



January 12, 2018

Via electronic filing

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

Re: Docket No. 20170225-EI

Dear Ms. Stauffer:

Enclosed for filing in the above dockets please find Sierra Club's Notice of Intent to Seek Official Recognition and the corresponding exhibits. Please contact me should you or your staff have any questions regarding this filing.

Sincerely,

/s/ Julie Kaplan

Julie Kaplan
Senior Attorney
Sierra Club
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Qualified Representative for Sierra Club

Enc.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for
 Dania Beach Clean Energy Center Unit 7,
 by Florida Power & Light Company

DOCKET NO. 20170225-EI

DATE: January 12, 2018

SIERRA CLUB'S NOTICE
 OF INTENT TO SEEK OFFICIAL RECOGNITION

Pursuant to Section 120.569(2)(i), F.S. and the Order Establishing Procedure, No. PSC-16-0473-PCO-EI, Sierra Club hereby gives notice that it may seek official recognition of the following documents:

Exhibit	Title	Author/Organization
A	Resolution of the City Commission of the City of Sarasota, Florida for a Transition to 100 Percent Renewable, Zero Emission Energy Sources	City Commission of the City of Sarasota
B	Resolution E-4909, ordering Pacific Gas and Electric Company (PG&E) to hold a competitive solicitation for energy storage and preferred resources to address two local sub-area capacity deficiencies and to manage voltage issues in another sub-area	California Public Utilities Commission
C	Short-Term Special Assessment Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation	North American Electric Reliability Corporation (NERC)
D	Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System	North American Electric Reliability Corporation (NERC)
E	U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017	National Renewable Energy Laboratory (NREL)
F	Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant	National Renewable Energy Laboratory (NREL)
G	SunShot 2030 for Photovoltaics (PV): Envisioning a Low-cost PV Future	National Renewable Energy Laboratory (NREL)

Please find the above documents attached as exhibits.

Respectfully submitted this 12th day of January, 2018.

/s/ Julie Kaplan

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Enc.

CERTIFICATE OF SERVICE
Docket No. 20170225-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 12th day of January, 2018, to the following:

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Qualified Representative for Sierra Club

Exhibit A

RESOLUTION NO. 17R-2648

A RESOLUTION OF THE CITY COMMISSION OF THE CITY OF SARASOTA, FLORIDA FOR A TRANSITION TO 100 PERCENT RENEWABLE, ZERO EMISSION ENERGY SOURCES IN ACCORDANCE WITH THE 100 PERCENT RENEWABLE ENERGY INITIATIVE; PROVIDING FOR READING OF THIS RESOLUTION BY TITLE ONLY; AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City of Sarasota is a coastal community on the front lines of the environmental, economic and public health impacts of climate change stemming from sea level rise, storm surge, flooding, and rising temperatures; and

WHEREAS, the City of Sarasota seeks a healthy, sustainable future with less toxic pollution threatening residents and more economic growth opportunities for workers; and

WHEREAS, the transition to 100 percent renewable, zero emission energy sources, such as solar power, will improve air and water quality and protect public health, particularly for the most vulnerable across our community; and

WHEREAS, 100 percent renewable, zero emission energy sources as well as energy efficiency represent an enormous economic opportunity for City of Sarasota to create jobs in an emerging industry and expand prosperity for residents; and

WHEREAS, one out of every 50 new jobs added in the United States in 2016 was created by the solar industry; and

WHEREAS, 100 percent renewable, zero emission energy sources and energy efficiency now offer greater economic security, lower electricity costs, and an affordable energy solution for City of Sarasota residents; and

WHEREAS, according to the U.S. Department of Energy, solar costs are down between 54 percent and 64 percent from 2008; and

WHEREAS, individuals, families, businesses, and institutions throughout the City of Sarasota seek greater energy freedom through the expansion of distributed 100 percent renewable, zero emission energy sources like rooftop solar; and

WHEREAS, business analysts have called Florida “the sleeping giant” of the solar industry; and

WHEREAS, in November 2016, the City of St. Petersburg became the first city in Florida to commit to transitioning to 100 percent renewable, zero emission energy sources; and

WHEREAS, the City of Sarasota has previously established a 35% community-wide greenhouse gas emission reduction goal by 2025, from a 2003 baseline; and

WHEREAS, the City of Sarasota has previously established a 35% municipal operations greenhouse gas emission reduction goal by 2025, from a 2003 baseline; and

WHEREAS, the City of Sarasota has established fast track permitting for private sector LEED certified buildings; and

WHEREAS, the City of Sarasota has entered into a “Renewable Energy, Energy Efficiency, and Energy Sustainability Agreement” with Florida Power and Light, as part of the 2010 Franchise Renewal; and

WHEREAS, the City of Sarasota has established that all new City buildings and major renovation projects shall use sustainable measures as outlined in LEED certification or “Alternative Compliance Pathways for Incentives”; and

WHEREAS, the City of Sarasota has established that all new urban expansion and infill developments shall use sustainable measures as outlined in LEED certification or “Alternative Compliance Pathways for Incentives”; and

WHEREAS, the City of Sarasota comprehensive plan stipulates that the City shall “actively pursue 100 percent renewable energy installations for City facilities”; and

WHEREAS, residents of the City of Sarasota and Sarasota County have recently formed a co-op to use their buying power to secure discounted prices for solar panels; and

WHEREAS, there is broad support for a just transition to 100 percent renewable, zero emission energy sources from City of Sarasota residents, business and institutions; and

WHEREAS, “renewable, zero emission energy” includes energy derived from solar, wind power sited in ecologically responsible ways, existing and low-impact hydroelectric, geothermal, and ocean/wave technology sources.

NOW THEREFORE BE IT RESOLVED BY THE CITY COMMISSION OF THE CITY OF SARASOTA, FLORIDA:

Section 1. The City of Sarasota adopts a community-wide target of powering the City with 100 percent renewable, zero emission energy sources not later than 2045.

Section 2. The City of Sarasota adopts a target of powering municipal operations with 100 percent renewable, zero emission energy sources not later than 2030, including at least 50 percent by 2024.

Section 3. The City Commission of the City of Sarasota direct its Sustainability Manager to incorporate these targets into the City's Climate Change Vulnerability Assessment and Adaptation efforts and planning processes and to work with community stakeholders to devise implementation strategies.

Section 4. The City of Sarasota, in pursuit of these targets, will seek to build inclusive community leadership and policy engagement, promote equity in energy and resource costs and ownership of related technologies, generate sustainable economic and employment opportunities and mitigate related losses; and provide regional leadership to address equity in climate and energy.

Section 5. The City of Sarasota Sustainability Manager will report on progress to the City Commission towards these goals every two years, beginning in 2018.

Section 6. This resolution shall take effect immediately upon adoption.

ADOPTED by the City Commission of the City of Sarasota upon reading by title only, after posting on the bulletin board at City Hall for at least three (3) days prior to adoption, as authorized by the Charter of the City of Sarasota this 19th day of June, 2017.

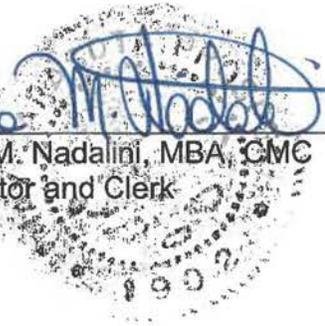


Shelli Freeland Eddie, Mayor

ATTEST:



Pamela M. Nadalini, MBA, CMC
City Auditor and Clerk



- Shelli Freeland Eddie, Mayor
- Liz Alpert, Vice Mayor
- Commissioner Jennifer Ahearn-Koch
- Commissioner Hagen Brody
- Commissioner Willie Charles Shaw

Exhibit B

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

AGENDA ID #16195
RESOLUTION E-4909
January 11, 2018

R E S O L U T I O N

Resolution E-4909. Authorizing PG&E to procure energy storage or preferred resources to address local deficiencies and ensure local reliability.

PROPOSED OUTCOME:

- Orders Pacific Gas and Electric Company to hold competitive solicitations for energy storage and preferred resources, to meet specific local area needs in three specified subareas.

SAFETY CONSIDERATIONS:

- Pacific Gas and Electric Company is required to ensure any contracts entered into provide that sellers shall operate the facilities in accordance with prudent and safe electrical practices.

ESTIMATED COST:

- This Resolution is expected to result in additional contracts, which could lead to increased ratepayer costs, but could also offset other costs. Actual costs of the contracts are unknown at this time.

By Energy Division's own motion.

SUMMARY

This Resolution orders Pacific Gas and Electric Company (PG&E) to hold a competitive solicitation for energy storage and preferred resources to address two local sub-area capacity deficiencies and to manage voltage issues in another sub-area.

BACKGROUND

Designation of Three Calpine-Owned Power Plants

In November 2016, Calpine sent a letter to the CAISO stating its desire to terminate Participating Generator Agreements (PGAs) for the four of its peaking units (Feather River, Yuba City, King City, and Wolfskill Energy Centers).¹ In June 2017, Calpine sent a letter to the CAISO explaining that it was assessing whether to make the Metcalf Energy Center available for CAISO dispatch effective January 1, 2018.² The claim for all these plants is that they are no longer economic to operate at current energy and Resource Adequacy (RA) capacity prices. Additionally, they claim that the CAISO's capacity procurement mechanism (CPM) does not provide a sufficient planning period for Calpine to make major maintenance, budget, and company planning decisions. Calpine's letter regarding Metcalf also explains the need for significant upgrades and capital expenditures. Calpine requested that the CAISO conduct reliability studies for the plants to determine whether they are needed to ensure local reliability. CAISO performed the studies, per Section 41.3 of the CAISO Tariff.

In March 2017, the California Independent System Operator (CAISO) determined that two of the four peaking units, Yuba City and Feather River Energy Centers, are needed to meet a local capacity need in the Pease sub-area and to continue to mitigate a voltage issue in the Bogue sub-area, respectively, both of which are located in the Sierra local capacity area (LCA). The CAISO designated both plants as reliability must-run resources (RMR) under tariff section 41. The Yuba City Energy Center is a 47.6 MW facility that has been designated to fulfill an identified capacity shortfall of 18 megawatts (MWs) in the Pease sub-area. The Feather River Energy Center is a 47.6 MW facility that has been designated to alleviate a high voltage issue in the Bogue sub-area and not a capacity shortfall.

In November 2017, the CAISO determined that the entire Metcalf Energy Center is needed for local reliability needs in the South Bay-Moss Landing sub-area of the Bay Area LCA, and designated the unit as RMR. The Metcalf Energy Center is a 580 MW facility. The South Bay-Moss Landing sub-area RA requirement for 2018 has been determined to be 2,221 MW. The available generation in this local sub-area has been determined to be 2,408 MW. The CAISO concluded that

¹ <http://www.caiso.com/Documents/DecisiononRequestforReliabilityMust-RunDesignations-Attachment-Mar2017.pdf>.

² http://www.caiso.com/Documents/CalpineLetter_CAISO_MetcalfEnergyCenterRetirementAssessment.PDF

removing any one unit of the Metcalf facility would result in a sub-area local deficiency.³

On November 2, 2017, Calpine filed three unexecuted RMR agreements for the aforementioned plants with the Federal Energy Regulatory Commission (FERC).

