. Silane is also the major feedstock in thin-film amorphous silicon (a-Si) PV. The a-Si/thin-film tandem segment of the PV industry also uses nitrogen trifluoride (NF_3) for reactor cleaning, which has a global warming potential 17,000 times greater than CO_2. The controlled use and production of NF_3 has been proven for specific production and end-use systems (for example, in the liquid crystal display industry), and its use in the a-Si/microcrystalline silicon PV industry will not alter the environmental benefits of PV replacing fossil fuels if best practices are adopted globally (Fthenakis et al. 2010).

The greatest concern surrounding thin-film cadmium telluride (CdTe) and copper indium gallium selenide (CIGS) PV is potential exposure to Cd, which the EPA defines as a Class B1 carcinogen (EPA 2000). Typical CdTe PV material contains 5 g of Cd per m^2 of module, whereas typical CIGS material (which can contain cadmium sulfide) contains less than 1 g of Cd per m^2 of module (Fthenakis and Zweibel 2003). Although Cd is not emitted during normal module operation, small emissions could occur during manufacturing or accidental fires. However, the life-cycle Cd emissions of CdTe and CIGS PV are orders of magnitude lower than Cd emissions from the operation of fossil-fuel power plants (Fthenakis 2004, Fthenakis et al. 2005, Fthenakis et al. 2008).

Recycling helps resolve end-of-life PV module issues, and the PV industry is proactively engaged in building recycling infrastructure. The technical and economic feasibility of recycling the semiconductor materials, metals, and glass from manufacturing scrap and spent PV modules has been established (Fthenakis 2000). Furthermore, recycling can provide a significant secondary source of materials that may be used in the production of future PV technologies, such as, tellurium, indium, and germanium (Fthenakis 2009). First Solar, which

manufactures thin-film CdTe PV, established the industry's first comprehensive, pre-funded module collection and recycling program, which the company claims will result in recycling 90% of the weight of each recovered First Solar PV module (First Solar 2010). In Europe, the PV industry has established PV Cycle, a voluntary program to recycle PV modules (PV Cycle 2010). The United States could adopt this type of industry-wide approach to manage the large-scale recycling and management of PV materials that will be required under the SunShot scenario.

The major constituents of CSP plants include glass, steel, and concrete. In addition, some CSP plants will contain a significant quantity of nitrate salt and organic heat transfer oil. All these materials are recyclable. For more detail on the material requirements for CSP plants, see Chapter 5.

7.2.6 Ecological and Other Land-Use Impacts

All development creates ecological and other land-use impacts. The primary impacts of solar development relate to land used for utility-scale PV and CSP (rooftop PV installations have negligible direct land-use impacts). As described in Section 7.2.3, under the SunShot scenario, these utility-scale installations are projected to require 370,000–1,100,000 ha of land by 2030 and 860,000–2,500,000 ha of land by 2050, mostly in the southern United States. However, as this chapter discusses, solar technologies can affect less land, emit lower levels of GHGs and other pollutants, and consume less water than some other electricity-generating technologies on a life-cycle basis. A thorough consideration of solar development weighs both positive and negative impacts.

Even with the most careful land selection, the projected utility-scale solar development may have significant local land-use impacts, especially on portions of the southern United States. Solar development should be consistent with national and local land-use priorities. This section discusses the potential impacts of solar development and strategies to reduce those impacts. Because the discussion is drawn largely from the draft *Solar Programmatic Environmental Impact Statement (Solar PEIS) on Solar Energy Development on BLM-Administered Lands in the Southwestern United States* (DOE and DOI 2010), it focuses on Southwestern impacts. However, each area in which solar development occurs is subject to a unique set of impacts. See Chapter 3 for the regional deployment of solar technologies under the SunShot scenario.

Impacts

The impacts of solar development include direct impacts, such as soil disturbance, habitat fragmentation, and noise, and indirect impacts, such as changes in surface water quality because of soil erosion at the construction site. The specific impacts of utility-scale solar development will depend on project location, solar technology employed, size of the development, and proximity to existing roads and transmission lines.

The potential ecological impacts in the southwestern United States are particularly important because of the large scale of solar development envisioned for this area. The Southwest supports a wide variety of plant communities and habitats, including arid and semiarid desert-scrub and shrub land, grasslands, woodlands, and savannas.

The wildlife in these areas includes diverse species of amphibians, reptiles, birds, and small and large mammals. Government agencies and conservation groups have identified a significant list of species that may be affected by solar development (DOE and DOI 2010).

Altering plant communities with development can strain wildlife living in or near these communities, making it more difficult to find shelter, hunt, forage, and reproduce. Fenced-in power plants can add further strain by affecting terrestrial and avian migration patterns. Aquatic species also can be affected—as can terrestrial and avian species that rely on aquatic habitats—if the water requirements of solar development result in substantial diversion of local water sources. Large areas covered by solar collectors also may affect plants and animals by interfering with natural sunlight, rainfall, and drainage. Solar equipment may provide perches for birds of prey that could affect bird and prey populations.

The potential impacts of solar development are not limited to ecological impacts. Solar development could affect a variety of activities that take place on public and private land. For example, conflicts may arise if development impacts cultural sites or interferes with U.S. Department of Defense (DOD) activities. In addition, loss of forage base could result in reduced grazing, which would disrupt the longstanding economic and cultural characteristics of ranching operations. Potential indirect impacts include conversion of land to provide support services and housing for people who move to the region to support the solar development, with associated increases in roads, traffic, and penetration into previously remote areas. The additional transmission infrastructure associated with solar development could create various impacts as well.

These are merely examples of the types of impacts that may be associated with solar development. For an exhaustive discussion, see DOE and DOI (2010) and other detailed environmental-impact studies. Less well-studied impacts are also important and must be evaluated as solar development progresses. For example, the local and global climate effects of changes in albedo—which determines the amount of incoming solar radiation that is reflected back into space—due to widespread PV and CSP deployment are not well studied. One study evaluated the net balance between GHG emissions reduction resulting from PV replacing fossil-fuel-based power generation (with PV growing to meet 50% of world energy demand in 2100) and a decrease in desert albedo due to PV module covering, concluding that the PV albedo effect would have little impact on global warming (Nemet 2009).

Impact Reduction

Consultation among government and tribal agencies, property owners, and other stakeholders early in the development-planning process can help identify potential land-use conflicts, applicable regulations, and strategies for reducing impacts. Site assessments by biologists and other experts can help identify specific ecological issues and strategies for addressing them. Thorough planning, employee education, and monitoring throughout a solar project's life cycle also can help reduce negative impacts. Management strategies and monitoring might even offer opportunities for improving the land within solar development areas, for example, by enhancing associated wildlife habitat (Fthenakis et al. 2011, Turney and Fthenakis 2011).

Strategies for avoiding or mitigating impacts may include avoiding development in sensitive areas, choosing sites and grouping development to minimize fragmentation, avoiding wildlife disturbance during vulnerable seasons, designing appropriate lighting, and designing projects to minimize contaminant release. Most of these examples are accepted, effective practices, but their implementation must be tailored to each specific project. See DOE and DOI (2010) and other detailed environmental-impact studies for greater detail. Also, see Section 7.3.1 for information about how various stakeholders are considering the impacts of solar development when choosing solar sites.

7.3 Siting Challenges for Utility-Scale Solar Projects

A close examination of specific areas will be necessary for siting utility-scale solar projects. This section discusses the issues surrounding siting to avoid environmentally sensitive areas; the federal, state, and local regulatory frameworks for utility-scale solar projects; and the issues involved with transmission siting. Distributed solar technologies—such as rooftop PV—do not cause the same concerns because their direct land requirements are minimal. Section 7.4 describes the unique siting challenges these technologies face.

7.3.1 Siting to Avoid Environmentally Sensitive Areas

As with any land development, the impacts of solar development on environmentally sensitive areas must be minimized. Various government-led initiatives have sought to identify areas with high solar-energy potential and relatively low environmental sensitivity as starting points for large-scale solar development. This section discusses the major initiatives: the U.S. Bureau of Land Management (BLM) Solar Energy Study Areas, California Renewable Energy Transmission Initiative (RETI), Western Governors' Association (WGA) Western Renewable Energy Zones (WREZ) initiative, and EPA RE-Powering America's Land project.

Lands that are part of the BLM National Landscape Conservation System (NLCS) are already excluded from solar development, including the following:

- Wilderness areas
- Wilderness study areas
- National monuments
- National conservation areas
- National wild and scenic rivers
- National scenic and historic trails
- Conservation lands of the California desert.

In a response to the Solar PEIS proposed by the BLM and U.S. Department of Energy (DOE), The Wilderness Society, Natural Resources Defense Council

(NRDC), and other contributors recommended expanding the areas excluded from solar development to include the following (ANL 2009):

- National recreational rivers, study rivers and segments, and eligible rivers and segments
- Areas of critical environmental concern
- Threatened, endangered, and sensitive-species habitat
- Critical cores and linkages for wildlife habitat
- Citizen-proposed wilderness areas
- Other lands with wilderness characteristics.

In June 2009, the BLM proposed a set of Solar Energy Study Areas, an initial set of suitable lands meant to accommodate solar development with minimal environmental conflicts (ANL 2011). The total area of these lands is about 273,000 ha. If all of these lands were allocated to solar development, they could produce about 110–390 TWh per year (based on the calculations in Table 7-1), or about 23%–82% of the SunShot scenario's total utility-scale solar-generation target in 2030.[61] Note that this initial set of lands was identified to expedite solar development; it should not be viewed as a limit on total potential solar development in the areas considered.

In California, RETI is seeking to identify competitive renewable energy zones (CREZs) that could be developed in the most cost-effective and least environmentally harmful manner (CEC 2009). RETI is an open and transparent collaborative process in which all interested parties are encouraged to participate. As of summer 2009, California CREZs identified by RETI included 21 sites potentially available for utility-scale solar projects with an estimated capacity of more than 61 gigawatts (GW) and energy production of 150 TWh per year (RETI 2009). The CREZ designations and sizes are subject to change. In 2009, California and the federal government initiated preparation of the Desert Renewable Energy Conservation Plan (DRECP), which is scheduled for completion in 2013 (DRECP 2011). This plan will identify areas appropriate for renewable energy development, identify protected areas, and establish a comprehensive environmental impact mitigation strategy for the Colorado and Mojave deserts.

The WGA, in collaboration with DOE, has undertaken a similar process to identify potential renewable energy zones (REZs) in the regions of the Western Interconnection (WGA 2009). The WREZ initiative was launched in May 2008, engaging stakeholders to identify areas with significant renewable energy resources with the goal of expediting appropriate renewable energy development and delivery. In June 2009, the WGA released the WREZ Phase 1 assessment of high-quality, developable renewable resource areas, which have a cumulative technical capacity of approximately 87 GW, or about 200 TWh per year, of utility-scale solar power. Following on this work, the WGA has expanded resource assessments and transmission planning within the Western Interconnection.

[61] Full realization of the solar potential in these areas is only a theoretical possibility because of development and other constraints.

The EPA, with assistance from DOE and NREL, developed the RE-Powering America's Land project to promote the use of current and formerly contaminated land and mining sites for renewable energy projects (EPA 2009). Maps and datasheets provide information about more than 2 million ha of land with potential for utility-scale CSP or PV installations in the western United States, although much of this land may not be suitable owing to slope or existing use. More than 9,000 additional sites for distributed PV are identified throughout the United States, ranging from 0.5–80 ha. Although state and federal laws and policies are intended to clarify—and sometimes provide protection against—liability risks related to developing contaminated land, the applicability of these laws and policies depends on the specifics of each potential project (EPA 2011). Renewable energy developers should thoroughly evaluate the potential for liability and additional costs before developing contaminated land (EPA 2011).

As these studies show, the potential resource for utility-scale solar deployment is enormous, indicating that careful selection can be made to reduce conflicts with environmental, cultural, and aesthetic interests—particularly with respect to public lands. Examination of these areas should yield lands suitable for hosting a large proportion of the utility-scale solar installations projected under the SunShot scenario.

7.3.2 Siting Regulatory Framework

Construction of utility-scale solar projects and their associated transmission infrastructure will require government review and approval at various levels. This section provides background on the National Environmental Policy Act of 1969 (NEPA) and Endangered Species Act of 1973 (ESA), the public's involvement in NEPA, and state and local regulation with a particular focus on California's experience. It also examines potential options for modifying the siting regulatory framework to support solar energy. Distributed solar technologies are subject to different processes (described in Section 7.4).

NEPA and ESA

Federal land management and permitting agencies will have to comply with applicable laws and regulations, including NEPA and ESA, in managing solar resources on federal lands. NEPA and its implementing regulations require the federal government to evaluate the effects of its actions on the environment and to consider alternative courses of action. The statute requires that an environmental impact statement (EIS) be prepared for major federal actions with the potential for significant impact on the quality of the human environment.

The ESA, in contrast, provides for the identification, or "listing," of wildlife and plant species as "endangered" or "threatened" if they meet specific criteria as well as for the designation of "critical habitat" for listed species. Once a species has been listed, federal agencies must consult with the U.S. Fish and Wildlife Service (USFWS) before taking any action that may affect listed species. Private landowners are also subject to ESA requirements.

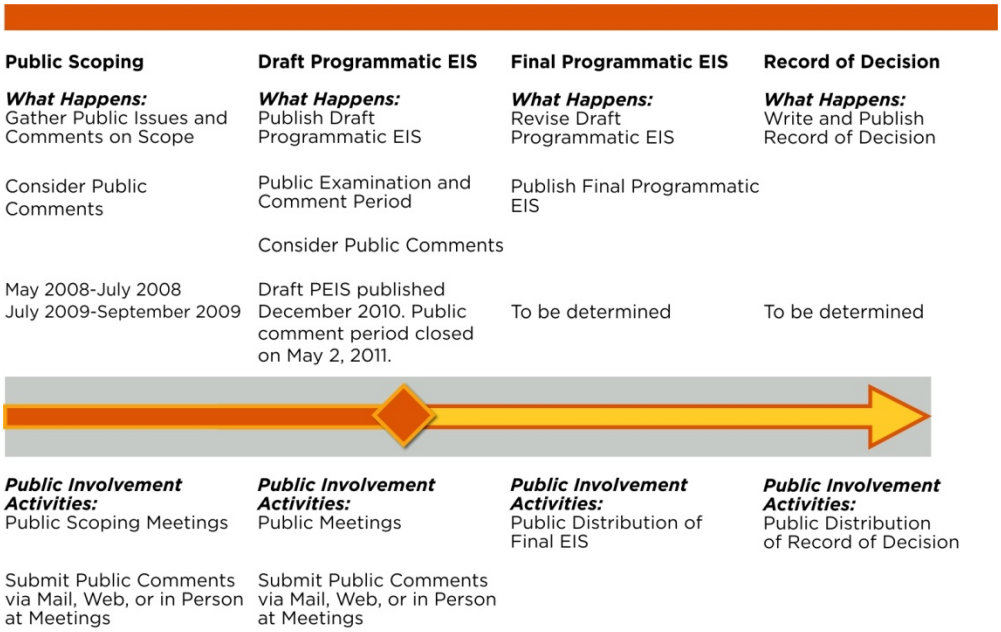
Because DOE and the U.S. Department of the Interior (DOI) have determined that establishing agency-wide solar energy programs constitutes major federal actions as

defined by NEPA, they have decided to jointly prepare a programmatic environmental impact statement (PEIS) (ANL 2011). A PEIS evaluates the environmental impacts of broad agency actions, such as the development of programs or the setting of national policies. For DOI (specifically BLM), the PEIS will involve the adoption of additional policy and mitigation strategies to use when evaluating utility-scale solar energy development on BLM lands. For DOE, the PEIS is aimed at establishing environmental policies and mitigation strategies to be considered in evaluating whether to support solar projects that will be located on BLM or other federal, state, tribal, or private lands. DOE and DOI will consult with USFWS pursuant to the ESA in connection with this PEIS.

Public Involvement in NEPA

The public, other federal agencies, and outside parties may provide input into the preparation of an EIS and then comment on the draft EIS when it is completed. After a final EIS is prepared and a decision about the proposed action is made, the relevant federal agency prepares a public record of the decision that addresses how the findings of the EIS—including consideration of alternatives—were incorporated into the agency's decision-making process. Figure 7-5 shows the basic structure for the Solar PEIS process and how it incorporates public involvement. The draft Solar PEIS was released for public comment in December 2010, and the public comment period ended in May 2011.

Figure 7-5. Public Involvement in the Solar PEIS Process



Source: ANL (2011)

State, Local, and California Regulation

In addition to the federal process described above, solar projects are subject to a diverse set of regulatory requirements—including different standards, information requirements, decision-making processes, and public-participation requirements—some of the variability and complexity of state regulations; it is not an exhaustive

list of states with regulations or an exhaustive list of regulations within the listed depending on the state in which they are located and, in some states, on their size and technology. Depending on the state, they may be regulated at the state level, local level, or both.

Table 7-5 shows a few examples of state regulatory considerations related to water use, project review and approval, and the environment. It is meant only to illustrate states. Regulations and interpretations of regulations change frequently. Examples of additional regulatory areas include historical/cultural preservation, public-participation processes, and incentives. California—where significant utility-scale solar development is projected—has one of the nation's strongest regulatory programs for both generation and transmission projects and is discussed in more detail below.

In California, all thermal-generating projects larger than 50 MW must be certified by the California Energy Commission (CEC), and this includes CSP projects. Large PV projects, because they are not thermal, do not come under the jurisdiction of the CEC. Smaller CSP and PV projects are primarily permitted at the county level.

Transmission lines that serve those projects are permitted by the California Public Utilities Commission (CPUC) or by municipal power authorities, while interconnections to the grid and assurance that projects maintain grid reliability are governed by the California Independent System Operator Corporation (CAISO) or municipal power authorities.

Except on federal lands, the CEC has essentially exclusive jurisdiction over large CSP plants. When projects 50 MW or larger are proposed for federal lands in California, the federal government works with the CEC to review the projects pursuant to a series of federal-state memoranda of understanding (MOUs).[62] The CEC's permitting process is designed to ensure compliance with all applicable state laws, ordinances, and regulations, including the California Environmental Quality Act (CEQA)[63] and the California Endangered Species Act (CESA).[64] The process incorporates project review by relevant state and local agencies as well as extensive public participation. In contrast, all utility-scale PV and smaller-scale solar thermal project proponents must independently obtain all required federal and state permits, including construction permits from the county in which the project is located, and it

[62] For example, see http://energy.ca.gov/siting/solar/BLM_CEC_MOU.PDF.
[63] See generally, California Energy Commission, Energy Facilities Licensing Process – Guide to Public Participation. http://www.energy.ca.gov/siting/guide_license_process.html. Extensive information about the CEC process is available at its website: http://www.energy.ca.gov/sitingcases/index.html including information for developers and the public.
[64] Although similar to their federal analogues, both CEQA and CESA have requirements that are different, thus adding to the complexity of the permitting process for projects located on federal lands in California.

Table 7-5. Examples of State Regulatory Considerations[a]

State	Water	Project	Environment
Arizona	Requirements based on location and water source; "Aquifer Protection Permit" required for discharges.	Application, review, and public hearing required for transmission lines ≥115 kilovolt (kV); power plants ≥100 MW must obtain Certificate of Environmental Compatibility.	Reviews based on animals and plants, noise, recreation, and environment.
California	Dry cooling default for regulated projects; wet cooling only with non-potable water or if dry cooling is deemed "uneconomic."	California Public Utilities Commission (CPUC) regulates investor-owned utility (IOU) transmission >50 kV; municipal utilities self-regulate; California Energy Commission (CEC) permits transmission for projects it regulates; CEC permits CSP >50 MW; smaller projects and PV permitted by counties.	California Endangered Species Act (CESA) protects species; usually 2 years of surveys for sensitive areas.
Florida	Water use and discharge permits issued through the Florida Electrical Power Plant Siting Act (PPSA) certification process.	PPSA is a one-stop certification procedure for construction/expansion of plants and transmission; PPSA applies to solar generators ≥75 MW, transmission associated with new power plants, and lines that are ≥230 kV, cross a county line, and are >15 miles in length.	Avoiding and/or mitigating impacts on state and federally listed animal and plant species may be required.
Nevada	New water rights or changes in existing rights regulated by State Engineer, usually involving public process; groundwater discharge permitting similar to Arizona's.	Public Utility Commission of Nevada (PUCN) permits construction; municipalities and certain trusts exempt from requirement to obtain a Certificate of Public Convenience and Necessity; PUCN regulates transmission >200 kV, power plants >150 MW; land- and air-quality permits also required.	Endangered species law covers plants and animals, but recovery plans, consultation, and critical habitat designation not required; harmful stream modification prohibited.
New Mexico	Regulations ensure that other water users not impaired and no additional depletions occur on fully appropriated streams or streams needed to fulfill interstate compact obligations.	Transmission ≥230 kV approved by New Mexico Public Regulation Commission (NMPRC); Renewable Energy Transmission Authority (RETA) implements state renewable energy law; approval needed from NMPRC for solar.	New Mexico Fish and Game Department guidelines on wildlife impacts applied to renewable energy projects.
Texas	Groundwater regulated through Groundwater Management Areas and local districts; no regulations specific to renewable energy.	Public Utility Commission of Texas (PUCT) regulates construction plants ≥10 MW if constructed, owned, or operated by a bundled electric utility; PUCT regulates CREZs established for wind power; no solar CREZ established to date.	Texas Parks and Wildlife Department recommends CREZ wildlife impact mitigation measures.
Utah	No specific limitations on water use for energy generation.	No single state agency has primary responsibility for plant siting; Certificate of Public Convenience and Necessity from Utah Public Service Commission required; various additional agencies establish requirements for specific projects.	State-listed species not protected by special regulations.

[a] This table illustrates generalized examples only. It does not represent an exhaustive list of states with regulations or an exhaustive list of regulations within the listed states and should not be relied upon to make decisions. Regulations and interpretations of regulations change frequently. The relevant government agencies are the best source of official, updated information.

Sources: Relevant state and utility websites accessed in 2010

is the county that is responsible for CEQA analysis and for ensuring that all significant adverse impacts are mitigated.[65]

Although the CEC's permitting process is required to be completed within 12 months, it has taken longer for CSP plants because of the CEC's lack of familiarity with CSP, the newness of some of the technologies, and the scale of the projects. The CEC and its staff are making significant progress to develop expertise and experience with these projects. The same is true of the staff at DOI and its agencies, with whom the CEC now prepares coordinated NEPA/CEQA reviews and joint environmental documents for most projects currently proposed on federal land.[66] Ultimately, it is expected that the integration of these two decision-making processes and environmental reviews will save time and effort for all concerned, including developers.

The CPUC regulates planning and construction of network transmission facilities [above 50 kilovolts (kV)] if they are owned by an investor-owned utility (IOU). CPUC prepares joint environmental documents with federal land management agencies (CPUC and BLM 2008). Municipal power authorities regulate the construction of lines that feed their own systems (either individually or through consortiums, such as the Transmission Agency of Northern California). Transmission facilities are subject to CEQA and its public participation opportunities and may also be required to comply with requirements of other state and federal agencies.

Siting and Permitting Improvements to Support Utility-Scale Solar Energy

To meet the SunShot scenario deployment levels, there are a number of options that could help improve the siting and permitting process. Most of these options could be pursued at the state, regional, or federal level. These options include:

- Developing clear and consistent criteria for environmental screening to aid in selecting optimal solar-generation sites. The California RETI process serves as a good example for other states or regions to follow.
- Developing a comprehensive and consistent strategy for environmental mitigation. Any funds set aside for mitigation purposes would ideally last for the duration of a project, and can be managed independently.
- Fostering cooperation between federal and state agencies responsible for permitting and streamlining the process among agencies. Although several states have undertaken efforts to streamline the permitting processes with the federal government, there has not been a region-wide effort to achieve this goal on a broader scale.[67]

[65] CEQA requires mitigation to the extent feasible. Where mitigation is not feasible, the permitting authority can deny the application or issue a Statement of Overriding Considerations that allows permitting despite the remaining impacts.
[66] See, e.g., CPUC and BLM (2008). Note that approval of projects on lands managed by the U.S. Department of Defense (DOD), DOE, or other federal agencies such as the U.S. Forest Service (USFS) would involve federal wildlife agencies, but not the U.S. Department of the Interior's (DOI) BLM.
[67] The Renewable Energy Policy Group is one example of a state's, specifically California (CA), efforts to streamline the permitting process with the federal government. A memorandum of understanding (MOU) was signed in fall 2009 between CA Governor Arnold Schwarzenegger and DOI Secretary Ken Salazar to merge the efforts and responsibilities of the CA Governor's office, CA Natural Resources Agency, and DOI in addressing issues surrounding the permitting of large-scale solar thermal plants (CA 2010).

- Staffing state and federal permitting agencies adequately to enable processing of renewable energy applications in a timely manner. This could include use of outside contractors and could be funded from reasonable application-processing fees. Educating staff on solar and other renewable technologies would also contribute to improving the efficiency of processing applications.

7.3.3 Transmission Siting

Establishing solar-energy transmission infrastructure presents unique challenges. The sections below discuss the transmission siting process, transmission regulations, and improving the regulatory framework to support solar energy.

Transmission Siting Process

The remote location of much of the envisioned utility-scale solar capacity will require the construction of new high-voltage transmission lines to transport electricity to population centers. Because transmission lines can cross private, public (state and federal), and tribal lands, the process of planning, permitting, and building new lines is highly visible and implicates many diverse interests—and it can be costly, time consuming, and controversial.

Before approval for new transmission is granted, the regulatory authority must determine that the project is necessary. Non-transmission alternatives must often be considered, including energy conservation, energy efficiency, distributed generation, and fully using unused capacity on existing transmission lines. When new transmission lines are deemed necessary, developers[68] and utilities must find the best routes to the greatest concentrations of renewable energy and build with the least possible impact to the environment. Transmission lines can fragment and interfere with wildlife habitats and corridors and can increase wildlife mortality due to collisions, electrocution, and by serving as perches for predators (WGA 2008). There are also concerns about the visual impacts and potential health impacts of transmission lines. Burying transmission lines can help avoid many of the environmental and aesthetic issues. However, burying lines may also have negative impacts on soil, vegetation, and other resources (Molburg et al. 2007), and underground lines are typically four times as expensive as overhead lines (Brown and Sedano 2004). Also, although high-voltage direct-current (DC) lines can be buried, there is a limit on the maximum voltage and length of alternating-current (AC) lines that can be buried.

In all, constructing major new transmission can require 7–10 years from planning to operation: 1 year for final engineering, 1–2 years for construction, and the rest of the time for planning and permitting. Substantial time and controversy are added to the process when environmental and related concerns are addressed at the end instead of the beginning. It is expected that the designation of REZs (see Section 7.3.1) will accelerate the development of renewable energy and associated transmission infrastructure. For example, the Texas CREZ program has resulted in significant new transmission for wind power projects.

[68] Transmission developers include IOUs, Federal Power Marketing Authorities [such as the Western Area Power Administration (WAPA)], publicly-owned utilities (such as Los Angeles Department of Water and Power), and, sometimes, independent merchant transmission developers.

Transmission Regulations

The existing regulatory framework for planning, siting, and allocating costs for transmission presents challenges to achieving the SunShot scenario's utility-scale solar deployment. Originally designed for vertically-integrated utilities that build their own, largely fossil-fueled generation, this framework would need to be modified to accommodate a more diverse generation portfolio that includes larger numbers of smaller, location-constrained renewable resources, distributed generation, aggressive conservation and demand response programs, and "smart grid" technologies.

Transmission planning in much of the western United States is done at the sub-regional level by IOUs on an ad hoc basis. In areas served by a Regional Transmission Organization (RTO) or independent system operator (ISO)—such as CAISO, the Electric Reliability Council of Texas (ERCOT), and various ISOs and RTOs in the Midwest and Northeast—planning is done for a larger region. RTOs and ISOs coordinate generation and transmission within their respective regions—including within or across state lines—to ensure balanced electricity supply and demand and to provide non-discriminatory transmission access. However, there is little coordination between RTOs or ISOs and little, if any, correlation to regions rich in renewable energy resources. In 2009, DOE initiated multi-stakeholder, interconnection-wide transmission planning in the Eastern and Western Interconnections, but it is too early to tell if these efforts will result in tangible regional transmission plans that support renewable energy development.

Transmission plans are reviewed by regional reliability councils to ensure they meet reliability and security requirements, but these councils have no enforcement authority to ensure projects are built. Actual siting decisions are made by state utility commissions or, in some cases, local siting authorities or federal land management agencies. The authorized state or local authority is responsible for approving the tariff for any retail sales associated with the new or expanded transmission facilities. If the transmission line supports interstate commerce, the Federal Energy Regulatory Commission (FERC) has jurisdiction for setting the wholesale transaction tariffs. FERC is also responsible for ensuring open access to all interstate transmission lines but lacks the authority to require states to plan or build transmission to serve renewable generators.

Cost allocation (i.e., who pays for transmission) is one of the most significant barriers to renewable energy development in the United States. This topic is discussed in Chapter 8.

Closely related to cost allocation is cost recovery. In areas outside an RTO or ISO, rates are typically set to recover the cost of transmission within a utility's footprint, which are known as "license plate rates." More common within an RTO or ISO service area are "postage stamp rates," which are uniform rates charged for all transmission service within a specified area. In either instance, FERC must approve the wholesale transmission tariff.

Merchant transmission developers have the option to either accept the FERC-approved postage stamp or license plate rates or hold an "open season" and try to get subscriptions for capacity on the proposed line, often with a large anchor tenant.

They may enter into bilateral agreements and charge fees to recover their costs that are outside the RTO- or ISO-approved tariffs, but which must still be approved by FERC.

Regardless of the method of cost recovery, there currently exists the phenomenon known as "rate pancaking." Energy transmitted across the service areas of multiple transmission owners is charged a separate transmission rate across each. Thus, the total amount charged is the sum of all transmission charges for each area. This can make the cost for transmitting renewable energy across multiple utility or RTO/ISO service areas prohibitively expensive.

Another issue is "right-sizing," i.e., sizing the transmission infrastructure to meet expected renewable energy development to minimize costs and environmental impact. For example, rather than building a single 500-kV line, two 500-kV lines could be built along the same right-of-way from the start, assuming sufficient renewable resources are available to ultimately use this infrastructure. PacifiCorp's Gateway transmission project is an attempt to right-size transmission to tap wind resources in Wyoming. The original plans called for two 500-kV lines along the same right-of-way (each capable of carrying about 1,500 MW), but PacifiCorp has been unable to obtain subscriptions to fill even one of the lines (Radford 2010). A core issue in right-sizing is cost recovery: should consumers pay up front for transmission capacity that will go unused for an undetermined period?

Transmission Improvements to Support Solar Energy

To achieve the SunShot scenario, there are a number of options that could help facilitate transmission improvements to support increased amounts of solar energy on the grid. Most of these options could be pursued at the regional or federal level. These options include:

- Planning transmission on a regional level.
- Conducting regional planning with involvement of multiple stakeholders from the beginning.
- Giving regional plans enforcement provisions that authorize or require states to site and permit their respective portions of the plan.
- Addressing cost-allocation and cost-recovery issues adequately.

In 2010, FERC issued a Notice of Proposed Rulemaking (NOPR) that addresses regional transmission planning and cost allocation. Should FERC's proposed rule become final, it could significantly improve the chances for building regional transmission to bring renewable energy to market. However, the NOPR contains many controversial provisions that are sure to delay its implementation or that could be significantly altered in the final rulemaking. Although it is encouraging that FERC is attempting to address regional cost allocation and planning, it is too early to tell how effective the rulemaking will be.

7.4 Siting Challenges for Distributed Solar Projects

Although distributed solar technologies do not face the same land-use issues as utility-scale technologies (discussed in Section 7.3), they do face siting challenges related to their use on residential and commercial buildings. Currently, inconsistency of codes and standards between jurisdictions and a lack of familiarity of states and municipalities with solar technologies present obstacles to the efficient deployment of solar systems. This section discusses current codes and permits, zoning ordinances and restrictive covenants, and ways to improve the acceptance of distributed solar technologies at the state and local levels.

7.4.1 Codes, Permitting, and Standards for Distributed Solar

This section discusses current codes and permits related to distributed solar, as well as the current and potential improvements that are being made to these processes through standardization.

Current Codes and Permits

Distributed solar technologies are subject to numerous government regulations and codes. These often vary from community to community and from state to state based on the opinion of the "authority having jurisdiction," which is usually the local building inspection authority (Nelson 2009). Even in the case of national codes, states and/or local authorities often impose additional requirements on the design, permitting, installation, or operation of a distributed solar system. The most common requirements for distributed PV involve building and electrical codes.

Building codes govern the safe construction of structures. For PV, the primary concerns are ensuring that the systems are secured to the roof, that they are not prone to wind damage and/or roof leakage, and that the roof can withstand the additional weight (Pitt 2008). Fire codes address fire prevention and safety in a structure's design, construction, and maintenance, as well as allowing for sufficient roof access for emergency personnel and/or building evacuation in the case of a fire. Similar to building codes, model fire codes are established at the national level, but some states and many local fire departments modify these codes. Each city has building inspectors responsible for enforcing building and fire codes.

Installing a distributed PV system generally requires meeting electrical codes set by the local building department and interconnection codes made by or with the local utility. Permits for these codes are designed to prevent safety hazards such as fires, electrocution, and power surges (Pitt 2008). Most jurisdictions' electrical codes are based on Article 690 of the National Electrical Code (NEC), which outlines the requirements for installing safe and reliable PV systems (DOE 2004). Some jurisdictions, such as the State of California, establish their own codes that go beyond the NEC. In addition to, and often in coordination with, the NEC, utilities require interconnection agreements before connecting any electricity generator to the distribution network. These rules are typically approved by the state utilities

commission or municipal utility authorities and, occasionally, by the state government. Interconnection rules are discussed in greater detail in the previous section.

Codes and regulations placed on distributed PV systems have resulted in processes that increase system cost and installation time. Each jurisdiction sets permitting fees, which can vary tremendously from one city to the next. In addition, installers may be challenged with the intricacies of requirements across different jurisdictions, and/or permitting officials may not understand system design. These inefficiencies have prevented projects from moving forward and/or have caused areas to avoid even having a permitting process (DOE 2009b).

Improvements through Standardization

Several entities facilitate the permitting and standardization of PV systems and their respective components, with the goal of increasing acceptance of distributed solar technologies. DOE has taken a lead role in this area through the establishment of the Solar America Board for Codes and Standards (Solar ABCs), a collaborative effort among stakeholders to develop coordinated recommendations to codes- and standards-making bodies for existing and new solar technologies. Solar ABCs develops model codes, standards, rules, and ordinances to remove barriers to the adoption of PV. In October 2009, Solar ABCs released a model expedited permitting process to support jurisdictions with implementing PV installations.

In addition, DOE has asked states to show what measures they are taking to encourage efficient and renewable energy as part of federal stimulus packages that provide assistance with a green focus. This effort, as well as the funds available for energy-efficiency projects and new solar construction, have assisted or motivated a number of states to examine their codes, and where prior standards did not exist, to develop them, often along the lines that other states had implemented. This standardization set a solid foundation for further federal standards. Industry-wide standards are also emerging, such as the 2009 adoption of a set of solar standards by the American National Standards Institute (ANSI).[69]

Achieving the SunShot targets will require additional streamlining and standardization of distributed solar siting requirements and processes. In particular, a unified permitting process across different regions would facilitate expansion of the distributed solar market. Another policy option to facilitate solar deployment is to require that certain new buildings be constructed in such a way that they may be easily retrofitted with PV technologies; this is often termed “solar-ready” construction.

7.4.2 Solar Rights and Solar Access Protection

Despite the growing support for renewable energy development at the state and local level, many consumers still face local ordinances or homeowner association rules that prohibit, restrict, or drastically increase the cost of installing a solar energy system. In general, zoning laws are established by local government ordinances,

[69] The American National Standards Institute approved the 2009 Uniform Solar Energy Code (USEC), a consensus-based model code for the installation, inspection, and maintenance of solar energy systems and component products, for accreditation as an American National Standard.

whereas restrictive covenants may be the product of planned community or homeowner association rules. Examples of potential zoning issues for distributed solar include obstructing side yards, erecting unlawful protrusions on roofs, and siting the system too close to streets or lot boundaries (DOE 2010a). Restrictive covenants may be even more particular and restrictive with regard to community aesthetics and visual requirements.

Distributed solar technologies need protection from local ordinances and covenants to achieve the SunShot targets. A solar rights law provides protection for residential and commercial entities by limiting or prohibiting private restrictions (e.g., neighborhood covenants and bylaws, local government ordinances, and building codes) on the installation of solar energy systems. Solar rights laws have been proven to support solar market expansion. California's Solar Rights Act, established in 1978 and updated several times since, places the financial burden of restricting solar installations on the restricting entity (DSIRE 2010). Vague or absent provisions in solar rights laws have led to lawsuits and delays in a number of states.

Meanwhile, owners of existing systems face potential challenges when growing trees or new structures on neighboring property shade their solar collectors. Given that there is no common-law right to sunlight in the United States, these issues present serious barriers to the adoption of solar energy. Solar access laws protect landowners' rights to present and future unobstructed direct sunlight (DOE 2010b). As of April 2011, 38 states have solar access laws, and local governments also have this authority (DSIRE 2011).

The most common approach to addressing the post-installation issues at the state level is the solar easement. The solar easement allows the owner of a solar energy system to secure rights to continued access to sunlight on a voluntary basis from a neighboring party whose property could be developed in such a way (e.g., building or foliage) as to impede the system's access to sunlight. As of September 2010, more than half of the states in the United States have solar easement provisions (DSIRE 2011). Some jurisdictions have incorporated solar easements into the solar permit process such that when a customer receives a permit, an easement is automatically recorded.