Established Procurement Process Not Followed

Use of RMR as a means to ensure reliability has been declining for more than a decade, since 2006. In 2006, the CAISO announced that it was reducing the use of RMR agreements by sixty percent for 2007.⁴ These three agreements appear to be the first time that the use of RMR has increased since 2006, based on our review CAISO staff's annual "RMR/Black Start/Dual Fuel Contract Status", the last of which was presented to the CAISO board in September 2017, in support of the board's decision to extend RMR agreement for three units owned by Dynegy in Oakland⁵. Further, we are concerned that normal regulatory process⁶ was not followed leading up to these RMR agreements. The normal process for procurement of capacity for reliability is in the following order:

- The CAISO conducts its annual local capacity technical study, with the results being adopted by the Commission in June.
- Generating resources offer their available capacity into load serving entities' (LSEs) resource adequacy (RA) competitive solicitations. System, local and flexible capacity is procured through this process. Alternatively, LSEs and generators negotiate and contract bilaterally outside of a competitive solicitation.
- As described in Section 43A of the CAISO tariff, in the event that CAISO identifies a shortfall following the normal RA process (which concludes with the annual RA compliance filing in October), it may activate the Capacity Procurement Mechanism (CPM). The CPM is

³ The three units of the Metcalf Energy Center are: 173 MWs; 170 MWs; and 237 MWs.

⁴ <https://www.caiso.com/Documents/CaliforniaISOReducesRMRContractsby60Percent.pdf>

⁵ http://www.caiso.com/Documents/Decision_ConditionalApproval_ExtendRMRContracts_2018-Memo-Sep2017.pdf

⁶ The CAISO staff make reference to the normal RA process in two memos to the CAISO Board, dealing with the Metcalf, Feather River and Yuba City RMR Designations:

http://www.caiso.com/Documents/Decision_ReliabilityMust-RunDesignation_MetcalfEnergyCenter-UpdatedMemo-Nov2017.pdf, and <http://www.caiso.com/Documents/Decision-RequestforReliabilityMust-RunDesignations-Memo-Mar2017.pdf>

also a competitive process, and is intended to be complimentary to the annual RA cycle.

In the case of all three plants, Calpine did not enter into any bilateral RA contracts for 2018. Instead, the company elected to communicate to the CAISO that it was planning to make these resources unavailable for CAISO dispatch unless it were awarded an RMR contract. Calpine cited the insufficiency of RA capacity prices and that CPM would not provide a planning period sufficient for Calpine to make major maintenance, budget, and planning decisions.

Potential Resultant Market Distortions

The Commission is concerned about impacts to ratepayers if the RMR contracts are executed and if they are extended. As discussed earlier in this Resolution, these contracts were developed outside of the normal resource adequacy process and the CAISO's Capacity Procurement Mechanism (CPM) was not initiated. Lack of competition, with in this instance these RMR contracts, can lead to market distortions and unjust rates for power. It is because of this concern that the Commission is exercising its broad procurement authority with this Resolution to authorize PG&E to conduct the solicitation for resources that can effectively fill local deficiencies and address issues identified. If contracted for, alternative resources could potentially be brought on line. These new resources could eliminate the need for the RMR contracts for the plants described in this Resolution, or limit their duration. In addition, these new resources would be subject to must offer obligations (MOO) in the wholesale energy markets. In contrast, RMR contracts cover the full cost of keeping the facility available, but the facility is only called upon to serve load if the specific contingency occurs, and is not subject to a MOO. In all other time periods, RMR designation can cause ongoing market distortions because it may serve as a disincentive to a plant from regular participation in the energy market.

Commission Authority to Direct Procurement

Section 701 of the Public Utilities Code gives the Commission broad authority to take any action to conduct its duties: *The commission may supervise and regulate every public utility in the State and may do all things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction.* We are not aware of any specific legislative prohibition against the Commission requiring PG&E conduct the solicitation required by this Resolution.

Several areas of California law give the Commission authority to act to ensure a safe and reliable energy supply for the state as well as just and reasonable retail rates for such services. The Commission's authority over utility regulation and supervision arises from the California Constitution, state law and court decisions as well as federal law including, but not limited to, the Federal Power Act, 16 U.S.C. § 791 et seq., and section 714 of the Energy Policy Act of 1992, 16 U.S.C. §824(g). (General Order 167, Section 1; see generally *Southern California Edison Company v. Public Utilities Commission* (2014) 227 Cal.App.4th 172, 186-196.)

Several state statutes direct the Commission to assure the long-term reliability of California's electric energy supply. Section 380 of the California Public Utilities Code⁷ requires the Commission to establish and enforce resource adequacy requirements to assure "development of new generating capacity and retention of existing generating capacity that is economic and needed." (Section 380, subs. (b)(1); see also subs. (c)-(f).)

The Commission also exercises authority not just over electric utilities, but also in state generation facilities. Section 761.3, subdivision (a) provides the Commission "shall implement and enforce standards for the maintenance and operation of facilities for the generation of electricity . . . located in the state to ensure their reliable operation." The commission shall enforce the protocols for the scheduling of powerplant outages of the Independent System Operator." The Commission designed General Order (G.O.) 167

"to implement and enforce standards for the maintenance and operation of electric generating facilities and power plants so as to maintain and protect the public health and safety of California residents and businesses, to ensure that electric generating facilities are effectively and appropriately maintained and efficiently operated, and to ensure electrical service reliability and adequacy." (G.O. 167, Section 1.)

Procurement of Preferred Resources and Energy Storage for Local Reliability

Energy storage and preferred energy resources can be fast-responding, reliable and constructed in a short timeframe. Energy storage and preferred energy resources are procured at increasing levels to meet local reliability requirements including capacity shortfalls, in lieu of conventional generation. Two examples follow:

⁷ All further statutory references shall be to the California Public Utilities Code unless otherwise specified.

In February 2013, as a result of the impending closure of the Once-Through-Cooling Plants and the unexpected closure of the San Onofre Nuclear Generating Station, the Commission required SCE to undertake solicitations for the West L.A. Basin and Moorpark sub-areas. SCE was required to procure a minimum amount of energy storage and preferred resources, within that solicitation. As a result, 510.66 MW of energy storage and preferred resources have been contracted by SCE and approved by the Commission. For storage alone, SCE's target was 50 MWs. Ultimately, more than 260 MWs were procured, more than five times the target, as storage proved to have an exceptionally high value in bid evaluation.

In May 2016, with Resolution E-4791, the Commission required Southern California Edison company to conduct an expedited procurement for both utility-owned and third party storage resources that could come online in Winter 2016, to alleviate any electric supply shortages resulting from natural gas interruptions. As a result, more than 100 MWs of grid-level energy storage are currently operating and contributing to reliability.

DISCUSSION

Solicitation

PG&E is directed to conduct one or more solicitations at its earliest opportunity, commencing no later than 30 days from the effective date of this Resolution.

Parameters for storage procurement:

1. PG&E may solicit bids for energy storage and preferred resources, either individually or in an aggregation.
2. Resources procured pursuant to this solicitation must be both:
 - a. On-line and operational by a date sufficient to ensure that the RMR contracts for the three plants – Metcalf Energy Center, Feather River Energy Center, and Yuba City Energy Center – will not be renewed for 2019.
 - b. Located within the relevant sub-area(s) and be interconnected at location(s) that will mitigate local capacity and voltage issues

sufficient to obviate the need for RMR contracts for the aforementioned plants.

3. Resources procured in this solicitation should be at a reasonable cost to ratepayers, taking into consideration the cost and value to PG&E, previous solicitations in which PG&E has awarded contracts to similar resources, the cost of the specific RMR contracts, with adjustments for contract terms such as contract length and expedited delivery date.
4. The portfolio of resources selected and contracted with should be of sufficient capacity and attributes to alleviate the deficiencies identified.

Cost Recovery

Per Public Utilities Code § 365.1(c)(2)(A) and (B) costs for procurement to address and alleviate local reliability issues, that are determined by the Commission to benefit all customers, may be recovered from all customers. The procurement directed by this Resolution would be required to alleviate local reliability issues in specific sub-areas as described in this Resolution. Thus, we authorize PG&E to request recording of costs of any contracts resulting from this solicitation in its Cost Allocation Mechanism, for recovery from all benefitting ratepayers.

PROTESTS

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

FINDINGS

1. Calpine filed three RMR contracts for the Feather River Energy Center, Yuba City Energy Center and Metcalf Energy Center, with the FERC, on November 2, 2017.
2. Calpine communicated its plans, in a letter to the CAISO, to make these facilities unavailable unless it were awarded an RMR contract.
3. Calpine claimed that RA capacity prices were insufficient and that CPM would not provide a sufficient planning period for Calpine to make major maintenance, budget, and personal planning decisions.
4. The three plants did not enter into any bilateral RA contracts with load serving entities.
5. The Public Utilities Code grants the Commission has broad authority to take any action to conduct its duties, including ordering procurement to ensure just and reasonable rates.
6. Authorizing PG&E to conduct a competitive solicitation to procure energy storage and preferred resources falls within the Constitutional Commission authority to assure long term energy supply at just and reasonable rates.
7. The Commission recognizes energy storage and preferred energy resources can be fast-responding, reliable, and may be able to be procured at sufficient quantity and reasonable cost to alleviate a projected capacity shortfalls and a high voltage issue in the South Bay-Moss Landing, Pease and Bogue sub-areas.
8. Energy storage and preferred energy resources can be constructed in a short timeframe, and may be able to be brought on-line in sufficient time as to obviate the need for RMR contracts, or their extension, for the Feather River Energy Center, Yuba City Energy Center and Metcalf Energy Center.
9. It is reasonable to require that any contracts that PG&E executes and submits to the Commission for approval, both have an on-line date sufficient to obviate the need for an extension of RMR contracts for the aforementioned plants in 2019, and interconnect in a location that will help alleviate the specific electric reliability issues discussed in this Resolution.
5. It is reasonable to require that resources procured in this solicitation be at a reasonable cost to ratepayers, taking into consideration the cost and value to PG&E, previous solicitations in which PG&E has awarded contracts to similar resources, the cost of the specific RMR contracts, with adjustments for contract terms such as contract length and expedited delivery date.
10. It is reasonable that any storage procured through this solicitation be able

to satisfy PG&E's overall storage mandate obligation, if it meets existing eligibility criteria.

11. Public Utilities Code Section 451 requires that every public utility maintain adequate, efficient, just, and reasonable service, instrumentalities, equipment and facilities to ensure the safety, health, and comfort of the public.
12. It is reasonable that PG&E ensures the any contracts entered into from this solicitation provide that sellers shall operate the facilities in accordance with prudent electrical practices.
13. In order to help address the short-term problem, it is important that projects be on-line in sufficient time to obviate the need for, or extension of, RMR contracts for the Feather River, Yuba City or Metcalf Energy Centers.
14. It is reasonable for PG&E to expedite the interconnection processes to allow a storage resource to connect to the grid.
15. It is reasonable that resources procured in this solicitation be at a reasonable cost, adjusting for different contract terms such as contract length and delivery date impacts.
16. It is reasonable to allow PG&E to seek approval of, and request cost recovery treatment for, any contracts resulting from this solicitation through one or more Tier 3 Advice Letters.

THEREFORE IT IS ORDERED THAT:

1. Pacific Gas and Electric Company is ordered to hold one or more competitive solicitation to address two local sub-area capacity deficiencies and to manage a high voltage issue in another sub-area.
2. PG&E may solicit bids for energy storage and preferred resources, either individually or in an aggregation.
3. Resources procured pursuant to this solicitation must be on-line and operational by a date sufficient to ensure that the RMR contracts for the three plants – Metcalf Energy Center, Feather River Energy Center, and Yuba City Energy Center – will not be renewed for 2019.
4. Resources procured pursuant to this solicitation must be located within the relevant sub-area(s) and be interconnected at location(s) that will mitigate local capacity and voltage issues sufficient to obviate the need for RMR contracts for the aforementioned plants.
5. Resources procured in this solicitation should be at a reasonable cost to ratepayers, taking into consideration the cost and value to PG&E, previous

solicitations in which PG&E has awarded contracts to similar resources, the cost of the specific RMR contracts, with adjustments for contract terms such as contract length and expedited delivery date.

6. The portfolio of resources selected and contracted with should be of sufficient capacity and attributes to alleviate the deficiencies identified.
7. Pacific Gas and Electric Company may contract with any resource at reasonable cost, and file Tier 3 Advice Letters for approval of contracts resulting from this solicitation.
8. Pacific Gas and Company shall take all reasonable steps to expedite the interconnection processes to allow storage resource to connect to the grid.
9. Pacific Gas and Electric Company may request authorization to record procurement costs for procurement in the solicitation authorized by this Resolution in its Cost Allocation Mechanism account.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on January 11, 2018, the following Commissioners voting favorably thereon:

TIMOTHY J. SULLIVAN
Executive Director

Exhibit C

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Short-Term Special Assessment

Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation

May 2016

RELIABILITY | ACCOUNTABILITY



**3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com**

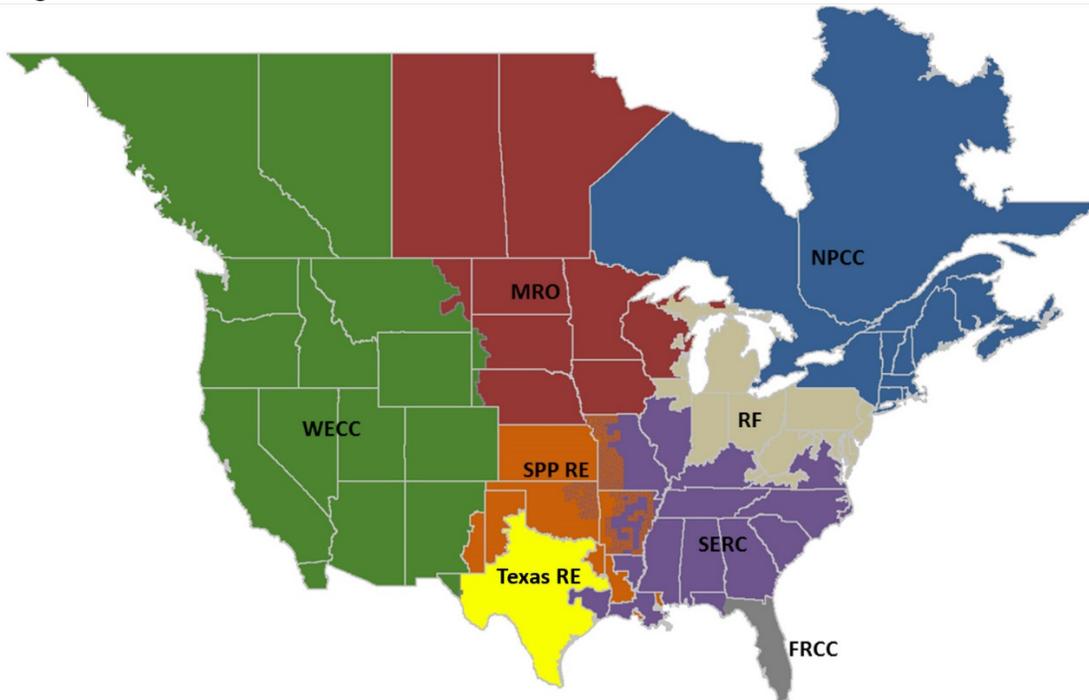
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Errata

8/23/2016

Modified tables and charts for all areas to align Dual-Fuel Capacity and Gas-Fired Capacity (non-Dual-Fuel) with corresponding values.

Executive Summary

NERC continues to assess the increasing risk of fuel disruption impacts on generator availability from the dependency of electric generation and natural gas infrastructure. In the past, NERC conducted two special assessments on gas-electric interdependencies; a primer highlighting key considerations in 2011¹ and a detailed framework for incorporating risks into reliability assessments in 2013.² As highlighted in a number of NERC long-term reliability assessments, substantial progress has been made in the last five years to improve coordination between natural gas pipelines, gas distribution companies, and electric industries. Even so, there are remaining concerns and opportunities to address on this subject.³

Until recently, natural gas interdependency challenges were most experienced during extreme winter conditions and focused almost exclusively on gas delivery through pipelines. However, a recent outage of an operationally-critical natural gas storage facility in Southern California—Aliso Canyon—demonstrates the potential risks to BPS reliability of increased reliance on natural gas without increased coordination between the two industries. The risk associated with Aliso Canyon, which may result in controlled load shedding, is expected to persist through the 2016 summer season, and potentially into the 2016/2017 winter and 2017 summer seasons. The challenges faced in California represent a series of risks that have been layered into the system over the past decade: significant dependency on a single and just-in-time delivery fuel source, specifically for ramping capability to meet load and generation variability; reduced amount of baseload and dispatchable resources; increased amounts of variable and distributed resources; increasing need of system flexibility; gas system dependency on storage to maintain operating pressure; and a lack of clear understanding of natural gas operational characteristics and potential impacts on BPS operations.

Understanding the interdependencies and operational differences between the two industries is critical to mitigating reliability risks going forward. The unavailability of the Aliso Canyon storage facility is the most recent example of the potential risks to BPS reliability posed by increased dependence on natural gas. Over the next several months, mitigation measures will be put into place by state regulators and the electric and gas utilities; however, these measures will not completely address challenges emerging from the reduction in resource adequacy. Even with mitigation measures in place, system operators from both the electric and gas industries in California are facing a major challenge this summer. CAISO studies identified 14 days of potential electric service interruption if natural gas constraints affect the Los Angeles basin generating facilities.⁴ Further study is needed to address any additional risks to the reliable operation of the BPS until further is known about the operation of the Aliso Canyon storage facility.

As growth in natural gas demand increases from the electric sector, pipeline transportation constraints, storage limitation, and contingencies on gas infrastructure will have a greater impact on gas-fired generation. Overdependence on a single fuel type increases the risk of common-mode or single-point-of-failure disruptions as experienced during recent extreme weather events, like the 2014 Polar Vortex.⁵ Disruptions in natural gas supply and delivery to generators have prompted the gas and electric industries to further examine reliability implications associated with an increasing dependence on the natural gas infrastructure needed to support electric generation. The gas and electric industries operate under different regulatory structures and rules that affect how infrastructure is planned, built, maintained, and operated.

¹ [NERC 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States; December 22, 2011](#)

² [NERC 2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power; June 5, 2013](#)

³ [NERC Reliability Assessment and Performance Analysis](#)

⁴ [California Public Utilities Commission: Aliso Canyon Risk Assessment Technical Report; April 5 2016](#)

⁵ [NERC 2014 Polar Vortex Review](#)

As dependence on natural-gas-fired generation increases in North America, the coordination efforts between natural gas pipelines and bulk power electric industries become more important and impactful to system reliability. For example, the relationship between gas availability and low temperatures further challenges the electric industry's ability to manage extreme weather conditions, particularly when conditions affect a wide geographic area and there is less support available from neighboring systems. Additionally, strain may be experienced during the summer months as electric peak loads occur during the same time frame that gas storage demands are being managed and pipelines undergo maintenance. These extreme weather events should serve as early indicators of more frequent impacts if natural gas supply and transportation are surpassed by the demand from natural gas-fired units that continue to predominantly rely on non-firm gas service.

This assessment identifies potential reliability considerations that should be addressed to maintain the reliable operation of the BPS through an operational risk analysis. It provides a short-term perspective by using the latest resource and demand projections from industry.⁶ The assessment focuses on areas with natural gas generation penetrations of greater than 40 percent, so the NPCC-New England (ISO-NE), NPCC-New York (NYISO), ERCOT, and WECC-CA/MX assessment areas were selected for evaluation.

NERC examined the changing resource mix within these areas and determined how much gas-fired generation has been added and how much is anticipated to serve peak load during the next 18–24 months. Scenarios were then created using either NERC GADS⁷ performance data or existing industry analysis to develop a range of assumptions around potential forced outages and unit unavailability. This assessment is not a prediction of the upcoming seasonal reliability, but rather provides sensitivity and extreme case evaluations to better understand the risk to BPS reliability.

The key findings of this assessment are:

1. Assessment areas with a growing reliance on natural gas-fired generation are increasingly vulnerable to issues related to gas supply unavailability. Common-mode, single contingency-type disruptions to fuel supply and deliverability in areas with a high penetration of natural gas-fired generation are reducing resource adequacy and potentially introducing localized risks to reliability.
2. Not only can impacts to BPS reliability occur during the gas-load peaking winter season, but they can also manifest during the summer season when electric demand is high and natural gas facilities are out of service, which can lower the operational capacity and flow of the pipeline system.
3. High levels of coordination between natural gas and electric system operators enable higher efficiency, higher resilience, and increased situational awareness and preparedness.

NERC recommends the following:

1. Planners and operators should continue accounting for the risks from extreme weather events and plan to ensure resource adequacy as a result of potential gas-fired generator outages. NERC's 2015 *Winter Reliability Assessment*⁸ outlined these operational challenges, what winter preparedness activities have been introduced, and what additional improvements are needed.
2. NERC, in collaboration with the Planning and Operating Committees, should establish guidelines for future reliability assessments to evaluate both short- and long-term fuel availability, generation operational characteristics, and other related risks.⁹ Resource and transmission planning should account for the potential of large, common-mode single-contingency-type disruptions to natural gas pipelines

⁶ [NERC 2015 Long-Term Reliability Assessment](#)

⁷ [Generating Availability Data System \(GADS\)](#)

⁸ [NERC 2015-16 Winter Reliability Assessment](#)

⁹ [NERC 2015 Long-Term Reliability Assessment](#)

and associated facilities, specifically for compression stations, well-head supply, and gas storage. These system states need to be simulated, studied, and assessed continuously.

3. System operators should enhance coordination strategies to address potential fuel supply interruptions due to unforeseeable conditions. Good utility practices and procedures, particularly in New England, enable high efficiency, higher resilience, and better situational awareness and preparedness.¹⁰ These practices should be shared and considered as more gas-fired generation is added.
4. NERC and WECC will work with respective entities to conduct a joint meeting whereby all involved entities will identify high-level reliability risks associated with the loss of the Aliso Canyon storage facility and develop mitigating strategies to ensure reliability.
5. The electric industry has taken positive steps to address coordination between the electric and natural-gas industries by developing good utility practices, operating procedures, enhanced communications between electric and natural gas industries, and collaboration with state and federal regulators to ensure electric reliability.¹¹ NERC recommends continued efforts to more fully comprehend the risks and potential mitigation measures, such as dual-fuel capability and firm delivery contracts, to address the risks from reliance and interdependency between these two industries.

¹⁰ [ISO-NE Rules and Procedures](#)

¹¹ [NERC 2015 Long-Term Reliability Assessment](#)

Introduction

Short-Term Special Assessment (STSA) Approach

This assessment evaluates four areas in the North American footprint; ISO-NE (Chapter 1), NYISO (Chapter 2), ERCOT (Chapter 3), and WECC-CA/MX (Chapter 4). The assessment provides an overview of electric reliability by analyzing potential generation supply risks in terms of unavailable natural gas for fueling electric generation. This short-term assessment investigates the state of natural gas-electric interdependency using a deterministic operational risk analysis for the next 18 months and includes four upcoming seasons: Summer 2016, Winter 2016/2017, Summer 2017, and Winter 2017/2018.

The NERC Summer 2015¹² and Winter 2015¹³ reliability assessments introduced this operational risk analysis, which evaluates past performances of resources to identify operational sensitivities for serving peak load. This approach provides a snap-shot view of a particular system by examining at-risk outages and an extreme natural gas availability scenario. The remaining available resources are then compared with normal (50/50)¹⁴ and extreme (90/10)¹⁵ peak load forecasts. This deterministic approach includes performance data but does not account for capacity and load relief programs, such as voltage reduction, passive demand response programs, or other emergency operating procedures.