Ensuring that homeowners and businesses have the right to install solar equipment on their property, and have a mechanism to protect their access to sunlight, will be essential to achieving the SunShot scenario. Without these provisions, a significant portion of the distributed rooftop potential could be made unviable.

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8. Solar Industry Financial Issues and Opportunities

8.1 Introduction

Although sunshine is free, capturing the sun's rays to generate electricity is a capital-intensive undertaking. Photovoltaic (PV) and concentrating solar power (CSP) technologies have high up-front costs and low operating costs. This means that improving their electricity-production economics is highly dependent on reducing their capital costs (addressed in previous chapters) and reducing the cost of financing those capital costs (addressed in this chapter). Solar technologies also tend to be long-lived assets, which means that long-term financing arrangements are not only appropriate, but are needed to enable investment recovery to be spread out over an extended period, resulting in lower lifetime per-unit electricity costs.
To date, government policies have driven the expansion of solar energy worldwide, and these policies have defined the amounts and types of financing used by solar market participants. In Europe, feed-in tariffs have been the primary stimulus for investment in renewable electricity, enabling a more traditional project finance approach to be used (i.e., usually involving significant amounts of non-recourse debt). In the United States, tax incentives—such as the production tax credit (PTC), investment tax credit (ITC), and accelerated tax depreciation—have been the primary policy tools.

Achieving the SunShot price targets is projected to make solar electricity broadly cost-competitive with electricity from other sources by 2020. This should stimulate private solar investment—and facilitate the use of mainstream financial instruments—by 2020 and beyond. During the transition to becoming fully cost-competitive, solar expansion will still likely be dependent on government incentives.

Under the SunShot scenario, there are two categories of solar financing challenges: financing the solar supply chain and financing solar projects (and associated transmission infrastructure). Financing the expansion of the solar supply chain—such as manufacturing facilities for PV modules and CSP mirrors—and the electrical transmission infrastructure should be relatively straightforward because many of the mechanisms for doing so are already well developed and liquid. Financing SunShot-scale solar project deployment—the widespread construction of distributed and utility-scale solar electricity-generating plants—is a greater challenge, with different considerations in the pre-2020 and post-2020 periods.

After reviewing the finance-related inputs used in the SunShot analysis, this chapter quantifies the amount of supply-chain and project financing required under the SunShot scenario. This is followed by a discussion of current and emerging financial structures and incentives that could help stimulate solar energy growth, especially in the pre-2020 transition period.

8.2 Review of Finance-Related Inputs Used in the SunShot Analysis

Table 8-1 provides an overview of the financial assumptions used in the SunShot analysis for the deployment of residential, commercial, and utility-scale PV and utility-scale CSP. As discussed in Chapter 3, the Solar Deployment System (SolarDS) model was used to analyze the residential and commercial PV markets, and the Regional Energy Deployment System (ReEDS) model was used for utility-scale PV and CSP, as well as for all other renewable and conventional generation technologies.

As of May 2011, neither SolarDS nor ReEDS is capable of modeling the intricate financial structures involving tax-equity investors, such as the partnership flip structures and leases described in this chapter, that are common in the industry today.[70] Instead, both models approximate the financial aspects of these structures by assuming that long-term debt financing is available for a significant portion of capital costs—i.e., the debt serves as a proxy for tax equity. Moreover, ReEDS assumes financing costs and capital structures that average the financial characteristics of utility-owned projects and projects owned by independent power producers (IPPs), as both ownership types contribute to the expansion of generation capacity. Finally, with the 40-year time horizon of the *SunShot Vision Study*, the SolarDS and ReEDS models use financial assumptions based on long-term historical data, where appropriate and available. The details on specific financing assumptions are provided in the notes below Table 8-1.

8.3 Financing Requirements for the Solar Supply Chain

Under the SunShot scenario, annual U.S. PV and CSP installations (including rebuilds) could stabilize at about 25–30 gigawatts (GW)/year (yr) and 3–4 GW/yr, respectively. Building out the U.S. PV and CSP manufacturing capacity to meet this demand would require investing roughly $25 billion by 2030 and $44 billion by 2050.[71,72] Although the investments required to finance these manufacturing capacity

[70] As of May 2011, the System Advisor Model (SAM) is able to model these advanced financing structures and can be found at www.nrel.gov/analysis/sam.

[71] Assumes: 1) Manufacturing capital expenditure (CapEx) costs, in terms of annual production capacity, decline from about $2/watt (W) in 2010 to about $0.5/W in 2020; the CapEx requirements for concentrated solar power (CSP) technologies are not well documented, so, conservatively, the CSP CapEx is assumed to be equal to the PV CapEx. 2) Annual U.S. installations (including rebuilds) grow to 25 GW/yr by 2030 and 30 GW/yr by 2050 for PV, and 3 GW/yr by 2030 and 4 GW/yr by 2050 for CSP. 3) Average economic life of manufacturing equipment is 10 years. 4) The manufacturing utilization rate is 80%.

[72] All cumulative values in this chapter are in net present value calculated using a 7% discount rate per the U.S. Office of Management and Budget (OMB) 2003 guidance.

Table 8-1. Solar Financing Assumptions

	SolarDS		ReEDS[a]	
	Residential Rooftop (new/retrofit)	Commercial Rooftop	Utility PV	Utility CSP
Inflation rate[b]	3%	3%	3%	3%
Loan rate (real)	4.5%[c]/6%[d]	4.5%[e]	4%[f]	4%[f]
Loan term (years)	30/15	20	15	15
Debt fraction	80%–100%[g]	60%	60%	60%
Equity rate (real)	N/A	N/A	11.7%[h]	11.7%[h]
Down payment (equity fraction)	0%–20%[g]	40%	40%	40%
Discount rate (real)	N/A[i]	N/A[j]	5.5%[k]	5.5%[k]
Depreciation	N/A	MACRS[l]	MACRS	MACRS
Federal tax	25%–33%[m]	35%	35%	35%
State tax	by state	by state	5%	5%
PV/CSP lifetime (years)	30	30	30	30

[a] The financial assumptions in ReEDS for utility-scale PV and CSP are the same for other renewable and conventional generation technologies. The one exception is loan terms, which vary between 15 and 30 years depending on technology.

[b] Conservative estimate of inflation based on historical U.S. Gross Domestic Product (GDP) deflator data over the last 30 years. Accessed November 2010 at: http://research.stlouisfed.org/fred2/data/GDPDEF.txt.

[c] Based on a 20-year historical average of real U.S. 30-year fixed mortgage rates. Accessed January 20, 2010, at: www.freddiemac.com/pmms/pmms30.htm (Freddie Mac 2010).

[d] Based on a 3-year historical average of real rates for $30,000 U.S. home equity loans. Accessed January 20, 2010, at: www.wsjprimerate.us/home_equity_loan_rates.htm.

[e] Based on a 12-year historical average of real yields of corporate bonds rated Aa and A by Moody's (SIFMA 2010).

[f] Reflects a nominal cost of debt of approximately 7%, the midpoint between the nominal costs of debt for higher-risk projects owned by investor-owned utilities and those owned by independent power producers (Wimer 2008).

[g] Assumes that 80% of residential customers use a 20% down payment, and 20% of residential customers use a 0% down payment to characterize the alternate ownership structures such as third-party PV ownership (NREL 2009, SEIA/GTM Research 2011a) or property-assessed clean energy (PACE) style financing (NREL 2010).

[h] Reflects a nominal cost of equity of 15%, the midpoint between the nominal costs of equity for investor-owned utilities and independent power producers (EEI 2009, Wimer 2008).

[i] SolarDS uses a simple payback time to adoption relationship for residential customers.

[j] SolarDS uses a payback time to adoption rate for commercial customers that use the internal rate of return of future cash flows.

[k] Reflects a nominal after-tax weighted average cost of capital (WACC) of 8.6%.

[l] MACRS (modified accelerated cost recovery system) is applied to taxable commercial customers.

[m] Assumes that 50% of residential customers are at a 25% federal tax rate, and the other 50% are at a 33% federal tax rate.

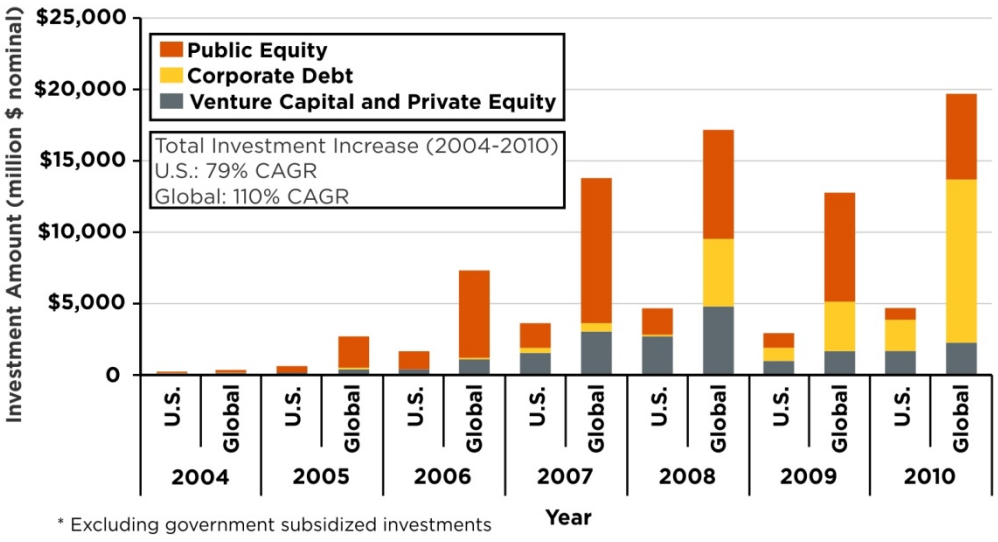
expansions are not trivial, on an annual basis they would require investments on the order of $1–$3 billion, well below levels seen during the past couple of years (as discussed below). Moreover, the necessary financing instruments and structures are well developed and well understood in the capital markets.

Historically, the solar supply chain has been financed primarily by a mix of venture capital (VC), private equity (PE), public equity, and corporate debt. VC investments

are often the earliest form of private investment in corporations, when both the potential reward and risk are the greatest. In the solar industry, PE is usually the next source of funding, as companies require additional and greater amounts of capital for manufacturing expansions. Finally, companies can issue public equity, selling shares of the company on the open market. In addition to equity financing, corporate debt can be used to fund a company's operations and expansions.

Figure 8-1 shows the dramatic increase in investment in the U. S. and global solar supply chain, including PV and CSP, over the past 6 years. In 2004, only $142 million and $231 million were invested in solar companies in the United States and globally, respectively. In 2010, solar supply chain investment reached more than $4.7 billion in the United States and nearly $20 billion globally, corresponding to 6-year compound annual growth rates (CAGRs) of 79% and 110%, respectively. Such rapid expansion indicates the ability of the VC, PE, public equity, and corporate debt capital markets to respond swiftly to signals of the solar industry's growth potential. In addition to the growth of total supply chain investment, the proportional mix of investment has shifted from riskier to more-secure financial instruments. In the years between 2004 and 2006, for example, corporate debt accounted for between 0% and 6% of total global investment, whereas in 2010 almost 60% of total investment in solar companies came from corporate debt.

Figure 8-1. U.S. and Global Solar Supply Chain Investment

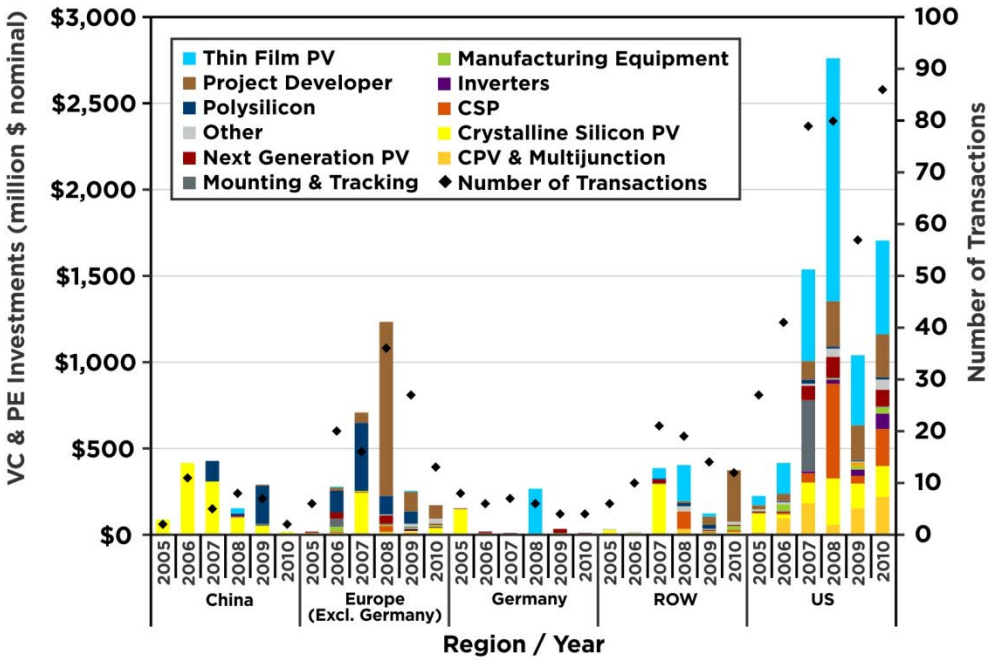


Source: Bloomberg New Energy Finance (2011)

Figure 8-1 excludes government-subsidized investments. Government-supported debt grew from $579 million in 2009 to $32.8 billion in 2010, to become greater than any other source of capital. Most of this government-supported debt was issued by the China Development Bank.

Figure 8-2 illustrates VC and PE investment in the solar supply chain, including PV and CSP, showing the technological and regional breakdown of such funding. U.S. companies have consistently received the most VC and PE funding, and a far more diverse set of solar technologies is financed in the United States than in the other active solar markets.

Figure 8-2. VC and PE Investment in the Solar Supply Chain



Source: Bloomberg New Energy Finance (2011)

8.4 Financing Requirements for Solar Project and Transmission Deployment

Deploying solar projects—i.e., deploying PV and CSP electricity-generating facilities—and associated transmission infrastructure will cost much more than expanding the solar supply chain under the SunShot scenario. This section explores the potential project and transmission costs.

8.4.1 Financing Solar Projects

Under the SunShot scenario, solar capacity in the United States is projected to meet 14% of total contiguous U.S. electricity demand by 2030 and 27% by 2050. To achieve these penetration levels, annual solar installations are projected to stabilize around 25–30 GW/yr for PV and 3–4 GW/yr for CSP. On an annual basis, this translates into roughly $40–$50 billion/yr.[73] On a cumulative basis, the required investments are roughly $250 billion through 2030 and $375 billion through 2050. Although these are significant investments, the total capital required to build all types of electric-generating equipment—conventional and renewable—in the SunShot scenario through 2050 is actually only $2 billion more than in the reference scenario. When other costs are considered—such as fuel, transmission, and operation and maintenance (O&M)—less money is actually spent in the SunShot

[73] Assumes solar technology costs and mix of PV and CSP technologies per SunShot scenario as described in Chapter 3 and Appendix A.

scenario than in the reference scenario (see Chapter 3). However, it is still relevant to consider what effect financing may have in achieving the SunShot scenario.

8.4.2 Financing Transmission

In both the SunShot and reference scenarios, the U.S. transmission infrastructure must be reinforced and expanded to accommodate new generation resources. Technical aspects of the transmission requirements are detailed in Chapters 3 and 6.

As discussed in Chapter 3, the projected cost of expanding transmission in both the SunShot and reference scenario from 2010 to 2050 is about $60 billion dollars (2010$, net present value). The discounted cost for the SunShot scenario is approximately the same as the reference, even though more transmission capacity is built, because this additional capacity is developed later in the study whereas the reference scenario develops more transmission capacity earlier in the study. Regardless, the entire cost of transmission expansion is equivalent to less than a few years of fuel savings in the SunShot scenario. The $60 billion transmission investment required in both scenarios is spread out over 40 years, representing about 2% of the total electric-sector costs. While building out the transmission infrastructure at this level will present many challenges (especially related to siting), it is within the historical range of U.S. transmission expenditures by investor-owned utilities, which was $2–$9 billion per year between 1995 and 2008 (Pfeifenberger et al. 2009).

8.5 Financial Structures and Incentives

As previously noted, although substantial investments will be required to finance SunShot-scale expansion of the solar manufacturing supply chain, there is sufficient capital to do so, and the necessary financing instruments and structures are well developed and understood in the capital markets. However, financing solar project deployment (e.g., new power plants) under the SunShot scenario will cost much more than financing the supply chain. Especially in the pre-2020 period, new financing options will be required before solar electricity is cost competitive with other electricity sources. In 2020 and beyond, cost-competitive solar energy should stimulate private solar investment and facilitate use of mainstream financial instruments. This section discusses the current financial incentives and financing structures that support U.S. solar and transmission projects, followed by a description of emerging solar project financing structures that may support solar deployment in the coming years.

8.5.1 Current Financial Incentives and Structures

Current financial incentives and structures for solar projects are based on the availability of government incentives, particularly the federal ITC. Although the *SunShot Vision Study* assumes that no solar projects receive an ITC after 2016, this incentive—and government incentives at other levels—will be important for stimulating solar deployment during the transition to solar cost competitiveness.[74]

[74] Although the SunShot scenario costs assumptions do not include any ITC after 2016, under the current Internal Revenue Service (IRS) tax code, the 30% ITC will revert to a 10% ITC for commercial and utility systems after 2016.

This subsection begins with a discussion of government incentive-based financing and then describes current solar financing structures, which are based on the availability of government incentives. Lastly, transmission financing considerations are discussed.

Government Incentives

Financial incentives for U.S. solar projects are provided by the federal government, state and local governments, and some local utilities. Historically, federal incentives have been provided primarily through the U.S. tax code, in the form of an ITC (which applies to residential, commercial, and utility-scale installations) and accelerated 5-year tax depreciation (which applies only to commercial and utility-scale installations). For commercial installations, the present value to an investor of the combination of these two incentives—which can be used only by tax-paying entities—amounts to about 56% of the installed cost of a solar project (Bolinger 2009).[75]

Most solar project developers are not in a financial position to absorb tax incentives themselves (due to lack of sufficient taxable income to offset deductions and credits[76]), and so they have had to rely on a small cadre of third-party "tax equity investors" who invest in tax-advantaged projects to shield the income they receive from their core business activities (e.g., banking). In doing so, these tax-equity investors monetize the tax incentives that otherwise could not be efficiently used by project developers and other common owners of the renewable energy plants.

Federal tax-based incentives may play a significant role in stimulating solar development until 2017, when the ITC is assumed to expire under the SunShot scenario. However, the amount of tax equity available for solar projects is uncertain. Due to the global financial crisis, tax-equity investments in renewable power projects in the United States peaked at $6.1 billion during 2007, declined to $3.4 billion during 2008, and plunged to $1.2 billion during 2009 (US PREF 2010). Assuming that the tax equity market is able to return to its former level of 2007 ($6.1 billion per year), that utilities enter the tax-equity market in force (UBS 2008), and other new tax-equity investors make significant contributions, the total size of the tax equity market could grow to about $10 billion per year in a relatively short period. However, solar energy would have to compete with other renewable energy technologies for this tax equity.

Federal benefits can be used in combination with state and local incentives, which come in many forms, including—but not limited to—up-front rebates, performance-based incentives, state tax credits, renewable energy certificate (REC) payments, property tax exemptions, and low-interest loans. Incentives at both the federal and state levels vary by sector and by whether or not the systems are utility scale or distributed. Incentive levels and eligibility also vary by type of technology.

[75] Although the accelerated 5-year tax depreciation has a present value to an investor of about 26%, only 12% of that value is from the accelerated schedule. The remaining 14% would have been realized under a conventional 20-year straight-line schedule.

[76] Offsetting income is particularly difficult for certain developers given the IRS's "passive income" rules affecting individuals, personal service corporations, and closely held corporations, which state that "passive income" can only offset "passive losses."

In most cases, solar project developers need to combine several of these federal, state, and local incentives to make projects economically viable. Given the complexity of capturing some of these incentives—particularly in combination—solar financiers have adopted (and in some cases, modified) complex ownership structures previously used to invest in other tax-advantaged sectors in the United States, such as low-income housing, historical buildings, and commercial wind projects. These financing structures—for projects on both the utility and customer sides of the meter—are described below.

Utility Side of the Meter

Although a number of utility-scale[77] CSP projects were built in California during the 1980s (and are still operating), the proliferation of large solar projects interconnected on the utility side of the meter has been a relatively recent phenomenon. Before 2010, there were only 113 megawatt (MW) direct current (MW_{DC}) of utility-scale PV capacity in the United States. In 2010, the United States installed 242 MW_{DC} of such projects. There were no CSP plants built from 1992–2006; since then, several facilities less than 10 MW alternating current (MW_{AC}) in size have been placed in service as well as a 64-MW_{AC} project in Nevada (2007) and a 75-MW_{AC} plant in Florida (2010) (SEIA/GTM Research 2011b). In most cases, these projects are owned by IPPs (in conjunction with tax equity investors), who sell the power to utilities under a long-term power purchase agreement (PPA).

Most of these projects are financed using one of the following three structures: a partnership flip, a sale/leaseback, or an inverted lease. Each of these tax-driven structures allocates the benefits of ownership among the project developer and various project investors. Solar projects can have multiple benefits: cash proceeds from the sale of power or lease of equipment to the site host, a federal ITC or cash grant, depreciation benefits, RECs, and state or local grants. Financial structures are chosen and modified to optimize each party's return, exposure to risk, and desired long-term ownership of a solar asset. Each transaction is complex and includes sophisticated structuring among the project developer, equity provider, debt provider, and sometimes even the end-users. Not surprisingly, these one-off arrangements are expensive and time consuming as they involve multiple attorneys, accountants, and other professional advisory services. This complexity results from having project developers go to great lengths to fully monetize incentives that are designed to increase the proliferation of solar projects. Wind projects, which must be structured similarly to monetize the tax credit and depreciation incentives, sacrifice approximately 40% of the value of the PTCs to use the tax capacity provided by tax equity investors (Hudson Clean Energy Partners 2009).

To date, most solar projects interconnected on the utility side of the meter have been financed by IPPs using one of the aforementioned three structures, with power sold to the utility under a long-term PPA. There are, however, some emerging issues with this IPP/PPA model. Under certain conditions, accounting principles may require the utility to essentially carry the project from which it is buying power on its balance

[77] Solar projects on the utility side of the meter are often referred to as utility-scale projects because they tend to be large (multi-megawatts) in size. However, smaller, distributed utility-scale generation—sometimes called wholesale distributed generation (DG)—often falls under the "utility side of the meter" category. In addition, utilities may explore other distributed-level opportunities in the future that are also on the utility side of the meter.

sheet as a long-term liability. This, in effect, means that the utility will be taking on risk that it cannot necessarily control. Similarly, debt-rating agencies increasingly view long-term PPAs as debt-equivalent obligations, meaning that an over-reliance on PPAs may negatively impact a utility's debt rating. Finally, with the price of solar power expected to decline rapidly in the coming years, a regulatory commission might question retroactively why a utility would have agreed to sign a PPA or even directly own a solar project at current solar power prices. As such, the risk of a retroactive disallowance of an investment in solar needs to be carefully explored with the governing regulatory commission and comfort established that the investment is prudent, regardless of the future projections of solar power prices.

Now that utilities are able to access the ITC utility ownership of solar projects interconnected on the utility side of the meter is becoming more common. There are a number of benefits and a number of challenges to utility ownership.

The largest benefit of utility ownership of solar assets is that utilities have "built-in" financing arrangements available to them through their ability to rate-base investments. This means that as long as a utility's regulatory commission supports the investment and allows the utility to participate in the generation ownership arena, the investment (plus a return on the equity invested) would be recovered through a cost-of-service revenue requirement that would be paid by all ratepayers over the life of the investment. This approach could eliminate the need to access capital markets on a project-level basis. In this model, the capital is provided through the utility's balance sheet, using traditional equity and debt instruments. A utility's investment in solar would be valued at the utility's weighted average cost of capital (WACC), which is typically significantly lower than that of an IPP. Further, a utility's rate-recovery period for investments in solar would likely be 25–30 years (i.e., based on the expected life of the asset), which is significantly longer than the 10–20-year recovery period typically seen in the IPP/PPA model. This longer financing horizon for utilities spreads out the annual revenue requirement, making the burden on customers less than through an IPP/PPA structure. An additional benefit of utility ownership is that they do not have to renegotiate contracts coming to an end with third-party generation owners; negotiating new terms, including PPA price has the potential to add costs over the life of an asset. Utilities also have a better knowledge of where the most appropriate places to site solar systems are in order to improve grid reliability and reduce grid congestion during peak hours.

However, there are two key challenges to utility ownership. First, utility regulators might not consider rate-basing of solar projects as prudent and may not approve the full value of the investment. Many utilities will not move forward without preauthorization from their regulators for owning solar assets above their utility's current avoided cost.

Second, regulations constrain how utilities are able to use the ITC. The economics of utility ownership are challenged by a regulatory measure that limits utilities' ability to pass on the full advantage of a solar project's tax benefits to their rate bases. In particular, the IRS currently requires that the benefit of the ITC to ratepayers be amortized over the life of the facility—a process called "normalization." Normalization defers the up-front tax benefit and dilutes the incentive intended under the federal tax code. Utilities cannot take the ITC without normalizing the tax benefit. Due to this normalization issue, many utilities have not purchased solar

assets. Instead, they have allowed IPP's to monetize the ITC and pass along the benefit through lower-priced electricity.

Customer Side of the Meter

Despite the increasing interest in utility-scale solar power projects (using both PV and CSP technologies), to date most solar-electric systems have been installed "behind the meter," meaning on the customer, rather than utility, side of the meter. These customer-side systems have been installed in both residential and non-residential applications and have primarily used PV technologies. Variations in tax rules between the residential and non-residential sectors, as well as varying tax status within the non-residential sector (e.g., commercial versus non-profit versus governmental) have given rise to a variety of different financing or ownership structures used in each sector or sub-sector.

Table 8-2 summarizes the principal financing options available, categorized as either self financed or third-party financed. Self-financed projects rely on some mix of equity (i.e., cash) provided and debt assumed by the site host, with the sources of that equity and debt varying considerably among the residential, non-residential taxable, and non-residential tax-exempt sectors. Prior to 2006, almost all behind-the-meter PV projects were self financed.

Table 8-2. Categorization of Financing Approaches for Behind-the-Meter PV Projects

		Residential	Non-Residential	
		Taxable	Taxable	Tax-Exempt
Self financed	Equity (Cash)	Cash savings	Balance-sheet finance	Internal funds or reserves
	Debt	Mortgage; home equity loans; property tax loans		Bank loans; muni bonds; CREBs[a]
Third-party financed	Lease	Operating lease	Operating lease	N/A
	Service contract (PPA)	Not as common as lease	More common than lease	Very common

[a] CREBs = clean renewable energy bonds.

Starting in 2006, however, third-party financing began to expand rapidly, particularly in the non-residential sector. This rapid expansion was driven in large part by an increase in the federal ITC from 10% to 30%. A 30% ITC coupled with accelerated tax depreciation was large enough to attract the attention of institutional tax equity investors, who partnered with PV project developers to offer solar leases and service contracts to mostly non-residential site hosts.

Under a solar lease, the tax equity investor, often in partnership with the project developer, owns the project and benefits from lease payments and tax benefits, while the site host makes lease payments and benefits from the power generated. Project operations may be managed by the site host or the tax equity investor, depending on local conditions. Another third-party financing mechanism is the solar service contract, which is often loosely referred to as a third-party PPA. Although the

contract itself is similar to a PPA on the utility side of the meter, on-site generation hosted by a customer entails a contract between the customer and the project owner (the utility is not involved), and it needs to be legally structured as a contract for solar services. Under this arrangement, the tax equity investor—again, often in partnership with the project developer—owns and operates the project, takes the tax benefits, and sells the energy to the site host, while the site host pays for the energy generated and uses it to displace energy that it would otherwise purchase from the utility. In either case, the goal has been to structure the lease or PPA payments such that the site host is paying no more than it would have otherwise paid to the utility, thereby making solar a budget-positive, or at least budget-neutral, proposition for the site host right from inception.

These third-party financing options have proven to be popular with site hosts for three primary reasons: 1) they reduce or eliminate the up-front cost to the host; 2) they enable full and efficient use of the federal tax incentives; and 3) system operations and maintenance are the responsibility of the third-party owner in the case of a solar service contract (and sometimes for solar leases). In the non-residential sector, PPAs have proven to be more popular than solar leases. Furthermore, for tax-exempt entities, traditional operating leases are not an option, and tax-exempt leases are not as favorable as service contracts (Bolinger 2009). Although relatively new in the residential sector, third-party financing options have recently made substantial inroads in this market segment as well, accounting for more than 20% of residential systems, and 30% of total systems, installed under the California Solar Initiative (CSI) incentives in 2010 (CSI 2011).

Financing Transmission

Transmission regulatory approvals (see Chapter 7) and cost allocation (i.e., who pays for transmission) for transmission expansion are among the most significant barriers to renewable energy development in the United States. Although there are many models for transmission cost allocation, the most common U.S. model to date requires the generator to fund transmission expansion, further explained below. However, a July 2011 federal order could change transmission cost allocation going forward, once implemented.

Under existing Federal Energy Regulatory Commission (FERC) rules for network—as opposed to radial, or one-way—transmission development or expansion, the transmission operator [typically the investor-owned utility (IOU)] can finance the transmission development itself and recover costs from ratepayers or require the generator to finance the cost for network upgrades up front. Utilities are often reluctant to finance transmission to serve renewable projects for fear that such investment would be deemed unreasonable by regulatory authorities if the generation failed to come online, potentially creating stranded costs that must be borne by their shareholders. To avoid such risks, they typically require developers to pay for all or a significant portion of the required network upgrades instead. Alternatively, developers may have to post a security deposit for the time it takes to build the new line. However, developers find it difficult to finance both a generating project and significant network upgrades. This situation has created a large logjam of generator interconnection waiting lists for transmission, known as interconnection queues.

An alternative to generator-funded cost allocation is socialization of transmission costs, i.e., distributing costs for transmission expansion and upgrades to all customers, which has had some success in enabling the financing of transmission for renewables. The reasoning is that expanding the transmission system benefits all customers by increasing competition, enhancing reliability, and providing access to renewable resources, among other benefits (Pfeifenberger et al. 2009). Within the Electric Reliability Council of Texas (ERCOT) Interconnection, these costs have been spread among all customers of all utilities for more than a decade. Transmission connecting Texas' recently created competitive renewable energy zones (CREZs) will be financed the same way.

The California Independent System Operator Corporation (CAISO) has implemented a cost-allocation model for the Tehachapi Transmission Project, which involved policymakers (CAISO and FERC) cooperating with local participants to approve a $1.8-billion transmission line that will allow about 4,500 MW of wind capacity to reach markets by 2013. This project involved up-front financing by Southern California Edison, using tariff-based cost recovery through transmission rates and pro rata fees paid by generators, with installation of the line preceding installation of the renewable generators that largely justify construction of the line (Pfeifenberger et al. 2009). Costs are spread among all generators interconnecting, but costs that are incurred prior to full subscription by generators are socialized. Similar arrangements can be contemplated for expansion of transmission for solar generating capacity.

In July 2011, FERC issued Order 1000, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities." The new order has the potential to facilitate transmission expansion as it relates to renewable energy projects in two main ways. First, local and regional transmission planning processes must consider transmission needs driven by state or federal laws or regulations [e.g., renewable portfolio standard (RPS) requirements]. Depending on how this is implemented, it could mean that utilities do not need to be concerned with regulatory stranded costs for renewable energy-specific transmission, because the FERC order could be used to prove the investment was prudent. Second, regional transmission cost allocation methods cannot require "participant funding" of transmission facilities. This could mean that generators may not be required to cover the full cost of transmission facilities. Implementation of this new FERC rule could help finance transmission for renewable energy projects going forward.

8.5.2 Emerging Solar Project Financing Structures

In addition to the more prevalent solar project financing structures described above, three emerging project financing structures have not yet been widely used to finance solar projects in practice; these include prepaid service contracts, property-assessed clean energy finance (PACE), and on-bill financing.

Prepaid Service Contract

A prepaid service contract is similar to a regular service contract (or third-party PPA) between the project owner and an offtaker (i.e., power purchaser) as described above, with one important exception: a significant portion of the power is purchased upfront, before it is delivered. This structure works well with governmental

institutions that can issue low-cost debt and use the proceeds to make an up-front payment. Because the project effectively benefits from both low-cost (and in certain cases tax-exempt) debt financing and the private sector tax benefits generated by the project, the effective cost of power under a prepaid service contract can be significantly lower than under other financing options (Bolinger 2009). Although several large wind projects built since 2007 have used prepaid service contracts, this financing structure has been slower to catch on with solar projects. In particular, it is difficult to justify the use of this rather involved and complex structure for relatively small PV projects—as opposed to larger wind projects. However, as larger PV and CSP projects, or portfolios of projects, have proliferated the prepaid service contract has begun to gain favor among developers and tax-exempt governmental offtakers.

Property-Assessed Clean Energy Finance Programs

In PACE programs, municipal financing districts lend the proceeds of bonds or other funds to property owners to finance end-user renewable energy and energy-efficiency improvements. The property owners then repay these loans over 15–20 years via annual assessments on their property tax bills. These programs offer the advantage of 100% financing with tax-deductible interest payments, as well as the loan being tied to the property rather than to the homeowner. Since the City of Berkeley, California, first announced the basic structure of its program in October 2007, PACE programs have spread rapidly across the country; 27 states and Washington DC have authorized PACE financing policies thus far (DSIRE 2011). Residential PACE programs hit a significant roadblock in mid-2010, however, when Fannie Mae and Freddie Mac, which underwrite a significant portion of home mortgages, determined that they would not purchase mortgages with PACE loans because PACE loans, like all other property tax assessments, are written as senior liens.[78] These issues are still being resolved, and while it is not yet known whether or how residential programs will move forward, PACE assessments remain a viable option in the commercial space. As of March 2011, there were four commercial PACE programs in operation, which had approved $9.69 million in funding for 71 projects, many of which were PV. There were also nine commercial programs in formal planning stages, and at least seven in preliminary planning stages (LBNL 2011).

On-Bill Financing

On-bill financing is a relatively new form of financing that combines a state subsidy, such as an up-front rebate or interest rate buy-down, with a loan from the electric utility. The goal is to reduce or eliminate the up-front cost of the project to the customer by financing all of the costs not covered through rebates with an on-bill adder. The loan payments are made over a period that is long enough—and with a low-enough interest rate—to create cost savings from the first day (Brown 2009b). This mechanism has been used only for energy efficiency and there are not any

[78] On July 6, 2010 the Federal Housing Finance Agency (FHFA), which regulates Fannie Mae, Freddie Mac, and the 12 Federal Home Loan Banks, issued a statement determining that PACE loans "present significant safety and soundness concerns" and called for a halt in PACE programs for these concerns to be addressed. FHFA determined that, "the size and duration of PACE loans exceed typical local tax programs and do not have the traditional community benefits associated with taxing initiatives" (FHFA 2010). Because Fannie Mae and Freddie Mac do not consider PACE loans to conform with traditional taxing initiatives, they are not interested in purchasing mortgages on homes with PACE liens. Certain PACE programs are attempting to solve the problem by setting up programs as second-tier liens.

known applications for solar; however, legislation was introduced (and failed to pass) in Hawaii, directing public utilities to implement on-bill financing for solar technologies (Brown 2009a). Despite the advantages of on-bill loans, this type of financing mechanism faces a number of implementation challenges (Brown 2009b): the need for a sizable amount of initial capital to fund the revolving loan, concern about the potential for defaults, uncertainty about how utilities will be regulated with respect to providing a loan versus a financing product, and the need to update utility billing systems to allow for automated and electronic management of on-bill loans.

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Appendix A. Model Descriptions

A.1 Modeling Overview

There were three primary models used in this study: the Regional Energy Deployment System (ReEDS) model (Short et al. 2011), the Solar Deployment System (SolarDS) model (Denholm et al. 2009), and the GridView model (ABB 2008). ReEDS uses regional cost and performance characteristics of the major electricity generation and storage technologies throughout the contiguous United States, regional resource limitations, and electricity demand and grid reliability requirements to select the cost-optimal regional deployment of technologies. Additionally, ReEDS optimizes transmission capacity expansion to accommodate the regional deployment of technologies. Through this economic optimization, ReEDS examines one possible set of impacts on the U.S. electric sector resulting from achieving the SunShot price targets. Major impacts include regional solar deployment levels, additional transmission capacity expansion requirements, additional firm and flexible resource requirements, emissions reductions, and electricity price and overall system cost impacts.

Because ReEDS is not designed to account for distributed rooftop photovoltaic (PV) generation, the penetration of distributed (residential and commercial) PV capacity is exogenously input into ReEDS from the SolarDS model. SolarDS is a market penetration model for commercial and residential rooftop PV, which takes as input regional electricity prices, financial incentives, regional solar resource quality, and rooftop availability.

Finally, the GridView model is used to determine the feasibility of operation of the systems projected by the ReEDS model by performing hourly simulations of the ReEDS system, subject to more rigorous treatment of power-flow transmission constraints than can be captured by ReEDS.

A.2 Regional Energy Deployment System

ReEDS is a generation and transmission capacity expansion model of the electricity system of the contiguous United States. ReEDS is unique among capacity expansion models for its highly discretized regional structure and detailed statistical treatment of the impact of variability of wind and solar resources on capacity planning, operating reserve requirements, and curtailment levels.