Data for the peak load forecasts, anticipated capacity, and net firm import capabilities were obtained from NERC's 2015 LTRA.¹⁶ Net firm imports do not include the potential maximum transfer capability based on daily dispatch and system topology. In reality, the transfer amount can be larger or smaller, depending on parameters such as market conditions, transmission availability, and area needs.

Figures I.1 and I.2 provide a breakdown of the individual components used for this analysis and what a potential capacity deficiency risk may look like. NERC used data from its Generator Availability Data System (GADS) to model generator outages pertaining to gas-fired and non-gas-fired outages to determine seasonal at-risk capacity; this method is further explained in Appendix A. The capacity determined to be at-risk is classified as follows: average forced non-gas outages, average forced gas outages, and maximum forced gas outages.

Peak load forecasts in excess of the anticipated capacity that is not considered at-risk, indicate a potential for capacity deficiencies. However, there are additional procedures available to system operators to mitigate this prior to shedding load. An additional scenario was introduced to this analysis that compared the total anticipated capacity to a specific natural gas unavailability type event for an area, such as loss of a gas pipeline by force majeure, compression and/or gas storage issues, or any circumstance that would prevent a gas-fired generating plant from obtaining fuel. This scenario was analyzed separately from the at-risk capacity to avoid potential double counting of gas-fired generator outages.

¹² [NERC 2015 Summer Reliability Assessment; May 2015](#)

¹³ [NERC 2015-16 Winter Reliability Assessment; December 2015](#)

¹⁴ Load projections are based on a 50/50 peak demand forecast; also referred to herein as net internal demand. Values represent the baseline values for each season, each with a range of possible outcomes based on probabilities around the baseline or midpoint. Projections are provided on an assessment area basis and are highly dependent on the data, methodologies, model structures, and other assumptions that often vary by Region, RC, assessment area, or BA.

¹⁵ NERC requested a load projection based on the 90th percentile probability. In general, this means that the severe load forecast is expected to reach this higher level once in every 10 years.

¹⁶ [NERC 2015 Long-Term Reliability Assessment; December 2015](#).

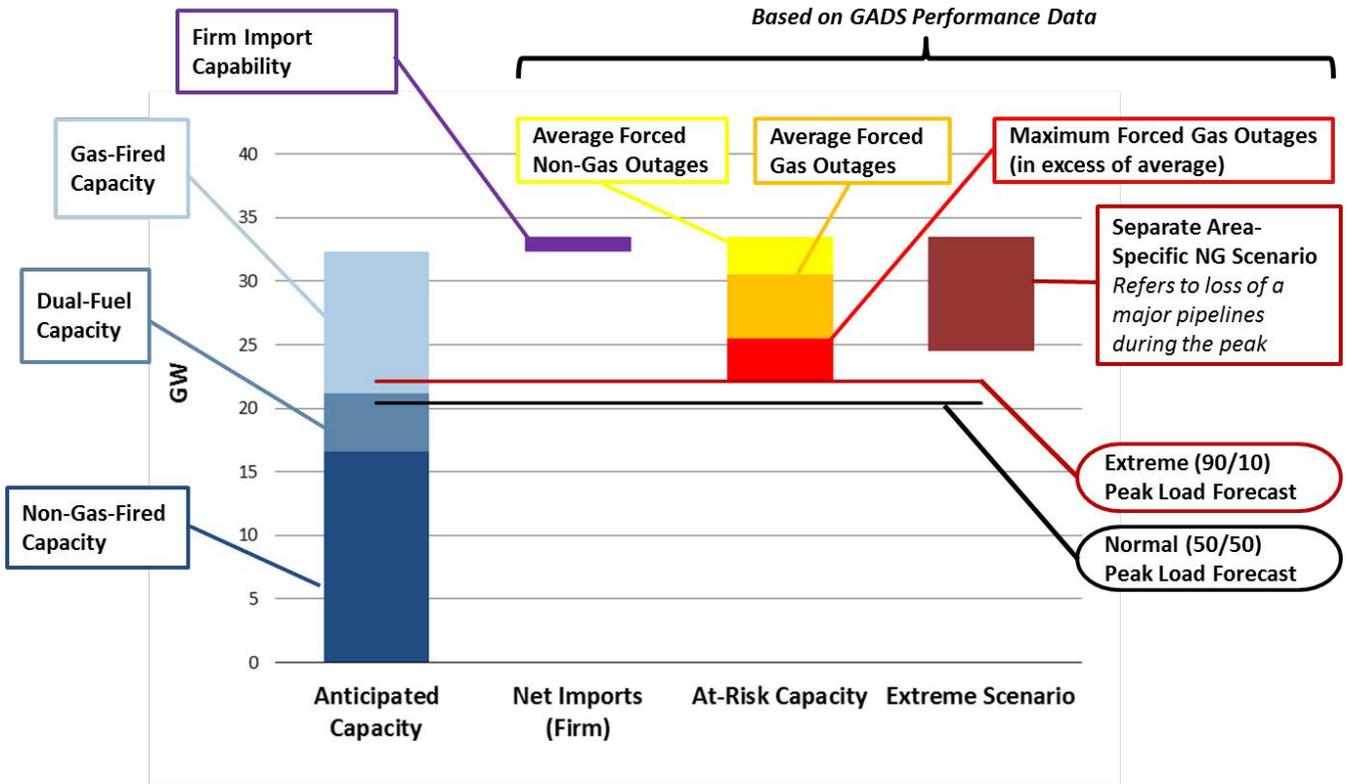


Figure I.1: Operational Risk Analysis - Component Breakdown

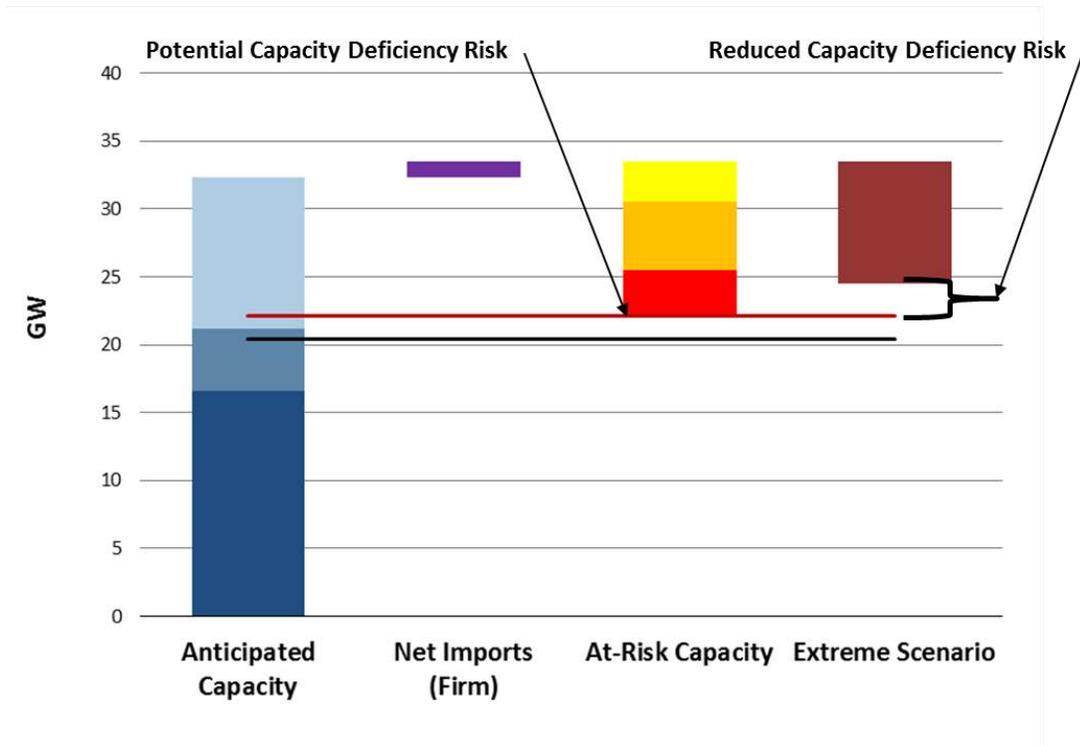


Figure I.2: Operational Risk Analysis – Interpreting Results

Chapter 1 – Independent System Operator of New England (ISO-NE)

Operational Risk Analysis - Natural Gas

Table 1 – ISO-NE Operational Risk Data

Load Projections		2016 Summer	2016/17 Winter	2017 Summer	2017/18 Winter
50/50 Peak Load Forecast (Reduced by Available DR)	—	26,147	20,433	25,801	20,444
90/10 Peak Load Forecast (Reduced by Available DR)	- -	28,485	21,122	28,174	21,132
Anticipated Capacity					
Total Capacity		30,862	32,715	30,095	32,375
Net Imports (Firm)		1,516	1,491	1,167	1,167
Non Gas-Fired Capacity (MW)		17,410	17,596	15,902	16,568
Dual-Fuel Capacity		4,216	4,576	4,230	4,590
Gas-Fired Capacity (non-Dual-Fuel)		9,236	10,543	9,964	11,217
Gas-Fired + Dual Fuel Capacity (MW)		13,452	15,119	14,193	15,807
Gas-Fired Capacity (% of Total On-Peak)		44%	46%	47%	49%
At-Risk Capacity					
Average Outages of Non Gas-Fired Generation		473	1,261	473	1,261
Average Outages of Gas-Fired Generation		337	316	337	316
Maximum Outages of Gas-Fired Generation		1,806	3,354	1,806	3,354
Extreme Scenario		4,365	4,365	4,365	4,365