More specifically, ReEDS is a linear program that minimizes overall electric system cost subject to a large number of constraints. The major constraints include meeting electricity demand and reserve requirements within specific regions, regional resource supply limitations, state and federal policy demands, technology growth

constraints, and transmission constraints. In satisfying these constraints in a least cost manner, the ReEDS optimization routine chooses from a broad portfolio of conventional generation, renewable generation, and storage technologies, as well as demand-side management, and the routine simultaneously optimizes technology capacity expansion, generator dispatch, and transmission capacity expansion. In the optimization, ReEDS considers the present value cost of its investment and operation decisions over an assumed financial lifetime (20 years for the present study). This cost minimization routine is applied for each 2-year period through 2050.

ReEDS represents the contiguous United States using 356 concentrating solar power (CSP)/wind resource regions and 134 power control areas (PCAs). This level of geographic detail enables the model to account for geospatial differences in resource quality, transmission needs, electrical (grid-related) boundaries, and political boundaries. ReEDS dispatches generation within 17 different time slices, including four time slices for each season representing morning, afternoon, evening, and nighttime, with an additional summer-peak time slice. This level of temporal detail—though not as sophisticated as an hourly chronological dispatch model—enables ReEDS to consider seasonal and diurnal changes in demand and resource availability. Moreover, because there are still significant demand and resource variations that can occur within each of these time slices, ReEDS utilizes statistical calculations derived from hourly data to estimate the capacity value, operating reserve requirements, and curtailment of variable wind and solar resources; these calculations also consider the correlations of hourly output profiles between resources in different locations. These measures are used to help ensure that the results that ReEDS provides are as geographically and temporally detailed as computational constraints allow, while also being consistent with an electricity system that is able to maintain an overall balance between supply and demand.

Major outputs of ReEDS are the regional deployment and dispatch of generator technologies, regional transmission capacity expansion, and power transfers between regions in the 17 different time slices. ReEDS also calculates the impacts of each scenario, including the total electric-sector cost, electricity price, fuel use and price, and direct combustion carbon dioxide (CO_2) emissions.

Additional detail for ReEDS can be found in the ReEDS model documentation (Short et al. 2011). Note that certain assumptions cited in the model documentation are different than those used in the SunShot study.

A.2.1 ReEDS Calculations

The cost-minimization routine in ReEDS is performed from 2006 to 2050 in 2-year steps (i.e., every 2 years). The equations below provide a simple representation of the ReEDS model for a single year's cost-minimization solve. ReEDS minimizes the total system cost ("*Total_Cost*") of meeting all of the constraints of the system by choosing the cost-optimal values of each of the variables (shown in all caps), including new generation capacity, time-slice-dependent electricity generation, and transmission capacity. After each modeled year's solve, ReEDS updates values—such as existing capacity of each technology ("*old_cap*") and costs and performances of new technologies—and continues on to the next year's solve. In the following equations, "*old"* refers to technologies or transmission that are already in

existence at the time of the current solve year, and "*new*" refers to potential new technology or transmission builds. Below the listing of equations are definitions of the sets (subscripts), parameters (constants), and variables shown in the equations.

Additional features in ReEDS not shown here include minimum loading requirements and planned and forced outages for dispatchable technologies, curtailment from renewable and must-run technologies, different types of operating reserves, renewable supply curves and resource constraints, and contracts of variable renewable power. In addition, this representation does not show the often non-linear calculations that occur between the model year solves. These and other features of ReEDS are discussed elsewhere in this appendix and in the ReEDS documentation (Short et al. 2011).

A.2.1.1 Objective Function [*Total_Cost* ($))]

The objective of each ReEDS solve is to minimize total cost of the system while abiding by all constraints. The total cost consists of fixed costs for new technologies, variable costs for all technologies, and transmission costs for new transmission builds. These costs represent the 20-year present value of a stream of costs. The following is the objective function:

$$
\begin{aligned}
Total_Cost \;=\; \min\Bigg[& \sum_{tech,reg} [NEW_CAP_{tech,reg} \times new_fix_cost_{tech,reg}] \\
& + \sum_{tech,reg,ts} [NEW_ELEC_GEN_{tech,reg,ts} \times (new_var_om_{tech} \\
& + fuel_{tech,reg}) \times hrs_{ts} + OLD_ELEC_GEN_{tech,reg,ts} \\
& \times (old_var_om_{tech} + fuel_{tech,reg}) \times hrs_{ts}] \\
& + \sum_{reg,reg'} [NEW_TRANS_CAP_{reg,reg'} \times new_trans_cost_{reg,reg'}] \Bigg]
\end{aligned}
$$

A.2.1.2 Constraints

ReEDS minimizes overall electric system cost subject to a large number of constraints. Equations for major constraints are shown below.

***Electricity_Demand*$_{reg,ts}$** (MW): In each region in each time slice, electricity generation from all technologies plus electricity imports minus electricity exports must be greater than demand for electricity. ReEDS reduces the contribution of electricity from each technology by the amount of curtailments that that technology induces in the system, although this has been left out of the equations below for simplicity. Curtailments are discussed in Section A.2.7.1.

$$
\begin{aligned}
\boldsymbol{Electricity_Demand_{reg,ts}}: & \sum_{dtech} [NEW_ELEC_GEN_{dtech,reg,ts} + OLD_ELEC_GEN_{dtech,reg,ts}] \\
& + \sum_{ndtech} [NEW_CAP_{ndtech,reg} \times new_cf_{ndtech,reg,ts} + old_cap_{ndtech,reg} \\
& \times old_cf_{ndtech,reg,ts}] + \sum_{reg'} [ELEC_TRANS_{reg',reg,ts}] \;> elec_demand_{reg,ts}
\end{aligned}
$$

Planning_Reserves$_{reg,ts}$ (MW): In each region in each time slice, firm capacity provided by all technologies plus firm capacity imports minus firm capacity exports must be greater than the planning reserve margin times peak demand. Dispatchable technologies contribute full nameplate capacity toward firm capacity, whereas non-dispatchable technologies contribute only a fraction of nameplate capacity (i.e., capacity value).

$$\boldsymbol{Planning_Reserves_{reg,ts}}: \sum_{dtech} [NEW_CAP_{dtech,reg} + old_cap_{dtech,reg}] + \sum_{ndtech} [NEW_CAP_{ndtech,reg} \times new_cv_{ndtech,reg,ts} + old_cap_{ndtech,reg} \times old_cv_{ndtech,reg,ts}] + \sum_{reg'} [CAP_TRANS_{reg',reg}] > peak_demand_{reg,ts} \times plan_res_marg_{reg}$$

Operating_Reserves$_{reg,ts}$ (MW): In each region in each time slice, the operating reserves provided by all technologies must exceed the operating reserve requirements. In ReEDS, there are multiple types of operating reserve requirements, as well as different types of operating reserves (e.g., quick-start or spinning), with each requirement having specific requirements for the type of operating reserves that can be used. Operating reserves are discussed in Section A.2.7.3.

$$\boldsymbol{Operating_Reserves_{reg,ts}}: \sum_{dtech} [NEW_RES_CAP_{dtech,reg,ts} + OLD_RES_CAP_{dtech,reg,ts}] > oper_res_req_{reg,ts}$$

Capacity_Use_Old$_{dtech,reg,ts}$ (MW): Existing dispatchable electricity generators in each region and time slice must divide their electricity generation capacity into either providing electricity generation or providing operating reserves. In ReEDS, there are additional restrictions on the ability of dispatchable generators to provide operating reserves, depending on the level of flexibility of those generators.

$$\boldsymbol{Capacity_Use_Old_{dtech,reg,ts}}: old_cap_{dtech,reg} > OLD_ELEC_GEN_{dtech,reg,ts} + OLD_RES_CAP_{dtech,reg,ts}$$

Capacity_Use_New$_{dtech,reg,ts}$ (MW): New dispatchable electricity generators in each region and time slice must divide their electricity generation capacity into either providing electricity generation or providing operating reserves. In ReEDS, there are additional restrictions on the ability of dispatchable generators to provide operating reserves, depending on the level of flexibility of those generators.

$$\boldsymbol{Capacity_Use_New_{dtech,reg,ts}}: NEW_CAP_{dtech,reg} > NEW_ELEC_GEN_{dtech,reg,ts} + NEW_RES_CAP_{dtech,reg,ts}$$

Transmission_Capacity_1$_{reg,reg',ts}$ (MW): Installed existing and new transmission capacity must exceed the power that is transferred between regions in each time slice.

$$\boldsymbol{Transmission_Capacity_1_{reg,reg',ts}}: NEW_TRANS_CAP_{reg,reg'} + old_trans_cap_{reg,reg'} > ELEC_TRANS_{reg,reg',ts}$$

Transmission_Capacity_2$_{reg,reg'}$ (MW): Installed existing and new transmission capacity must exceed the capacity that is contracted between regions. These capacity contracts are annual, so they do not depend on time slice.

$$\boldsymbol{Transmission_Capacity_2_{reg,reg'}}: NEW_TRANS_CAP_{reg,reg'} + old_trans_cap_{reg,reg'} > CAP_TRANS_{reg,reg'}$$

A.2.1.3 Sets (subscripts)

The following are descriptions of the sets in the ReEDS equations, which appear as subscripts in the equations.

reg, reg': Regions. ReEDS has various levels of regional disaggregation, discussed in Section A.2.2.

ts: Time slices. ReEDS has 17 time slices in each year, discussed in Section A.2.3.

tech: The set of all electricity generation technologies including storage. For ReEDS, these are discussed in Section A.2.4.

dtech: Dispatchable technologies such as coal, nuclear, natural gas, and storage.

ndtech: Non-dispatchable technologies such as wind and PV.

A.2.1.4 Parameters (constants)

The following are descriptions of the parameters or constants that appear in the ReEDS equations.

old_cap$_{tech,reg}$ (MW): Electricity generation capacity of each technology in each region that is already in existence at the start of the solve year.

old_cf$_{ndtech,reg,ts}$ (dimensionless): Average capacity factor for each existing non-dispatchable technology in each time slice in each region.

new_cf$_{ndtech,reg,ts}$ (dimensionless): Average capacity factor for new potential capacity of each non-dispatchable technology in each time slice in each region.

elec_demand$_{reg,ts}$ (MW): Average electricity demand in each time slice in each region.

old_cv$_{ndtech,reg,ts}$ (dimensionless): Average capacity value of existing capacity for each non-dispatchable technology in each time slice in each region. Capacity values of non-dispatchable technologies are limited by time-slice-dependent capacity factors and variability.

new_cv$_{ndtech,reg,ts}$ (dimensionless): Average capacity value of new potential capacity for each non-dispatchable technology in each time slice in each region. Capacity values of non-dispatchable technologies are limited by time-slice-dependent capacity factors and variability.

peak_demand$_{reg,ts}$ (MW): Peak simultaneous electricity demand in each time slice in each region.

plan_res_marg$_{reg}$ (dimensionless): Planning reserve margin in each region.

oper_res_req$_{reg,ts}$ (MW): Operating reserve margin requirement in each region in each time slice. In ReEDS, there are multiple types of operating reserve requirements that must be satisfied, discussed in Section A.2.7.3.

old_trans_cap$_{reg,reg'}$ (MW): Existing transmission capacity connecting each region to neighboring regions.

new_fix_cost$_{tech,reg}$ ($/MW): Fixed costs associated with potential new electricity generation capacity of each technology in each time slice. This includes capital costs as well as fixed operation and maintenance (O&M) costs.

old_var_om$_{tech}$ ($/MWh): Variable costs associated with electricity generation from existing capacity. This includes variable O&M costs.

new_var_om$_{tech}$ ($/MWh): Variable costs associated with electricity generation from new potential capacity. This includes variable O&M costs.

fuel$_{tech,reg}$ ($/MWh): Cost of fuel associated with electricity generation from a specific technology in a given region. Fuel costs depend on technology-specific heat rates and regional fuel prices.

hrs$_{ts}$ (hrs): The hours contained in each time slice.

new_trans_cost$_{reg,reg'}$ ($/MW): Cost of new transmission connecting each region to its neighboring regions. This depends on regional differences in cost of transmission and differences in the distances between center-points of the regions.

A.2.1.5 Variables

The following are descriptions of the variables that appear in the ReEDS equations.

NEW_ELEC_GEN$_{tech,reg,ts}$ (MW): Average electricity generation from new technologies in each region in each time slice.

OLD_ELEC_GEN$_{tech,reg,ts}$ (MW): Average electricity generation from existing technologies in each region in each time slice.

NEW_CAP$_{tech,reg}$ (MW): New electricity generation capacity of each technology in each region.

ELEC_TRANS$_{reg,reg',ts}$ (MW): Average net electricity transmitted from each region, *reg*, to each neighboring region, *reg'*, in each time slice. A negative value of this would indicate that electricity is being transmitted on average from *reg'* to *reg*.

CAP_TRANS$_{reg,reg'}$ (MW): Firm capacity contracts from *reg* to *reg'*.

NEW_RES_CAP$_{dtech,reg,ts}$ (MW): Electricity generation capacity from new dispatchable technologies that has been committed to providing operating reserves in each region in each time slice.

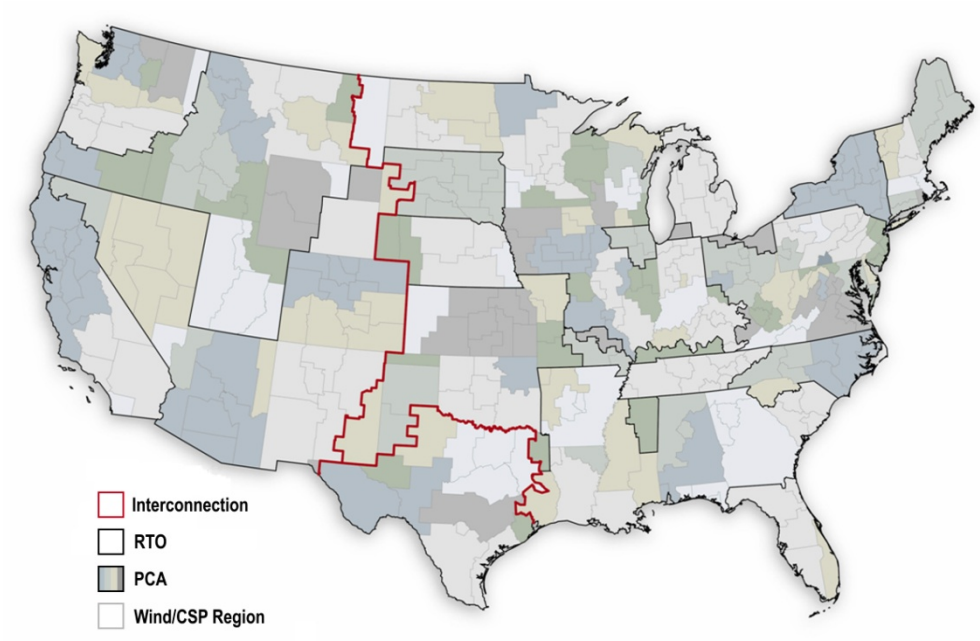
OLD_RES_CAP$_{dtech,reg,ts}$ (MW): Electricity generation capacity from existing dispatchable technologies that has been committed to providing operating reserves in each region in each time slice.

NEW_TRANS_CAP$_{reg,reg'}$ (MW): New transmission capacity built between each region, *reg*, and each neighboring region, *reg'*.

A.2.2 ReEDS Regions

The geographical scope of the ReEDS model covers the contiguous United States. There are five types of regions included in ReEDS, listed below. Each type of region has various functions, and major examples of these functions are given in the list. A map of selected region types is shown in Figure A-1.

Figure A-1. ReEDS CSP/Wind Regions, PCA Regions, Regional Transmission Organization (RTO) Regions, and Interconnection Regions



- *CSP/wind resource regions*. There are 356 CSP/wind resource regions. This is the level at which CSP and wind capacity expansion occur, CSP and wind resource availability and quality are evaluated, and wind and CSP resources

have access to local demand centers and transmission lines. CSP/wind resource regions are bounded by gray lines in Figure A-1.

- *PCAs.* There are 134 PCAs. This is the regional level at which electric power demand and reserve margin requirements must be satisfied, and at which all non-wind/CSP technology capacity expansion occurs, including PV expansion. Furthermore, the national transmission grid is represented in ReEDS as connections between the PCAs. PCA boundaries reflect electrical (grid-related) boundaries, political and jurisdictional boundaries, and demographic distributions.[79] The PCAs are shown in Figure A-1 as color shaded groups of CSP/wind resource regions.
- *Regional Transmission Organization (RTO) regions.* There are 21 RTOs. This is the regional level at which operating reserve requirements must be met, and the level at which capacity value and curtailment of variable renewable power is calculated. Figure A-1 shows the different RTOs assumed for the present study. Some of the model RTOs include existing RTOs[80] and others (particularly those in the western states) are assumed for modeling purposes based on current transmission plans.
- *North American Electric Reliability Corporation (NERC) regions*. There are 13 NERC regions/subregions (not shown in figure). Generally, inputs to the model from the U.S. Energy Information Administration (EIA) and the National Energy Modeling System (NEMS) model are provided at the NERC subregional level. These inputs include fuel prices and demand profiles over time.
- *Interconnection regions.* There are three asynchronous interconnections in the United States: the Eastern Interconnection, Western Interconnection, and Electric Reliability Council of Texas (ERCOT) Interconnection. Due to the asynchronicity of the three interconnections, new transmission lines across interconnection boundaries require installations of new alternating current (AC)-direct current (DC)-AC intertie capacity (and their associated costs). Interconnection boundaries are shown in Figure A-1 by the solid red lines.

A.2.3 ReEDS Time Slices

ReEDS represents seasonal and diurnal variations in demand and non-dispatchable generator output profiles via 17 time slices, shown in Table A-1. There are four time slices in each of the four different seasons,[81] as well as a "peak" time slice in the summer. In ReEDS, dispatch of dispatchable generators is optimized to satisfy demand and operating reserve requirements in each of these time slices. Variability of electrical generation and demand is characterized within each time slice as well to calculate capacity value, curtailment levels, and additional operating reserve

[79] Although existing boundaries for Balancing Authority Areas (BA Areas) are considered in the design of the power control areas (PCAs), the PCA boundaries are generally not aligned with the boundaries of real BA Areas.
[80] Examples of existing Regional Transmission Organizations (RTOs) include Midwest Independent Transmission System Operator (MISO), Independent System Operator New England (ISO-NE), PJM Interconnection LLC (PJM), Southwest Power Pool (SPP), and California Independent System Operator Corporation (CAISO).
[81] The seasons are defined based on the following definitions: Summer = June, July, and August; Fall = September and October; Winter = November, December, January, and February; Spring = March, April, and May.

Table A-1. ReEDS Time Slice Definitions

Slice Name	Number of Hours Per Year	Season	Time Period
H1	736	Summer	10:00 p.m. to 6:00 a.m.
H2	644	Summer	6:00 a.m. to 1:00 p.m.
H3	328	Summer	1:00 p.m. to 5:00 p.m.
H4	460	Summer	5:00 p.m. to 10:00 p.m.
H5	488	Fall	10:00 p.m. to 6:00 a.m.
H6	427	Fall	6:00 a.m. to 1:00 p.m.
H7	244	Fall	1:00 p.m. to 5:00 p.m.
H8	305	Fall	5:00 p.m. to 10:00 p.m.
H9	960	Winter	10:00 p.m. to 6:00 a.m.
H10	840	Winter	6:00 a.m. to 1:00 p.m.
H11	480	Winter	1:00 p.m. to 5:00 p.m.
H12	600	Winter	5:00 p.m. to 10:00 p.m.
H13	736	Spring	10:00 p.m. to 6:00 a.m.
H14	644	Spring	6:00 a.m. to 1:00 p.m.
H15	368	Spring	1:00 p.m. to 5:00 p.m.
H16	460	Spring	5:00 p.m. to 10:00 p.m.
H17	40	Summer Peak	40 highest demand hours of summer 1:00 p.m. to 5:00 p.m.

requirements from variable energy resource (VER) technologies. For more detail, see Section 0.

A.2.4 ReEDS Technologies

This section describes each ReEDS technology considered in this study, and provides tables of major cost and performance characteristics.

A.2.4.1 Photovoltaics

There are three PV technologies modeled in ReEDS:

- Central PV
- Distributed utility-scale PV
- Distributed rooftop PV.

All PV technologies are sited at the PCA regional level in ReEDS. Central PV and distributed utility-scale PV are both handled endogenously in ReEDS, whereas distributed rooftop PV capacity projections are developed by the SolarDS model and are passed exogenously into ReEDS at the PCA level. Capacity factors of distributed rooftop PV in each ReEDS time slice reflect the mix of orientations built in SolarDS within each ReEDS PCA by 2050. See Section A.3 for more information on the SolarDS model.

Central PV and distributed utility-scale PV are described separately in the following sub-sections.

A.2.4.1.1 Central PV

Central PV in ReEDS represents utility-scale 1-axis-tracking systems with a representative size of 100 megawatts (MW). Costs for central PV in the SunShot and reference scenarios are shown in Table A-2. Costs for the SunShot scenario are discussed in greater detail in Chapter 4 of this report, while costs for the reference scenario were developed by Black & Veatch (forthcoming). In addition, central PV is assumed, upon installation, to have a grid connection cost of $120/kilowatt (kW).

Table A-2. Central PV Technology Cost Projections (2010$)

Install Year	SunShot Central PV Costs			Reference Central PV Costs		
	Capital	Fixed O&M	Variable O&M	Capital	Fixed O&M	Variable O&M
	$/kW [a]	$/kW/yr	$/MWh	$/kW	$/kW/yr	$/MWh
2010	4,000	20	0	4,000	51	0
2015	2,200	15	0	2,700	49	0
2020	1,000	7	0	2,500	46	0
2025	1,000	7	0	2,400	44	0
2030	1,000	7	0	2,400	42	0
2035	1,000	7	0	2,300	40	0
2040	1,000	7	0	2,200	38	0
2045	1,000	7	0	2,100	36	0
2050	1,000	7	0	2,100	34	0

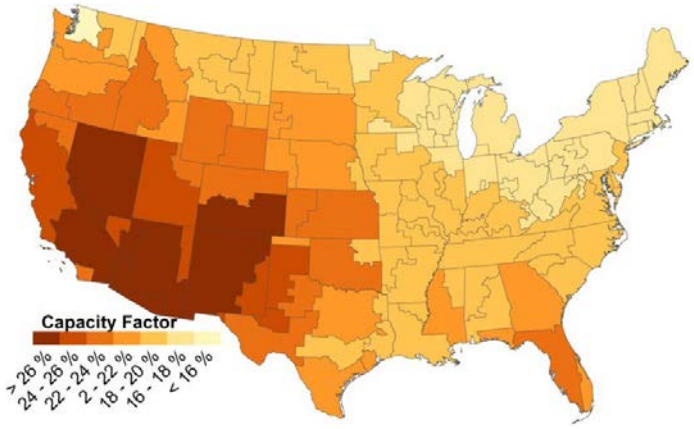
O&M: operation and maintenance; kW: kilowatt; yr: year; Mwh: megawatt-hour

[a] The 2010 capital costs for utility-scale (central) PV were originally entered in 2009 dollars. In the final run on which this report is based, the 2010 capital costs for utility-scale PV were adjusted to 2010 dollars, i.e., $4,100/kilowatt (kW). A subsequent model run using the values included in this table indicated that this adjustment did not change the results substantially, i.e., less than 1%.

Performance characteristics for central PV were developed with the System Advisor Model (SAM) (NREL 2010a) using annual hourly weather files from the National Solar Radiation Database (NSRDB) for 939 sites throughout the contiguous United States from 1998 to 2005 (NREL 2007). For each site, generation profiles were averaged across the 8-year time period. The site with the highest average annual PV capacity factor[82] in each PCA was used to represent the performance (i.e., capacity factor in each time slice) of central PV capacity installed in that area. A map of the resulting annual capacity factors for central PV by PCA is shown in Figure A-2.

[82] Capacity factors are defined as the ratio of electrical energy generated by a unit over a given period of time divided by the maximum amount of electrical energy that could have been produced by the same unit if it were operated at maximum capacity. Annual PV capacity factors represent the average annual alternating current (AC) electrical power [megawatt (MW)] generated by a given unit of direct current (DC)-rated PV capacity (MW). Annual concentrating solar power (CSP) capacity factors represent the average annual AC electrical power (MW) generated by a given unit of AC-rated CSP capacity (MW).

Figure A-2. Central PV Capacity Factors



A.2.4.1.2 Distributed Utility-Scale PV

Distributed utility-scale PV in ReEDS represents utility-scale 1-axis-tracking systems with a representative size of 1–20 MW located within and directly connected to distribution networks. Capacity of these systems is limited to less than 15% of the distribution network capacity.[83] Capital costs for distributed utility-scale PV (Table A-3) are assumed to be about 8.5% higher than central PV costs.

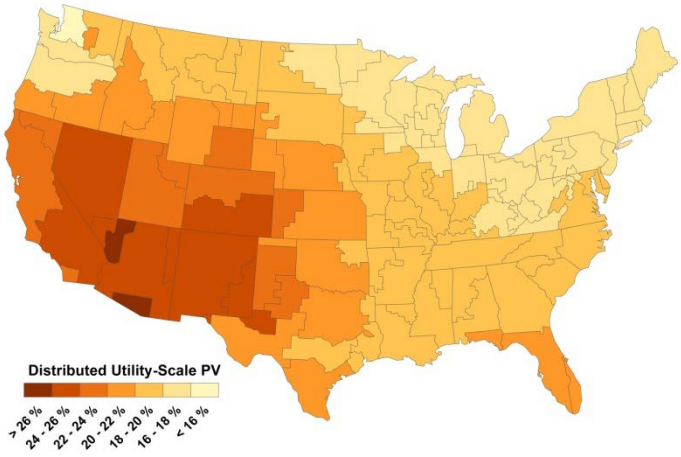
Table A-3. Distributed Utility-Scale PV Technology Cost Projections (2010$)

Install Year	SunShot Distributed Utility-Scale PV Costs			Reference Distributed Utility-Scale PV Costs		
	Capital	Fixed O&M	Variable O&M	Capital	Fixed O&M	Variable O&M
	$/kW	$/kW/yr	$/MWh	$/kW	$/kW/yr	$/MWh
2010	4,400	20	0	4,400	51	0
2015	2,400	15	0	2,900	49	0
2020	1,100	7	0	2,800	46	0
2025	1,100	7	0	2,700	44	0
2030	1,100	7	0	2,600	42	0
2035	1,100	7	0	2,500	40	0
2040	1,100	7	0	2,400	38	0
2045	1,100	7	0	2,300	36	0
2050	1,100	7	0	2,200	34	0

Similar to central PV, performance characteristics for distributed utility-scale PV were developed using SAM, except the performance in each PCA used the average PV power output across all NSRDB sites within that PCA. The reason for this difference in approach is that distributed utility-scale PV is limited to distribution centers, and therefore siting options are more limited than for central PV. Regional

[83] Distribution network capacity is tracked at the power control area (PCA) regional level in ReEDS.

Figure A-3. Distributed Utility-Scale PV Capacity Factors



capacity factors for distributed utility-scale PV are similar to central PV but consequently reduced, as shown in Figure A-3. However, ReEDS assumes all electric power generated by distributed PV (both rooftop and distributed utility-scale) systems is effectively consumed within the distribution networks and does not incur transmission and distribution (T&D) losses.

A.2.4.2 Concentrating Solar Power

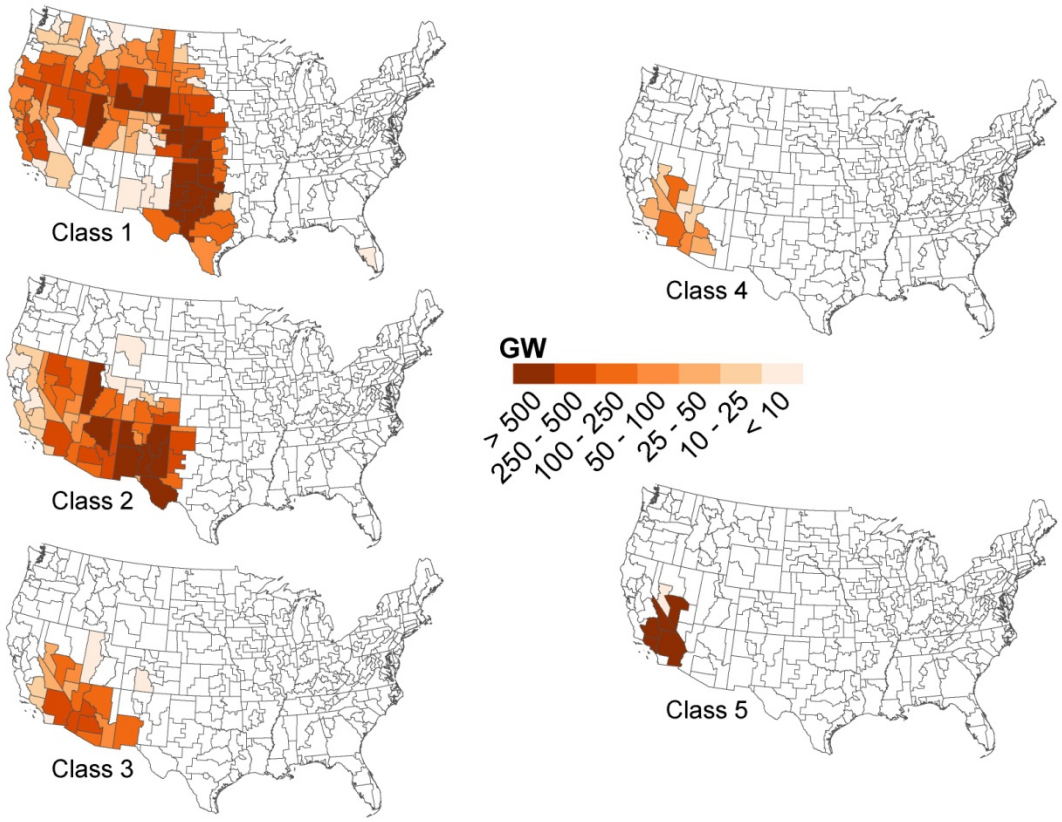
There are two main CSP technologies modeled in ReEDS: CSP without thermal energy storage (TES), and CSP with at least 6 hours of TES, each described in the following sections. Both technologies rely on the same resource, which is divided into five resource classes based on direct-normal irradiance (DNI):

- Class 1: 5–6.25 kilowatt-hours (kWh)/square meter (m^2)/day
- Class 2: 6.25–7.25 kWh/m^2/day
- Class 3: 7.25–7.5 kWh/m^2/day
- Class 4: 7.5–7.75 kWh/m^2/day
- Class 5: > 7.75 kWh/m^2/day.

Figure A-4 shows the CSP resource available at each wind/CSP resource region[84] assuming a solar multiple[85] of two. Since only regions with DNI greater than 5 kWh/m^2/day are considered, CSP resource is predominantly found in the western states. In addition to DNI, available land area and slope also limits the available CSP resource. In particular, regions having a slope greater than 3% are excluded. The available land area for each CSP resource class is converted into gigawatts (GW) of available capacity assuming a plant density of 31 MW/square kilometer (km^2) for a system with a solar multiple of two. Plant density for systems with other solar

[84] Note that although the resource is quantified at the 356 CSP/wind region level, only CSP without thermal energy storage (TES) is located at this level. CSP with TES is located at the 134 PCA region level.
[85] Solar multiple is defined as the ratio of the power capacity of the collection field to the capacity of the power block. For CSP systems with storage, the number of hours of storage is based on the capacity of the power block.

Figure A-4. CSP Available Resource by Class (for Solar Multiples of Two)



multiples is assumed to scale inversely with solar multiple. As an example, a CSP system with a solar multiple of one would be assumed to have a plant density of 62 MW/km^2, or twice that of a system with a solar multiple of two.

CSP performance for each CSP resource class was developed using typical DNI year (TDY) hourly resource data (NREL 2010b) from representative sites of each CSP/wind resource region. The TDY weather files were processed through the CSP modules of SAM (NREL 2010a) for each type of CSP system considered in ReEDS. Performance characteristics for each CSP system are explained in more detail in Section A.2.4.2.1 and A.2.4.2.2.

In addition to the capital and O&M costs discussed in the following sub-sections, a supply curve representing the cost of connecting individual CSP sites to the existing grid as well as to local demand centers was developed based on a geographic information system (GIS) database of the resource, existing grid,[86] and loads. A similar supply curve was developed for wind. In addition to the transmission costs associated with the supply curves, a $120/kW fee for connection to the grid is applied to new CSP plants in ReEDS.

[86] Ten percent of the total carrying capacity of each transmission line was assumed to be available for CSP spur lines.

A.2.4.2.1 CSP without Storage

The CSP system without TES in ReEDS is represented as a dry-cooled trough plant with a solar multiple of 1.4. Cost projections were developed by Black & Veatch (forthcoming) and are shown in Table A-4. Note that CSP without TES was not modeled with different costs for the SunShot and reference scenarios, as SunShot costs were only used for CSP with TES.

Table A-4. CSP without TES Technology Cost Projections (2010$)

Install Year	Capital $/kW	Fixed O&M $/kW/yr	Variable O&M $/MWh
2010	5,000	50	0
2015	4,800	50	0
2020	4,600	50	0
2025	4,400	50	0
2030	4,200	50	0
2035	4,100	50	0
2040	3,900	50	0
2045	3,700	50	0
2050	3,500	50	0

Performance characteristics (i.e., capacity factors in each time slice) for CSP without TES of each resource class were developed with the CSP module of SAM, configured with a dry-cooled 100-MW turbine and solar multiple of 1.4, using the weather TDY files located at representative sites of each resource class. The average annual capacity factors of each class are shown inTable A-5.

Table A-5. CSP without TES Average Annual Capacity Factors for Each Class

CSP Class	Average Capacity Factor
1	0.20
2	0.25
3	0.28
4	0.28
5	0.29

A.2.4.2.2 CSP with Storage

ReEDS considers CSP systems with TES to have at least 6 hours of storage, for which ReEDS assumes full capacity credit valuations. Although a mix of trough and tower technologies are expected to be built throughout the timeframe of the study, for modeling simplicity ReEDS assumes cost and performance characteristics of towers for the current study. The towers are assumed to be dry-cooled.

In ReEDS, CSP systems with TES are represented by three separate components: the field (collectors), storage, and turbine (power block). The model is allowed to choose solar multiples and amounts of storage, within boundaries discussed later in

this section. Greater solar multiples result in higher capacity factors, and greater amounts of storage allow the systems to be more flexible, although both increase capital costs per kilowatt of installed turbine capacity. Average costs for CSP systems with TES in the SunShot and reference scenarios are shown in Table A-6, and average annual capacity factors are shown in Table A-7 for each resource class. The costs and performance characteristics represent systems with a solar multiple of 2.5 and 11 hours of storage, which are the average characteristics for systems built by 2050 in the SunShot scenario. SunShot costs are described in more detail in Chapter 5, while reference costs were developed by Black & Veatch (forthcoming). SunShot costs and performance characteristics shown here will deviate slightly from those in Chapter 5 of the report, as the systems have slightly different configurations.

Table A-6. CSP with 11 Hours of TES Base Characteristics and Costs (2010$)

	SunShot CSP with TES Costs			Reference CSP with TES Costs		
Install Year	Capital	Fixed O&M	Variable O&M	Capital	Fixed O&M	Variable O&M
	$/kW	$/kW/yr	$/MWh	$/kW	$/kW/yr	$/MWh
2010	9,200	75	3	9,200	49	0
2015	7,900	60	3	8,800	49	0
2020	3,400	45	3	8,500	49	0
2025	3,400	45	3	7,500	49	0
2030	3,400	45	3	6,700	49	0
2035	3,400	45	3	5,900	49	0
2040	3,400	45	3	5,900	49	0
2045	3,400	45	3	5,900	49	0
2050	3,400	45	3	5,900	49	0

Table A-7. Average Annual Capacity Factors for CSP Systems with 11 Hours of TES

CSP Resource Class	Average Capacity Factor
1	0.45
2	0.54
3	0.59
4	0.60
5	0.62

CSP systems with TES are assumed to be fully dispatchable within the energy limitations imposed by the time-profile of the solar insolation, solar multiple, and hours of thermal storage. Because of this, capacity factors by time slice of CSP with TES are an output of the model, not an input. Instead, the profile of power input from the solar field of the CSP plants are model inputs, based on SAM simulations from the TDY weather files that span the range of solar multiples allowed in ReEDS.

While solar multiple and hours of storage are allowed to be system-specific in ReEDS, the system configurations must abide by certain restrictions. First, to ensure that these systems are capable of providing firm capacity to the system during peak demand periods, they are restricted to have at least a capacity factor of 40% in addition to the minimum 6 hours of storage. These systems are also restricted to capacity factors of less than 65% and solar multiples of less than 2.5 to limit curtailment effects that become significant at these higher solar multiples. In addition, prescribed amounts of storage as a function of solar multiple were developed using SAM, as the broad time slices and typical-day profiles in ReEDS disallow it from fully capturing the amount of storage required for a given plant performance. For towers, at the highest allowed solar multiple of 2.5, a minimum of 11.25 hours of storage is required.

A.2.4.3 Wind

ReEDS considers five resource classes of wind, shown in Table A-8, based on wind power density and wind speed at 50 meters above ground. Available land area of each wind class in each CSP/wind resource region is derived from state wind resource maps and modified for environmental and land-use exclusions. The available wind area is converted to available wind capacity using the constant multiplier of 5 MW/km^2. Available wind capacity is shown in Figure A-5. The colored areas just outside of the coastal regions represent offshore wind.