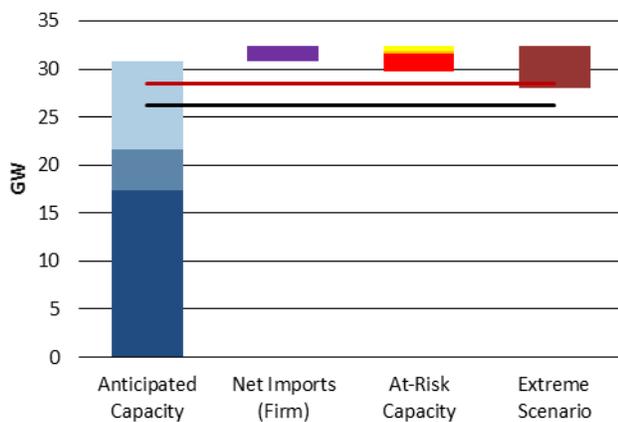


Figure 1.1: ISO-NE Summer 2016 Gas Operational Risk

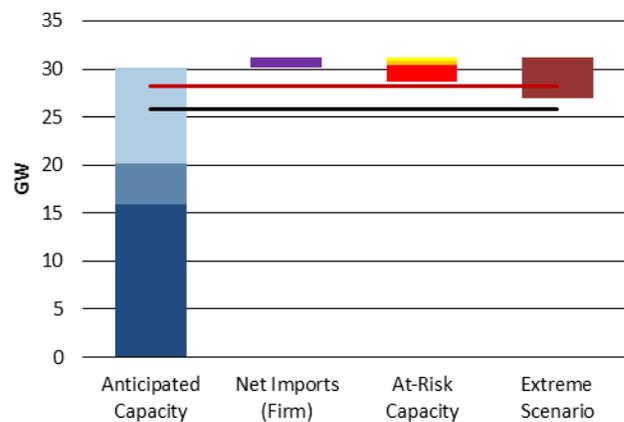


Figure 1.2: ISO-NE Summer 2017 Gas Operational Risk

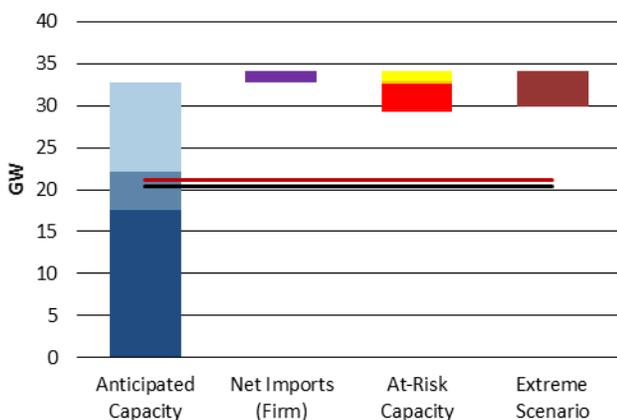


Figure 1.3: ISO-NE Winter 2016/17 Gas Operational Risk

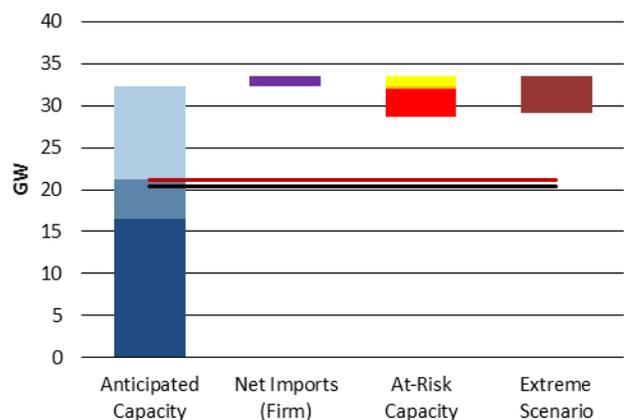


Figure 1.4: ISO-NE Winter 2017/18 Gas Operational Risk

Key Takeaways and Assumptions

- ISO-NE extreme scenario numbers are based on an extreme loss of a major pipeline supplying the area. In this particular case, the extreme scenario number is total capacity (100 percent) of the gas pipeline minus 50 percent of the dual-fuel capacity in the area. This analysis assumes that a conservative 50 percent or more of the dual-fuel units will be available to support reliability for an unexpected loss of a natural gas pipeline. ISO-NE has various programs in place to test the fuel-switching functionality for all dual-fuel units on an annual basis and, in an ideal scenario, more than 50 percent of the affected units would switch fuels and stay online.
- Prior studies by ISO-NE show that potential force majeure events would not cause a sudden loss of fuel to generators located on the affected pipeline, and based on pipeline conditions at the time, would take between several minutes to hours to impact pressure and flow to downstream customers. Theoretically, this provides ample time for both generator owners and system operators to start implementation of remedial actions to supplement the upcoming loss of generation.
- Based on this extreme scenario analysis, ISO-NE might experience tight operational conditions for the 2016 and 2017 summer seasons from the loss of a major gas pipeline that supplies the area. ISO-NE has emergency operating procedures in place to address this extreme scenario.

ISO-NE Summary

- About 8.2 GW of proposed generation is natural gas fired, representing about 60 percent of the new capacity being installed by Summer 2016.¹⁷
- The area has limited natural gas pipeline capacity, despite the tremendous growth in natural gas-fired generating capacity. This, coupled with growing demand from the heating sector, results in existing pipelines running at or near maximum capacity most of the time, particularly so in winter.¹⁸
- Extreme demand scenarios are evaluated annually and serve as the basis for ISO-NE's winter reliability programs that have been in place since Winter 2013/2014. The primary focus of the extreme winter weather scenarios is to assess the potential unavailability of natural gas to fuel generators when temperatures are lower than normal.
- The ISO-NE long- and short-term outage coordinators evaluate and account for gas-fired generation that may be at risk in determining seasonal operable capacity margins. ISO-NE would balance stressed system conditions with real-time supplemental commitments and the use of emergency procedures as needed.
- Fuel surveys are in place to request fuel inventory, availability and switching information from generators that are listed as dual-fuel generators. The fuel surveys solicit information concerning applicable time to switch fuels, testing requirements, power output/air permit limitations, and other operational limitations, such as startup capability on alternative fuels and ramping capability, simultaneous fuel operation (burning both oil and gas at the same time), and environmental restrictions. There are also provisions to allow for cost recovery of successful dual-fuel commissioning and testing. This provision is in effect until 2018 and provides for annual testing, verification, and availability requirements.¹⁹
- To measure at-risk gas generation and improve situational awareness, ISO-NE has developed a gas utilization tool (GUT) that assists control room operators in the evaluation of current and next-day operating plans. The tool uses data gathered from the electronic bulletin boards (EBBs) of gas pipelines serving New England and visualization with estimated scheduled deliveries based on historical nominations for local distribution companies, commercial and industrial loads. The tool provides an

¹⁷ [ISO-NE 2016 Regional Electricity Outlook; January 2016](#)

¹⁸ [ISO-NE Natural Gas Infrastructure Constraints](#)

¹⁹ [ISO-NE Market Rule 1 - Appendix K - III.K.5 "Winter Reliability Solutions 2015-16, 2016-17 and 2017-18 Winter Seasons" 01/28/2016](#)

estimation of the remaining natural gas pipeline capacity available for use by the New England power sector along with a forecast of natural-gas-fired generation at risk.

- The FERC-approved Winter Reliability Program²⁰ has been critical to maintaining power system reliability and, until forward capacity market incentives are implemented in 2018, the program will continue to help address several challenges that could have an impact on generation during the winter operating period.
- ISO-NE and the regional natural gas sector have had on-going communications and coordination since 2005. After the cold snap of January 2004, the regional natural gas sector, as represented through the Northeast Gas Association (NGA)²¹ in concert with ISO-NE, began to co-chair the Electric/Gas Operations Committee (EGOC). The EGOC is open to all parties, but primarily consists of representatives from the electric sector (i.e., ISO-NE, NYISO, and PJM) and the regional gas sector (i.e., pipelines, LDCs, LNG, and fuel suppliers, etc.).²² EGOC meetings usually take place both pre- and post-season, and the 50th meeting of the committee will take place this May. This relationship has improved understanding, education, training, and communications for both industries within New England.

²⁰ [FERC Docket No. ER15-2208-000 Winter Reliability Program - ISO-NE; September 11, 2015](#)

²¹ [Northeast Gas Association](#)

²² [ISO-NE Electric/Gas Operations Committee](#)

Chapter 2 – New York Independent System Operator (NYISO)

Operational Risk Analysis – Natural Gas

Table 1: NYISO – Operational Risk Data

Load Projections		2016 Summer	2016/17 Winter	2017 Summer	2017/18 Winter
50/50 Peak Load Forecast (Reduced by Available DR)	—	32,512	23,639	32,655	23,603
90/10 Peak Load Forecast (Reduced by Available DR)	—	35,763	26,003	35,920	25,964
Anticipated Capacity					
Total Capacity					
Net Imports (Firm)		1,147	-	1,555	404
Non Gas-Fired Capacity (MW)		23,507	24,259	23,222	23,974
Dual-Fuel Capacity		12,111	13,403	12,111	13,403
Gas-Fired Capacity (non-Dual-Fuel)		3,781	4,086	3,781	4,086
Gas-Fired + Dual Fuel Capacity (MW)		15,892	17,489	15,892	17,489
Gas-Fired Capacity (% of Total On-Peak)		40%	42%	41%	42%
At-Risk Capacity					
Average Outages of Non Gas-Fired Generation		1,124	1,052	1,124	1,052
Average Outages of Gas-Fired Generation		378	632	378	632
Maximum Outages of Gas-Fired Generation		1,434	2,387	1,434	2,387
Extreme Scenario		2,871	2,871	2,871	2,871

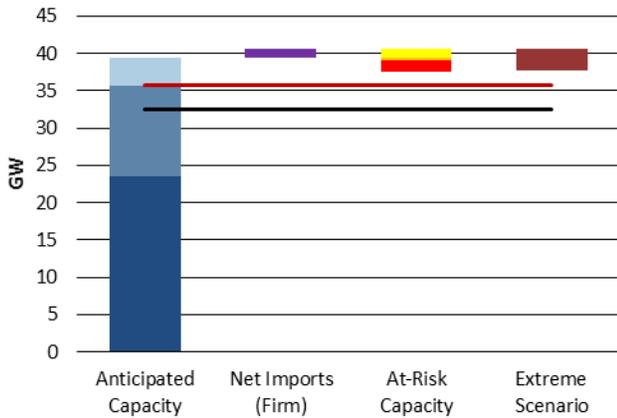


Figure 2.1: NYISO Summer 2016 Gas Operational Risk

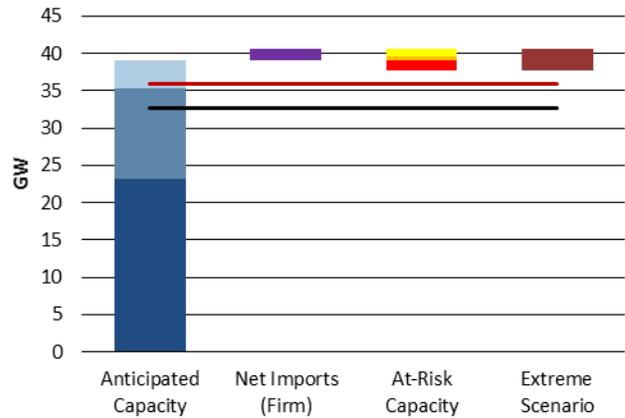


Figure 2.2: NYISO Summer 2017 Gas Operational Risk

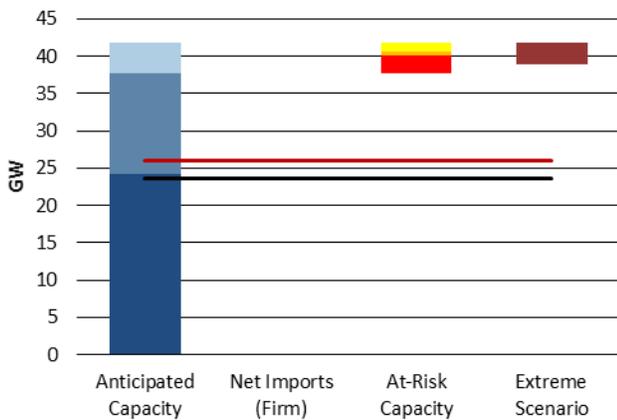


Figure 2.3: NYISO Winter 2016/17 Gas Operational Risk

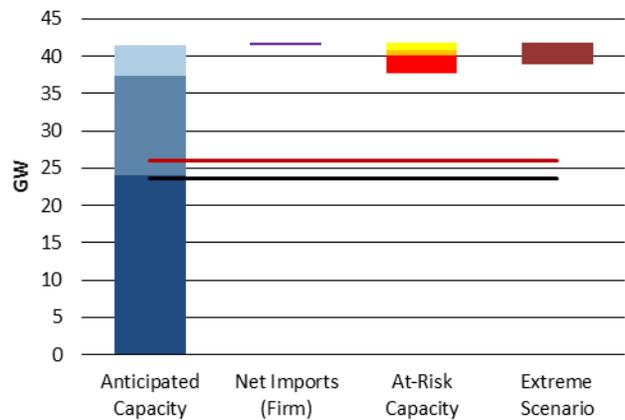


Figure 2.4: NYISO Winter 2017/18 Gas Operational Risk

Key Takeaways

- While the New York region does rely on natural gas as one of its predominant fuel sources, the region has more than one gas pipeline feeding generating plants and supplying firm customers.
- Hence, based upon the operational risk metrics, the New York region is not projected to experience tight operational margins for upcoming seasons.