Table A-8. Classes of Wind Power Density

Wind Class	Wind Power Density, W/m^2	Speed, M/s
3	300–400	6.4–7.0
4	400–500	7.0–7.5
5	500–600	7.5–8.0
6	600–800	8.0–8.8
7	>800	>8.8

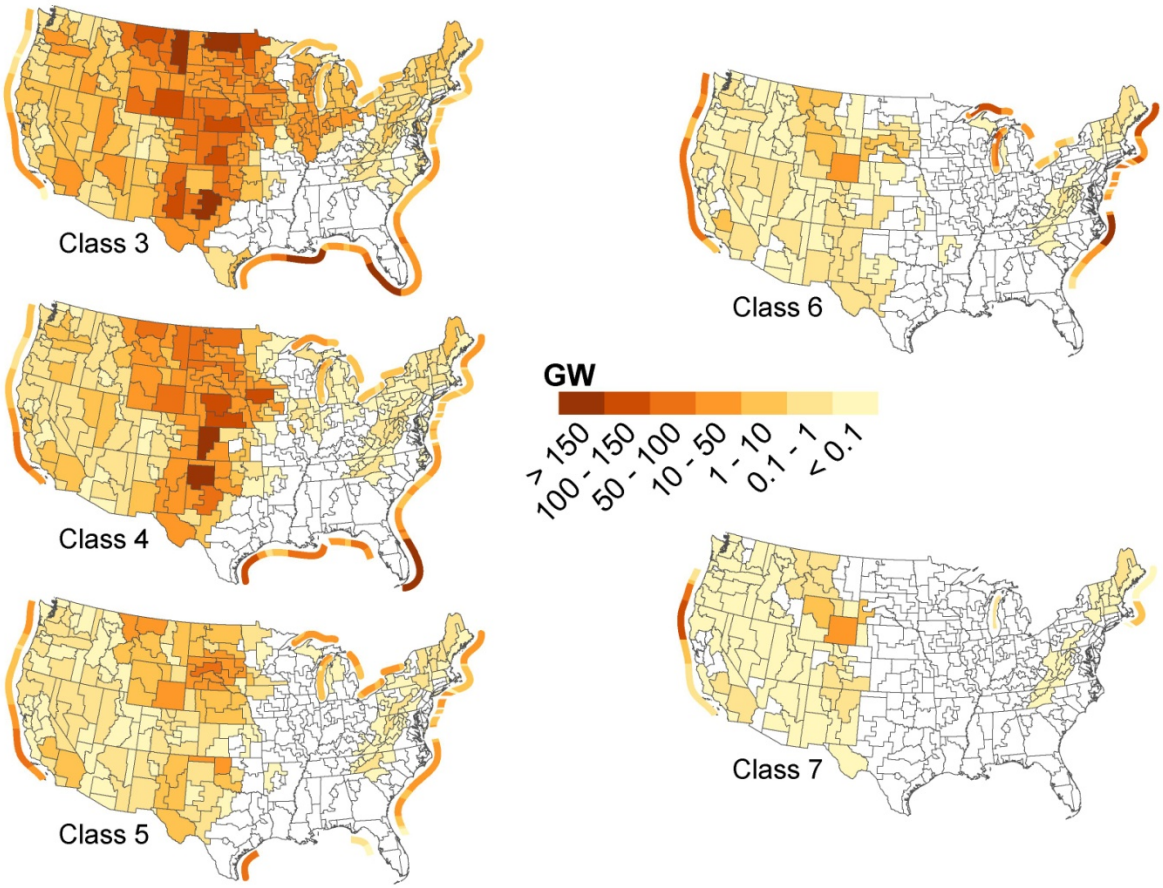
W/m^2 = watts per square meter; m/s = meters per second. Wind speed measured at 50 m above ground level.

Source: Elliott and Schwartz (1993)

Wind cost and performance parameters were developed by Black & Veatch (forthcoming), and are shown in Table A-9 (for onshore wind) and Table A-10 (for offshore wind). Capacity factor adjustments by time slice were made for each class of each region based on AWS Truepower text supplemental database files and the National Commission on Energy Policy/National Center for Atmospheric Research (NCEP/NCAR) global reanalysis mean values.

To account for the higher degree of variability in resource quality and land availability for wind technologies (as compared to other technologies), a supply curve representing the cost of connecting individual wind sites to the existing grid as well as to local demand centers was developed based on a GIS database of the

Figure A-5. Wind Available Resource by Class



resource, existing grid,[87] and loads. A similar supply curve was developed for CSP. In addition to the transmission costs associated with the supply curves, a $120/kW fee for connection to the grid is applied to new wind plants in ReEDS.

A.2.4.4 Conventional and Other Renewable Generators

ReEDS includes all major technologies that contribute to electricity generation in the United States. ReEDS is allowed to build new power plants of certain types, but not all. The following is a complete list of additional technologies considered in ReEDS for the *SunShot Vision Study*, as well as designations if new plants are allowed to be built or not. All existing and new plants in ReEDS are sited at the 134 PCA region level.

- Hydropower: existing plants only
- Gas-combustion turbine (gas-CT): new and existing plants
- Gas-combined cycle (gas-CC): new and existing plants

[87] Ten percent of the total carrying capacity of each transmission line was assumed to be available for wind spur lines.

Table A-9. Land-Based Wind Technology Cost (2010$) and Performance Projections

Wind Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)
3	2010	0.32	2,000	60	0
3	2015	0.33	2,000	60	0
3	2020	0.33	2,000	60	0
3	2025	0.34	2,000	60	0
3	2030	0.35	2,000	60	0
3	2035	0.35	2,000	60	0
3	2040	0.35	2,000	60	0
3	2045	0.35	2,000	60	0
3	2050	0.35	2,000	60	0
4	2010	0.36	2,000	60	0
4	2015	0.37	2,000	60	0
4	2020	0.37	2,000	60	0
4	2025	0.38	2,000	60	0
4	2030	0.38	2,000	60	0
4	2035	0.38	2,000	60	0
4	2040	0.38	2,000	60	0
4	2045	0.38	2,000	60	0
4	2050	0.38	2,000	60	0
5	2010	0.42	2,000	60	0
5	2015	0.42	2,000	60	0
5	2020	0.42	2,000	60	0
5	2025	0.42	2,000	60	0
5	2030	0.43	2,000	60	0
5	2035	0.43	2,000	60	0
5	2040	0.43	2,000	60	0
5	2045	0.43	2,000	60	0
5	2050	0.43	2,000	60	0
6	2010	0.44	2,000	60	0
6	2015	0.44	2,000	60	0
6	2020	0.44	2,000	60	0
6	2025	0.45	2,000	60	0
6	2030	0.45	2,000	60	0
6	2035	0.45	2,000	60	0
6	2040	0.45	2,000	60	0
6	2045	0.45	2,000	60	0
6	2050	0.45	2,000	60	0
7	2010	0.46	2,000	60	0
7	2015	0.46	2,000	60	0
7	2020	0.46	2,000	60	0
7	2025	0.46	2,000	60	0
7	2030	0.46	2,000	60	0
7	2035	0.46	2,000	60	0
7	2040	0.46	2,000	60	0
7	2045	0.46	2,000	60	0
7	2050	0.46	2,000	60	0

Table A-10. Shallow Offshore Wind Technology Cost (2010$) and Performance Projections

Wind Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)
3	2010	0.36	3,700	100	0
3	2015	0.36	3,500	100	0
3	2020	0.37	3,400	100	0
3	2025	0.37	3,200	100	0
3	2030	0.38	3,000	100	0
3	2035	0.38	3,000	100	0
3	2040	0.38	3,000	100	0
3	2045	0.38	3,000	100	0
3	2050	0.38	3,000	100	0
4	2010	0.39	3,700	100	0
4	2015	0.39	3,500	100	0
4	2020	0.39	3,400	100	0
4	2025	0.40	3,200	100	0
4	2030	0.40	3,000	100	0
4	2035	0.40	3,000	100	0
4	2040	0.40	3,000	100	0
4	2045	0.40	3,000	100	0
4	2050	0.40	3,000	100	0
5	2010	0.45	3,700	100	0
5	2015	0.45	3,500	100	0
5	2020	0.45	3,400	100	0
5	2025	0.45	3,200	100	0
5	2030	0.45	3,000	100	0
5	2035	0.45	3,000	100	0
5	2040	0.45	3,000	100	0
5	2045	0.45	3,000	100	0
5	2050	0.45	3,000	100	0
6	2010	0.48	3,700	100	0
6	2015	0.48	3,500	100	0
6	2020	0.48	3,400	100	0
6	2025	0.48	3,200	100	0
6	2030	0.48	3,000	100	0
6	2035	0.48	3,000	100	0
6	2040	0.48	3,000	100	0
6	2045	0.48	3,000	100	0
6	2050	0.48	3,000	100	0
7	2010	0.50	3,700	100	0
7	2015	0.50	3,500	100	0
7	2020	0.50	3,400	100	0
7	2025	0.50	3,200	100	0
7	2030	0.50	3,000	100	0
7	2035	0.50	3,000	100	0
7	2040	0.50	3,000	100	0
7	2045	0.50	3,000	100	0
7	2050	0.50	3,000	100	0

- Pulverized coal: existing plants with and without scrubbers; new plants with scrubbers
- Coal-integrated gasification combined cycle (IGCC): new and existing plants
- Oil/gas/steam (OGS): existing plants only
- Nuclear: new and existing plants.
- Geothermal: new and existing plants
- Biopower: new and existing plants
- Cofire: new plants and retrofits of coal plants
- Landfill gas and municipal solid waste: existing plants only.

Costs and heat rates for conventional technologies that are allowed new plant construction in ReEDS were developed by Black & Veatch (forthcoming) and are shown in Table A-11.

Outage rates, minimum plant loading requirements, and emissions rates of all conventional technologies are shown in Table A-12. "Forced outage rates" represent unplanned outage events, and effectively reduce capacity factors of these plants during all ReEDS time slices of the year. "Planned outage rates" represent planned maintenance events, and are assumed in ReEDS to reduce capacity factors only in non-summer time slices. Together, the outage rates define the availability of the plants, though a plant's capacity factor is an output of the model as the optimum solution may require a plant to operate below this maximum availability. Though conventional technologies in ReEDS are dispatchable, they must pay a penalty for ramping significantly to their peaks and must abide by minimum plant loading requirements, which specify the minimum level of output of plants that are operating in each season. However, plants are allowed to shut down for entire seasons. For example, nuclear plants have a minimum plant loading of 100%, which means that active nuclear capacity in each season must generate at peak output. However, national nuclear power output may vary between seasons as nuclear capacity is brought online or offline between seasons.

A.2.4.4.1 Retirements

Retirements of generators are handled in multiple ways in ReEDS, depending on the particular technology.

- *Coal retirements*. Existing coal units retire based roughly on an 80-year lifetime; one-eightieth of existing coal capacity is assumed to retire annually.
- *Oil/gas/steam retirements.* Existing OGS units retire based on a 50-year service life; each unit is assumed to retire 50 years from its year of installation.
- *Nuclear retirements.* Existing nuclear plants are retired according to their specific year of installation. Plants built prior to 1980 have an assumed 60-year lifetime, and plants built after 1980 have an assumed 80-year lifetime (beyond the timeframe of this study).

Table A-11. Cost (2010$) and Performance Characteristics for Conventional Generation

	Install Date	Capital Cost $/kW	Fixed O&M $/kW/yr	Var O&M $/MWh	Heat Rate 10^6 Btu/MWh
Gas-CT	2010	660	5	30	13
Gas-CT	2015	660	5	30	10
Gas-CT	2020	660	5	30	10
Gas-CT	2025	660	5	30	10
Gas-CT	2030	660	5	30	10
Gas-CT	2035	660	5	30	10
Gas-CT	2040	660	5	30	10
Gas-CT	2045	660	5	30	10
Gas-CT	2050	660	5	30	10
Gas-CC	2010	1,200	6	4	8
Gas-CC	2015	1,200	6	4	7
Gas-CC	2020	1,200	6	4	7
Gas-CC	2025	1,200	6	4	7
Gas-CC	2030	1,200	6	4	7
Gas-CC	2035	1,200	6	4	7
Gas-CC	2040	1,200	6	4	7
Gas-CC	2045	1,200	6	4	7
Gas-CC	2050	1,200	6	4	7
Coal	2010	2,900	23	4	10
Coal	2015	2,900	23	4	9
Coal	2020	2,900	23	4	9
Coal	2025	2,900	23	4	9
Coal	2030	2,900	23	4	9
Coal	2035	2,900	23	4	9
Coal	2040	2,900	23	4	9
Coal	2045	2,900	23	4	9
Coal	2050	2,900	23	4	9
Coal-IGCC	2010	4,100	32	7	9
Coal-IGCC	2015	4,100	32	7	9
Coal-IGCC	2020	4,100	32	7	9
Coal-IGCC	2025	4,100	32	7	8
Coal-IGCC	2030	4,100	32	7	8
Coal-IGCC	2035	4,100	32	7	8
Coal-IGCC	2040	4,100	32	7	8
Coal-IGCC	2045	4,100	32	7	8
Coal-IGCC	2050	4,100	32	7	8
Nuclear	2010	6,200	130	0	10
Nuclear	2015	6,200	130	0	10
Nuclear	2020	6,200	130	0	10
Nuclear	2025	6,200	130	0	10
Nuclear	2030	6,200	130	0	10
Nuclear	2035	6,200	130	0	10
Nuclear	2040	6,200	130	0	10
Nuclear	2045	6,200	130	0	10
Nuclear	2050	6,200	130	0	10

10^6 Btu: million British thermal units

Table A-11. Cost (2010$) and Performance Characteristics for Conventional Generation (Continued)

	Install Date	Capital Cost $/kW	Fixed O&M $/kW/yr	Var O&M $/MWh	Heat Rate 10^6 Btu/MWh
Geothermal	2010	3,000 to >10,000	230	0	0
Geothermal	2015	3,000 to >10,000	230	0	0
Geothermal	2020	3,000 to >10,000	230	0	0
Geothermal	2025	3,000 to >10,000	230	0	0
Geothermal	2030	3,000 to >10,000	230	0	0
Geothermal	2035	3,000 to >10,000	230	0	0
Geothermal	2040	3,000 to >10,000	230	0	0
Geothermal	2045	3,000 to >10,000	230	0	0
Geothermal	2050	3,000 to >10,000	230	0	0
Biopower	2010	3,900	96	15	15
Biopower	2015	3,900	96	15	14
Biopower	2020	3,900	96	15	14
Biopower	2025	3,900	96	15	14
Biopower	2030	3,900	96	15	14
Biopower	2035	3,900	96	15	13
Biopower	2040	3,900	96	15	13
Biopower	2045	3,900	96	15	13
Biopower	2050	3,900	96	15	13
Cofired Coal/Bio	2010	3,100	26	6	10
Cofired Coal/Bio	2015	3,100	26	6	9
Cofired Coal/Bio	2020	3,100	26	7	9
Cofired Coal/Bio	2025	3,100	26	7	9
Cofired Coal/Bio	2030	3,100	26	8	9
Cofired Coal/Bio	2035	3,100	26	9	9
Cofired Coal/Bio	2040	3,100	26	10	9
Cofired Coal/Bio	2045	3,100	26	11	9
Cofired Coal/Bio	2050	3,100	26	12	9

- *Gas-CC and gas-CT retirements.* Gas plants are retired according to their year of installation. One twenty-fourth of existing gas-CC and gas-CT capacity built before 2000 is retired annually until 2030 to reflect a 24-year lifetime of that gas capacity. Then, starting in 2030, one-thirtieth of cumulative gas capacity is retired annually through 2050.
- *Renewable retirements.* All new and existing CSP, utility PV, wind, and geothermal plants are assumed to retire according to their specific lifetimes.[88] After retirement, the capacity is automatically rebuilt in ReEDS, with the appropriate capital costs incurred at that time.

[88] In determining system cost impacts, lifetimes of CSP, utility-scale PV, and geothermal are assumed to be 30 years. Lifetime of wind is 20 years.

Table A-12. Outage Rates, Minimum Plant Loading Requirements, and Emissions Rates of Conventional Technologies in ReEDS

	Forced Outage Rate	Planned Outage Rate	Minimum Plant Loading	Emission Rates (lbs/10^6 Btu Fuel Input)			
				SO_2	NO_x	Hg	CO_2
Hydro[89]	5%	2%	55%	0	0	0	0
Gas-CT	3%	5%	0%	0.0006	0.08	0	122
Gas-CC	4%	6%	0%	0.0006	0.02	0	122
Old Coal	6%	10%	40%	1.57	0.448	4.6E-06	204
New Coal	6%	10%	40%	0.0785	0.02	4.6E-06	204
Coal-IGCC	8%	10%	50%	0.0184	0.02	4.6E-06	204
OGS	10%	12%	40%	0.026	0.1	0	122
Nuclear	4%	12%	100%	0	0	0	0
Geothermal	13%	12%	90%	0	0	0	0
Biomass	9%	6%	40%	0.08	0	0	0
Cofired Old	7%	2%	40%	0.157	0.448	4.6E-06	204
Cofired New	7%	8%	40%	0.0785	0.02	4.6E-06	204
Landfill Gas	5%	9%	0%	0	0	0	-157

SO_2: sulfur dioxide
NO_x: nitrogen oxides
Hg: mercury

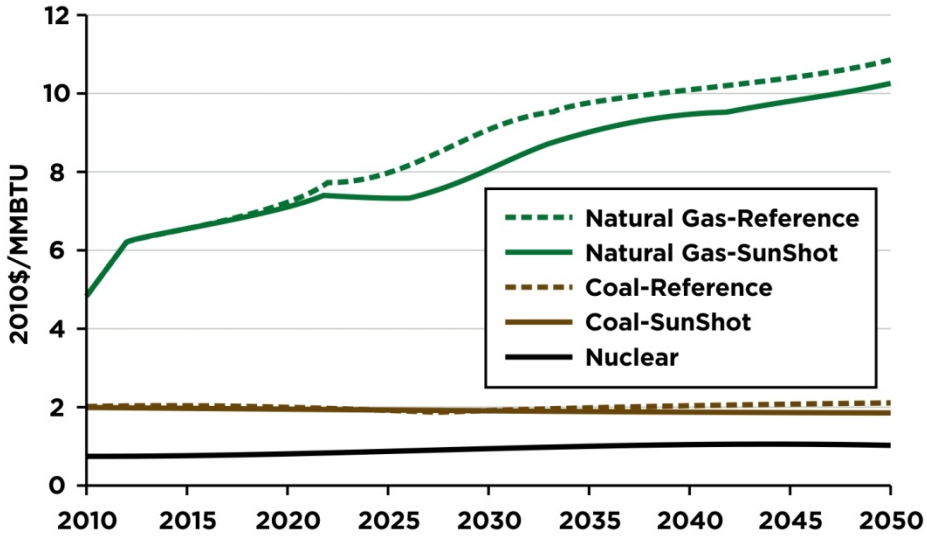
A.2.4.4.2 Fuel Prices

National average coal, natural gas, and nuclear fuel prices in the SunShot and reference scenarios are shown in Figure A-6. These prices are based on the *Annual Energy Outlook 2010 (AEO 2010)* (EIA 2010),[90] but natural gas and coal fuel prices are adjusted upward from *AEO 2010* if demand for that fuel is increased in ReEDS with respect to *AEO 2010* forecasted demand, and adjusted downward if demand is decreased with respect to *AEO* forecasted demand. The levels of adjustment are based on the differences in economy-wide fuel usage and price in the *AEO 2010* reference, low economic growth, and high economic growth cases. These adjustments result in different natural gas and coal fuel prices between the SunShot and reference scenarios. Nuclear fuel prices, on the other hand, are assumed to be independent of nuclear fuel demand.

Fuel costs are also adjusted by the 13 modeled NERC regions/subregions to reflect regional variation in fuel cost.

[89] Hydropower has additional seasonal generation limits, based on the GridView database of hydropower capacity located in the Western Electricity Coordinating Council (WECC). Hydropower generation elsewhere is assumed to be distributed evenly across seasons.
[90] The *Annual Energy Outlook* (AEO) forecasts fuel prices through 2035, and a linear interpolation between 2015 and 2035 is used to extrapolate AEO natural gas and coal fuel prices through 2050. Nuclear fuel prices are assumed to remain constant after 2035.

Figure A-6. Natural Gas, Coal, and Nuclear Fuel Prices (2010$)



A.2.4.5 Storage and Interruptible Load

ReEDS considers three utility-scale electricity storage options: pumped hydropower storage (PHS), batteries, and compressed air energy storage (CAES). Storage technologies are capable of providing a variety of services to the system. These technologies can shift daily demands, provide planning and operating reserves (see Section A.2.7.2 and A.2.7.3), and reduce levels of curtailment from VERs (see Section A.2.7.1).

Storage technologies are located at the PCA region level in ReEDS. PHS and CAES are location-restricted due to hydrology and topography—for PHS—and geology—for CAES. In contrast, utility-scale batteries are not restricted to any subset of regions. The 21 GW of existing PHS capacity is included in the model, and new PHS resource is conservatively limited to those sites identified in the Federal Energy Regulatory Commission (FERC) licensing process (FERC 2010).

Cost and performance characteristics for storage technologies were developed by Black & Veatch (forthcoming), and are shown in Table A-13. Round-trip efficiency (RTE) is defined as electrical power out divided by electrical power in, and is generally less than one due to storage inefficiencies. However, since CAES uses natural gas, its RTE is greater than one. Outage rates and emissions rates of all storage technologies are shown in Table A-14. These parameters are described in the preceding section. Note that only CAES has emissions, since it operates on natural gas.

Table A-13. Costs (2010$) and Performance Characteristics for Storage Technologies

	Install Date	Capital Cost $/kW	Fixed O&M $/kW/yr	Var O&M $/MWh	Round-Trip Efficiency	Heat Rate 10^6 Btu/MWh
Pumped hydro	2010	2,000	31	0	0.80	0
Pumped hydro	2015	2,000	31	0	0.80	0
Pumped hydro	2020	2,000	31	0	0.80	0
Pumped hydro	2025	2,000	31	0	0.80	0
Pumped hydro	2030	2,000	31	0	0.80	0
Pumped hydro	2035	2,000	31	0	0.80	0
Pumped hydro	2040	2,000	31	0	0.80	0
Pumped hydro	2045	2,000	31	0	0.80	0
Pumped hydro	2050	2,000	31	0	0.80	0
Batteries	2010	4,100	26	60	0.75	0
Batteries	2015	4,000	26	60	0.75	0
Batteries	2020	3,900	26	60	0.75	0
Batteries	2025	3,700	26	60	0.75	0
Batteries	2030	3,600	26	60	0.75	0
Batteries	2035	3,500	26	60	0.75	0
Batteries	2040	3,400	26	60	0.75	0
Batteries	2045	3,300	26	60	0.75	0
Batteries	2050	3,200	26	60	0.75	0
CAES	2010	900–1,200	12	2	1.25	5
CAES	2015	900–1,200	12	2	1.25	5
CAES	2020	900–1,200	12	2	1.25	5
CAES	2025	900–1,200	12	2	1.25	5
CAES	2030	900–1,200	12	2	1.25	5
CAES	2035	900–1,200	12	2	1.25	5
CAES	2040	900–1,200	12	2	1.25	5
CAES	2045	900–1,200	12	2	1.25	5
CAES	2050	900–1,200	12	2	1.25	5

Table A-14. Outage Rates and Emissions Rates of Storage Technologies in ReEDS

	Forced Outage Rate	Planned Outage Rate	Emission Rates (lbs/10^6 Btu fuel input)			
			SO_2	NO_x	Hg	CO_2
Pumped-hydro	4%	3%	-	-	-	-
Batteries	2%	1%	-	-	-	-
CAES	3%	4%	0.0006	0.08	0	122

Interruptible load represents the annual load that utilities can use as operating reserves under conditions set forth by contracts between the utilities and the demand entity. In ReEDS, interruptible load can only be used to satisfy contingency and

forecast error reserve requirements; interruptible load cannot be used to satisfy frequency regulation reserve requirements.

In ReEDS, interruptible load is represented by PCA-level supply curves that range in cost from $3/kW/year (yr) to $38/kW/yr for each PCA region. The total amount of load that may be used as interruptible load varies by region and over time. In 2010, the region with the least abundant interruptible load resource only allows 1% of peak demand, whereas the region with the highest amount of resource allows 8% of peak demand. In 2030, these numbers increase to 11% and 17%, respectively. The interruptible supply curves are based on a resource assessment by FERC (FERC 2009) and cost data from EIA (EIA 2009).

A.2.5 Transmission

Transmission in ReEDS follows a "pipeline" methodology, meaning power shipped directly between regions is simply constrained by the size of the transmission lines and Kirchoff's current law (i.e., energy conservation), but not by Kirchoff's voltage law. In more realistic depictions of transmission systems, the flow of electric power is determined by the topology of the transmission network and the characteristics of the lines that make up the network, meaning that flows between regions can actually be constrained by transmission lines far from the connecting regions in question. Though ReEDS does not explicitly include power-flow analysis, the existing transmission network for ReEDS was derived based on analysis from the GridView model (Section A.4), which includes more realistic DC power flow algorithms. The GridView analysis was used to determine transmission interface limits among neighboring PCAs.[91] ReEDS represents the grid as a network of connections between the center points of neighboring PCAs.

In addition to the existing grid, ReEDS is allowed to expand transmission capacity along both existing and new corridors between neighboring PCAs. This expansion allows power to be shipped from any PCA to any other that is connected by this network. Costs of transmission were developed by the National Renewable Energy Laboratory (NREL), and are shown in Table A-15. Different regions have different costs of transmission, due to the assumed prevalence of either 500-kilovolt (kV) or 765-kV lines, as well as regional cost multipliers (EnerNex 2010) which reflect additional siting costs. The transmission line costs include a 25% contingency factor, which accounts for the fact that lines are overbuilt to accommodate greater power transfers only during contingency events. In addition to the cost of transmission lines, regional supply curves of costs for substation construction, which primarily include cost of transformers to step between transmission line voltages and distribution network voltages, are included. The substation supply curves were developed from the GridView database. An additional cost of $230/kW of transmission capacity is charged for building capacity across interconnections, to account for the necessary AC-DC-AC intertie construction.

[91] Neighboring PCAs correspond to geographically contiguous PCAs and PCAs that are currently connected via transmission lines (e.g., long distance direct-current lines).

Table A-15. Transmission Costs (2010$) Used in ReEDS

	Value	Applicable Regions
500-kV Line Costs [$/MW-mile(mi)]	1,500	WECC, TRE, SPP, FRCC, SERC
765-kV Line Costs ($/MW-mi)	1,200	Rest of the country
Line Cost Multiplier	3.56x	CA, NY, NE, East PJM
Line Cost Multiplier	1.58x	West PJM
Substation Costs ($/kW)	11–25	All
AC-DC-AC Intertie Costs ($/kW)	230	Crossing Interconnects

WECC: Western Electricity Coordinating Council
TRE: Texas Reliability Entity
SPP: Southwest Power Pool
FRCC: Florida Reliability Coordinating Council
SERC: Southeastern Electric Reliability Corporation

In addition to the transmission costs discussed above, grid interconnection costs are applied to most generation and storage technologies upon construction. As described previously, these costs are not applied to distributed utility-scale PV and rooftop PV installations. For conventional technologies in which siting and transmission may be more significant issues (e.g., hydropower, nuclear, and coal), grid interconnection costs are twice as high.

In addition to the grid interconnection costs in Table A-16, since CSP and wind resource quality depends heavily on location, supply curves for each CSP/wind region—of which there are 356—in the United States were developed to account for the additional transmission line construction for connecting these resources to the

Table A-16. Grid Connection Costs (2010$) for All ReEDS Technologies

	Grid Connection Cost ($/kW)
Hydro	230
Gas-CT	120
Gas-CC	120
Coal	230
Coal-IGCC	230
OGS	120
Nuclear	230
Geothermal	230
Biomass	120
Cofire	230
Wind	120
Central PV	120
Distributed Utility-scale PV	0
CSP	120
Pumped Hydro	120
Batteries	120
CAES	120

grid as well as to local demand centers. These supply curves are explained in the CSP (A.2.4.2) and wind (A.2.4.3) sections.

Transmission power losses are characterized by a factor of 1%/100 miles. In other words, 1% of electrical power is lost for every 100 miles that power travels. Note that distribution losses are not considered endogenously in ReEDS, and are estimated at 5.3% of end-use demand.[92] Distribution losses do not apply to distributed utility-scale and rooftop PV, however, as these technologies are assumed to be located within distribution networks.

A.2.6 Financial Parameters

General financial parameters used in ReEDS are shown in Table A-17. The 5.5% real discount rate is based on a weighted average cost of capital (WACC) using a 15% nominal rate of return on equity (RROE), 7% nominal interest rate, 3% inflation rate, 35% federal tax rate, and 5% state tax rate. These financial assumptions are described in more detail in Chapter 8.

Table A-17. General Financial Parameters in ReEDS

Inflation	3%
Nominal Interest Rate	7%
Nominal Rate of Return On Equity (RROE)	15%
Debt Fraction	60%
Federal Tax	35%
State Tax	5%
Real Discount Rate [weighted average cost of capital (WACC)]	5.5%

Technology-specific financial parameters used in ReEDS are shown in Table A-18. The construction cost multiplier, when multiplied by overnight capital costs of each technology, represents the adjustment on capital cost due to the interest payments during the construction period. All technologies use the general interest rate and required RROE (Table A-17), except that 6% carbon risk premiums (real) on interest rate and required RROE are applied to coal technologies.[93] Renewable technologies also have modified accelerated cost recovery system (MACRS) depreciation schedules. Solar technologies have a 30% investment tax credit (ITC) until 2016 and 0% ITC thereafter. Wind technologies receive a production tax credit of about $21/megawatt-hours (MWh) through 2012. The capital cost financial multiplier encompasses the effects of all financial parameters on the capital cost (e.g., construction costs, depreciation, financing, and taxes) and, when multiplied by overnight capital cost, represents the present value of revenue that a project must have to recover all costs over a 20-year evaluation period. This is the adjustment to

[92] Distribution losses were estimated based on the difference between AEO 2010 projections of transmission and distribution (T&D) losses through 2030 and ReEDS reference case projections of transmission losses alone through 2030. ReEDS only models interzonal transmission losses (between PCAs), so the distribution loss estimates also include intrazonal transmission losses (within PCAs).
[93] The 6% carbon premium is equivalent to the medium range of values being used by utilities in long-term resource planning (Barbose et al. 2008).

Table A-18. Financial Parameters by Technology in ReEDS

Plant Type	Construction Cost Multiplier	Interest/RROE Real Risk Adjustment	ITC	Depreciation (years)	Capital Cost Financial Multiplier
Hydro	1.03	0.00	0.0	15	1.32
Gas-CT	1.03	0.00	0.0	15	1.32
Gas-CC	1.05	0.00	0.0	15	1.34
Coal	1.14	0.06	0.0	15	2.06
Coal-IGCC	1.14	0.06	0.0	15	2.06
OGS	1.14	0.00	0.0	15	1.46
Nuclear	1.14	0.00	0.0	15	1.46
Geothermal	1.07	0.00	0.1	15	1.06
Biomass	1.07	0.00	0.0	15	1.21
Cofire	1.14	0.06	0.0	15	2.06
Wind	1.03	0.00	0.0	5	1.17
CSP (pre-2016)	1.03	0.00	0.3	5	0.74
CSP (post-2016)	1.03	0.00	0.0	5	1.17
Util. PV (pre-2016)	1.02	0.00	0.3	5	0.73
Util. PV (post-2016)	1.02	0.00	0.0	5	1.16
Pumped Hydro	1.03	0.00	0.0	15	1.32
Battery	1.02	0.00	0.0	15	1.31
CAES	1.05	0.00	0.0	15	1.34

ITC: investment tax credit

capital cost used by ReEDS for each technology as the technologies compete to minimize overall 20-year present value costs of the system.

A.2.6.1 State Renewable Portfolio Standards and Incentives

Table A-19 presents the RPS goals used in ReEDS as obtained from the Database of State Incentives for Renewables & Efficiency (DSIRE) (DSIRE 2010). The state RPS requires a utility to install or generate a certain fixed amount of renewable capacity or energy. Unless prohibited by law, a state might also meet the requirement by importing electricity. In addition, the states of Delaware, Illinois, Maryland, Missouri, North Carolina, New Hampshire, New Jersey, New Mexico, Nevada, Ohio, and Pennsylvania have solar set-asides, which require that a certain fraction of the RPS be met specifically with solar resources. In the SunShot scenario, the deployment of solar and wind in the long-term in general vastly exceeds the state RPS targets.

In addition to the federal wind production tax credit, the states of Iowa, Idaho, Minnesota, New Jersey, New Mexico, Oklahoma, Washington, and Wyoming have state-level production or investment incentives for wind.

Table A-19. State RPS Requirements as of July 2010

State	RPS Start Year	RPS Full Implementation	RPS (%)
AZ	2006	2025	6.2
CA	2004	2020	32.4
CO	2007	2020	19.4
CT	2006	2020	21.5
DE	2008	2021	13.9
IL	2008	2025	22.1
KS	2011	2020	15.6
MA	2004	2020	19.5
MD	2006	2022	19.3
ME	2000	2017	39.3
MI	2012	2015	10.0
MN	2010	2020	27.4
MO	2011	2021	9.8
MT	2008	2015	10.0
NC	2010	2021	11.1
NH	2008	2025	23.4
NJ	2005	2021	24.9
NM	2006	2020	15.2
NV	2005	2025	22.0
NY	2003	2015	20.9
OH	2009	2024	11.0
OR	2011	2025	20.4
PA	2007	2021	17.5
RI	2007	2019	15.8
WA	2012	2020	12.7
WI	2006	2015	10.1

Source: DSIRE (2010)

A.2.7 Resource Variability and System Reliability

Variable energy resource (VER) technologies, which include wind, CSP without storage, and PV, produce power that is variable, non-dispatchable, and uncertain. Generally, greater penetrations of these technologies lead to greater levels of curtailment and required operating reserves and a diminished contribution to planning reserve requirements per unit of VER capacity. These requirements are explained more in-depth in the following sub-sections.

In ReEDS, the variability of each VER technology is characterized using simulated hourly power output data, described in the PV, CSP, and wind sections: A.2.4.1 – A.2.4.3. The hourly data were used to calculate the standard deviation of power output for each VER technology in each of the ReEDS time slices. The standard deviation was used to characterize variability of individual technologies, but reserve

sharing entities—in ReEDS, the 21 RTO regions shown in Figure A-1—are more concerned with the aggregate variability of all demand and generation on the system. To more fully capture aggregate variability, correlation statistics were also calculated between the power outputs of geographically separated wind, CSP, and PV plants. In general, greater geographic distance between two CSP, PV, or wind plants leads to a lower degree of correlation between power outputs, which decreases the variability of their combined generation. Because of this, all else being equal, ReEDS will choose to separate generators of a given type to reduce variability of the output.

The standard deviations and correlation statistics, along with the capacity factors for each VER technology in each time slice, were used in calculations of curtailment, capacity value, and operating reserve requirements, each described in the following sections.

A.2.7.1 Variable Energy Resource Curtailment

Because VER generation is variable, there are certain times that VER power exceeds that which can be used by the system. This is often due to higher-than-expected VER outputs, lower-than-expected electrical demand, transmission constraints, and minimum loading constraints that force other generators to stay online. At these times the total generated power is in excess of the demand, and the excess power must be non-economically curtailed.

ReEDS estimates expected levels of curtailment induced by VER technologies (as a fraction of VER generation) for each time slice in each RTO region through a statistical expected value calculation. This calculation depends on the probability distributions of electrical demand and VER electrical output to that RTO, minimum loading requirements of other generators, and the amount of electrical storage, since storage may be used to shift power that would otherwise have been curtailed to times in which the power is needed.

A.2.7.2 Planning Reserve Requirements and VER Capacity Value

Planning reserve requirements ensure that adequate generating capacity is available during all times of the year by requiring that this capacity be higher than peak demand plus some margin (“reserve margin”). In ReEDS, planning reserve requirements must be satisfied in each PCA in every time slice—with respect to that time slice’s peak expected demand. The specific reserve margin that must be satisfied depends on the NERC region/subregion associated with each PCA. Table A-20 shows these requirements by NERC region.

All dispatchable generator-types, including CSP systems with storage, count their full capacity toward the reserve margin requirement. This is not the case, however, for VER technologies such as wind, CSP without storage, and PV, since these technologies certainly cannot be relied on to contribute more than their expected output, which is simply based on the technology’s capacity factor during each time slice. In addition, the variability of VER technologies about their expected output further reduces the amount they can contribute. The fraction of capacity that can be reliably counted toward the planning reserve requirement is referred to as the “capacity value” of the plant. To determine the capacity value associated with a VER technology, a statistical effective load-carrying capability (ELCC) calculation

Table A-20. Reserve Margin Requirements (Above Peak Time Slice Demand) by NERC Region

East Central Area Reliability Coordination Agreement (ECAR)	15%
Electric Reliability Council of Texas (ERCOT)	13%
Mid-Atlantic Area Council (MAAC)	15%
Mid-America Interconnected Network (MAIN)	15%
Mid-Continent Area Power Pool (MAPP)	15%
New York (NY)	15%
New England (NE)	15%
Florida Reliability Coordinating Council (FRCC)	16%
Southeastern Electric Reliability Council (SERC)	15%
Southwest Power Pool (SPP)	14%
Northwest Power Pool (NWP)	17%
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)	17%
California (CA)	17%

is performed in ReEDS between every 2-year optimization period. The ELCC is defined as the amount of electrical demand that may be added in each time slice for an incremental increase in capacity of a given VER technology without increasing the loss of load probability.