NYISO Summary

- For 2015/16 Local Distribution Companies (LDCs) have adequate capacity, but remains congested due to residential and commercial customer demand.²³
- The NYISO Market Mitigation and Analysis Department²⁴ performed on-site visits of several generating stations (totaling 14,901 MW) to discuss past winter operations and preparations for Winter 2015/2016. Their visits focused on units with low capacity factors. A pre-visit questionnaire included assessments of natural gas availability during peak conditions, issues associated with burning or obtaining oil, emissions limitations, preventative maintenance plans, and the causes of failed starts, programs to improve performance, and programs to insure switchyard reliability. They found that generators have increased generation testing, cold-weather preventative maintenance, fuel capabilities, and fuel-switching capabilities to improve winter operations.²⁵
- Generators connected to LDC in NYISO have strict dual-fuel requirements. Some New York LDCs require dual-fuel capability under their Electric Generation Service classifications. LDCs generally reserve the right to inspect the facility and may require customers to prove the backup generation and fuel storage capability of the facility. Penalties for non-compliance, discoverable either through inspection or failure to switch to a backup fuel during an interruption, are generally tied to the price of a backup fuel.²⁶
- In NYISO, eleven generators hold firm mainline transportation contracts. Four of these contracts are for volumes sufficient to fuel the full plant capacity, the others range from approximately one-third to three-fourths of plant capacity. Seven of the contracts are held by generators which are ultimately served by LDCs; the character service of the last leg of the transportation path is currently unknown. In National Grid's (NGrid) Long Island service territory, for example, generators can negotiate a limited-curtailment or "quasi-firm" character of service. Such arrangements typically have a temperature trigger or a specified number of days of curtailment rights, thereby assuring the generation company of firm service during the remainder of the year.²⁷
- New and planned pipeline expansions will enable additional Marcellus gas to flow into the New York Control Area (NYCA) Levitan & Associates, Inc., "NYCA Pipeline Congestion and Infrastructure Adequacy Assessment," New York Independent System Operator, September 2013.²⁸

²³ [New York Public Service Commission - Winter Fuels Outlook: Natural Gas Supply for the 2015-2016 Winter Season; October 27, 2015](#)

²⁴ [NYISO Market Mitigation and Analysis Department](#)

²⁵ [NPCC Reliability Assessment for Winter 2015-16 - Final Report; December 1, 2015](#)

²⁶ [EIPC Gas-Electric System Interface Study - Final Draft; April 4, 2014](#)

²⁷ [Ibid](#)

²⁸ [NYCA Pipeline Congestion and Infrastructure Adequacy Assessment; September, 2013](#)

Chapter 3 – Texas Reliability Entity (TRE)/Electric Reliability Council of Texas (ERCOT)

Operational Risk Analysis - Natural Gas

Table 1: ERCOT – Operational Risk Data

Load Projections		2016 Summer	2016/17 Winter	2017 Summer	2017/18 Winter
50/50 Peak Load Forecast (Reduced by Available DR)	—	67,657	51,935	68,514	52,797
90/10 Peak Load Forecast (Reduced by Available DR)	- -	74,423	57,129	75,365	58,076
Anticipated Resources					
Total Resources		78,141	79,696	80,033	84,155
Net Imports (Firm)		392	835	392	835
Non Gas-Fired Capacity (MW)		32,274	31,408	33,466	31,929
Dual-Fuel Capacity		6,225	6,433	6,225	6,433
Gas-Fired Capacity (non-Dual-Fuel)		39,642	41,855	40,342	45,794
Gas-Fired + Dual Fuel Capacity (MW)		45,867	48,288	46,567	52,227
Gas-Fired Capacity (% of Total On-Peak)		59%	61%	58%	62%
At-Risk Capacity					
Average Outages of Non Gas-Fired Generation		2,275	2,741	2,275	2,741
Average Outages of Gas-Fired Generation		583	861	583	861
Maximum Outages of Gas-Fired Generation		1,705	8,782	1,705	8,782
Extreme Scenario		3,500	5,000	3,500	5,000

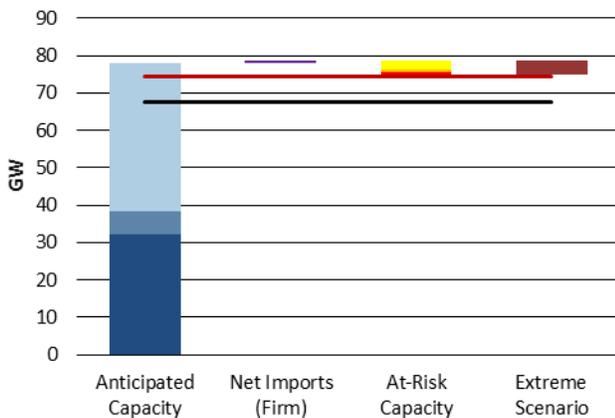


Figure 3.1: ERCOT Summer 2016 Gas Operational Risk

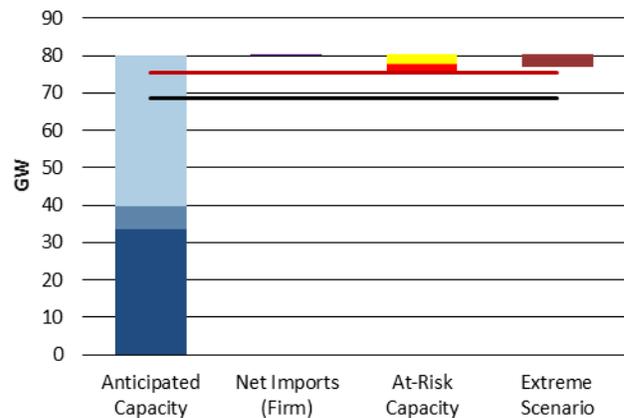


Figure 3.2: ERCOT Summer 2017 Gas Operational Risk

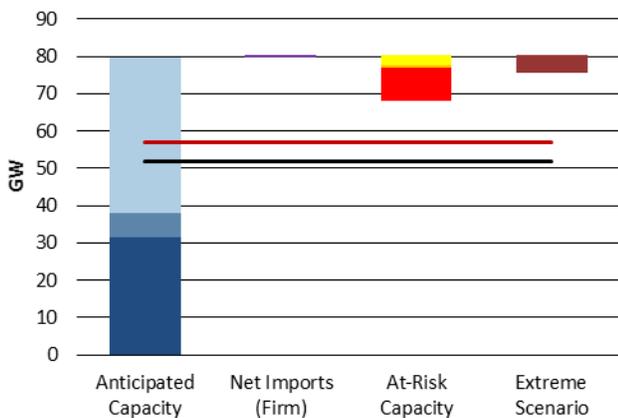


Figure 3.3: ERCOT Winter 2016/17 Gas Operational Risk

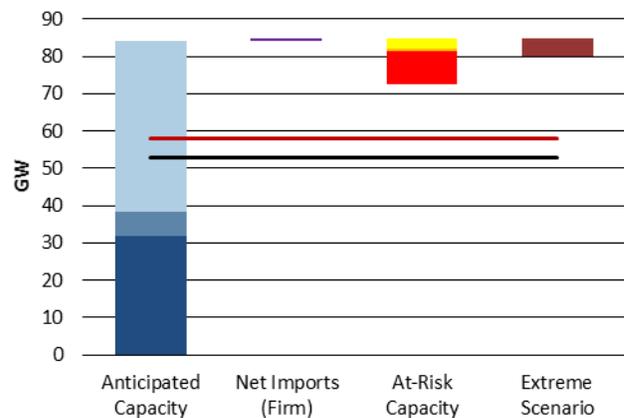


Figure 3.4: ERCOT Winter 2017/18 Gas Operational Risk

Key Takeaways

- Loads in Texas tend to be higher in summer compared to the winter season, leading to tighter margins in the summer.
- Texas has various emergency operating procedures in place to address high loads, such as load responsive assets.

Texas RE and ERCOT Summary

- Natural gas, at 48.3 percent, continues to be the dominant fuel used to generate electricity in the ERCOT area, followed by coal at 28.1 percent. In 2015, wind moved from fourth to third, at 11.7 percent, providing about 40.8 million MWh during the year. Wind surpassed nuclear power, which increased slightly from 2014; nuclear power provided 39.4 million MWh, or 11.3 percent of total energy used.²⁹
- Texas is the largest producer of natural gas in the U.S. and also has the highest number of miles of natural gas pipeline.³⁰ There has been extensive pipeline construction over the last 10 years as a result of development of unconventional gas supplies in the Barnett and Eagle Ford shale areas. The ERCOT area has sufficient natural gas supply infrastructure to support gas-fired generation requirements for the next 18 months and beyond. Intrastate pipelines predominantly serve electric generators in ERCOT, with 13 pipeline systems supplying gas. Seven interstate pipelines also provide gas supplies for the area. The majority of gas-fired generators (60 percent based on a generator survey) have access to multiple pipeline interconnections with various supply receipt options and most are able to acquire supplies in excess of their peak needs.
- Gas supply disruptions are most likely to occur during extended periods of cold weather during the winter season, while hurricanes and pipeline outages represent a lower and more localized supply disruption risk. To assess cold weather-related supply disruption risks, ERCOT developed gas curtailment scenarios for its winter *Seasonal Assessment of Resource Adequacy* (SARA) reports.³¹ These scenarios consist of expected and extreme levels of capacity reduction resulting from temperature-driven natural gas curtailments at power plants. These curtailments are based on low winter temperatures reaching certain thresholds at which outages and derates are expected to occur based on natural gas transportation restrictions. Data for scenario development comes from regional low temperature assumptions and an “Hourly Power Plant Transportation Restriction Plan” for a local distribution company that serves northern Texas, as well as generation owner surveys and ERCOT operator event logs for gas curtailment-driven generation capacity reduction events. For its Winter 2015/2016 SARA report (Figure 3.5), ERCOT includes about 1,500 MW of gas curtailment outages/derates for typical temperatures at the time of the winter peak load hour, and an additional 1,060 MW of outages/derates, assuming that extreme cold temperatures occur during the peak load hour. Based on these potential capacity reduction levels and the assumed threshold amount of operating reserves needed to avoid energy emergency alerts, ERCOT concluded that gas curtailments due to cold weather represent a low risk to system resource adequacy during the winter months.
- Generators in the ERCOT area are required by protocols to notify ERCOT any time their fuel suppliers make them aware of issues that might limit their operation. ERCOT operations staff also issues various weather emergency preparedness notices that may include requests for real-time information on resource fuel capabilities. Since 2015, ERCOT has been working directly with the natural gas pipelines and local distribution companies to identify critical loads for gas supply and provide ERCOT operators with advance warning for gas curtailment actions.

²⁹ [ERCOT Press Release - "Energy use in ERCOT Region grows 2.2 percent in 2015"; January 15, 2016](#)

³⁰ [EIA - U.S. State Rankings: Natural Gas Marketed Projections, 2014](#)

³¹ [ERCOT - Seasonal Assessment of Resource Adequacy for the ERCOT Region - Winter 2015/2016; November 2, 2015](#)

- ERCOT issues a “Unit Alternative Fuel Capability” survey in the fall of each year to generator owners, intended to ascertain details on fuel usage and deliverability (firm versus non-firm), alternative fuel sources, the latest fuel-based unit curtailments, and the number of hours to transition to an alternative fuel.
- ERCOT has also implemented a rigorous winter preparedness testing mechanism for generating plants with exposure to extreme weather.