The capacity value for wind, PV, and CSP without storage is calculated independently for each time slice. In general, for a given PCA, the planning reserve constraint is only important in the most stringent time slice, whereas in the other time slices, the requirement will be exceeded. For example, in a PCA with a summer peak demand, the planning reserve constraint is usually most stringent in the summer afternoon time slice. However, with large-scale solar deployment, the constraint could become more stringent in the summer evening time slice than in the summer afternoon. Because of this, as PV penetration increases, its capacity value can drop dramatically from relatively high values (in the summer afternoon) to very low values (during the evening hours).

A.2.7.3 Operating Reserves

In addition to ensuring adequate capacity to satisfy long-term planning reserve requirements, ReEDS requires adequate operating reserve capacity to meet daily operating reserve requirements. Operating reserve requirements ensure that there is enough flexible generator capacity (spinning or quick-start capable) or responsive demand (interruptible load) that can be dispatched to meet unanticipated changes in loads and/or power availability. In ReEDS, these requirements must be satisfied in each RTO in all time slices.

The resources that can contribute to these reserve requirements in ReEDS are:

- *Spinning reserves.* Conventional and storage technologies that are generating power can operate below maximum capacity and keep the remainder on reserve. The amount of capacity that may be counted toward the requirements depends on the amount that can be ramped up rather quickly (e.g., in less than 10 minutes).

- *Quick-start reserves.* Technologies that can start up quickly (~10 minutes) from an off state, such as gas-CT.
- *Interruptible load.* Agreements between utilities and consumers that allow partial utility control of demand.

Operating reserve requirements included in ReEDS are:

- *Contingency reserve requirements.* These requirements ensure that an unanticipated change to the operational status of generators or transmission lines (e.g., due to unforeseen outages) will not cause an extended disruption to electricity end users. In ReEDS, the contingency reserve requirement is set at 6% of average demand in each time slice. At least half of this requirement must be met with spinning reserves or interruptible load whereas the other half can be met by quick-start units. The relevant time scale for contingency events is about 10 minutes.
- *Frequency regulation reserve requirements.* These requirements ensure that sub-minute deviations between demand and generation can be minimized. Due to the short time scales involved, only spinning reserves can satisfy the frequency regulation requirements. In ReEDS, this requirement is set at 1.5% of average demand in each time slice.
- *Additional VER regulation reserve requirements.* These requirements ensure that additional spinning reserves, beyond the 1.5% of average demand, are available to handle minute-level wind and PV[94] variability. In ReEDS, this requirement is assumed to be three standard deviations of 10-minute wind persistence forecast error (Ela et al. 2011). Sample wind data were used to develop a relationship between wind capacity factor and standard deviation per capacity of wind. Due to a lack of 10-minute PV data, the same relationship was assumed between PV capacity factor and standard deviation.
- *VER forecast error reserve requirements.* These requirements ensure stability of the system despite uncertainties in forecasting for wind and PV. Generally, forecast error reserve requirements increase as wind and PV penetration grows. The forecast error reserve requirements for wind and PV in ReEDS are assumed to be two standard deviations (Zavadil et al. 2004) of their respective average forecast errors in each RTO in each time slice. Forecasts for wind are assumed to be simple hourly persistence forecasts, based on simulated wind power output data (EnerNex 2010, GE 2010) for each wind resource class of each ReEDS region. In other words, wind forecast errors are simply the differences between simulated power output from one hour to the next. PV forecasts for a given hour are modified persistence forecasts, using the output from the previous hour as well as the average change between those 2 hours over the previous 15 days to account for the known apparent daily solar trajectory. Since forecast errors occur over longer time scales (roughly an hour) than contingency or frequency regulation events, ReEDS assumes that up to five-sixth of the requirement can be met by quick-start units, and the remainder must be met by a combination of spinning reserves and interruptible load.

[94] CSP without storage is considered to have enough thermal inertia (about 30 minutes) to not require additional operating reserves.

A.2.8 Direct Electric-Sector Costs

Overall system costs (see Chapter 3) include investments in electrical power generating capacity, reserve capacity, and transmission capacity, as well as fuel and operation and maintenance (O&M) costs. To better reflect overall societal cost, these costs do not include financing or financial incentives (for instance, the federal ITC), nor do they include taxes.

Overall present value of system costs through 2030 include all capital investments until 2030 as well as operation costs of the 2030 system until 2050. Likewise, present value costs through 2050 include all capital investments through 2050 as well as operation costs of the 2050 system through 2070. This methodology captures the additional fuel cost savings of the SunShot scenario over the reference scenario post 2030 and post 2050, respectively.

To calculate the present value of costs, a 7% discount rate was used, under guidance from the U.S. Office of Management and Budget (OMB 2003), with 2010 as the base year.

A.2.9 Electricity Price

Electricity price is calculated in ReEDS for every 2-year time period of the model. The electricity price is meant to reflect a regulated electricity market structure. There are three main components of electricity price:

- *Rate-base.* The rate-base includes annual payments on all investments in electrical power generator capacity, reserve capacity, and transmission capacity. The investments made in each 2-year time period of the model are assumed to be paid off over the next 30 years.
- *Generation Costs.* Generation costs include all fuel and O&M costs.
- *Non-Generation Transaction Costs.* The two components above are used to determine wholesale electricity prices, and this component includes all utility maintenance fees, administrative fees, and profit margins that mark-up wholesale rates to retail rates. ReEDS does not endogenously calculate non-generation transaction costs, and these costs are assumed to be fixed over time in ReEDS. The costs are assumed to be equal to the difference between historical retail rates in the start year of the model (2006) and the ReEDS-calculated wholesale rates (i.e., rate-base plus generation costs) in 2006.

A.2.10 Electric Power Demand Projections

The electrical demand forecast for the SunShot and reference scenarios was taken from the reference scenario of the *AEO 2010* (EIA 2010) and represents a "business as usual" growth in electricity demand. As ReEDS does not represent on-site generation technologies, this electricity demand projection does not include demand met by on-site generation. This NERC-level demand data were distributed among ReEDS PCAs using county-level demand data in 2006 (Ventyx 2006) and assuming that the fraction of NERC-level demand met by each PCA in each NERC region remains constant at 2006 levels through 2050.

A.3 Solar Deployment System Model

The SolarDS model was used in the *SunShot Vision Study* to simulate the evolution of residential and commercial rooftop PV markets. SolarDS is a bottom-up, market-penetration model that simulates residential and commercial rooftop PV markets in the continental United States through 2050 (Denholm et al. 2009). SolarDS was developed by NREL to examine the market competitiveness of rooftop PV based on regional solar resources, capital costs, financing structures, electricity prices, utility rate structures, net metering, carbon policy, and federal and local incentives.

SolarDS simulates PV markets at a high level of regional disaggregation by calculating hourly PV generation in 216 solar resource regions (Figure A-7) and combining PV output with state-based electricity rate distributions calculated using rate data from thousands of electric service providers. Regional PV economic performance is used to simulate PV adoption rates for six residential customer types (new and retrofit construction on three building types) and 28 commercial customer types (new and retrofit construction for 14 different customer/building types). Adoption rates are combined with a residential and commercial building stock database—accounting for building type,[95] roof orientation, roof shading, and building ownership—to calculate the annual and cumulative installed PV capacity. More detail on this methodology can be found in the SolarDS model documentation (Denholm et al. 2009).

A.3.1 Rooftop PV Economics

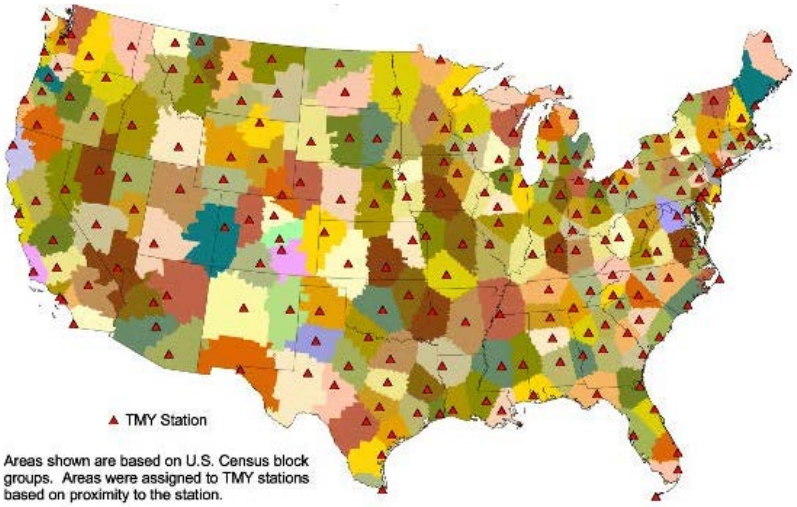
PV revenues are characterized by combining regional PV generation, state-based retail electricity rate distributions, tax burdens, incentives, and net-metering[96] parameters. Regional PV generation is characterized using data from 216 Typical Meteorological Year (TMY) stations, as shown in Figure A-7. PV output is calculated for several roof orientations, including flat-mounted modules and tilted modules (representative of a common roof tilt) with azimuth orientations ranging from ±90° from the south in 30° increments. Alternating current PV output is calculated for each location and orientation using the PVFORM/PVWATTS model (Marion et al. 2005).

Local retail electricity rates vary significantly within and between states. SolarDS characterizes the distribution of customer rate structures (flat, time-of-use, and demand-based rates) using tariff sheets from the largest service providers in each state. SolarDS characterizes the distribution of retail electricity rates for each state using Energy Information Administration (EIA) form 861 data (EIA 2007), which provide total revenue and sales for more than 3,000 electric service providers in the United States. Electricity rate escalations are projected through 2035 using EIA's *Annual Energy Outlook 2010* (EIA 2010) and extrapolated from 2035 to 2050 using

[95] The size of residential rooftop PV installations varies by building type, ranging from 4–6 kilowatts (kW) for single family homes. Commercial PV installation size also varies by building type, ranging from about 30–200 kW.

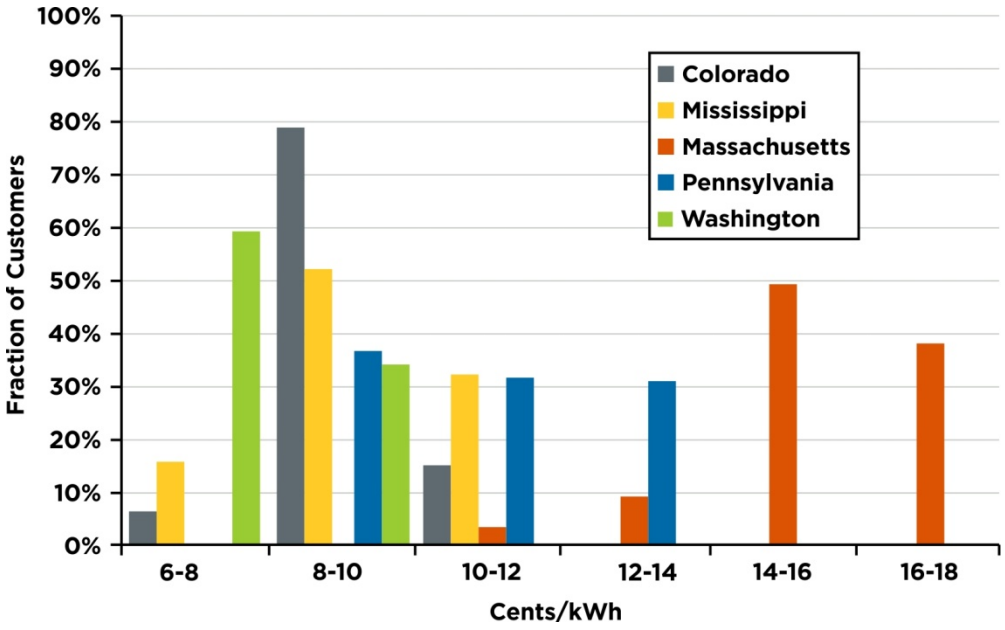
[96] A fraction of PV generation directly offsets electricity purchased from the grid and receives retail electricity rates, and the remaining fraction of PV generation is exported to the grid. In this analysis, exported electricity is valued at the marginal cost of electricity from combined-cycle natural gas generation.

Figure A-7. The 216 Solar Resource Regions Used in SolarDS, with Observation Stations Shown as Red Triangles



Source: NREL

Figure A-8. Distribution of State-Level Retail Electricity Rates for Residential Customers Calculated Using Utility Rate Sheets



the mean *AEO* growth rates from 2025 to 2035. Figure A-8 illustrates the distribution of retail electricity rates for residential customers in five U.S. states and the differences among the states.

Rooftop PV prices and financing costs were simulated for the *SunShot Vision Study* using PV price projections from Chapter 4 and financing terms from Chapter 8. Current state and federal PV incentives were included in all SolarDS scenarios. Both the reference and SunShot scenarios were simulated using conservative assumptions,

including no future incentives that are not currently in place, conservative net metering, and no carbon policy.

PV revenue streams and price projections are combined into annual cash flows that are used to generate PV payback times. Annual PV cash flows are calculated as follows:

Annual Cash Flow (t) = – Loan Down payment (t = 0)
+ State and Federal Tax Incentives (t = 1)
+ Avoided Electricity Costs (t)
+ Tax Savings on Loan Interest (t)
– Loan Payment (t)
– Operations and Maintenance Costs (t)

The loan down payment is assumed to be an upfront cost paid before the first year of ownership. State and federal incentives are assumed to be earned during the first year of ownership. All other costs and revenues are calculated annually. Annual cash flows are used to calculate region-specific PV payback times. Payback time is defined differently for residential and commercial systems following EIA (2010). Residential payback is defined as the time required for the money invested in a PV project to be recouped through system revenues and to stay positive for the remainder of the investment period. This measure of payback is frequently used in the PV literature (Nofuentes et al. 2002, Sidiras and Koukios 2005, Audenaert et al. 2010) and is calculated by finding the minimum time required to satisfy the following two constraints:

$$\sum_{t=0}^{Payback\ Time} \frac{Revenue_t - Cost_t}{(1+d)^t} > 0$$

$$\sum_{t=Payback\ Time}^{N} \frac{Revenue_t - Cost_t}{(1+d)^t} > 0$$

The first constraint identifies the time required for the cumulative system revenues to exceed cumulative system costs, and the second constraint ensures that this condition is met for the duration of the PV investment.

Commercial PV payback times are defined based on the internal rate of return (IRR) of project cash flows following EIA (2010). IRR represents the discount rate at which the project net present value (NPV) equals zero and is calculated using the following relationship:

$$NPV = \sum_{t=0}^{N} \frac{Revenue_t - Cost_t}{(1+IRR)^t} = 0$$

IRRs are frequently interpreted as annualized investment returns, and we define an IRR-based payback time by calculating the time required for an investment accruing at the system IRR to double in value, following EIA (2010):

$$(1+IRR)^{Payback\ Time} = 2$$

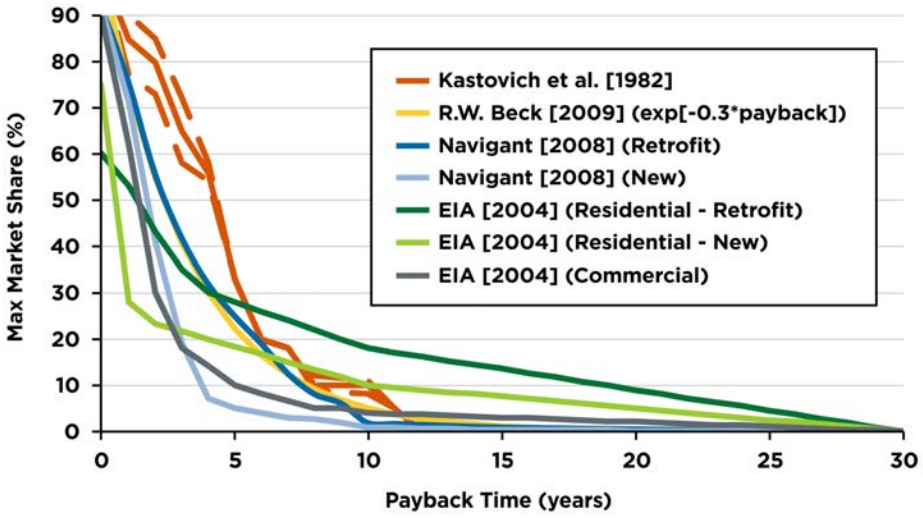
$$Payback\ Time = \frac{log(2)}{log(1+IRR)}$$

These equations are used to calculate PV payback times, which are then used to simulate customer adoption behavior as described in the next section.

A.3.2 Rooftop PV Adoption

PV adoption is simulated using a semi-empirical relationship between PV payback time and the maximum fraction of customers that might adopt PV (Kastovich et al. 1982, EIA 2004, Navigant 2008, R.W. Beck 2009). Maximum customer adoption fractions are approximated based on survey studies and expert elicitations from industry participants. Figure A-9 shows maximum market share relationships derived and used in previous studies. The reference and SunShot scenarios use the market share adoption curves developed by Navigant Consulting (2008).[97]

Figure A-9. Relationship between PV Maximum Market Share and PV Payback Time, Representing the Fraction of Customers Likely to Invest in PV for a Range of Payback Times



After the maximum market share is estimated, PV is diffused into this maximum market using a Bass diffusion model (Bass 1969). The Bass model represents the interaction of early technology adopters and late adopters to simulate a characteristic S-shaped technology-diffusion relationship. The following equation expresses a solution to the differential Bass equation,[98] and it represents the potential diffusion of PV technology into the maximum market share estimated by the relationships in Figure A-9:

[97] For a description of the impacts of using different market-adoption assumptions, see Drury et al. (2010).
[98] The Bass diffusion characteristics depend on the economics of a PV system, with quicker adoption for more economic systems. See Denholm et al. (2009) for a detailed description.

$$Adoption\ Rate\,(t) = \frac{1 - e^{-(p+q)T}}{1 + \left(\frac{q}{p}\right) e^{-(p+q)T}}$$

Where t represents the model year, T represents the total number of years that PV has been commercially available in the market, p represents the *coefficient of innovation* (used to characterize the impact of early PV adopters), and q represents the *coefficient of imitation* (used to characterize the impact of late PV adopters). The p and q parameters are varied in the SolarDS model based on the economics of PV systems such that PV diffuses more quickly as payback times decrease. The T parameter is also modified to better represent early and late adopters for each region independently (Denholm et al. 2009).

The final step in simulating rooftop markets is to calculate PV capacity additions from the customer adoption characteristics. This is done using a residential and commercial building stock database and statistically filtering this database to remove shaded roofs, obstructed roof space, and roofs that are unsuitable for PV adoption. The remaining building stock is scaled by the associated market adoption fractions using a distribution of customer- and building-dependent PV system sizes; residential systems have mean sizes of approximately 5 kW, and commercial systems have mean sizes of approximately 75–100 kW, depending on the deployment scenario. Using this methodology, the technical potential of the residential and commercial rooftop PV markets is approximately 300 GW each. Approximately 132 GW of commercial and 108 GW of residential rooftop PV capacity is deployed in the SunShot scenario by 2050.

The distributed rooftop PV capacity projections from SolarDS are exogenously input into the ReEDS model for each year of the simulation. Rooftop PV capacity is characterized for each ReEDS PCA region, and hourly PV generation profiles are calculated based on the mix of rooftop orientations that are deployed in SolarDS.

A.4 GridView Model

Designed and marketed by ABB, Inc., GridView is a commercial unit commitment and hourly economic dispatch model that simulates the financial operation of the electric power system with a constrained transmission grid based on a DC power flow (ABB 2008). GridView commits and dispatches electric generating units in order to minimize the production cost of the system as a whole while meeting electricity demand and reliability reserve requirements. GridView models the same generation technologies that are represented in ReEDS, including thermal generators,[99] hydroelectric generators and pumped storage, variable generators such as wind and PV, CSP with thermal storage, and CAES. GridView also represents interruptible load, as does ReEDS.

[99] The thermal generators modeled in GridView include generators that utilize conventional fuels (e.g., natural gas, coal, and uranium) and renewable fuels (e.g., biomass and geothermal).

GridView minimizes the total system production cost—including generator dispatch, transmission violation penalty, and unserved load penalty costs—via the following objective function:

$$Total_Cost = \min\left[\sum_t \left\{\sum_i \left(C_i\left(q_{i,t}\right) + N_i u_{i,t} + SU_i s_{i,t}\right) + penalties\right\}\right]$$

Where the decision variable $q_{i,t}$ represents the generation provided by generator i in hour t and $u_{i,t}$ and $s_{i,t}$ are binary variables that indicate whether unit i is up and has been started up (respectively) during hour t. Parameters $C_i(q_{i,t})$, N_i, and SU_i represent the piecewise linear generating cost function, no-load cost, and startup cost for generator i. The optimization is subject to a number of constraints, which are simplified in the equations below. One of the constraints is system energy balance:

$$D_t = \sum_i q_{i,t}$$

Where D_t is the system demand at time t. Spinning reserves are another constraint:

$$\sum_i sp_{i,t} \geq SR \quad ; \qquad sp_{i,t} + q_{i,t} \leq Cap_i$$

Where $sp_{i,t}$ is the spinning reserves provided by generator i at time t. SR is the spinning reserve requirement for the system, which depends on solar and wind penetrations. Cap_i is the maximum capacity at generator i. Constraints also bound generator operating limits, startup costs, ramping constraints, and transmission line ratings.

In the present study, GridView is used to supplement the ReEDS analysis by modeling the detailed operation of the system in 2050 for the SunShot scenario. GridView helps to demonstrate the operational feasibility of a system with high solar and wind penetration by using an hourly time step, a more accurate representation of thermal generation ramp-rate limits, and a more realistic representation of transmission power flows as compared to ReEDS. As a result of these capabilities, GridView can analyze how the system responds to uncertain ramps in the output of variable generation and provides a more complete understanding of the need for curtailment in times when generation supply exceeds demand.

The inputs for the GridView analysis are based on the ReEDS results from the SunShot scenario in 2050. Transmission capacity and generator fleet expansion results from ReEDS are input into GridView as individual units and lines. The database of existing electric system infrastructure comes from the WECC Transmission Expansion Planning Policy Committee, ERCOT, and the NERC Multiregional Modeling Working Group. The electric power systems represented in these three datasets were merged into a single database, connected with high-voltage direct current (HVDC) lines (as modeled by ReEDS), and centrally dispatched to minimize production cost. The assumption of nationwide dispatch represents either a single system operator that manages the entirety of the U.S. electric system or

frictionless markets between separate system operators. The transmission system in GridView is capable of operating in a detailed nodal format, where every major substation and transmission line is modeled individually. However, computational constraints and the spatial resolution of the ReEDS output limited the GridView analysis conducted in the present study to an aggregated zonal format, where transmission constraints are modeled only across the interfaces between the 134 assumed PCAs as defined by ReEDS.

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Appendix B. Tables Supporting Chapter 3 Figures

This appendix provides the raw data results from the Regional Energy Deployment System (ReEDS) associated with figures in *Chapter 3: Analysis of PV and CSP Growth in the SunShot Scenario*.

Table B-1. Figure 3-1. Cumulative Installed Capacity for Rooftop Photovoltaics (PV), Utility-Scale PV, Concentrating Solar Power (CSP), and All Solar Technologies [gigawatts (GW)]

	Rooftop PV	Utility PV	CSP	Total Solar
2010	1	0	0	2
2015	4	5	2	11
2020	19	31	3	53
2025	63	106	12	182
2030	121	181	28	329
2035	169	256	47	472
2040	201	331	62	594
2045	221	370	74	666
2050	240	391	83	714

Table B-2. Figure 3-2. Evolution of Electricity Generation in SunShot and Reference Scenarios ("Other" Includes Biomass and Geothermal Technologies) [terawatt-hours (TWh)]

	2010 Gen	2030 Reference	2030 SunShot	2050 Reference	2050 SunShot
Nuclear	790	757	757	448	448
Coal	1,849	1,600	1,561	2,215	1,411
Gas-CC	762	1,333	966	1,603	1,406
Gas-CT	11	34	25	37	27
Oil-gas-steam	31	51	49	0	0
Hydro	277	280	278	280	279
Other	27	65	49	65	48
Wind	115	342	236	435	283
CSP	1	4	137	9	412
Utility PV	0	17	335	68	710
Distributed PV	2	34	155	81	302
Storage	0	0	0	0	0

Gas-CC = combined cycle natural gas plant; Gas-CT = gas combustion turbine

Table B-3. Figure 3-3. Annual Avoided Fuel Use in the SunShot Scenario

	2030	2050
Gas Use (Quad/yr)	2.6	1.5
Coal Use (Quad/yr)	0.4	7.3
Fuel Cost (Bil$/yr)	34	41

Quad: quadrillion British thermal units

Table B-4. Figure 3-4. Evolution of Electricity-Generation Capacity in SunShot and Reference Scenarios ("Other" Includes Biomass and Geothermal Technologies) (GW)

	2010 Capacity	2030 Reference	2030 SunShot	2050 Reference	2050 SunShot
Nuclear	100	96	96	57	57
Coal	309	218	213	300	192
Gas-combined cycle (CC)	164	249	181	333	275
Gas-combustion turbine (CT)	125	248	223	335	314
Oil-gas-steam	135	98	98	24	24
Hydro	78	79	79	79	79
Other	4	9	7	9	7
Wind	44	107	79	132	91
CSP	0	2	28	3	83
Utility PV	0	9	181	32	391
Distributed PV	1	25	121	62	240
Storage	20	38	29	43	38

Table B-5. Figure 3-6. Cumulative Installed PV and CSP Capacity in the SunShot Scenario in 2030 and 2050 (GW)

	2030 PV	2030 CSP	2050 PV	2050 CSP
Alabama	2.3	0	6.6	0
Arizona	14.2	10.1	23.5	22.6
Arkansas	1.6	0	10.2	0
California	38.4	10.1	53.4	24.2
Colorado	6.3	2.1	11.7	8.2
Connecticut	5.3	0	8.1	0
Delaware	1.6	0	4.5	0
Florida	39.1	1.9	74.7	1.9
Georgia	13.1	0	25.5	0
Idaho	0.5	0	1.7	0
Illinois	2.6	0	6.1	0
Indiana	6	0	26.4	0
Iowa	1.6	0	2.7	0
Kansas	4	0	10.2	0
Kentucky	2.5	0	5.9	0
Louisiana	3.6	0	5.4	0
Maine	0.8	0	1.4	0
Maryland	7.5	0	13.3	0
Massachusetts	2.7	0	5	0
Michigan	2.8	0	18.8	0
Minnesota	2	0	7.4	0
Mississippi	1.2	0	7	0
Missouri	5.6	0	9.8	0
Montana	0.4	0	1.4	0
Nebraska	1.3	0	2.2	0
Nevada	5.4	0.5	8.7	2.3
New Hampshire	0.6	0	1	0
New Jersey	7.2	0	14.2	0
New Mexico	3.4	2.1	6.9	9.6
New York	7.7	0	19.2	0
North Carolina	8.2	0	21.7	0
North Dakota	0.2	0	0.8	0
Ohio	3.8	0	13.3	0
Oklahoma	11.1	0.2	15.7	0.5
Oregon	0.6	0	3.6	0
Pennsylvania	4.8	0	14.7	0
Rhode Island	2.6	0	4.4	0
South Carolina	14.5	0	18.8	0
South Dakota	0.3	0	0.6	0
Tennessee	3.9	0	19.4	0
Texas	41	0.6	78.4	12.6
Utah	6.3	0.1	12.8	1.1
Vermont	0.3	0	2.3	0
Virginia	8.7	0	21.2	0
Washington	1.9	0	2.3	0
West Virginia	0.2	0	1.5	0
Wisconsin	1.4	0	5	0
Wyoming	0.2	0	1.7	0

Table B-6. Figure 3-7. Fractions of CSP, PV, and Wind Electricity Generation in Each Interconnection for the SunShot Scenario

	Wind	PV	CSP
2030 Western	6%	16%	14%
2030 Electric Reliability Council of Texas (ERCOT)	6%	14%	0%
2030 Eastern	5%	9%	0%
2050 Western	6%	23%	33%
2050 ERCOT	6%	21%	7%
2050 Eastern	5%	18%	1%

Table B-7. Figure 3-10. Net Energy Transmitted Between Interconnections (Negative Values Represent Imported Energy, Positive Values Represent Exported Energy) (TWh)

	Western to Eastern	Eastern to ERCOT
Reference 2030	-9	-7
SunShot 2030	14	3
Reference 2050	-6	7
SunShot 2050	64	-2

Table B-8. Figure 3-11. Comparison of the National Generation Mix Simulated in GridView and ReEDS for the Reference and SunShot Scenarios, 2050

	ReEDS 2050 Reference	GridView 2050 Reference	ReEDS 2050 SunShot	GridView 2050 SunShot
PV	2.8%	2.8%	18.8%	19.2%
CSP	0.2%	0.2%	7.5%	7.1%
Wind	7.9%	8.0%	5.1%	5.3%
Other	1.6%	1.4%	1.3%	1.1%
Hydropower	6.5%	6.3%	6.4%	6.4%
Gas-CT	0.7%	3.1%	0.5%	2.7%
Gas-CC	29.2%	26.3%	25.5%	23.7%
Coal	43.4%	44.0%	28.2%	28.5%
Nuclear	8.2%	7.9%	8.1%	7.9%
Curtailment	-0.3%	0.0%	-1.4%	-1.7%

Table B-9. Figure 3-14. Direct Electric-Sector Costs for the Reference and SunShot Scenarios (Billion $)

	Reference 2010–2030	SunShot 2010–2030	Reference 2010–2050	SunShot 2010–2050
Conventional Capital	165	114	315	203
Conventional O&M	717	703	748	723
Fuel	1,566	1,407	1,739	1,544
Transmission	45	41	61	60
Other Renewables	317	269	368	303
CSP	8	45	10	83
Utility PV	20	92	28	133
Distributed PV	29	74	40	101

O&M: operation and maintenance

Table B-10. Figure 3-15. Average U.S. Retail Electricity Rates in the SunShot and Reference Scenarios [2010 cents/kilowatt-hour (kWh)]

	Reference	SunShot
2010	10.1	10.1
2012	10.4	10.4
2014	10.5	10.5
2016	10.6	10.6
2018	10.7	10.7
2020	10.9	10.8
2022	11.1	10.9
2024	11.2	10.9
2026	11.4	10.9
2028	11.6	11.1
2030	12	11.4
2032	12.3	11.6
2034	12.7	11.9
2036	12.9	12.1
2038	13.2	12.3
2040	13.3	12.4
2042	13.4	12.5
2044	13.5	12.6
2046	13.6	12.7
2048	13.8	12.8
2050	13.9	13

Table B-11. Figure 3-16. Annual Electric-Sector Carbon Dioxide (CO_2) Emissions in the SunShot and Reference Scenarios
[million metric tons (MMT) CO_2]

	Reference	SunShot
2010	2,090	2,090
2012	2,240	2,240
2014	2,220	2,220
2016	2,210	2,210
2018	2,210	2,210
2020	2,210	2,210
2022	2,210	2,200
2024	2,220	2,170
2026	2,220	2,120
2028	2,200	2,070
2030	2,210	2,030
2032	2,270	2,000
2034	2,360	1,980
2036	2,440	1,980
2038	2,530	1,990
2040	2,560	1,960
2042	2,590	1,950
2044	2,630	1,950
2046	2,660	1,950
2048	2,690	1,950
2050	2,710	1,950

Table B-12. Figure 3-17. Cumulative Electric-Sector Emissions Reductions in the SunShot Scenario Relative to the Reference Scenario (MMT CO_2)

2010	0
2012	0
2014	0
2016	0
2018	0
2020	0
2022	30
2024	140
2026	320
2028	570
2030	940
2032	1,490
2034	2,230
2036	3,150
2038	4,230
2040	5,420
2042	6,710
2044	8,070
2046	9,490
2048	10,970
2050	12,490

Appendix C. Sensitivity of Renewable Electricity Technology Deployment Projections to Technology Price Assumptions

C.1 Introduction

This appendix examines the sensitivity of renewable electricity technology deployment projections to technology price assumptions. The *SunShot Vision Study* models the effects of reducing the price of solar energy systems by about 75% between 2010 and 2020. In comparison, the prices of conventional and other renewable electricity technologies are assumed to change relatively little during the study period. Because the models used in the analysis project the mix of electricity-generating technologies based on least-cost deployment, solar deployment is dependent on the assumed solar price reductions. Similarly, if the prices of other renewable electricity technologies were varied along with the price of solar technologies, the projected mix of electricity-generating technologies would depend on those price assumptions as well. Scenarios[100] exploring the effects of various solar price reductions and various non-solar renewable price reductions are described below.

C.2 Sensitivity of Solar Deployment to Solar Prices

To explore the sensitivity of solar deployment to solar technology prices, solar deployment was modeled using two price scenarios, in addition to the SunShot and reference scenarios. These two scenarios included cost reductions that were less aggressive than the SunShot targets: 1) Photovoltaic (PV) prices decline by 50% between 2010 and 2020, and 2) PV prices decline 62.5% between 2010 and 2020. Table C-1 shows the SunShot and sensitivity scenario prices for all solar technologies and applications. The SunShot scenario's 2010 utility-scale PV benchmarked price is $4/watt (W); thus, the sensitivity scenarios' 2020 utility-scale

[100] Note that these sensitivity scenarios do not assume any potential costs for mercury and air toxins, carbon emissions, or other environmental externalities.

Table C-1. Price Inputs for SunShot and Sensitivity Scenarios

Technology/Application	SunShot Scenario 2020 -75% Price	Sensitivity Scenario 2020 -62.5% Price	Sensitivity Scenario 2020 -50% Price	Reference Scenario 2020
PV – Residential [$/watt $(W)_{DC}$]	1.50	2.25	3.00	3.78
PV – Commercial ($/$W_{DC}$)	1.25	1.88	2.50	3.36
PV – Utility Scale ($/$W_{DC}$)	1.00	1.50	2.00	2.51
CSP, 6/14 hour Storage ($/$W_{AC}$)[a]	3.60	4.87	6.14	6.64

[a] All values are for CSP systems with 14 hours of thermal storage except for the reference scenario value, which is for 6 hours of thermal storage.

PV prices are $2/W and $1.50/W, respectively. Similarly, the sensitivity scenarios' 2020 distributed PV (residential and commercial) prices are 50% and 62.5% lower in relation to their 2010 benchmarked prices. For concentrating solar power (CSP), the decline in installed capital cost was set to yield a similar level of relative cost reduction on an LCOE basis, including a shift to increased storage. The increased levels of storage assumed for CSP are reflected in Table C-1 with higher values for capacity factors. All conventional and non-solar renewable technology prices are the same for the SunShot and sensitivity scenarios. In all other parameters, the sensitivity analysis matches the SunShot analysis.

Figure C-1 and Figure C-2 show the results of the sensitivity analysis. In the SunShot scenario, installed solar capacity reaches 330 gigawatts (GW) in 2030 and 715 GW in 2050 (Figure C-1). In the 62.5% price decline scenario, solar capacity reaches 270 GW in 2030 (18% lower than in the SunShot scenario) and 470 GW in 2050 (35% lower). In the 50% price decline scenario, solar deployment drops dramatically: 130 GW in 2030 (59% lower than in the SunShot scenario) and 200 GW in 2050 (73% lower). In the reference scenario, solar capacity reaches 40 GW in 2030 (89% lower than in the SunShot scenario) and 100 GW in 2050 (86% lower). Figure C-2 shows similar results for solar generation fraction. Clearly, solar market penetration is sensitive to the projected level of PV and CSP price reductions. These results indicate that there is a threshold at which solar deployment increases non-linearly as price decreases. This threshold is below $2/W for utility-scale PV (and an equivalent level of price reduction for distributed PV and CSP).

C.3 Sensitivity of Electricity-Generating Mix to Non-Solar Renewable Energy Prices

To explore the sensitivity of the electricity-generating mix to non-solar renewable technology prices, modeling was performed with non-solar renewable price reductions/performance improvements that are more aggressive than those in the SunShot scenario. These more aggressive assumptions are shown in Table C-2 and are included in the SunShot renewable electricity-evolutionary technology

improvement (SSRE-ETI) scenario. SunShot solar price reductions were used both for the SunShot scenario and the SSRE-ETI scenario. In all other parameters, the analysis matched the SunShot analysis.