Seasonal Assessment of Resource Adequacy for the ERCOT Region Winter 2015/2016 - Final Release Date: November 2, 2015			
<u>Forecasted Capacity and Demand</u>			
Operational Resources (excluding wind), MW	68,063	Based on current ratings reported through the unit registration process	
Switchable Capacity Total, MW	3,702	Rated capacity of resources that can interconnect with other regions and are available to ERCOT	
less Switchable Capacity Unavailable to ERCOT, MW	(470)	Based on survey responses of Switchable Resource owners	
Mothball Resources, MW	0	Based on seasonal Mothball units plus Probability of Return responses of Mothball Resource owners	
Private Use Network Capacity Contribution, MW	4,433	Average capability of the top 20 hours in the winter peak seasons for the past three years	
Non-Coastal Wind Resources Capacity Contribution, MW	2,287	Based on 18% of rated capacity for non-coastal wind resources per Nodal Protocols Section 3.2.6.2.2	
Coastal Wind Resources Capacity Contribution, MW	622	Based on 37% of rated capacity for coastal wind resources per Nodal Protocols Section 3.2.6.2.2	
RMR Resources to be under Contract, MW	0	No RMR resources currently under contract	
Non-Synchronous Ties Capacity Contribution, MW	371	Average capability of the top 20 hours in the winter peak seasons for the past three years	
Planned Resources (not wind), MW	7	Based on projected dates provided by developers of generation resources	
Planned Non-Coastal Wind, MW	189	Based on projected dates and 18% of rated capacity for non-coastal wind resources	
Planned Coastal Wind, MW	136	Based on projected dates and 37% of rated capacity for coastal wind resources	
[a] Total Resources, MW	79,341		
[b] Peak Demand, MW	57,400	Peak forecast is based on expected demand and weather conditions for winter 2015	
[c] Reserve Capacity [a - b], MW	21,941		
	Forecasted Season	Extreme Peak Load / Typical Generation	Extreme Peak Load / Extreme Generation
Peak Load Adjustment (1)	0	3,434	3,434
Typical Maintenance Outages (2)	4,061	4,061	4,061
Typical Forced Outages (2)	3,756	5,268 (3)	5,268 (3)
Extreme Forced Outages (4)	0	0	4,584
[d] Total Uses of Reserve Capacity	7,817	12,763	17,347
[e] Capacity Available for Operating Reserves (c-d), MW	14,124	9,178	4,594
Less than 2,300 MW indicates risk of EEA1			
(1) Winter Peak Load Extreme Forecast is 60,834 MW based on the 90th percentile level.			
(2) Maintenance Outages and Forced Outages based on average of historical outage data for December, January and February weekdays, hours ending 7 am to 10 am (starting in 2010).			
(3) Includes typical outages/derates due to natural gas curtailments during extreme peak load hours.			
(4) Extreme Forced Outages include forecasted derates due to natural gas curtailments at low ambient temperatures during extreme peak load hours.			

Figure 3.5: ERCOT Winter 2015-16 SARA Report Chart

Chapter 4 – Western Electricity Coordinating Council (WECC) – CA/MX Area

Operational Risk Analysis – Natural Gas

Table 1: WECC CA-MX – Operational Risk Data

Load Projections		2016 Summer	2016/17 Winter	2017 Summer	2017/18 Winter
50/50 Peak Load Forecast (Reduced by Available DR)	—	52,669	38,213	52,919	38,245
90/10 Peak Load Forecast (Reduced by Available DR)	-	57,936	42,034	58,211	42,070
Anticipated Resources					
Total Resources					
Net Imports (Firm)		63,748	54,438	65,823	54,445
Non Gas-Fired Capacity (MW)		2,296	2,296	2,296	2,296
Dual-Fuel Capacity		19,051	8,545	19,241	7,593
Gas-Fired Capacity (non-Dual-Fuel)		1,497	1,497	1,497	1,497
Gas-Fired + Dual Fuel Capacity (MW)		43,200	44,396	45,085	45,355
Gas-Fired Capacity (% of Total On-Peak)		44,697	45,893	46,582	46,852
		70%	84%	71%	86%
At-Risk Capacity					
Average Outages of Non Gas-Fired Generation		1,027	3,571	1,027	3,571
Average Outages of Gas-Fired Generation		337	484	337	484
Maximum Outages of Gas-Fired Generation		2,658	1,391	2,658	1,391
Extreme Scenario		9,800	9,800	9,800	5,000

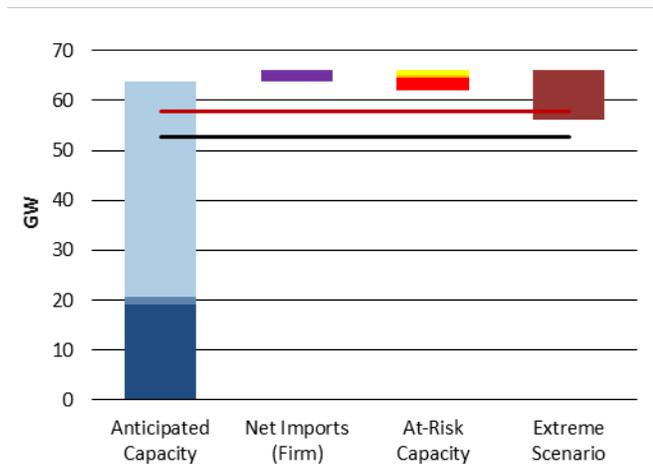


Figure 4.1: CA-MX Sum. 2016 Gas Operational Risk

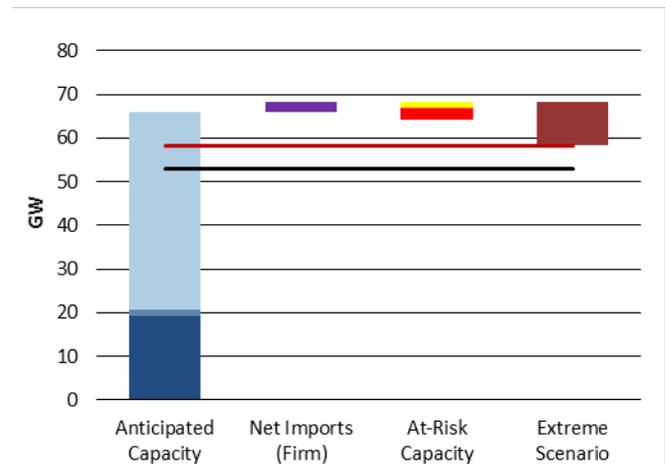


Figure 4.2: CA-MX Sum. 2017 Gas Operational Risk

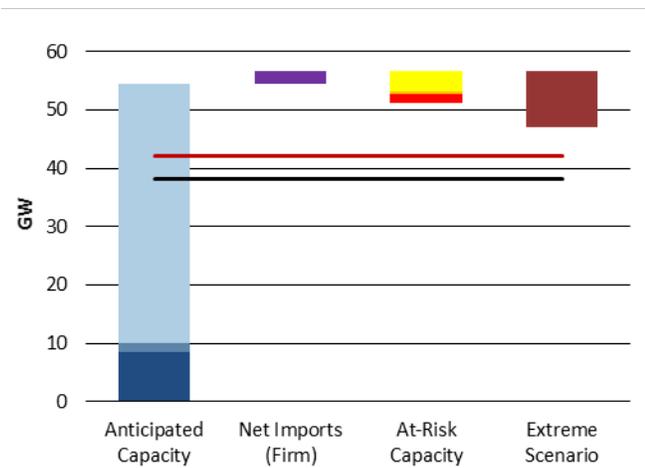


Figure 4.3: CA-MX Win. 2016/17 Gas Operational Risk

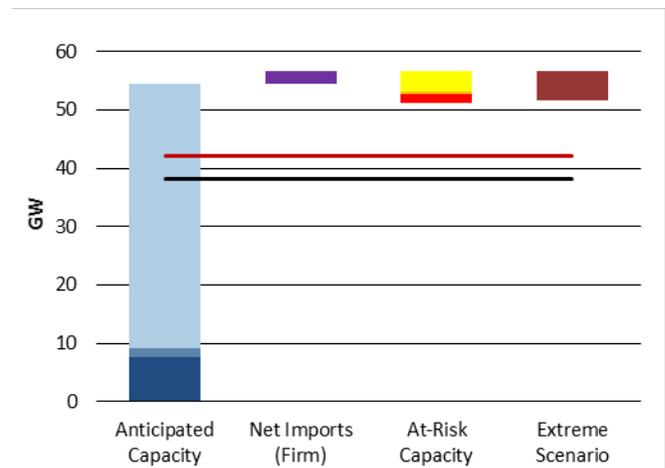


Figure 4.4: CA-MX Win. 2017/18 Gas Operational Risk

Key Takeaways

- Southern California may face reliability challenges in summer 2016, possibly stretching into winter 2016/2017 and summer 2017, due to the reduction of capacity at Aliso Canyon. This is reflected in the Extreme Scenario for summer 2016 and summer 2017, as that scenario included outages of the 17 gas plants in the Los Angeles Basin that rely on Aliso Canyon.
- Operations in Southern California could be further impacted by the loss of import capacity. In both the summer 2016 and 2017 extreme scenario cases, a reduction in net imports would likely result in adverse impacts.
- Overall assessment of the WECC footprint doesn't show any significant adverse impacts for upcoming seasons, except under the Extreme Scenario for summer 2017 and summer 2018. This is due to the review of the CA/MX area in aggregation.
- WECC and CAISO have measures in place to help mitigate this gas supply constraint by increasing imports and relying on CAISO's analysis for Aliso Canyon to shed load when necessary.

WECC Summary

Aliso Canyon

In October 2015, a gas leak was detected at the Aliso Canyon natural gas storage facility in southern California. The Aliso Canyon facility is a critical component of the gas system in the Los Angeles Basin. It is one of the largest natural gas storage facilities in the U.S. and is essential in providing a reliable gas supply to 18 large power plants with approximately 9,800 MW of capacity in the Los Angeles basin. Of its 86 Bcf working gas capacity, only 15 Bcf is being stored currently. There is a moratorium on injection of fuel into Aliso Canyon until all wells at the facility have been checked and appropriate action taken to ensure no further leaks.

A technical Assessment Group comprised of the California Energy Commission, the California Public Utilities Commission, the California Independent System Operator, the Los Angeles Department of Water and Power (LADWP), along with the Southern California Gas Company is analyzing both the gas and electric system impacts associated with the loss of the Aliso storage capability. The central finding of the group's Technical Report is that there are real reliability risks to the electric system associated with the loss of Aliso Canyon. Given the uncertain operating status of Aliso Canyon, the reliability of natural gas supply is likely to be threatened from 23 to 31 days of the year. Risks on the natural gas system have a profound effect on the electric supply system, which relies on natural gas to fuel power generators and provide ramping capability to balance an increasing amount of variable generation in California. Key factors leading to potential curtailments on the electric system include differences between receipts and send out on the gas system, gas system maintenance work, and unplanned outages. On as many as 12 to 21 days, gas service curtailments could be large enough to force the California ISO and LADWP to curtail electricity service to customers across a wide area in the LA Basin. 14 of these days could occur in the summer.

The Technical Assessment Group also created an Aliso Canyon Action Plan³² that presents measures that would help mitigate, but not eliminate, the risk of gas curtailments large enough to cause electricity interruptions. Considerations in developing mitigation plans for the coming summer and winter include limits to import capability, gas balancing practices, and the use of the remaining 15 Bcf working gas in Aliso Canyon for electric reliability. The measures range from targeted consumer communications, new efficiency and demand response measures, greater operational coordination, tariff changes, and clear direction to Southern California Gas to use the gas currently stored at Aliso Canyon, if necessary to prevent electricity interruptions.

³² [California ISO Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin](#)

In a parallel effort, the CAISO formed a group to look at potential reliability risks to both gas and electricity markets in Southern California due to the limited operation of the Aliso Canyon gas storage facility. Through an expedited stakeholder process, the group created a proposal for tariff changes that addresses gas balancing, electricity and gas scheduling misalignment and market-based mitigation measures.³³ CAISO's proposal identifies ways to mitigate risks that impact the electric system when rapid ramping will exceed the dynamic capability of the gas system (i.e., contingency recovery, renewable generation following, or significant changes in load). In its proposal, CAISO also anticipates needing the flexibility to reduce available transfer capability on Path 26, a set of three 500-kV lines connecting Southern California Edison Co.'s intertie with Pacific Gas and Electric Co. to the north. The proposal stated that flexibility would be needed to ensure sufficient transfer capability to support reliable grid operations. The proposal also includes measures to mitigate risks where planned and unplanned outages on the gas system limit pipeline and storage that impact gas availability.