Figure C-1. Total Solar Capacity Under a Range of Solar Price-Reduction Scenarios

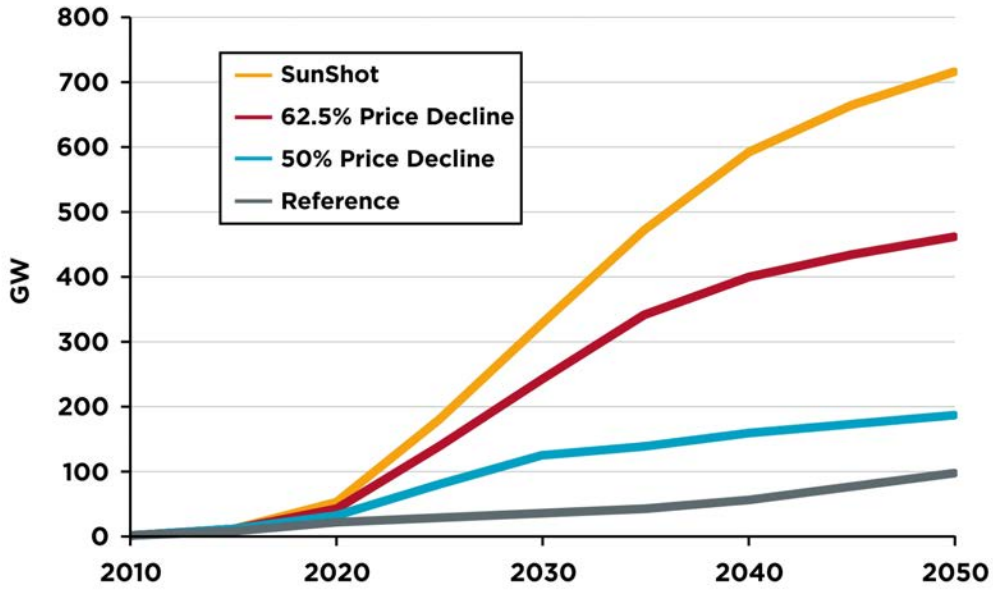


Figure C-2. Total Solar Generation Fraction Under a Range of Solar Price-Reduction Scenarios

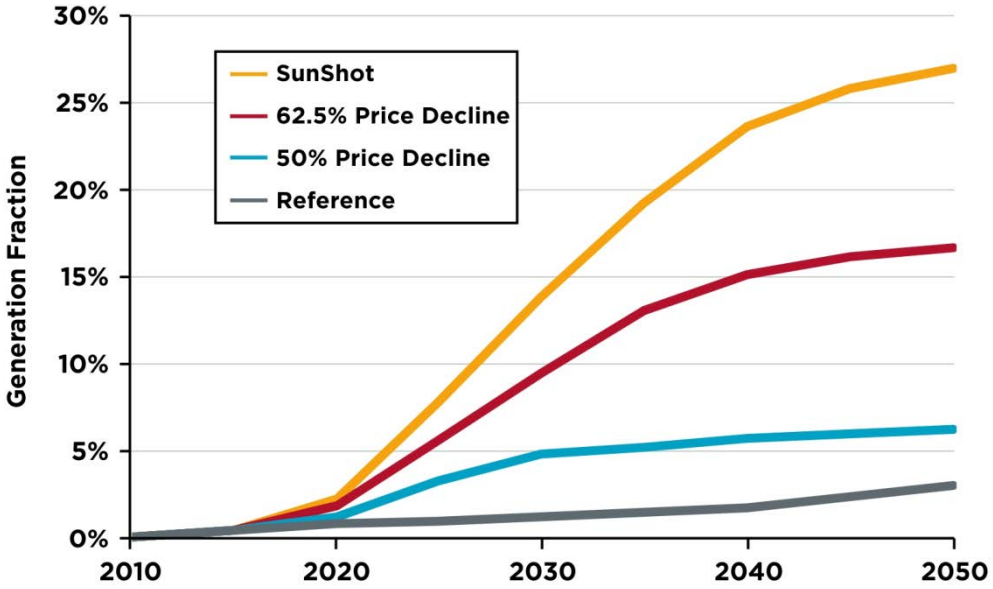


Table C-2. Price and Performance Inputs for SunShot and SSRE-ETI Scenarios

Technology	Price and Performance	
	SunShot Scenario	SSRE-ETI Scenario
Solar	SunShot targets	SunShot targets
Onshore wind	Reference	Capital cost decreases from about $2,000/kilowatt (kW) to $1,775/kW during 2010–2035. Performance ~10% above reference level in 2010, additional ~10% performance improvement by 2030. Capacity factors substantially higher than in reference. Wind levelized cost of energy (LCOEs) approach solar LCOEs by 2035.
Offshore wind	Reference	Capital cost decreases from about $3,650/kW to $2,700/kW during 2010–2035. Performance improvements similar to onshore wind. Capacity factors substantially higher than in Reference.
Biopower	Reference	Capital cost slightly lower, operation and maintenance (O&M) 30%–50% lower than reference. Heat rate starts at lower value than in reference and improves by ~30% during 2010–2050.
Geothermal	Reference	Capital cost decreases ~10% by 2030 and ~20% by 2050. Includes about 25 GW of additional "undiscovered" resource.
Hydropower	Reference	O&M ~40% lower than reference.
Non-renewable technologies	Reference	Reference

Reference prices and performance are from Black & Veatch (forthcoming). See Appendix A for details.

Figure C-3 shows the installed capacity results of the sensitivity analysis. Wind capacity increases significantly in the SSRE-ETI scenario. In 2030, wind capacity is 119 GW in the SSRE-ETI scenario, 51% higher than in the SunShot scenario (79 GW). In 2050, wind capacity is 240 GW, 164% higher than in the SunShot scenario (91 GW). At the same time, solar capacity (PV plus CSP) decreases slightly in the SSRE-ETI scenario. In 2030, solar capacity is 317 GW, 4% lower than in the SunShot scenario (330 GW). In 2050, solar capacity is 655 GW, 8% lower than in the SunShot scenario (715 GW). To accommodate the additional variable renewable energy capacity in the SSRE-ETI scenario, gas-combustion turbine (gas-CT) capacity increases while gas-combined cycle (Gas-CC) capacity decreases. Coal capacity increases by 11 GW (5%) in the SSRE-ETI scenario compared with the SunShot scenario in 2030, but it decreases by 27 GW (14%) in 2050. This result highlights the complementarity of the solar and wind resources. Even with a substantial build-out of wind generation capacity, there is only a small reduction in solar capacity. Together, these two renewable resources largely complement rather than compete with each other, enabling a much higher penetration of renewable generation on the grid.

Figure C-3. Electricity Capacity by Source, SunShot and Sensitivity Scenarios

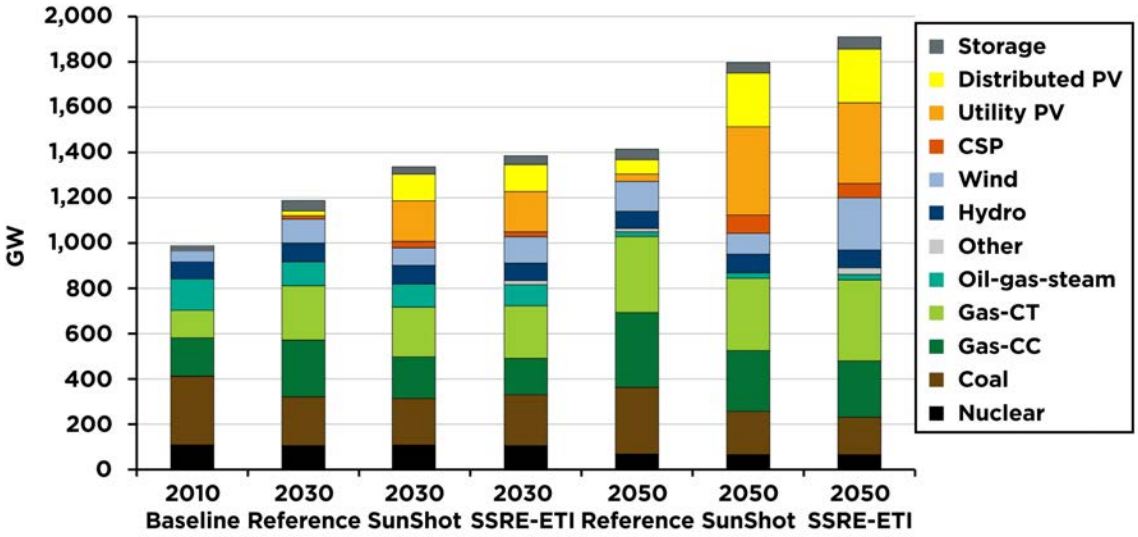
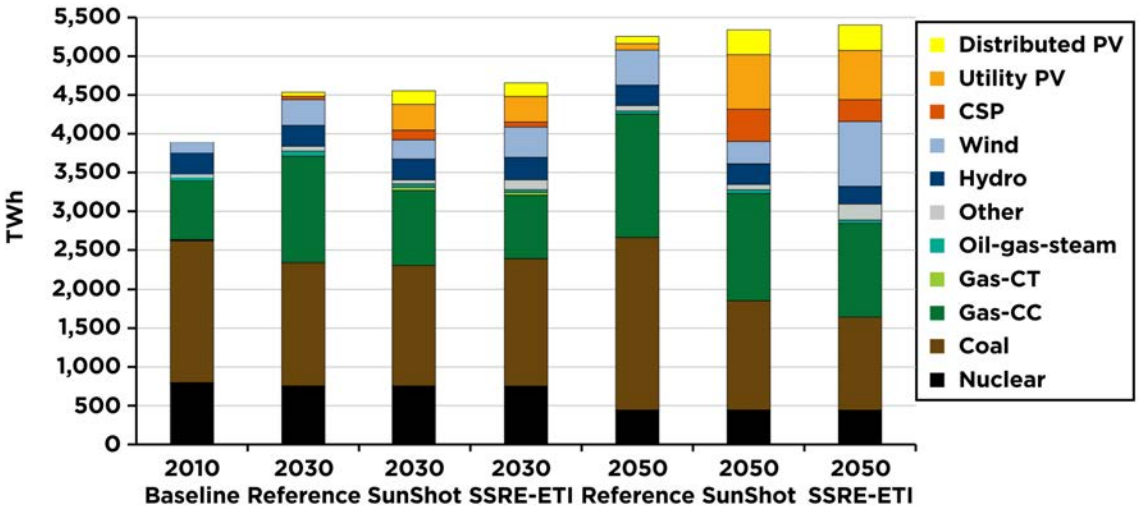


Figure C-4 shows the electricity generation results of the sensitivity analysis. In 2030, wind contributes 8% of generation in the SSRE-ETI scenario, compared with 5% in the SunShot scenario with low technology costs for solar alone. In 2050, wind contributes 16% of generation in the SSRE-ETI scenario, compared with 6% in the SunShot scenario. The share of electricity from "Other" sources—which include geothermal and biopower—increases in the SSRE-ETI scenario (3% in 2030, 4% in 2050) compared with the SunShot scenario (1% in 2030 and 2050). At the same time, the contribution of solar decreases in the SSRE-ETI scenario (12% in 2030, 23% in 2050) compared with the SunShot scenario (14% in 2030, 27% in 2050). By 2050, the combined contribution of coal and natural gas also decreases in the SSRE-ETI scenario compared with the SunShot scenario (from 53% to 45%).

Figure C-4. Electricity Generation by Source, SunShot and Sensitivity Scenarios



Clearly, the increased penetration of non-solar renewable technologies in the SSRE-ETI scenario, due to reduced prices and/or improved performance, reduces solar capacity and electricity generation. However, the contribution of fossil fuels is reduced even more substantially by 2050 because of the increased renewable penetration.

C.4 Sensitivity of Solar Deployment to Natural Gas Prices

An additional sensitivity on the Sunshot scenario was run with lower natural gas prices because natural gas fuel supply assumptions in the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook* 2011 (*AEO 2011*) were significantly more optimistic than those of *AEO 2010*. The same methodology for constructing a new natural gas supply curve in ReEDS was used for *AEO 2011* as was used for *AEO 2010* (see Appendix A). This resulted in natural gas prices that were \$1.50 /10^6 British thermal units (Btu) to \$2.00 /10^6 Btu lower in the *AEO 2011* natural gas fuel price sensitivity than in the SunShot scenario, assuming the same amounts of gas usage. This sensitivity produced 400 terawatt-hours (TWh) more electricity generation from natural gas combined cycle plants than SunShot in 2050, or 7% of total electricity generation. However, 350 TWh of this additional gas generation merely replaced coal generation, mostly from new coal plants that were built in the SunShot scenario after 2034. The solar generation fraction for this sensitivity was 25.5%, as compared to 26.9% in the SunShot scenario. These results suggest that if solar costs reach SunShot targets, solar will be able to compete with natural gas generation at a range of natural gas fuel prices, and that natural gas does not compete directly with solar at high-solar penetrations because the load shape has shifted.

C.5 References

U.S. Energy Information Administration, EIA. (2010). *Annual Energy Outlook 2010*. Report No. DOE/EIA-0383 (2010). Washington, DC: U.S. EIA.

EIA. (2011). *Annual Energy Outlook 2011*. Report No. DOE/EIA-0383 (2011). Washington, DC: U.S. EIA.

Appendix D. Authors, Reviewers, and Other Contributors

D.1 Overview

The U.S. Department of Energy (DOE) would like to acknowledge the *SunShot Vision Study's* authors, reviewers, and other contributors listed below. This report draws heavily on research, analysis, and material created for DOE's draft *Solar Vision Study*, which was in development from June 2009 through December 2010. When DOE's SunShot Initiative was launched in February 2011, the *Solar Vision Study* was redeveloped to fit the SunShot framework, resulting in this *SunShot Vision Study*. The following acknowledgments represent the full spectrum of participation during the evolution of this project, including coordinators and production support; the *SunShot Vision Study* authors, editors, and reviewers; and the draft *Solar Vision Study* steering committee, authors, external reviewers, and other contributors.

The final version of the *SunShot Vision Study* is the sole responsibility of DOE. The participation of external reviewers of the *SunShot Vision Study* and authors and external reviewers of the draft *Solar Vision Study* does not imply that they or their respective organizations either agree or disagree with the findings of this report.

D.2 Coordination and Production

D.2.1 Lead Editors and Coordinators

The following individuals were responsible for leading the drafting, review, and editing processes for the *SunShot Vision Study* and draft *Solar Vision Study* in support of, and in collaboration with, staff from the DOE Solar Energy Technologies Program (SETP).

Robert Margolis	National Renewable Energy Laboratory
Charlie Coggeshall	New West Technologies, LLC
Jarett Zuboy	Consultant

D.2.2 Production, Editing, and Graphic Design

The production, editing, and graphic design/formatting for both studies were supported by the following individuals.

Sheri Anstedt	Consultant, Quality Control Editor
Julie Chappell	Energetics Incorporated, Graphics Lead
Charlie Coggeshall	New West Technologies, LLC, Document Version Control
Tina Eichner	National Renewable Energy Laboratory, Communications Lead
Tommy Finamore	Energetics Incorporated, Graphic Design
Linh Truong	National Renewable Energy Laboratory, Website Support
Joshua Bauer	National Renewable Energy Laboratory, Cover Graphic Design
Susan Kaczmarek	Energetics Incorporated, Document Layout Coordinator
Courtney Kendall	National Renewable Energy Laboratory, Communications Support
Anthony Lopez	National Renewable Energy Laboratory, Technical Graphics Support
Susan Moon	National Renewable Energy Laboratory, Technical Editor (*Solar Vision Study*)
Andrew Perry	National Renewable Energy Laboratory, Technical Graphics Support
Billy Roberts	National Renewable Energy Laboratory, Technical Graphics Support
Jarett Zuboy	Consultant, Technical Editor (*SunShot Vision Study*)

D.3 *SunShot Vision Study* Authors, Editors, and Reviewers

The *SunShot Vision Study* used the post-external review version of the draft *Solar Vision Study* as a starting point. Much of the *SunShot Vision Study* effort was internal, utilizing expertise from DOE staff, contractors, and national laboratories. The public was engaged, however, through an open external review process in which input was provided by more than 30 individuals representing key sectors of the solar industry.

D.3.1 Authors and Editors

The following individuals were responsible for key elements of the analysis, writing, and revision process that took place from March through October, 2011. Examples of activities during this process include developing and modeling the SunShot and reference scenarios; drafting and editing each chapter's content; and addressing comments made by external reviewers.

Galen Barbose	Lawrence Berkeley National Laboratory
Mark Bolinger	Lawrence Berkeley National Laboratory
Gregory Brinkman	National Renewable Energy Laboratory
Charlie Coggeshall	New West Technologies, LLC
Karlynn Cory	National Renewable Energy Laboratory
Paul Denholm	National Renewable Energy Laboratory
Easan Drury	National Renewable Energy Laboratory
Abraham Ellis	Sandia National Laboratories
David Feldman	National Renewable Energy Laboratory
Jesse Gary	U.S. Department of Energy
Alan Goodrich	National Renewable Energy Laboratory
Garvin Heath	National Renewable Energy Laboratory
Benjamin Kroposki	National Renewable Energy Laboratory
Trieu Mai	National Renewable Energy Laboratory
Robert Margolis	National Renewable Energy Laboratory
Matthew Mowers	National Renewable Energy Laboratory
Craig Turchi	National Renewable Energy Laboratory
Jarett Zuboy	Consultant

D.3.2 Internal Reviewers

The following individuals provided comments on the *SunShot Vision Study* during various stages of the report's development and were internal to the process.

Sam Baldwin	U.S. Department of Energy
Shubhra Bansal	Mantech International Corporation
Kathleen Bolcar	U.S. Department of Energy (formerly)
Jennifer DeCesaro	U.S. Department of Energy
Adam Goldstein	New West Technologies, LLC (formerly)
Victor Kane	U.S. Department of Energy
Joseph Stekli	U.S. Department of Energy
Frank Wilkins	U.S. Department of Energy (formerly)
Minh Le	U.S. Department of Energy
Kevin Lynn	U.S. Department of Energy
Gian Porro	National Renewable Energy Laboratory
Ramamoorthy Ramesh	U.S. Department of Energy
Walter Short	National Renewable Energy Laboratory

D.3.3 External Reviewers

The draft chapters of the *SunShot Vision Study* were made public for external review and comment from July 25 through August 15, 2011. All contributors (authors and reviewers) to the draft *Solar Vision Study* were invited to review the draft *SunShot*

Vision Study. An additional 16 individuals were invited to review the draft *SunShot Vision Study* by the Program Manager of DOE's Solar Energy Technologies Program, Ramamoorthy Ramesh. Finally, the review process was open to the general public via a publically accessible website. Note that colleagues of some individuals listed below also provided input, as well as staff from the Solar Energy Industries Association (SEIA).

Neenan Bernard	Electric Power Research Institute
Julie Blunden	SunPower Corporation
Richard Brewer	SunPower Corporation
Matt Campbell	SunPower Corporation
Corrie Clark	Argonne National Laboratory
Ed DeMeo	Renewable Energy Consulting Services, Inc
Nadav Enbar	Electric Power Research Institute
Kevin Fox	Keyes & Fox, LLP
Vasilis Fthenakis	Brookhaven National Laboratory
Bryan Hannegan	Electric Power Research Institute
Heidi Hartmann	Argonne National Laboratory
David Hochschild	Solaria Corporation
Robert Horner	Argonne National Laboratory
Revis James	Electric Power Research Institute
Tom Key	Electric Power Research Institute
Carl Lenox	SunPower Corporation
Cara Libby	Electric Power Research Institute
Jordan Macknick	National Renewable Energy Laboratory
Arjun Makhijani	Institute for Energy and Environmental Research
Alex Marker	SCHOTT North America, Inc
JM Morabito	Alcatel-Lucent
Jaim Nulman	eTe Solutions, LLC
Bill Powers	Powers Engineering
Christopher Raup	Consolidated Edison, Inc.
Moshe Sadeh	HelioFocus
Adam Shor	Electric Power Research Institute
J Charles Smith	Utility Wind Integration Group
Gerhard Stry-Hipp	Fraunhofer ISE
Dick Swanson	SunPower Corporation
Mike Swearingen	Tri-County Electric Cooperative, Inc
Blair Swezey	SunPower Corporation
Bolko von Roedern	National Renewable Energy Laboratory
Eicke Weber	Fraunhofer ISE
Gerhard Willeke	Fraunhofer ISE

D.4 *Solar Vision Study* Steering Committee, Authors, External Reviewers, and Other Contributors

The draft *Solar Vision Study* was launched in June 2009 and drew on a steering committee and working groups with more than 140 representatives from solar companies, utilities, financial firms, universities, national laboratories, non-profits, industry associations, and other organizations. A draft of the *Solar Vision Study* was circulated for external review during June 2010. Comments were received from more than 50 individuals representing stakeholders across the solar industry. The contributions made by authors and reviewers of the draft *Solar Vision Study* provided a starting point for the *SunShot Vision Study*, with the exception of material focused on solar heating and cooling technologies, which was not included in the *SunShot Vision Study*.

D.4.1 Steering Committee and Chapter Working Group Authors and Contributors

The following list includes the draft *Solar Vision Study* steering committee, working group authors, and other contributors such as those involved in the analysis development and modeling process.

A steering committee was formed during the second quarter of 2009 to provide strategic guidance and feedback throughout the development of the draft *Solar Vision Study*. The Solar Energy Industries Association and the Solar Electric Power Association aided in identifying the individuals for this role. The committee representatives are in italics below. An asterisk (*) denotes individuals who were 'observers' of the steering committee.

Each chapter had a working group consisting of chapter leaders and members with varying types of responsibility. The objective of each group was to draft its respective chapter to be technically sound and consistent with the analyses used for the draft *Solar Vision Study*. The working groups were developed through recommendations by the draft *Solar Vision Study* steering committee as well as input from DOE.

David Arfin	SolarCity
Rainer Aringhoff	Solar Millennium
Jim Baak	The Vote Solar Initiative
Justin Baca	Solar Energy Industries Association
Sam Baldwin*	U.S. Department of Energy
Jessica Ballard	Infinia Corporation
Galen Barbose	Lawrence Berkeley National Laboratory
Bianca Barth	Solar Electric Power Association
John Bartlett	New West Technologies, LLC (formerly)
Kelly Beninga	WorleyParsons
Julie Blunden	*SunPower Corporation*
Mark Bolinger	Lawrence Berkeley National Laboratory

Peter Brehm	Infinia Corporation
Gregory Brinkman	National Renewable Energy Laboratory
Adam Browning	The Vote Solar Initiative
Nathaniel Bullard	New Energy Finance
Bob Cart	GreenVolts (formerly)
Caroline Chapman	National Renewable Energy Laboratory
Bob Charles	Sargent & Lundy
Stephen Chin	UBS
Barry Cinnamon	*Akeena Solar*
Charlie Clark	Cascade Consulting Partners
Charlie Coggeshall	New West Technologies, LLC
Kevin Collins	First Solar, Inc.
Karlynn Cory	National Renewable Energy Laboratory
Carrie Cullen Hitt	Solar Alliance
Ken Davis	Sargent & Lundy
Jennifer DeCesaro	U.S. Department of Energy
Kevin DeGroat	Antares Group
Bernadette Del Chiaro	Environment California
Paul Denholm	National Renewable Energy Laboratory
Jim Dietz	Plextronics, Inc.
Tom Dinwoodie	SunPower Corporation
Aron Dobos	National Renewable Energy Laboratory
Stephen Doig	Rocky Mountain Institute
Easan Drury	National Renewable Energy Laboratory
Martha Duggan	*United Solar*
Dave Eaglesham	First Solar, Inc.
Pam Eaton	The Wilderness Society
Abraham Ellis	Sandia National Laboratories
Barry Friedman	National Renewable Energy Laboratory
Vasilis Fthenakis	Brookhaven National Laboratory
Sean Galligher	Stirling Energy Solutions, Inc.
Jesse Gary	U.S. Department of Energy
Charlie Gay	*Applied Materials*
Randy Gee	SkyFuel Inc.
Patrick Geenen	Sargent & Lundy
Katherine Gensler	Solar Energy Industries Association
Rick Gilliam	*SunEdison (an MEMC company)*
Lori Glover	SOLID Energy
Susan Gouchoe	North Carolina State University, North Carolina Solar Center (formerly)
Bill Gould	SolarReserve
Nathanael Greene	*Natural Resources Defense Council*
Tom Guardino	Cascade Consulting Partners

Julia Hamm	*Solar Electric Power Association*
Charlie Hanley	*Sandia National Laboratories*
Dennis Harper	First Solar, Inc.
Bob Hassett	U.S. Department of Energy (formerly)
Arthur Haubenstock	BrightSource Energy, Inc.
Garvin Heath	National Renewable Energy Laboratory
Christy Herig	Solar Electric Power Association
Tom Hoff	Clean Power Research
Cynthia Hunt Jaehne	Morse Associates, Inc.
Eric John	SkyFuel Inc.
Margarett Jolly	Consolidated Edison, Inc.
Dan Kammen	*University of California, Berkeley*
Dave Kearney	Kearney & Associates
Tom Key	*Electric Power Research Institute*
Tom Kimbis	Solar Foundation
Marty Klepper	Skadden, Arps, Slate, Meagher, and Flom, LLP & Affiliates
Greg Kolb	Sandia National Laboratories
Ben Kroposki	National Renewable Energy Laboratory
Hal LaFlash	Pacific Gas and Electric Company
Mark Lausten	SRA International (formerly Sentech)
Bob Leckinger	FAFCO
Carl Lenox	SunPower Corporation
Debbie Lew	National Renewable Energy Laboratory
Craig Lewis	RightCycle
Cara Libby	Electric Power Research Institute
Josh Linn	*Massachusetts Institute of Technology*
John Lushetsky*	U.S. Department of Energy
Kevin Lynn	U.S. Department of Energy
Jordan Macknick	National Renewable Energy Laboratory
Jeff Mahoney	Rheem Manufacturing Company
Robert Margolis	*National Renewable Energy Laboratory*
Alex Marker	SCHOTT Solar, Inc.
Andrew Martinez	National Renewable Energy Laboratory
Jim McVeigh	SRA International (formerly Sentech)
Mark Mehos	National Renewable Energy Laboratory
Joel Meister	Solar Energy Industries Association
Tim Merrigan	National Renewable Energy Laboratory
James Milford	National Renewable Energy Laboratory
JoAnn Milliken*	U.S. Department of Energy
Andrew Mills	Lawrence Berkeley National Laboratory
Paula Mints	Navigant Consulting
Fred Morse	*Morse Associates, Inc.*

Matthew Mowers	National Renewable Energy Laboratory
John Mucci	*Consolidated Edison, Inc.*
Hannah Muller	U.S. Department of Energy
Terry Murphy	*SolarReserve (formerly)*
Milena Naedenova	Applied Materials
Sobia Navqi	Abengoa Solar
Denise Nelson	Consolidated Edison, Inc.
Les Nelson	*Western Renewables Group*
Robert (Bob) O'Hara	Sargent & Lundy
Sean Ong	National Renewable Energy Laboratory
Steve O'Rourke	*Deutsche Bank (formerly)*
Jim Pacheco	eSolar, Inc.
Terry Peterson	Solar Power Consulting
Ole Pilgaard	Heliodyne, Inc.
Hank Price	Abengoa Solar
Selya Price	National Renewable Energy Laboratory (formerly)
Michael Rader	Solar Energy Industries Association
Tanya Raterman	Cascade Consulting Partners
Christopher Raup	Consolidated Edison, Inc.
Rick Raushenbush	GreenVolts, Inc.
Rick Reed	*SunEarth, Inc.*
Rhone Resch	*Solar Energy Industries Association*
Wilson Rickerson	Meister Consultants Group
Sally Rosauer	FAFCO
David Rubin	*Pacific Gas and Electric Company*
Andrew Sabel	Alanod Solar
Rob Sargent	Environment America
Vishal Shah	Barclays Capital (formerly)
Charlie Shipp	SC Partners, LLC
Walter Short	National Renewable Energy Laboratory
Gianluca Signorelli	MMA Renewable Ventures (formerly)
Eric Silagy	*Florida Power & Light Company*
Katherine Stainken	Solar Energy Industries Association
Cai Steger	Natural Resources Defense Council
Joshua Stein	Sandia National Laboratories
Joe Stekli	U.S. Department of Energy
Scott Stephens	U.S. Department of Energy
Samir Succar	Natural Resources Defense Council
Patrick Sullivan	National Renewable Energy Laboratory
Dick Swanson	SunPower Corporation
Blair Swezey	SunPower Corporation
Andy Taylor	BrightSource Energy, Inc.
Mike Taylor	Solar Electric Power Association

Dan Ton	U.S. Department of Energy
Craig Turchi	National Renewable Energy Laboratory
Cyrus Wadia	U.S. Executive Office of the President
Johanna Wald	Natural Resources Defense Council
Peter Weiner	Paul Hastings
Kathy Weiss	*First Solar, Inc.*
Frank Wilkins	U.S. Department of Energy (formerly)
Ryan Wiser	*Lawrence Berkeley National Laboratory*
Ahmar Zaman	UBS
Carl Zichella	Sierra Club (formerly)
Jarett Zuboy	Consultant
Ken Zweibel	*George Washington University Solar Institute*

D.4.2 External Reviewers

The following list consists of individuals who provided comments during the draft *Solar Vision Study* external review period from May 28 through June 25, 2010. Recommendations by the chapter working groups and input from DOE provided the basis for selecting specific individuals to be invited to the review process. In addition, the draft chapters were posted on a publically accessible website and available for comment from the general public. Over 50 individuals external to the draft *Solar Vision Study* process provided comments on one or more draft chapters. This total and the list below do not include individuals internal to the draft *Solar Vision Study* development process (e.g., active working group members) who provided comments during the review process.

Mark Alstrom	WindLogics Inc. (a NextEra Energy company)
Rahim Amerkhail	Federal Energy Regulatory Commission
Bulent Basol	EncoreSolar
Chip Bircher	Utility Solar Water Heating Initiative (USH20)
Travis Bradford	Greentech Media
Bob Carver	New York State Energy Research and Development Authority
Matt Clouse	U.S. Environmental Protection Agency
Jessica Cockrell	Federal Energy Regulatory Commission
James Critchfield	U.S. Environmental Protection Agency
Ed DeMeo	Renewable Energy Consulting Services, Inc.
Joel Dickinson	Salt River Project
Jay Diffendorfer	U.S. Geological Survey
Ronald Flood	Arizona Public Service
Kevin Fox	Keyes & Fox, LLP
Yoel Gilon	BrightSource Energy, Inc.
Jennifer Gleason	Environmental Law Alliance Worldwide (ELAW)
Richard Halvey	Western Governors' Association

Heidi Hartmann	Argonne National Laboratory
David Hochschild	Solaria Corporation
Tom Hoff	Clean Power Research
Mark Jacobsen	Stanford University
Charles Jennings	AGL Energy Limited
Sue Kateley	California Solar Energy Industries Association
Jonathan Kelves	Sierra Club
Jason Keyes	Keyes & Fox, LLP
Mike King	NERA Economic Consulting
Ron Lehr	Western Grid Group
Robert Litwin	Pratt-Whitney Rocketdyne
Thomas Mancini	Sandia National Laboratories
Adam Mendelson	SunPower Corporation
Dave Menucicci	Building Specialist Inc
John Miller	Sentech, Inc.
Joe Morabito	Alcatel-Lucent
Babul Patel	Nexant Inc.
Cedric Philibert	International Energy Agency
Bill Powers	Powers Engineering
Linda Resseguie	U.S. Bureau of Land Management
Jacques Roeth	New York State Energy Research and Development Authority
Andrew Ryan-Smith	National Grid
Jigar Shah	Carbon War Room
Larry Sherwood	Interstate Renewable Energy Council
Greg Smestad	Solar Energy Materials and Solar Cells
J Charles Smith	Utility Wind Integration Group
Marty Smith	Xcel Energy
Phil Smithers	Arizona Public Service
Kathleen Sullivan	Abengoa Solar
Ted Sullivan	Lux Research
Cecilia Tam	International Energy Agency
Craig Tyner	eSolar, Inc.
Joe Tyrrell	3M
Harin Ullal	National Renewable Energy Laboratory
Bolko vonRoedern	National Renewable Energy Laboratory
Thomas Wells	Southern Company
Sahm White	FIT Coalition
Cherif Yousseff	Sempra Energy

D.4.3 Solar Vision Workshop, October 26, 2009

The Solar Vision Workshop was held on October 26, 2009, in Anaheim, California, adjacent to the Solar Power International Conference. The purpose of the workshop was to review the status and direction of the draft *Solar Vision Study*, by providing a venue for each chapter working group to present its respective chapter's progress, as well as address questions and concerns from the steering committee, other working group members, and the general public. The following list includes all participants (more than 100 individuals) in attendance at the workshop. An asterisk (*) is used to identify individuals who were external to the draft *Solar Vision Study* process.

Rajiv Advani*	Advantage for Analysts
Savina Angel*	SEMI PV Group
David Arfin	SolarCity
Jim Baak	The Vote Solar Initiative
Justin Baca	Solar Energy Industries Association
Jessica Ballard	Infinia Corporation
Galen Barbose	Lawrence Berkeley National Laboratory
John Bartlett	New West Technologies, LLC (formerly)
Kelly Beninga	WorleyParsons
Gordon Bigler*	MicroGrid Energy Corporation
Walter Block*	Building Industries
Julie Blunden	SunPower Corporation
Molly Borchers	Sentech, Inc.
Lynnae Boyd*	National Renewable Energy Laboratory
Peter Brehm	Infinia Corporation
Adam Browning	The Vote Solar Initiative
Marni Carroll	Iberdrola Renewables
Bob Cart	GreenVolts, Inc. (formerly)
Bob Charles	Sargent & Lundy
Mark Chen*	Abound Solar
Charlie Coggeshall	New West Technologies, LLC
Kevin Collins	First Solar, Inc.
Craig Cornelius*	Hudson Clean Energy Partners
Karlynn Cory	National Renewable Energy Laboratory
Carrie Cullen Hitt	The Solar Alliance
Ken Davis	Sargent & Lundy
Jennifer DeCesaro	U.S. Department of Energy
Paul Denholm	National Renewable Energy Laboratory
Thomas Dinwoodie	SunPower Corporation
Martha Duggan	United Solar
Ed Etzkorn	U.S. Department of Energy
Barry Friedman	National Renewable Energy Laboratory
Sean Gallagher	Tessera Solar
Charlie Gay	Applied Materials
Katherine Gensler	Solar Energy Industries Association
Rick Gilliam	SunEdison (an MEMC company)

Lori Glover	SOLID Energy
Susan Gouchoe	North Carolina Solar Center
Bill Gould	SolarReserve
Richard Gruber*	First Solar, Inc.
Micah Haman*	Puget Sound Energy
Charles Hanley	Sandia National Laboratories
Dennis Harper	First Solar, Inc.
Bob Hassett	U.S. Department of Energy
Arthur Haubenstock	BrightSource Energy, Inc.
Jim Haugen*	Clean Power Research
Tom Hoff	Clean Power Research
Roland Hulstrom*	National Renewable Energy Lab
Eric John	SkyFuel, Inc.
Izumi Kaizuka*	RTS Corporation
Juris Kalejs*	American Capital Energy
Bill Kammerer*	FIT Coalition
David Kearney	Kearney & Associates
Tom Kimbis	The Solar Foundation
Ben Kroposki	National Renewable Energy Laboratory
Hal LaFlash	Pacific Gas and Electric Company
Mark Lausten	Sentech, Inc.
Craig Lewis	RightCycle
Joshua Linn	Massachusetts Institute of Technology
Craig Lund*	1366 Technologies
John Lushetsky	U.S. Department of Energy
Jeffrey Luth*	Az4Solar.org
Robert Margolis	National Renewable Energy Laboratory
Alex Marker	SCHOTT Solar, Inc.
Joseph McCabe*	Ascent Solar
Jan McFarland	California Alternative Energy & Advanced Transportation Financing Authority
Jim McVeigh	Sentech, Inc.
Mark Mehos	National Renewable Energy Laboratory
Tim Merrigan	National Renewable Energy Laboratory
Paula Mints	Navigant Consulting
Ray Morgan*	SEMI PV Group
Fred Morse	Morse Associates, Inc.
Matt Mowers	National Renewable Energy Laboratory
Terry Murphy	SolarReserve
Denise Nelson	Consolidated Edison, Inc.
James Nelson*	University of California, Berkeley
Sam Newman*	Rocky Mountain Institute
Patricia Nugent*	Dow Chemical
Bob O'Hara	Sargent & Lundy
Steve O'Rourke	Deutsche Bank
Ben Pasquier	Clean Power Research

Craig Patterson*	K.R. Saline & Associates PLC
Terry Peterson	Terry M. Peterson, Ph.D.
Selya Price	National Renewable Energy Laboratory (formerly)
Hank Price	Abengoa Solar Inc.
Richard Raushenbush	GreenVolts
Rick Reed	SunEarth Inc.
Sally Rosauer	FAFCO
Vishal Shah	Barclays Capital
Gianluca Signorelli	MMA Renewable Ventures (formerly)
Eric Silagy	Florida Power & Light Company
Chrissy Skudera	New West Technologies
Cai Steger	Natural Resources Defense Council
Joshua Stein	Sandia National Laboratories
Mark Storch*	Plextronics
Samir Succar	Natural Resources Defense Council
Dick Swanson	SunPower Corporation
Blair Swezey	SunPower Corporation
Mike Taylor	Solar Electric Power Association
Andy Taylor	BrightSource Energy
Cindy Tindell	Florida Power & Light
Craig Turchi	National Renewable Energy Laboratory
Cyrus Wadia	U.S. Executive Office of the President
Johanna Wald	Natural Resources Defense Council
Peter Weiner	Paul Hastings
Carl Zichella	Sierra Club (formerly)
Ken Zweibel	George Washington University Solar Institute

Appendix E. Glossary

Acre-foot: The volume of water that will cover an area of 1 acre to a depth of 1 foot.

Alternating current (AC): A type of electrical current, the direction of which is reversed at regular intervals or cycles. In the United States, the standard is 120 reversals or 60 cycles per second. Electricity transmission networks use AC because voltage can be controlled with relative ease.

Amorphous silicon (a-Si): A thin-film, silicon photovoltaic (PV) cell having no crystalline structure. Manufactured by depositing layers of doped silicon on a substrate. See also single-crystal silicon and polycrystalline silicon.

Authority having jurisdiction: A federal, state, or local entity having statutory authority for approving equipment, an installation, or a procedure.

Balance-of-systems (BOS): Represents all components and costs other than the photovoltaic modules/array. It includes design costs, land, site preparation, system installation, support structures, power conditioning, operation and maintenance costs, indirect storage, and related costs.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Base load: The average amount of electric power that a utility must supply in any period.

Behind the meter (customer side of the meter): The location where a generating technology (such as a PV system) is connected to the electricity grid. A behind-the-meter PV system is connected between the utility meter and the facility using the electricity, so all electricity generated by the PV systems that is not being used by the facility flows through the utility meter to the grid.

Brayton cycle: A thermodynamic cycle using constant pressure, heat addition and rejection, representing the idealized behavior of the working fluid in a gas turbine type heat engine.

British thermal unit (Btu): The amount of heat required to raise the temperature of 1 pound of water 1 degree Fahrenheit; equal to 252 calories.

Building-integrated photovoltaics (BIPV): A term for the design and integration of photovoltaic (PV) technology into the building envelope, typically replacing conventional building materials. This integration may be in vertical facades, replacing view glass, spandrel glass, or other facade material; into semitransparent skylight systems; into roofing systems, replacing traditional roofing materials; into shading “eyebrows” over windows; or other building envelope systems.

Cadmium telluride (CdTe): A polycrystalline thin-film photovoltaic material.

Cap and trade: An established policy tool that creates a marketplace for emissions. Under a cap and trade program, the government regulates the aggregate amount of a type of emissions by setting a ceiling or cap. Participants in the program receive allocated allowances that represent a certain amount of pollutant and must purchase allowances from other businesses to emit more than their given allotment.

Capacity: The load that a power generation unit or other electrical apparatus or heating unit is rated by the manufacture to be able to meet or supply.

Capacity factor (CF): The ratio of the average load on (or power output of) an electricity-generating unit or system to the capacity rating of the unit or system over a specified period of time. For a solar plant, it is equivalent to: [Annual kilowatt-hours (kWh) generated for each kilowatt (kW) alternating current (AC) of peak capacity {[in kWh per peak kilowatt (kW_p)]}/8,760 hours per year.

Capital costs: The cost of field development and plant construction and the equipment required for industry operations.

Central receiver (power plants): Also known as "power towers," central receivers use fields of two-axis tracking mirrors known as heliostats. Each heliostat is individually positioned by a computer control system to reflect the sun's rays to a tower-mounted thermal receiver. The effect of many heliostats reflecting to a common point creates the combined energy of thousands of suns, which produces high-temperature thermal energy. In the receiver, molten nitrate salts absorb the heat energy. The hot salt is then used to boil water to steam, which is sent to a conventional steam turbine-generator to produce electricity.

Climate change: A term used to describe short and long-term effects on the Earth's climate as a result of human activities such as fossil-fuel combustion and vegetation clearing and burning.

Cogeneration: The generation of electricity or shaft power by an energy conversion system and the concurrent use of rejected thermal energy from the conversion system as an auxiliary energy source.

Combined cycle (CC): An electric-generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric-generating unit.

Combined heat and power plant (CHP): A plant designed to produce both heat and electricity from a single heat source.

Combustion: The process of burning; the oxidation of a material by applying heat, which unites oxygen with a material or fuel.

Commercial sector: An energy-consuming sector that consists of service-providing facilities and equipment of businesses; federal, state, and local governments; and other private and public organizations, such as religious, social, or fraternal groups.

Concentrating solar power (solar thermal power system) (CSP): Solar energy conversion technologies that convert solar energy to electricity, by heating a working fluid to power a turbine that drives a generator. Examples of these systems include central receiver systems, parabolic dish, and solar trough.

Concentrator (PV): A photovoltaic module, which includes optical components such as lenses (Fresnel lens) to direct and concentrate sunlight onto a solar cell or smaller area. Most concentrator arrays must directly face or track the sun. They can increase the power flux of sunlight hundreds of times.

Conventional fuel: The fossil fuels: coal, oil, and natural gas.

Copper indium (gallium) diselenide (CIGS): A polycrystalline thin-film photovoltaic material (sometimes incorporating gallium (CIGS) and/or sulfur).

Crystalline silicon (c-Si): A type of photovoltaic cell made from a slice of single-crystal silicon or polycrystalline silicon.

Curtailment: A reduction in the scheduled capacity or energy delivery of an agreement to transfer energy.

Customer side of the meter: See "Behind the meter".

Demand: The rate at which electricity is delivered to or by a system, part of a system, or piece of equipment expressed in kilowatts, kilovolt amperes, or other suitable unit, at a given instant or averaged over a specified period of time.

Demand-side management (DSM): The process of managing the consumption of energy, generally to optimize available and planned generation resources.

Diffuse insolation: Sunlight received indirectly as a result of scattering due to clouds, fog, haze, dust, or other obstructions in the atmosphere.

Direct current (DC): A type of electricity transmission and distribution by which electricity flows in one direction through the conductor, usually relatively low voltage and high current. To be used for typical 120 volt or 220 volt household appliances, DC must be converted to alternating current (AC), its opposite.

Direct incentive: Cash given back to consumers for a qualified solar installation. Direct incentives include up-front rebates and grants and production-based incentives that are typically distributed over several years.

Direct-normal irradiance (DNI): The amount of solar radiation from the direction of the sun.

Discount rate: The interest rate at which the Federal Reserve System stands ready to lend reserves to commercial banks. The rate is proposed by the 12 Federal Reserve banks and determined with the approval of the Board of Governors.

Dish: See "Solar thermal parabolic dishes".

Dispatchability: The ability to schedule and control the generation and delivery of electric power.

Distributed generation (DG): A term used by the power industry to describe localized or on-site power generation.

Distributed utility-scale generation: For the purposes of this report, distributed utility-scale includes PV systems with a representative size of 1–20 megawatts (MW) located within and directly connected to distribution networks.

DOE: In this context, always refers to the U. S. Department of Energy, although other departments may have the same acronym.

Ecological impact: The effect that a man-caused or natural activity has on living organisms and their non-living (abiotic) environment.

Electricity generation: The process of producing electricity by transforming other forms or sources of energy into electrical energy; commonly expressed in kilowatt-hours.

Energy: The capability of doing work; different forms of energy can be converted into other forms, but the total amount of energy remains the same.

Energy demand: The requirement for energy as an input to provide products and/or services.

Energy efficiency: A ratio of service provided to energy input. Services provided can include buildings-sector end uses such as lighting, refrigeration, and heating: industrial processes; or vehicle transportation. Unlike conservation, which involves some reduction of service, energy efficiency provides energy reductions without sacrifice of service.

Energy Information Administration (EIA): An independent agency within the U.S. Department of Energy that develops surveys, collects energy data, and does analytical and modeling analyses of energy issues.

Feed-in tariff (FIT): A renewable energy policy that typically offers renewable energy project developers a guaranteed payment for electricity produced by their renewable energy system over a fixed period, usually 15 to 20 years.

Fixed-tilt array: A photovoltaic array set in at a fixed angle with respect to horizontal.

Fresnel lens: An optical device that focuses light like a magnifying glass; concentric rings are faced at slightly different angles so that light falling on any ring is focused to the same point.

Fuel: Any material substance that can be consumed to supply heat or power. Included are petroleum, coal, and natural gas (the fossil fuels), and other consumable materials, such as uranium, biomass, and hydrogen.

Gigawatt (GW): A unit of power that has an instantaneous capability equal to 1 billion watts, 1 million kilowatts, or 1,000 megawatts.

Gigawatt-hour (GWh): One billion watt hours.

Grid-connected system: Independent power systems that are connected to an electricity transmission and distribution system (referred to as the electricity grid) such that the systems can draw on the grid's reserve capacity in times of need, and feed electricity back into the grid during times of excess production.

Heat-transfer fluid (HTF): A gas or liquid used to move heat energy from one place to another; a refrigerant.

Heliostat: A device that tracks the movement of the sun; used to orient solar concentrating systems.

Independent power producer (IPP): A company or individual that is not directly regulated as a power provider. These entities produce power for their own use and/or sell it to regulated power providers.

Independent system operator (ISO): An independent, federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system.

Insolation: The solar power density incident on a surface of stated area and orientation, usually expressed as watts per square meter or British thermal units per square foot per hour. See diffuse insolation and direct insolation.

Installed capacity: The total capacity of electrical generation devices in a power station or system.

Interconnection: A connection or link between power systems that enables the systems to draw on each other's reserve capacity in times of need. This includes any one of the three major electric system networks in North America: Eastern Interconnection, Western Interconnection, and the Electric Reliability Council of Texas (ERCOT).

Inverter: A device that converts direct current electricity (from, for example, a solar photovoltaic module or array) to alternating current for use directly to operate appliances or to supply power to a electricity grid.

Investor owned utility (IOU): A power provider owned by stockholders or other investors; sometimes referred to as a private power provider, in contrast to a public power provider that is owned by a government agency or cooperative.

Irradiance: The direct, diffuse, and reflected solar radiation that strikes a surface. Usually expressed in kilowatts per square meter. Irradiance multiplied by time equals insolation.

Junction: A region of transition between semiconductor layers, such as a p/n junction, which goes from a region that has a high concentration of acceptors (p-type) to one that has a high concentration of donors (n-type).

Kilowatt (kW): A standard unit of electrical power equal to 1,000 watts, or to the energy consumption at a rate of 1,000 joules per second.

Kilowatt-hour (kWh): A unit or measure of electricity supply or consumption of 1,000 watts over the period of one hour; equivalent to 3,412 British thermal units.

Levelized cost of energy (or electricity) (LCOE): A means of calculating the cost of generating energy (usually electricity) from a particular system that allows one to compare the cost of energy across technologies. LCOE takes into consideration the installed solar energy system price and associated costs such as the cost of financing, land, insurance, operation and maintenance, and other expenses.

Load: The demand on an energy producing system; the energy consumption or requirement of a piece or group of equipment. Usually expressed in terms of amperes or watts in reference to electricity.

Load-serving entity (LSE): Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

Megawatt (MW): 1,000 kilowatts, or 1 million watts; standard measure of electric-power plant-generating capacity.

Megawatt-hour (MWh): One thousand kilowatt-hours or 1 million watt-hours.

Metric ton (tonne) (MT): A unit of mass equal to 1,000 kilograms or 2,204.6 pounds.

Multicrystalline (mc): A semiconductor (photovoltaic) material composed of variously oriented, small, individual crystals. Sometimes referred to as polycrystalline or semicrystalline.

Multijunction device: A high-efficiency photovoltaic device containing two or more cell junctions, each of which is optimized for a particular part of the solar spectrum.

National Electric Code (NEC): Contains guidelines for all types of electrical installations. The 1984 and later editions of the NEC contain Article 690, "Solar Photovoltaic Systems" which should be followed when installing a PV system.

Net metering: The practice of using a single meter to measure consumption and generation of electricity by a small generation facility (such as a house with a wind or solar photovoltaic system). The net energy produced or consumed is purchased from or sold to the power provider, respectively.

Nitrogen oxides (NO_x): The products of all combustion processes formed by the combination of nitrogen and oxygen.

Nominal price: The price paid for goods or services at the time of a transaction; a price that has not been adjusted to account for inflation.

Parabolic dish (solar): A solar energy conversion device that has a bowl shaped dish covered with a highly reflective surface that tracks the sun and concentrates sunlight on a fixed absorber, thereby achieving high temperatures, for process heating or to operate a heat (Stirling) engine to produce power or electricity.

Parabolic trough (solar): A solar energy conversion device that uses a trough covered with a highly reflective surface to focus sunlight onto a linear absorber containing a working fluid that can be used for medium temperature space or process heat or to operate a steam turbine for power or electricity generation.

Peak demand/load: The maximum energy demand or load in a specified time period.

Peak power: Power generated that operates at a very low capacity factor; generally used to meet short-lived and variable high-demand periods.

Peak watt: A unit used to rate the performance of solar cells, modules, or arrays; the maximum nominal output of a photovoltaic device, in peak watts (W_p) under standardized test conditions, usually 1,000 watts per square meter of sunlight with other conditions, such as temperature specified.

Peaking capacity: Power generation equipment or system capacity to meet peak power demands.

Photovoltaic (conversion) efficiency: The ratio of the electric power produced by a photovoltaic device to the power of the sunlight incident on the device.

Photovoltaic array: An interconnected system of photovoltaic modules that function as a single electricity-producing unit. The modules are assembled as a discrete structure, with common support or mounting. In smaller systems, an array can consist of a single module.

Photovoltaic cell: The smallest semiconductor element within a photovoltaic module to perform the immediate conversion of light into electrical energy (direct current voltage and current). Also called a solar cell.

Photovoltaic module: The smallest environmentally protected, essentially planar assembly of solar cells and ancillary parts, such as interconnections, terminals, (and protective devices such as diodes) intended to generate direct current power under unconcentrated sunlight. The structural (load carrying) member of a module can either be the top layer (superstrate) or the back layer (substrate).

Photovoltaic system: A complete set of components for converting sunlight into electricity by the photovoltaic process, including the array and balance of system components.

Polycrystalline silicon: A material used to make photovoltaic cells, which consist of many crystals unlike single-crystal silicon.

Power: Energy that is capable or available for doing work; the time rate at which work is performed, measured in horsepower, watts, or British thermal units per hour. Electric power is the product of electric current and electromotive force.

Power (solar) tower: A term used to describe solar thermal, central receiver, power systems, where an array of reflectors focus sunlight onto a central receiver and absorber mounted on a tower.

Power purchase agreement (PPA): A legal contract between an electricity generator and electricity purchaser. Solar power purchase agreements typically provide a long-term contract to purchase electricity generated from a solar installation on public or private property; a type of third-party ownership model.

Public utility (or services) commission (PUC or PSC): These are state government agencies responsible for the regulation of public utilities within a state or region. A state legislature oversees the PUC by reviewing changes to power generator laws and rules and regulations and approving the PUC's budget. The commission usually has five commissioners appointed by the governor or legislature. PUCs typically regulate electric, natural gas, water, sewer, telephone services, trucks, buses, and taxicabs within the commission's operating region. The PUC tries to balance the interests of consumers, environmentalists, utilities, and stockholders. The PUC makes sure a region's citizens are supplied with adequate, safe power provider service at reasonable rates.

Ramp rate: The rate at which load on a power plant is increased or decreased. The rate of change in output from a power plant.

Rankine cycle: The thermodynamic cycle that is an ideal standard for comparing performance of heat engines, steam power plants, steam turbines, and heat pump systems that use a condensable vapor as the working fluid. Efficiency is measured as work done divided by sensible heat supplied.

Real dollars: These are dollars that have been adjusted for inflation.

Receiver: The component of a central receiver solar thermal system where reflected solar energy is absorbed and converted to thermal energy.

Renewable energy: Energy from resources that naturally replenish themselves and are virtually inexhaustible. Renewable energy resources include biomass, hydropower, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

Renewable energy certificate or credit (REC): A REC represents the property rights to the environmental, social, and other non-power qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source.

Renewable portfolio standard (RPS): A mandate requiring that renewable energy provides a certain percentage of total energy generation. The mandate is sometimes referred to as a renewable electricity standard or RES.

Reserve capacity: The amount of generating capacity a central power system must maintain to meet peak loads.

Residential sector: An energy-consuming sector that consists of living quarters for private households. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a variety of other appliances.

Retail (electricity market): Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, are also included in this category.

Semiconductor: Any material that has a limited capacity for conducting an electric current. Certain semiconductors, including silicon, gallium arsenide, copper indium diselenide, and cadmium telluride, are uniquely suited to the photovoltaic conversion process.

Set aside: A mandate or goal for some fraction of a renewable portfolio standard to be met with designated technologies such as photovoltaics.

Silicon (Si): A semi-metallic chemical element that makes an excellent semiconductor material for photovoltaic devices. It crystallizes in face-centered cubic lattice like a diamond and is commonly found in sand and quartz (as the oxide).

Solar access: The ability of one property or area to continue to receive sunlight without obstruction from a nearby home or building, landscaping, or other impediment.

Solar field: Solar field is a term used to describe the geographic area of solar collectors used for concentrating solar power systems.

Solar resource: The amount of solar insolation a site receives, usually measured in kilowatt-hours per square meter per day, which is equivalent to the number of peak sun hours.

Solar right law: A law or ordinance that furnishes protection for homes and businesses by limiting or prohibiting restrictions (for example, neighborhood covenants and bylaws, local government ordinances, and building codes) on the installation of solar energy systems.

Solar thermal electric system: See “concentrating solar power”.

Steam turbine: A device that converts high-pressure steam, produced in a boiler, into mechanical energy that can then be used to produce electricity by forcing blades in a cylinder to rotate and turn a generator shaft.

Stirling engine: A heat engine of the reciprocating (piston) where the working gas and a heat source are independent. The working gas is compressed in one region of the engine and transferred to another region where it is expanded. The expanded gas is then returned to the first region for recompression. The working gas thus moves back and forth in a closed cycle.

Storage capacity: The amount of energy an energy storage device or system can store.

Therm: A unit of heat containing 100,000 British thermal units (Btu).

Thermal energy: The energy developed through the use of heat energy.

Thermal energy storage: The storage of heat energy during power provider off-peak times at night, for use during the next day without incurring daytime peak electric rates.

Thin film: A layer of semiconductor material, such as copper indium diselenide or gallium arsenide, a few microns or less in thickness, used to make photovoltaic cells.

Tracking solar array: A solar energy array that follows the path of the sun to maximize the solar radiation incident on the photovoltaic surface. The two most common orientations are (1) 1-axis, where the array tracks the sun east to west and (2) two-axis, where the array points directly at the sun at all times. Tracking arrays use both the direct and diffuse sunlight. Two-axis tracking arrays capture the maximum possible daily energy.

Transmission: The process of sending or moving electricity from one point to another. This usually defines that part of an electric power provider's electric power lines from the power plant buss to the last transformer before the customer's connection.

Turbine: A device for converting the flow of a fluid (such as air, steam, water, or hot gases) into mechanical motion.

Utility-scale: For the purposes of this report, larger systems installed on the ground are called "utility-scale PV." These systems can range from a few megawatts to hundreds of megawatts. Large utility-scale systems greater than 20 megawatts are typically connected to the electricity-transmission system which transmits electricity from generating plants to electrical substations.

Utility: A regulated entity which exhibits the characteristics of a natural monopoly (also referred to as a power provider). For the purposes of electric industry restructuring, "utility" refers to the regulated, vertically-integrated electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system which serves retail customers.

Voltage: The amount of electromotive force, measured in volts, that exists between two points.

Wafer: A thin sheet of semiconductor (photovoltaic material) made by cutting it from a single crystal or ingot.

Watt (W): The rate of energy transfer equivalent to one ampere under an electrical pressure of one volt. One watt equals 1/746 horsepower, or 1 joule per second. It is the product of voltage and current (amperage).

Watt-hour (Wh): The electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

Wholesale (electric market): The purchase and sale of electricity from generators to resellers (retailers), along with the ancillary services needed to maintain reliability and power quality at the transmission level.

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Energy Efficiency &
Renewable Energy

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Printed with a renewable-source ink on paper containing at least 50% wastepaper, including 10% post consumer waste.

Prepared by the National Renewable Energy Laboratory (NREL)
NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

DOE/GO-102012-3037 • February 2012



IREC
INTERSTATE RENEWABLE ENERGY COUNCIL

U.S. Solar MARKET TRENDS 2012

JULY 2013 *Larry Sherwood*



Agua Caliente Solar Project in Yuma County, Arizona

EXECUTIVE SUMMARY

Solar energy markets are booming in the United States due to falling photovoltaic (PV) prices, strong consumer demand, available financing, renewable portfolio standards (RPSs) in some states, and financial incentives from the federal government, states and utilities. The capacity of PV installations increased by 80 percent to 3.3 GW_{DC} compared with 2011 and, for the first time, over 50 percent of that capacity was in the utility sector.

The federal Investment Tax Credit (ITC) of 30 percent provides an important foundational incentive for most installations. Installed prices for distributed PV installations fell by at least 12 percent in 2012 and have fallen by 33 percent since 2009. The prices of some individual system components, especially modules, have fallen even more. Lower prices increase consumer demand for solar installations.

PV trends:

- Solar installations were 12 percent of all electric power installations in 2012.
- PV capacity installed in 2012 more than doubled for larger systems in the utility sector. State renewable portfolio requirements are an important reason for the large growth in the utility sector. Four of the largest 10 installations received a federal loan guarantee from the U.S. Department of Energy.
- The five largest installations all supply power to Pacific Gas and Electric Company (PG&E) in California. In fact, 30 percent (1 GW_{DC}) of the total U.S. photovoltaic capacity installed in 2012 goes to supply PG&E.
- The capacity of distributed grid-connected PV installed in 2012 increased by 36 percent compared with 2011. Nearly 95,000 distributed PV systems were installed in 2012. Residential installations grew by 61 percent, fueled by the increasing use of leases and third-party ownership of these systems.
- In 2012, more than two-thirds of grid-connected PV system installations were concentrated in California, Arizona, New Jersey and Nevada. Of the Top 10 states for 2012 installations, Arizona, Hawaii, Maryland, Massachusetts, Nevada, and North Carolina more than doubled the capacity installed the year before.

Concentrating solar power (CSP) trends:

- No new CSP plants were connected to the grid in 2012, though several plants are under construction for completion in 2013 and later years.

Over the near term, the prospect for growth in solar installations is bright. Early indicators point to continued market growth in 2013 due to the federal ITC, continued falling prices, state RPSs, and completion of installations begun by the end of 2012 in order to participate in the 1603 Treasury Grant Program. Companies have announced plans for many large solar electric projects, including both PV and CSP projects. Some of these projects are under construction and will come on-line between 2013 and 2016.

About IREC

The Interstate Renewable Energy Council, Inc. (IREC) is a non-profit organization accelerating the use of renewable energy since 1982. Today, IREC is a nationally recognized thought leader, stakeholder coordinator, expert resource and facilitator of regulatory reform. Our work expands consumer access to clean energy; generates information and objective analysis grounded in best practices and standards; and leads national efforts to build a quality-trained clean energy workforce, including a unique credentialing program for training programs and instructors. www.irecusa.org.

COVER: Copper Mountain Solar Complex in Boulder City, Nevada

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1. INTRODUCTION

The solar market, while relatively young, is an increasingly important and vital part of the American economy. What are the trends in this market, and what forces are at work? Which sectors of the market are strongest, and why? What are the prospects for solar energy in the near future?

This report answers these questions by providing public data on U.S. solar electric installations by technology, state and market sector. Public data on solar installations help industry, government and non-profit organizations improve their efforts to increase the number (and capacity) of solar installations across the United States. Analysis of multi-year installation trends and state installation data helps these stakeholders learn more about state solar markets and evaluate the effectiveness of marketing, financial incentives and education initiatives.

Different solar energy technologies create energy for different end uses. This report covers solar technologies that produce electricity, including PV and CSP. Other solar technologies provide hot water, space heat, and space cooling, but are not included in this report.

PV cells are semi-conductor devices that generate electricity when exposed to the sun. Manufacturers assemble the cells into modules, which can be installed on buildings, parking structures or in ground-mounted arrays. PV was invented in the 1950s and first used to power satellites. As prices declined, PV systems were installed in many off-grid installations, i.e., installations not connected to the utility grid. In the last decade, grid-connected installations have become the largest sector for PV installations. PV is used in large and small installations and in installations on either the customer or utility side of the meter.

CSP systems use mirrors and collecting receivers to heat a fluid to a high temperature (from 300˚F to more than 1,000˚F), and then run the heat extracted from the fluid through a traditional turbine power generator or Stirling engine. CSP can also be paired with existing or new traditional power plants, providing high-temperature heat into the thermal cycle. These generating stations typically produce bulk power on the utility side of the meter rather than generating electricity on the customer side of the meter. CSP plants were first installed in the United States in the early 1980s, and installations continued through the early 1990s. Although many of these installations still generate power today, until recently, few new systems had been installed since the early 1990s. Installations have resumed, with one large plant constructed in 2010 and a number of new plants are under construction for completion between 2013-2015. In another application, concentrating solar thermal can provide high temperature solar process heat for industrial or commercial applications. A few systems are installed each year using this technology. Concentrating PV systems are classified in this report as PV installations and not as CSP installations.

For all solar technologies, the United States is only a small, but growing, part of a robust world solar market. Product availability and pricing generally reflect this status. Globally, Germany is the largest market for PV and Spain is the top market for CSP. In North America, Ontario, Canada, ranks as one of the largest PV markets and is discussed briefly in Section 2. (Other than Ontario's market, this report does not analyze markets outside the United States.)

The data-collection methods and the assumptions used in this report are described in detail in Appendices A and B.

2. PHOTOVOLTAICS

Overall Trends in Installations and Capacity

2012 was another banner year for solar, with large increases in both the number and capacity of PV facilities. The capacity of 2012 PV installations increased by 80 percent to 3.3 GW_{DC} compared with 2011 (Figure 1). The annual capacity growth rate has exceeded 40 percent for six straight years, and the compound annual growth rate for the last 10 years is an astounding 65 percent. The total installed capacity of utility installations increased by two-and-one-half times, and distributed installations, largely on residential, commercial and government buildings, increased by 36 percent.

The cumulative installed grid-connected PV capacity increased to 7.4 GW_{DC} (Figure 2).The capacity of PV systems installed in 2012, 3.3 GW_{DC}, was more than ten times the capacity of PV installed in 2008, just four years earlier. In 2012, 0.5 GW_{DC} were installed on residential buildings, 1.0 GW_{DC} at non-residential sites and 1.8 GW_{DC} in the utility sector (Figure 2).

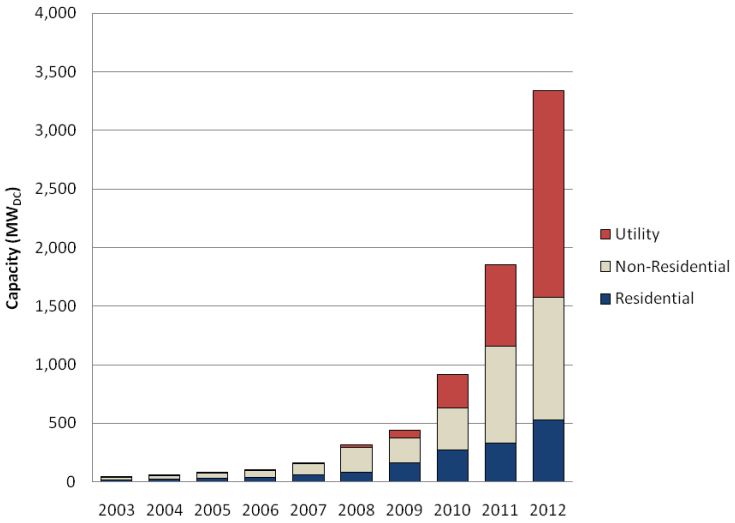


Figure 1: Annual Installed Grid-Connected PV Capacity by Sector (2003-2012)



Copper Ridge School in Scottsdale, Arizona

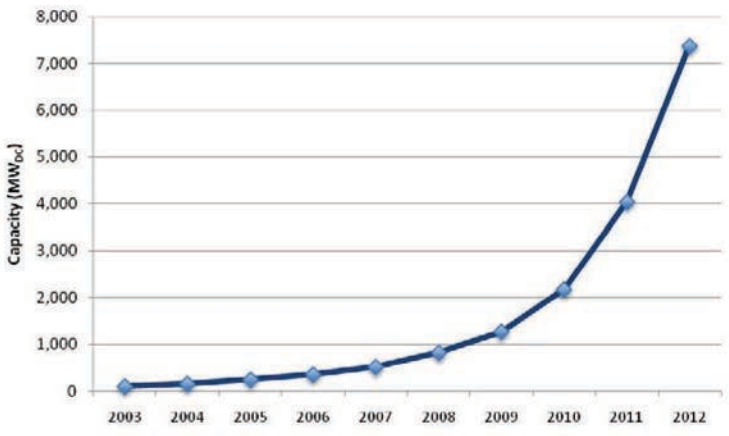


Figure 2: Cumulative U.S. Grid-Connected PV Installations (2003-2012)

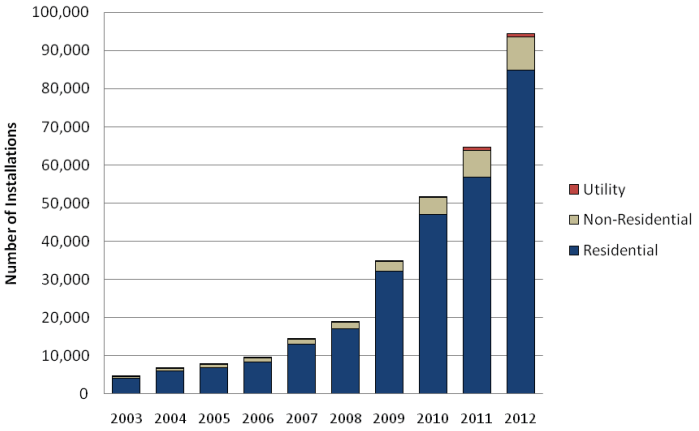


Figure 3: Number of Annual U.S. Grid-Connected PV Installations (2003-2012)



Residential PV Installations

Some PV installations are off-grid and are used to power facilities that are too expensive to interconnect to the grid, such as cabins, telecommunications facilities and road signs. Based on anecdotal information, the size of this market is very small compared with grid-connected installations. IREC has not collected data for these off-grid installations, and they are not included in this report's charts.

Almost 95,000 grid-connected PV installations were completed in 2012, a 46 percent increase over the number of installations in 2011. Residential systems accounted for 90 percent of these installations (Figure 3). By contrast, residential systems accounted for only 16 percent of the PV capacity installed in 2012. At the end of 2012, 316,000 PV installations were connected to the U.S. grid, including 283,000 residential installations.

In 2012, PV installations were 12 percent of new electricity generation installed during the year (Figure 4). In 2011, PV installations were eight percent of new additions. The electricity generated by PV and CSP installations was 0.3 percent of all electricity generation in the U.S. during 2012, 65 percent of which was used at the customer site. The remainder was shipped through the utility distribution system.

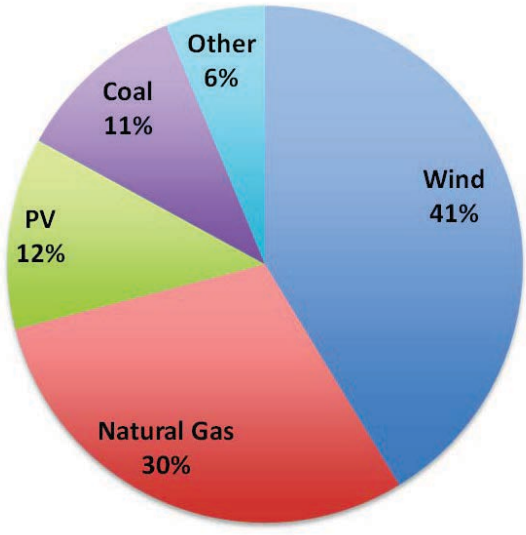


Figure 4: New U.S. Generation Installed in 2012 by Technology

Source: Energy Information Agency (EIA 2013) with IREC PV data



University of California at Davis West Village combines advanced energy efficient design features with a 4MW high efficiency SunPower solar system. It is the largest zero net energy development in the nation.

The important factors driving PV installation growth vary by sector and state.

The following factors helped drive PV growth in 2012.

- **Federal ITC**. There was stability in the federal ITC at 30 percent and the accelerated depreciation schedule for commercial installations was also unchanged. Tax credits for both residential and commercial installations are currently in place through 2016. With this stable incentive, developers and installers can plan and market their products and consumers can make rational decisions without arbitrary incentive deadlines.
- **Lower Installed Costs**. The total installed cost for distributed installations fell 12 percent in 2012 and has fallen 33 percent over the past three years. The cost decline is even greater for utility installations. Falling module costs is the primary reason for the cost declines, but all cost components have fallen, including inverter costs and soft costs such as permitting.
- **Federal Cash Grants**. In February 2009, as part of the American Recovery and Reinvestment Act (ARRA), Congress enacted the U.S. Treasury Grant in Lieu of Tax Credits Program. This program, commonly known as the 1603 Treasury Grant Program, provides commercial installations with the alternative of a cash grant instead of the tax credit. The Program was originally scheduled to expire at the end of 2010, but was extended through the end of 2012. This expiration caused many projects to begin construction late in 2012 to qualify for the Program, with completion scheduled in 2013 through 2016. In 2012, 3,460 completed projects were awarded $2.3 billion in cash grants (Treasury 2013). This is more than double the amount awarded in 2011. Solar projects received 35 percent of 1603 Treasury Grant funding in 2012 compared with only 17 percent in 2011.
- **State RPS Requirements**. States encourage investments in utility-scale solar plants with RPS policies. An RPS requires that a certain percentage of electricity generation come from renewable energy. Some states have a solar carve-out that additionally requires a certain percentage of the renewable generation come from solar energy. The terms of each state's RPS are different. In some states, RPS guidelines have led to solar renewable energy credit (SREC) markets, which in turn have resulted in increased demand for and installation of distributed solar installations. SREC markets are most developed in the Mid-Atlantic states and in Massachusetts. Of the 14 states and territories with more than 10 MW of utility sector installations in 2012, 12 have an RPS, usually with a solar requirement.
- **Federal Loan Guarantees**. As part of ARRA, the U.S. Department of Energy was authorized to offer loan guarantees for renewable energy and other energy projects. The program expired in September 2011, but projects that received loan guarantees by that date can still be completed. In 2012, the three largest PV installations each received loan guarantees from this program for at least a portion of the project's capital cost.
- **Third-Party Ownership** of solar installations has long been the dominant ownership model for utility and non-residential distributed installations. In recent years this ownership model has expanded to the residential sector and is now the dominant ownership model in all sectors. This structure is called a lease, a power purchase agreement (PPA) or third-party ownership. In each case, a third-party owns the system and the consumer makes regular payments to the owner. For distributed systems, the system is located at the consumer's facility or home and the consumer uses the electricity generated at their site. With a third-party owner, the consumer avoids paying the large up-front capital cost of a PV system.

- **Net Metering**. Net Metering is a simple option for consumers to offset their monthly electricity bills by producing their own energy. It allows customers to send excess energy from an onsite renewable energy system back to the grid, and receive a 1:1 kilowatt-hour credit for that energy. In 2012, 90 percent of distributed installed capacity was net metered. IREC provides summary tables of state net metering policies (IREC 2013).
- **State and Utility Rebates**. State and utility financial incentives have historically been one of the most important factors driving PV growth, especially for residential and commercial distributed installations. Of the 2012 Annual Top Ten States (Table 3), nine have state or utility rebate programs available for at least some of the installations. However, the importance of rebates is declining. The impact of these rebates varies greatly from state to state and, in general, rebates per watt have decreased as the cost of PV installations has decreased. The largest rebate program in the country, the California Solar Initiative (CSI), has been reducing rebates in a planned manner for years and the rebates will end in 2013. However, solar markets continue to grow in California. The Database of State Incentives for Renewables & Efficiency (DSIRE) provides summary tables of state and utility financial incentives (DSIRE 2013).

Grid-Connected Installations by Sector

The growth rate of grid-connected PV varies by market sector: residential, non-residential and utility. Distributed installations, on the customer's side of the meter, produce electricity used on-site and include both residential and non-residential facilities. Examples of non-residential facilities are government buildings, retail stores and military installations. In contrast, utility installations are on the utility's side of the meter and produce bulk electricity for the grid. Table 1 shows examples of installations in each sector.

Utility-Sector Installations

Utility-sector PV installations more than doubled in 2012 compared to 2011. The utility sector's share of all U.S. grid-connected PV installations grew from virtually none in 2006 to 15 percent in 2009, 32 percent in 2010, and 53 percent in 2012. The factors that influence the large growth in utility sector installations include RPSs, lower installed costs, and federal loan guarantees.

Table 1: SAMPLE INSTALLATIONS BY SECTOR

Sector	Example Installations
Residential	• Residential installation owned by homeowner or building owner; electricity generated is used on-site • Residential installation owned by third party, with electricity sold to or used by the homeowner or building owner
Non-Residential	• Non-residential installation owned by building owner; electricity generated is used on-site • Non-residential installation owned by third party, with electricity sold to the building owner and used on-site
Utility	• Installation owned by utility; electricity generated goes into bulk power grid • Installation owned by third party; electricity generated goes into bulk power grid • Installation owned by building owner (residential or commercial); electricity generated goes into bulk power grid through a feed-in tariff, PPA or other agreement



California Valley Solar Ranch, San Luis Obispo County, California

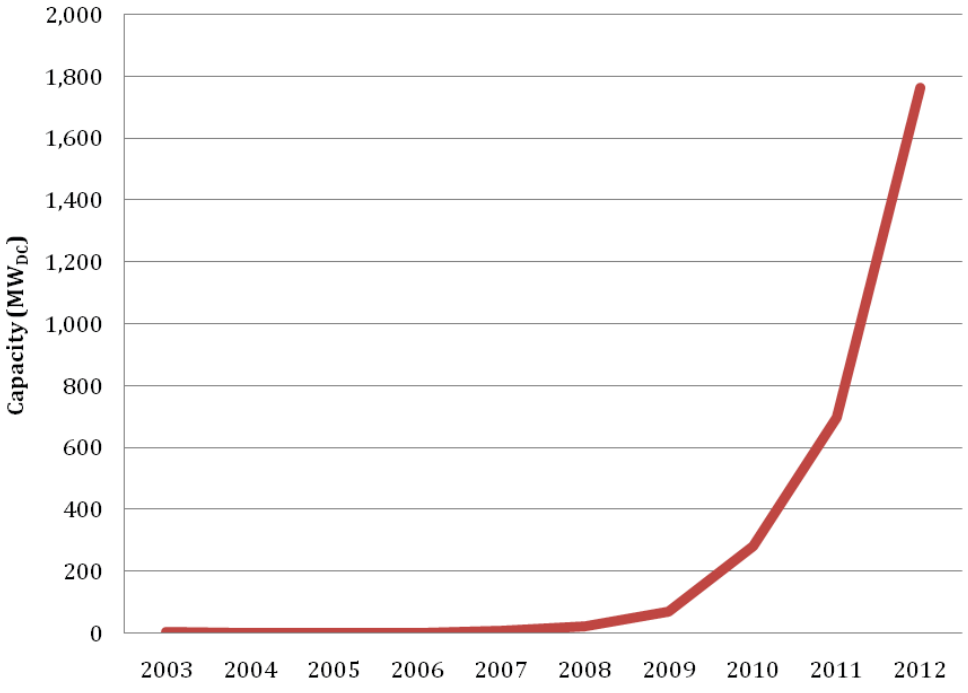


Figure 5: Annual Installed Grid-Connected Utility Sector PV Capacity (2003-2012)



Copper Mountain Solar Complex in Boulder City, Nevada

In 2012, 50 utility-sector plants larger than 5 MW_{DC} were installed with a total capacity of 1.5 GW_{DC}. These large facilities were 85 percent of the utility-sector installations in 2011. An additional 11 installations of 5 MW_{DC} or larger were installed in the non-residential sector with a combined capacity of 105 MW_{DC}. In total, these 61 generators larger than 5 MW_{DC} comprised 48 percent of the total PV capacity installed in 2012.

Of the 10 largest PV installations in the United States, eight were completely or partially installed in 2012 (Table 2). The five largest installations provide electricity for PG&E and are located in Arizona, California and Nevada.

State RPS requirements with solar carve-outs are encouraging investments in utility-scale solar plants in some states. Although

Table 2: TEN LARGEST U.S. PV INSTALLATIONS

Plant Name	Location	Size (MW_{DC})	Year Built	Owner	Utility Purchaser
1. Agua Caliente	Yuma, AZ	289*	2012	NRG & MidAmerican Solar	PG&E
2. Mesquite Solar 1	Arlington, AZ	207	2011-12	Sempra U.S. Gas & Power	PG&E
3. Copper Mountain Solar 1 & 2	Boulder City, NV	192	2010 & 2012	Sempra U.S. Gas & Power*	PG&E
4. California Valley Solar Ranch	San Luis Obispo County, CA	130**	2012	NRG Energy	PG&E
5. Alpaugh	Alpaugh, CA	66	2012	Consolidated Edison Development	PG&E
6. Silver State Nevada	Primm, NV	58	2012	Enbridge	NV Energy
7. Kammerer	Sacramento, CA	38	2012	Google & Suntap Energy	SMUD
8. San Luis Valley Solar Ranch	Mosca, CO	35	2012	Iberdrola Renewables	Xcel
9. Cimarron	Cimarron, NM	35	2010	Southern Co. & Turner Renewables	Tri-State
10. Webberville	Webberville, TX	35	2011	FRV AE Solar LLC	Austin Energy

* Copper Mountain Solar 2 is also owned by Consolidated Edison Development. ** Includes amount constructed through 2012. Plant still under construction and final size will be larger.

the California RPS does not have a solar carve-out, it is still encouraging many utility solar installations. In 2012, 1.6 GW_{DC} or 94 percent of the utility-sector installations were in states with RPS requirements. Over three-quarters of utility installations are located in just four states: Arizona, California, Nevada and North Carolina.

Financing is also important. The three largest utility sector installations received a federal loan guarantee for at least a portion of their installation costs, and these loan guarantees supported 574 MW_{DC} of installations. Although this program is known for high profile failed loans to Solyndra and other manufacturers, none of the guaranteed loans for specific solar installations failed and these loan guarantees are a crucial component of the overall financial package for these projects. Federal tax incentives, grants and the lower cost of PV modules also made these investments attractive.

Figure 6: Ownership Status for 2012 Utility Sector PV Installations

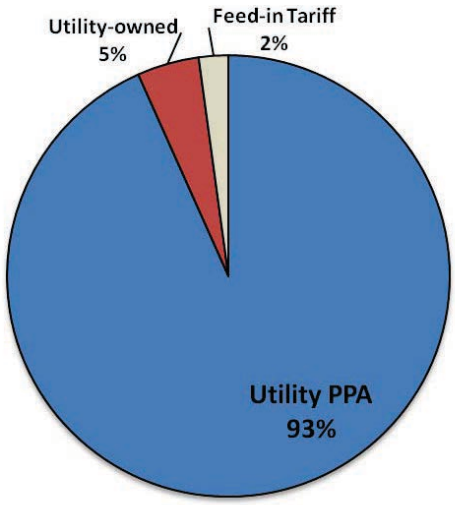


Figure 6 shows the ownership status of utility-sector installations, 93 percent of which are PPAs. In this arrangement, a third-party builds and owns the PV facility and the electricity is sold to a utility through a long-term power purchase agreement. The use of PPAs in the utility sector is growing and the capacity of utility-owned installations completed in 2012 decreased by 58 percent compared with 2011.

About two percent of the utility-sector installations are through feed-in tariff programs or similarly structured programs. The capacity installed through feed-in tariff programs decreased by 12 percent in 2012 compared with 2011 installations. In these programs, the utility pays the customer for the PV electricity produced and then sells the electricity as part of their regular electricity sales. These are defined as utility-sector installations because the electricity serves utility customers generally rather than the customer where the installation is located. However, the size of these installations is more similar to the size of distributed installations with an average size of 66 kW_{DC}. By contrast, the average size of the other utility-sector installations is 4,300 kW_{DC}.

Construction began or continued in 2012 on many additional utility-sector installations, and utilities and developers have announced plans for even more projects to be built in the next few years. Installations in this sector seem poised for continued growth.

Distributed Installations

Distributed installations provide electricity for use at the host customer's site, like a home or business. In 2012, the amount of distributed grid-connected PV capacity installed annually in the United States increased by 36 percent to 1.6GW_{DC}. Nearly



Construction of Agua Caliente Solar Project in Yuma County, Arizona

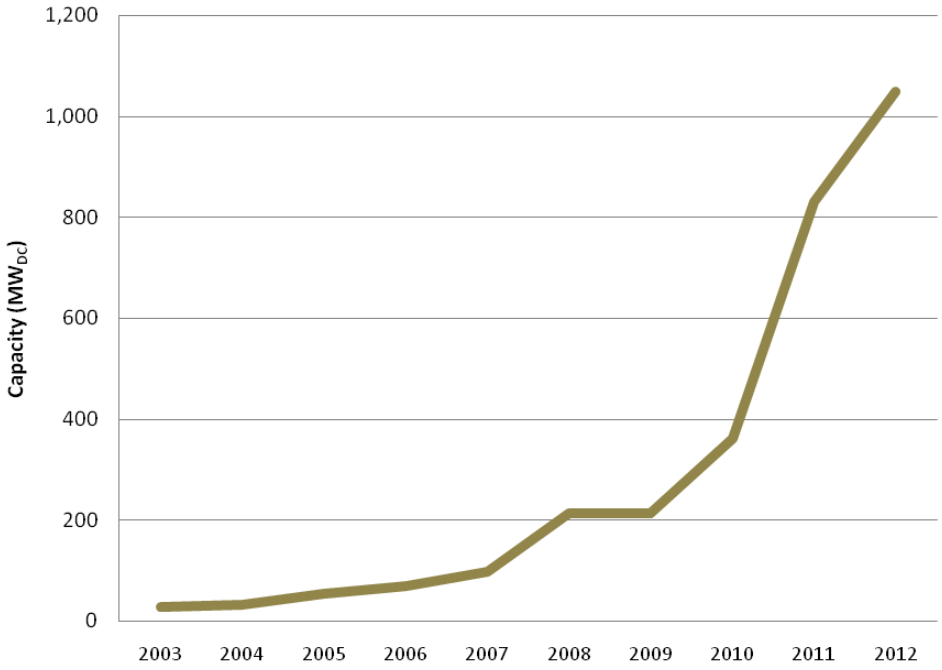


Figure 7: Annual Installed Grid-Connected Non-Residential Sector PV Capacity (2003-2012)

94,000 distributed PV systems were installed in 2012, a 46 percent increase over the number of distributed PV systems installed in 2011. The distributed growth was strongest in the residential sector in 2012, a change from the previous year when non-residential installations were surging.

Non-Residential Sector Installations

The capacity of non-residential sector installations, which includes sites such as government buildings, retail stores and military installations, increased by 26 percent in 2012 compared with 2011 (Figure 7). The average size of a non-residential distributed installation remained virtually the same at 120 kW_{DC}. The largest 2012 installations in this sector were a 20 MW_{DC} installation at an Apple data center in Maiden, NC, and a 16 MW_{DC} installation at Maryland's St. Mary's University with power sold to the Maryland Department of General Services and the University of Maryland System. Factors that influence the growth in non-residential installations include the federal ITC and the cash grant program, lower installed costs, net metering and state and utility rebates.

The 1603 Treasury Grant Program expired at the end of 2012. Projects begun by the end of 2012 can still qualify for this grant program, but new installations begun in 2013 and later will not qualify. One-third to one-half of non-residential sector installations received a grant through this program.

Residential Sector Installations

The number of residential installations increased by 61 percent in 2012 compared with 2011 (Figure 8). Residential installations are 16 percent of the total U.S. market on a capacity basis, but 90 percent of the number of installations. The average size of a residential PV system increased seven percent to 6.2 kW_{DC}. Factors that influence the growth in residential installations include the federal ITC, lower installed costs, retails PPAs and solar leases, net metering and state and utility rebates.

An increasing number of residential systems are financed using the leasing or third-party ownership model. For example, in

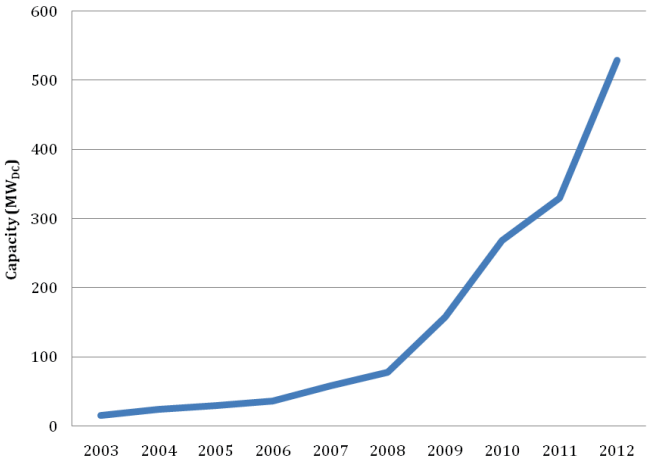


Figure 8: Annual Installed Grid-Connected Residential Sector PV Capacity (2003-2012)



Residential PV Installation in Massachusetts

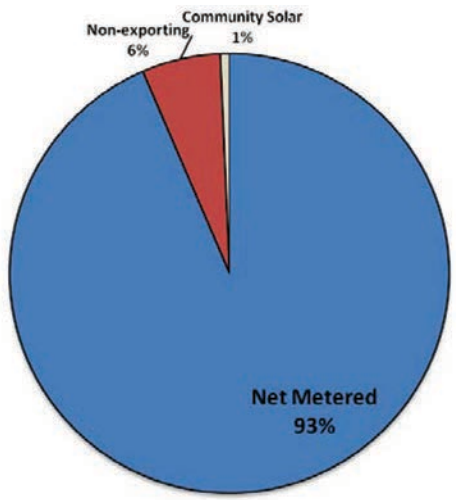
In states with high-cost electricity, the combination of lower installed costs, stable federal tax incentives, and favorable net metering policies are growing the residential market.

the California Solar Initiative, the capacity-basis percentage of residential systems owned by a third-party has increased from seven percent in 2009 to 28 percent in 2011 to 40 percent in 2012. In states with high-cost electricity, the combination of lower installed costs, stable federal tax incentives, and favorable net metering policies are growing the residential market, even with declining local incentives. California and Hawaii were the two largest residential markets in 2012; 57 percent of all residential installations were in these two states. Both rely less on rebate incentives than in the past.

For residential consumers not using the lease or third-party ownership model, federal incentives remained stable in 2012. Stable incentives encourage more homeowners to purchase solar (incentive levels are set through 2016). In addition to federal incentives, most residential installations occur in states with state or local incentives.

In 2012, 93 percent of the residential and non-residential distributed PV installations were net-metered as shown in Figure 9. This market share for net-metered systems has remained consistent for the past few years. The rules governing net metering transactions vary widely from state-to-state and utility-to-utility. About six percent of the distributed PV systems are non-exporting, meaning that all of the solar generated electricity is used on the customer's grid-connected site.

Figure 9: Generation Status for 2012 Distributed PV Installations



About one percent of distributed PV systems use a community share solar model. A community share solar installation is a facility interconnected to the utility distribution system, and the electricity generated is credited to subscribers of the installation. Community share solar allows customers who are otherwise unable to have a solar system, such as renters or property owners with poor solar access, to receive solar electricity.

Grid-Connected Installations by State

In 2012, more than two-thirds of grid-connected PV system installations were concentrated in California, Arizona, New Jersey and Nevada, as shown in Table 3. Of the Top 10 states for 2012 installations, Arizona, Nevada, Massachusetts, North Carolina, Hawaii and Maryland more than doubled their installed capacity from the prior year. Nevada, Hawaii, and Maryland joined the Top 10 Installation list for 2012, replacing New Mexico, Pennsylvania, and Texas. In Nevada, four large utility installations totaling 215 MW_{DC} were completed in 2012 and represent most of the Nevada capacity installed last year. Nevada is a popular location for utility installations. Its ranking in the Top 10 Installation list fluctuates wildly, depending on how many utility installations are completed in a given year. Hawaii and Maryland made the Top 10 Installation list due to large growth in distributed installations. New Mexico and Pennsylvania both saw large drops in capacity installed last year. In New Mexico, utility sector installations dropped significantly, and in Pennsylvania, distributed installations dropped due to the end of the Pennsylvania Sunshine Rebate Program. In Texas, installation capacity grew, but not enough to keep Texas on the Top Ten Installation list.

State policies affect PV installations, with most installations happening in the few states with good solar policies. All states in

the Top Ten Installation list have state RPSs, which mandate that utilities generate a percentage of their power from solar or other renewable sources, and tend to encourage larger installations. Arizona and Nevada also benefit from solar installations supplying power to Pacific Gas & Electric to help meet the California RPS requirement. The RPS requirements and structure varies widely from state-to-state.

Though their impact on the total market is declining, financial rebates are important state policies, especially for smaller



Concentrating PV at Alamosa Solar Farm in Colorado

Table 3: 2012 ANNUAL TOP TEN STATES
Ranked by Grid-Connected PV Capacity Installed in 2012

2012 Rank by State	2012 (MW_{DC})	2011 (MW_{DC})	11-12 Percent Change	2012 Market Share	2011 Rank
1. California	983	547	80%	29%	1
2. Arizona	709	288	146%	21%	3
3. New Jersey	391	305	28%	12%	2
4. Nevada	226	19	1062%	7%	15
5. Massachusetts	123	42	190%	4%	10
6. North Carolina	122	45	169%	4%	9
7. Hawaii	114	40	182%	3%	11
8. Colorado	103	76	36%	3%	6
9. Maryland	80	24	227%	2%	12
10. New York	56	68	-18%	2%	7
All Other States	434	402	8%	13%	–
Total	**3,341**	**1,856**	**80%**	**--**	**--**

2011 and 2012 columns include installations completed in those years. “2012 Market Share” means share of 2012 installations. “2011 Rank” is the state ranking for installations completed in 2011.

installations. Five years ago, owners of most PV installations received a cash rebate from a state or utility incentive program and this rebate was the most important element of the financial package. In that era, no state had a significant amount of installations without also having a rebate program. For the past three years, the incentive expenditures have been declining, in part because the rebates per watt have been declining and in part because some states have stopped these programs. Despite the decreasing expenditures, installed capacity of facilities with rebate support continues to increase. When PV is less expensive, less incentive money is necessary to encourage installations.

On a cumulative per capita basis, the top five states — Arizona, Nevada, Hawaii, New Jersey and New Mexico — remained the same as the previous year, although the ranking of these five states changed (Table 5).

Table 4: CUMULATIVE TOP TEN STATES
Ranked by Grid-Connected PV Cumulative Installed Capacity through 2012

	MW_{DC}	Market Share
1. California	2,559	35%
2. Arizona	1,106	15%
3, New Jersey	956	13%
4. Nevada	350	5%
5. Colorado	300	4%
6. North Carolina	208	3%
7. Massachusetts	207	3%
8. New Mexico	203	3%
9. Hawaii	199	3%
10. New York	179	2%
All Other States	1,106	15%
Total	**7,374**	**--**

Table 5: PER CAPITA TOP TEN STATES
Ranked by Grid-Connected PV Cumulative Installed Capacity per Capita (W_{DC}/person) through 2012

	Cumulative through 2012 (W_{DC}/person)	2012 Installations (W_{DC}/person)
1. Arizona	173.1	110.9
2. Hawaii	146.6	84.0
3. Nevada	129.5	83.5
4. New Jersey	108.7	44.4
5. New Mexico	98.7	18.4
6. California	68.7	26.4
7. Colorado	59.6	20.5
8. Delaware	51.4	22.0
9. Vermont	44.7	26.0
10. Massachusetts	31.7	18.8
National Average	**23.9**	**10.8**

Information on Top State Markets

Solar electric market activity has more to do with state incentives and policies than with the amount of available sunlight or solar resource. Most of the top states for grid-connected PV offer financial incentives and/or have an RPS policy with a solar mandate. The combination of state and/or local incentives and the federal ITC created strong markets for most of the installations around the country. There are relatively few installations in locations with no state, utility or local incentives or with no RPS policy that includes a solar mandate. This section describes the market conditions in the states with the largest number of installations. As solar prices fall, increasingly electricity prices and rate policies become an important factor in state markets. States with high electricity prices will have more robust solar markets.

In 2007, **California** launched its 10-year, $3 billion *Go Solar California* campaign. The largest part of this campaign is the California Solar Initiative (CSI), overseen by the California Public Utilities Commission (CPUC). The CSI awards rebates and performance-based incentives to customers serviced by the state's three investor-owned electric utilities: Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric. With $327 million in CSI incentives, more than 400 MW_{DC} of PV was installed in 2012 through this program.[1] These incentives are based on actual system performance of larger systems and expected system performance of smaller systems. Incentive levels are reduced over the duration of the program in 10 "steps," based on the aggregate capacity of solar installed. Because of these step reductions, the incentives paid by the program decreased by six percent in 2012, but the capacity installed through the program increased by 31 percent. The CSI was prudently designed as a long-term program, so the industry in California can rely on long-term policy stability. The program will exhaust available funds in 2013. As the CSI incentives end, installations continue to increase. California's steep, tiered electric rate schedule and large, peak period time-of-use rates, combined with net metering, provide enough of an incentive for consumers to continue to install solar energy systems.

[1] Note that California agencies typically report in MW_{AC} and the data are presented here in MW_{DC}.



Partially completed Agua Caliente Solar Project in Yuma County, Arizona

In addition, the California Energy Commission (CEC) administers the New Solar Home Partnership Program for PV installations on new homes, and the CPUC manages the Multi-Family Affordable Solar Housing and the Single-Family Affordable Solar Housing Programs.

Beginning in 2008, California required municipal utilities to offer solar incentives. Installations in municipal utility service territories in California totaled 229 MW_{DC} in 2012, more than double the 2011 installations. The capacity of distributed installations by California public utilities increased by 69 percent to 84 MW_{DC} in 2012. A number of municipal utilities have offered incentives for many years, and the larger municipal utilities in Sacramento and Los Angeles have installed a large number of PV systems over the past decade or more.

The result of these programs is that 40 percent of all distributed PV installations in the U.S. have been in California. California has long had strong incentives and good net metering policies. Now, as the incentives are ending, dropping PV prices and high electricity rates are propelling continued growth in distributed installations.

California also has large markets for utility installations due to an RPS requirement of 20 percent renewable energy generation by 2013 and 33 percent by 2020. This includes all renewable technologies and inspired many PV installations in 2012. This requirement led to 488 MW_{DC} of utility sector solar installations in California in 2012, plus an additional 520 MW_{DC} of utility installations in Arizona and Nevada where the electricity produced flows to California. Fully 48 percent of all utility sector installations either are in California or supply electricity for the California market.

Arizona ranks second for 2012 capacity installed, and it more than doubled the capacity installed in 2011. However, the numbers are skewed by the fact that 58 percent of the 2012 capacity installed was at two utility plants supplying electricity to PG&E in California. These two plants, Agua Caliente and Mesquite Solar 1, were the two largest U.S. solar installations at the end of 2012. If we look just at installations in Arizona that supply electricity for Arizona, the state would fall to third place, and the growth rate would be a much more modest 23 percent.

Arizona solar policy has evolved over the past several years. The current requirement is that 15 percent of electricity be generated from renewable sources by 2025. Distributed generation must provide 30 percent of this energy, divided equally between residential and non-utility, non-residential installations. Solar water heaters may also provide RECs for RPS compliance in Arizona. Although residential installations increased by 83 percent, distributed non-residential installations decreased by 41 percent compared with 2011 installations. The market for net metered systems in 2013 and beyond is uncertain, with the state's largest utility (Arizona Public Service) relying on a study it commissioned that concludes that residential net-metered customers are currently being subsidized by other customers. Solar energy advocates have countered with a study showing that no subsidy exists, and the Arizona Corporation Commission is reviewing the evidence.



Ground-mount array at Maui Arts Cultural Center in Maui, Hawaii

The combination of state and/or local incentives and the federal ITC created strong markets for most of the installations around the country.

In **New Jersey**, an RPS with a solar requirement built a strong PV market. The solar requirement was 306 GWh in 2011, increasing to 5,316 GWh in 2026. In the early years of the New Jersey program, rebates were the most important driver for solar installations. Rebate expenditures peaked in 2006 at $78 million. In 2012, rebate expenditures were $2.4 million for 17 MW_{DC} of installations. This means the capacity of installations increased 24 percent with 82 percent less financial incentives than in 2011. Now, for most installations, the capacity-based rebate program has been converted into a performance-based incentive that involves payments based on the actual energy production of a PV system. This performance-based program created a market for SRECs, which New Jersey utilities use to comply with the RPS. In 2012, new installations with a combined capacity of 373 MW_{DC} were selling SRECs, representing 96 percent of new installations in New Jersey. Although New Jersey SREC prices crashed in 2012, the state made policy changes to stabilize its long-term SREC market.

Nevada has an RPS with a solar carve-out that requires one percent solar generation in 2013, 1.3 percent in 2020 and 1.5 percent in 2025. Although the state has a rebate program called RenewableGenerations, distributed installations are less than five percent of the capacity installed in 2012. Almost half of the 2012 capacity is due to one utility installation, Copper Mountain Solar Complex, which supplies electricity to PG&E in California.

Massachusetts has a long history of providing rebates for PV installations. In 2010, Massachusetts awarded $37 million in rebates for 14 MW_{DC} of PV installations. These installations represented 63 percent of the PV capacity installed in Massachusetts that year. In 2012, the state awarded $8 million in rebates for 14 MW_{DC} of PV installations. Thus, 80 percent fewer rebate dollars funded the same amount of installed PV capacity. During the same period, the amount of installed capacity not receiving rebates increased from 9 MW_{DC} to 108 MW_{DC}. This is due to the Massachusetts RPS, which has a solar carve-out of 0.163 percent in 2012 and 0.2744 percent in 2013. Massachusetts uses an SREC market for compliance with the RPS requirements.

North Carolina has an RPS requiring 0.2 percent from solar by 2018. Most North Carolina installations sell the generated solar electricity to utility companies. North Carolina set up the Renewable Energy Tracking System to track RECs and record compliance with the standard.

Hawaii has the highest electricity rates in the country by far. The 2012 average price of nearly $0.34/kWh is more than twice the rate in any other state and three and a half times the national average electricity price. Hawaii also has a personal state solar income tax credit. Some 94 percent of Hawaii installations were distributed in 2012. The financial benefits of PV are usually more favorable in Hawaii than in any other U.S. state and on a per capita basis, Hawaii had, by far, the most installed capacity of distributed PV in 2012.

In 2005, **Colorado** voters passed Amendment 37, which created an RPS with a solar mandate equal to 0.4 percent of retail electricity sales. Later, the legislature doubled the overall RPS requirements and the solar mandate. The current requirement is that utilities must have three percent distributed generation by 2020 with half of that total serving retail customers. Xcel Energy is by far the largest utility in the state, and 95 percent of Colorado's PV installations in 2012 were part of Xcel's programs. Though it offers capacity-based rebates for smaller, customer-sited PV systems, Xcel has ended incentives for larger distributed installations. As a result, 2012 distributed non-residential installations fell by 50 percent compared with installations in 2011.

Maryland has an RPS with a solar carve-out requiring 0.1 percent from solar in 2012 and increasing to two percent in 2020. Installations in Maryland have grown quickly and, of the Top 10 States for Annual Capacity, Maryland had the highest growth rate of all states except for Nevada.

New York has had long-term significant rebate programs operated by the New York State Energy Research and Development Authority and the Long Island Power Authority. Because of these programs, distributed installations increased by 81 percent in 2012 compared with 2011. Overall, the total annual

capacity installed in New York decreased in 2012 compared with 2011. This is due to the fact that BP Solar built two large utility installations with a combined capacity of 37.6 MW_{DC} in 2011. There were no utility sector installations in New York n 2012.

Although this report covers U.S. installations, the market across the border in the province of **Ontario**, Canada, is also noteworthy. In 2012, Ontario added installations with a capacity of about 226 MW_{DC}, which is 16 percent less than the capacity installed in 2011. If Ontario were a U.S. state, it would have ranked fourth on IREC's list of states. A feed-in tariff program begun in 2008 jump-started the Ontario solar market.



Ground mount installation in Worton, Maryland

3. CONCENTRATING SOLAR POWER

No new concentrating solar plants were completed in 2012 (Figure 10). To date, slightly more than 500 MW CSP plants are in the U.S., much of them built in the late 1980s and early 1990s. In 2013, CSP plants generating nearly 800 MW are likely to be completed at sites in California, Nevada and Arizona. This includes three power towers at the Ivanpah Solar Project in Barstow, California, which was 92 percent complete as of May 2013. Additional plants are under construction for completion in 2014 and 2015.

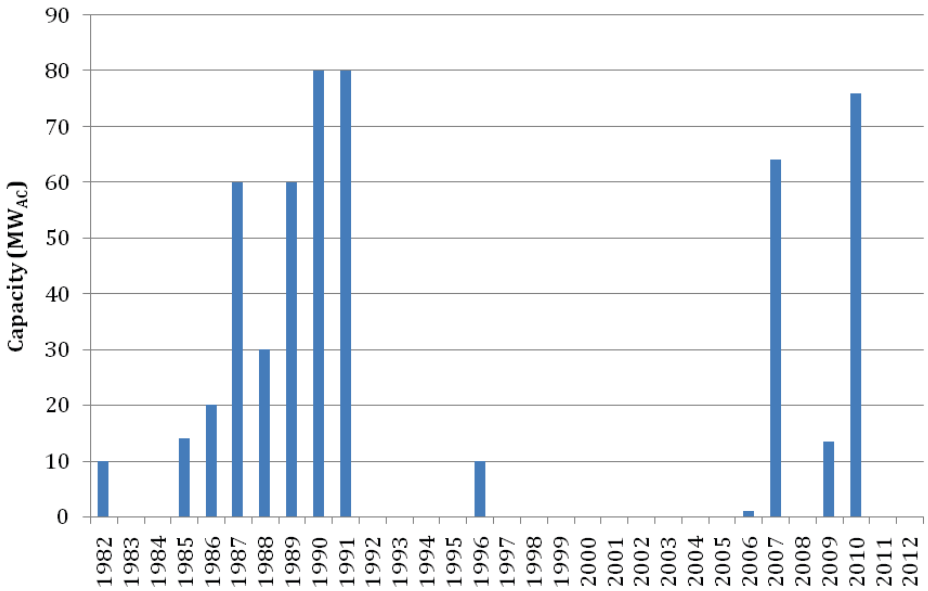


Figure 10: Annual Installed U.S. CSP Capacity (1982-2012)

4. PROSPECTS FOR 2013

What can we expect in U.S. solar markets in 2013? As of June 2013, indicators pointed to continued growth in grid-connected PV. Reductions in PV module prices, continuation of the federal ITC, strong state RPSs, net metering policies and available capital for third-party ownership will help drive market growth.

Many large solar projects began construction in 2012 in order to take advantage of the 1603 Treasury Grant Program. These installations, both distributed and utility-sector projects, will be completed in 2013 through 2016. Since projects that begin construction in 2013 will no longer have the cash grant option, developers will need to find entities, such as banks and insurance companies with tax bills large enough to take advantage of remaining tax credits. Solar developers have announced several large funding packages in 2013, indicating that financing continues to be available for more installations.

5. CONCLUSION

PV markets continue to grow in the United States. More than 3.3 GW_{DC} of PV installations were completed in 2012 at 95,000 sites. The capacity installed was 80 percent greater than the amount installed in 2011. The markets for each solar technology are concentrated in a few states.

PV installations are getting larger. Almost half of the capacity installed in 2012 was at just 61 sites with a capacity of 5 MW_{DC} or larger. The largest 2012 installation was nearly 290 MW_{DC} and there were four installations larger than 100 MW_{DC}.

These markets depend on a combination of federal and state policies and financial incentives, the most significant of which include:

- Federal ITC
- U.S. 1603 Treasury Grant Program
- Federal loan guarantees
- State RPSs, especially those with solar requirements
- Net metering
- State, utility or local rebates or other financial payments.

In addition to government policies, the following factors are important contributors to the growth of solar markets:

- Lower installed costs for PV installations
- Availability of capital for third-party ownership of systems.

U.S. PV market growth will continue in 2013, with larger utility-sector projects leading the way.

ACKNOWLEDGEMENTS

This material is based upon work supported by the Department of Energy under Award Number DE-EE0005352 - REGULATORY AND UTILITY SOLUTIONS TO ADVANCE SUNSHOT INITIATIVE GOALS.

The author appreciates the data supplied by many national, state and utility offices and programs, in addition to data shared by Andrew Krulewitz of GreenTech Media and Rebecca Campbell of Solar Electric Power Association. Jane Weissman, President and CEO of IREC, supported this work and Janet Meyer provided valuable assistance with data collection and editing. Jason Keyes, Tim Lindl, Becky Campbell and Jane Pulaski provided helpful reviews.

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APPENDIX A
DATA SOURCES

Grid-Connected PV

State data were obtained for grid-connected PV installations from the following sources:

- State agencies or organizations administrating state incentive programs
- Utility companies
- Energy Information Agency data on New Electricity Generation Plants and Net Metered Systems (EIA 2013 and EIA 2012)

GreenTech Media, in cooperation with the Solar Energy Industries Association, collects solar installations data on a quarterly basis (GTM/SEIA 2012). The Solar Electric Power Association publishes an annual report on installation by utility that is based on an annual utility survey (Krishanmoorthy, Taylor & Campbell 2013). Since 2010, IREC has collaborated on both of these other installations reports and exchanged data. This collaboration results in better and more extensive installation data. With the growth of the PV market, data collection becomes more complex and multiple sources help improve data quality.

The data quality depends on the source. Certainly, this study misses some installations. Data based on incentives paid have historically been the most reliable data. As rebates fund a smaller share of PV installations each year, incentive databases become less important data sources.

Off-Grid PV

IREC does not collect data for these installations, and they are not included in this report's charts.

Solar Heating and Cooling

Previous editions of this report included data for solar heating and cooling installations. However, this year's report does not include this data.



Concentrating PV at Alamosa Solar Farm in Colorado



Residential PV Installation in Arizona

APPENDIX B
ASSUMPTIONS

Solar Capacity

Capacity measures the maximum power that a system can produce. For a solar energy system, the capacity is the output under "ideal" full sun conditions. Capacity is typically measured in watt (W), kiowatts (kW), or megawatts (MW). A kilowatt of one technology usually does not produce the same amount of energy, commonly measured in kilowatt-hours (kWh) for electricity, as a kilowatt of another technology. Thus, capacity for one energy technology is not directly comparable to the capacity for another technology.

This study reports PV capacity in direct current (DC) watts under Standard Test Conditions ($W_{DC\text{-}STC}$) of 1000 W/m^2 solar irradiance and 25° C PV module temperature. This is the capacity number that manufacturers and others typically report; it is also the basis for rebates in many states.

A number of states and utilities report capacity in alternating current (AC) watts. The California Energy Commission calculates AC watts by multiplying DC watts under PVUSA Test Conditions by the inverter efficiency at 75 percent of load. The resulting capacity ($W_{AC\text{-}PTC}$) is a more accurate measure of the maximum power output under real world conditions.

The California Solar Initiative (CSI) reports installation capacity in both DC and AC watts. Therefore, the average ratio between AC and DC watts can be determined for each year. According to the CSI data in 2010, AC watts were 86.2 percent of DC watts. In 2012 the ratio increased to 86.9 percent. In cases where the capacity was reported in AC watts, IREC used 86.5 percent to convert the data to DC watts.

Number of Installations

For grid-connected PV installations, this study uses actual data on the number of installations. For the data, which show residential and non-residential installations, real data are used whenever possible. For data sources which only report the size of the installations, this study assumes all installations less than 10 kW_{DC} are residential installations.

The results for cumulative installations include all new installations in previous years. No accounting was made for systems that are no longer operational.

Date of Installation

This report uses the best data available on the date of installation. Ideally, this is based on the date when the installation was connected and producing power. Calendar Year (CY) is used as the year basis for all data.

In some cases, data are available for when the applicant finished the installation and applied for the incentive payment. When this information is available, it was used as the installation date.

In many cases, the agency that administers an incentive program reports the date on which the incentive payment was made. If these are the only data available, this is the installation date used in this report.

Net Metering

In states where net-metering data was unavailable, IREC assumed that systems meeting the local rules for net-metered systems were net-metered.

Changes from Last Year's Report

This edition of this report uses the best available data for all years at the time of publication. Some data from past years were updated. Thus, installed capacity and number of installations shown in this report for 2011 and earlier are not always identical to what was reported in the 2011 or earlier editions of this report.

APPENDIX C

GRID CONNECTED PV INSTALLATIONS BY STATE

State	Capacity Installed in 2012 (MW_{DC})				Cumulative Installed Capacity (MW_{DC})
	Residential	Non-Residential	Utility	Total	
Alabama	*	0.1	0.5	0.6	1.1
Alaska	*	*	*	*	*
Arizona	66.2	69.0	573.7	708.8	1,106.4
Arkansas	0.5	*	*	0.6	1.5
California	200.1	295.2	487.8	983.2	2,559.3
Colorado	20.1	15.5	67.4	102.9	299.6
Connecticut	3.8	3.7	*	7.5	39.6
Delaware	2.0	2.7	15.0	19.7	46.1
District of Columbia	1.3	1.0	*	2.3	13.9
Florida	5.3	10.4	6.2	21.9	116.9
Georgia	0.6	6.6	1.0	8.2	21.4
Hawaii	70.3	37.0	6.9	114.3	199.5
Idaho	0.4	0.3	*	0.7	1.0
Illinois	1.0	2.7	23.1	26.7	42.9
Indiana	0.4	0.6	*	0.9	4.4
Iowa	0.4	0.7	*	1.1	1.2
Kansas	0.1	0.2	*	0.3	0.5
Kentucky	0.1	*	1.3	1.5	4.8
Louisiana	11.0	0.9	*	11.9	18.2
Maine	1.4	0.3	*	1.7	2.8
Maryland	6.5	42.8	30.4	79.7	116.8
Massachusetts	14.6	104.1	4.5	123.2	207.3
Michigan	3.4	7.7	*	11.1	19.9
Minnesota	1.3	3.2	27.9	6.5	11.3
Mississippi	*	*	0.1	0.1	0.7
Missouri	6.9	9.7	*	16.6	18.5
Montana	1.0	0.4	*	1.4	2.2
Nebraska	*	*	*	0.1	0.4
Nevada	2.1	8.5	215.0	225.6	349.7
New Hampshire	1.0	1.3	*	2.3	5.4
New Jersey	42.9	262.9	84.9	390.7	955.7
New Mexico	5.2	4.8	27.9	37.9	203.4
New York	15.8	39.8	*	55.6	179.4
North Carolina	0.5	20.0	101.9	122.4	207.9
North Dakota	*	*	*	*	0.1
Ohio	2.0	40.4	5.9	48.3	79.9
Oklahoma	0.1	*	*	0.2	0.3
Oregon	5.8	4.9	10.0	20.6	56.4
Pennsylvania	10.0	21.3	*	31.3	164.3

GRID CONNECTED PHOTOVOLTAIC INSTALLATIONS BY STATE continued

State	Capacity Installed in 2012 (MW_{DC})				Cumulative Installed Capacity (MW_{DC})
Rhode Island	0.1	0.6	*	0.7	1.9
South Carolina	0.3	0.2	*	0.5	4.6
South Dakota	*	*	*	*	*
Tennessee	*	0.2	22.8	23.0	45.0
Texas	9.3	9.6	35.7	54.7	140.3
Utah	1.3	3.7	0.6	5.6	10.0
Vermont	5.3	2.3	8.8	16.3	28.0
Virginia	1.0	4.3	*	5.2	10.5
Washington	5.2	2.0	*	7.2	19.5
West Virginia	0.9	0.2	*	1.1	1.7
Wisconsin	0.9	7.3	*	8.2	21.1
Wyoming	0.3	*	*	0.4	0.6
Territories	*	3.6	25.8	29.4	29.8
TOTAL	**528.9**	**1,053.1**	**1759.2**	**3,341.1**	**7,373.8**

* = less than 100 kW_{DC} or data not available

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