The outage at Aliso Canyon³⁴ is the most recent demonstration of how BPS reliability is affected by the increasing interdependency between the electric and natural gas industries. While the mitigation measures being undertaken will help reduce the risk of electricity service interruptions, they do not eliminate the risk. The challenges faced in California represent a series of risks that have been layered into the system over the past decade: significant dependency on a single and just-in-time delivery fuel source, specifically for ramping capability to meet load and generation variability; reduced amount of baseload and dispatchable resources; increased amounts of variable and distributed resources; increasing need of system flexibility; gas system dependency on storage to maintain operating pressure; and a lack of clear understanding of natural gas operational characteristics and potential impacts on BPS operations. Continued coordination between electric and gas industry entities will be critical to mitigating risks and minimizing their impact.

The four most impactful measures to help mitigate risk are: tightening the gas balancing rules; giving generators dispatch information two days in advance so that they can procure gas more accurately; directing the use of the remaining gas in Aliso Canyon to prevent electric service interruptions; and completing inspection of the Aliso Canyon storage facility to allow the resumption of safe injection. The long-term risks associated with Aliso Canyon will not be known until more is known about the longer term operational prospects of Aliso Canyon.

³³ [California ISO Aliso Canyon Gas-Electric Coordination - Straw Proposal; April 15, 2016](#)

³⁴ [California Public Utilities Commission: Aliso Canyon Risk Assessment Technical Report; April 5 2016](#)

Chapter 5 – Conclusions

In 2015, natural gas surpassed coal as the predominant fuel for electric generation and is the leading fuel type for capacity additions. Despite substantial progress in coordination between the gas and electric industries, the growing reliance on natural gas continues to raise reliability challenges regarding the interdependence of the industries and the adequacy of gas and electric infrastructure. Both industries have an opportunity to further enhance planning approaches by considering fuel deliverability, availability, and responses to infrastructure contingencies that are unique to each area and integrate them into resource adequacy and other planning and operating practices.

The electric sector's growing reliance on natural gas raises concerns regarding the ability to maintain BPS reliability when facing constraints on the natural gas delivery systems. The extent of these concerns from Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), electricity market participants, industrial consumers, national and regional regulatory bodies, and other government officials vary throughout North America; however, concerns are most acute in areas where power generators rely on non-firm fuel contracts.

Disruptions as experienced during recent extreme weather events, such as the 2014 Polar Vortex, provide clues to the current relationships between gas availability and extremely low temperatures. As gas-fired generation increases, the amount of generation capacity potentially impacted also increases, particularly when conditions affect a wide geographic area and support from the neighboring areas is unavailable. These extreme weather events serve as early indicators of more frequent impacts to the BPS as more natural-gas-fired units continue to rely solely on just-in-time and non-firm fuel sources.

While gas-electric supply and transportation issues are especially important during the winter season, the summer season presents a separate set of potential reliability concerns that also require ongoing attention. Specifically, the electricity industry must be aware of pipeline and gas distribution company equipment maintenance schedules and promote ongoing coordination to ensure individual generators do not face fuel shortages; principally those that could have been resolved through increased coordination.

Natural gas supply, transportation, and distribution infrastructure adequacy concerns, particularly in certain parts of North America, are causing NERC, industry, and policymakers to refocus attention on the interdependency between natural gas and electricity industries. While coordination efforts between the gas and electric industries continue to improve, the potential still exists for a mismatch between the availability of natural gas delivery and demand from the electric sector. This can be particularly challenging in areas where a significant amount of the capacity and reserve capacity are susceptible to fuel supply interruptions, potentially resulting in more frequent generator outages.

The gas and electric industries have recently made substantial progress to enhance coordination and develop new strategies to address system reliability due to fuel supply concerns. However, additional areas need attention. Specifically, in areas where natural gas constitutes a large portion of the generation mix, system planners need to more thoroughly examine system reliability needs to determine if more firm fuel contracts or dual-fuel capabilities are needed. Fuel availability and deliverability should be specifically considered and integrated into resource adequacy and other planning assessments.

More attention is also needed regarding operational coordination strategies between gas and electric industries. System operators should develop or enhance coordination strategies to address potential fuel supply interruptions, especially prior to anticipated extreme weather events. Generator owners should consider securing on-site, secondary fuel inventories in the event that gas service is curtailed. Operating criteria, forecasting, commitment, scheduling, dispatch and balancing practices, procedures, and tools should take fuel supply chain risks into account and lead to mitigation measures to assist operators in maintaining BPS reliability. Enhanced

training should be considered in light of the increasing need for electric and pipeline/LDC operator communications and coordination.

This short-term assessment focused on four assessment areas within the North American BPS that have a greater than 40 percent level of natural-gas-fired generation thereby relying significantly on natural-gas-fired units as well as the upstream infrastructure (pipelines, compressor stations, natural gas wells, distribution, etc.) necessary to deliver reliable natural gas supply to generating facilities. The assessment determined that all areas generally can meet their natural gas needs over the short-term horizon without relying on emergency operating procedures. WECC CA/MX had the largest risk for reliability issues, demonstrating that in the extreme peak load and the severe scenario, they could experience potential difficulty in meeting their peak demand and operating reserve requirements without initiating emergency operating procedures.

While this analysis determined limited short-term risk in the assessed areas during extreme events, longer term implications emerge as the data shows more outages as a result of fuel supply unavailability as more natural gas-fired generation is installed. The Aliso Canyon gas storage outage demonstrates that even outside of extreme and severe scenario analyses, one gas sector contingency can have an impact on BPS reliability and resource adequacy. This one event, which has the ability to affect up to 9,800 MW of Los Angeles-basin generation, underscores the need to identify the need for dual-fuel capability and to develop contingency plans to address the potential effects of a major fuel supply chain contingency.

Appendix A

Method Used to Model Generator Outages

The scope of this assessment includes an analysis of the potential operational risks within the next four peak seasons and across four ISOs: CAISO, ERCOT, ISO-NE, and NYISO. All capacity, demand, and transfer data were obtained from the *2015 Long-Term Reliability Assessment* data set. The extreme weather demand values were assumed by adding 10 percent of the net internal demand on top of the 50/50 peak load forecast. Five years of event data from the Generator Availability Data System (GADS) were analyzed to obtain three classifications of generator outages:

1. Average outages of non-gas-fired generation
2. Average outages of gas-fired generation
3. Maximum outages of gas-fired generation

Mandatory reporting of generator outages to GADS does not include electric generating units below 20 MW nor does it incorporate solar or wind generating capacity outages. Instead, these variable energy resources are assumed to supply a specific capacity contribution across a seasonal peak load hour. This data is presented in relation to the total anticipated capacity which assumes that all other capacity is considered “available” regardless of actual system dispatch or units in reserve/economic shutdown.

Average Outages Methods and Assumptions

- Event data from 2010–2014 were obtained from GADS.
- Only forced outage event types (U1, U2, U3, and SF) were used.
- Events were sorted by their unit type to obtain: Gas-Fired and Non Gas-Fired based events.
- Units were sorted by their physical state location to obtain an approximate area of study: e.g., NYISO outage data was comprised of all units in New York.
- Outage capacity in MW (Unit Rating — Net Available Capacity) was multiplied by the total outage time to calculate the total unavailable energy for each event in MWh.
- The calculated total unavailable energy data were sorted and aggregated together by the starting month for each year.
- Each month’s calculated total unavailable energy were average together for all five years to obtain the monthly unavailable energy average; e.g. $(\text{Jan 2010} + \text{Jan 2011} + \text{Jan 2012} + \text{Jan 2013} + \text{Jan 2014}) \div 5 = \text{Averaged January Energy}$
- Each monthly unavailable energy average was divided by the total number of hours within the data scope to obtain the monthly unavailable capacity average; e.g. $\text{Averaged January Energy} \div (5^{\text{ years}} * 31^{\text{ days}} * 24^{\text{ hours}}) = \text{Averaged January Capacity}$
- Monthly unavailable capacity averages for all months in both seasons were averaged together to obtain the final result of the average outage for any hour within a season; e.g. $(\text{Averaged January Capacity} + \text{Averaged February Capacity} + \text{Averaged December Capacity}) \div 3$

Maximum Outages Methods and Assumptions

- Event data from 2010–2014 were obtained from GADS.
- Only immediate forced outage event types (U1 and SF) were used.

- Events were sorted by their unit type to obtain: Gas-Fired based events.
- Units were sorted by their physical state location to obtain an approximate area of study: (e.g. NYISO outage data was comprised of all units in New York.)
- Outage capacities in MW (Unit Rating — Net Available Capacity) were aggregated by their start date.
- The maximum was obtained for each daily capacity outage aggregation across all five years: e.g. January 1st Maximum = Max of (Jan 1st 2010, Jan 1st 2011, Jan 1st 2012, Jan 1st 2013, Jan 1st 2014)
- The final results used for each season were obtained by taking the maximum daily capacity outage aggregation of all days within the summer and winter months: (e.g., maximum daily outage between June 1st– September 30th)
- The values shown as maximums for the tables and charts are *in excess* of the average gas outages. This was to avoid potentially double counting outages.

Final Results

Summer Outage Data (MW)

Area	Maximum Outages of Gas-Fired Generation	Average Outages of Gas-Fired Generation	Average Outages of Non Gas-Fired Generation
CAISO	2,658	337	1,027
ERCOT	1,705	583	2,275
ISO-NE	1,806	337	473
NYISO	1,434	378	1,124

Winter Outage Data (MW)

Area	Maximum Outages of Gas-Fired Generation	Average Outages of Gas-Fired Generation	Average Outages of Non Gas-Fired Generation
CAISO	1,391	484	3,571
ERCOT	8,782	861	2,741
ISO-NE	3,354	316	1,261
NYISO	2,387	632	1,052

Appendix B

ISO-NE Natural Gas – Electric Operations

The scenario developed for the New England Region assumes a natural gas pipeline “rupture” within the area. This scenario was developed due to the large amount of gas-fired generation located within the ISO New England Balancing Area. Approximately 44 percent of the generating capacity within the area is fueled by natural gas, and gas-fired energy production was approximately 49 percent in 2015.

This theoretical scenario would qualify as a “force majeure” event within the pipeline’s tariff structure. As such, pipeline operators would invoke a series of actions to locate and then isolate the break in the pipe to minimize the amount of natural gas escaping to ensure public safety. It should be noted that some pipeline systems within New England have more than one pipeline located within their “rights-of-way.” After shutting valves to sectionalize the pipe break and confirming public safety, gas control operators would work to back-feed the pipeline from supply sources located downstream of the break. This would entail maximizing interconnects with other pipelines, interrupting non-firm loads, and maximizing injections of vaporized LNG. Gas control is able to deliver gas to firm customers located upstream of the theoretical pipe-break.

Soon after the pipeline is sectionalized and safety is ensured, gas control operators would then try to restore natural gas deliveries to their firm customers. This force majeure event would mandate that any remaining operational gas pipeline capacity would be pro-rationed among firm customers. All non-firm customers would be immediately asked to curtail their consumption of gas. For New England, this would mean that virtually all natural gas-fired power generators would lose their fuel supplies. Prior studies have shown that the majority of gas-fired power generators within New England rely on capacity release, secondary-firm, and interruptible contracts. Those generators that have functional dual-fuel capability would try to fuel switch to their secondary fuel supply, typically liquid fuels which would include kerosene, jet fuel, and Ultra-Low Sulphur Diesel fuel (ULSD). Power generators that are single fuel (natural gas-only) would have to cease energy production.

Exhibit D

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System

November 2017

RELIABILITY | ACCOUNTABILITY



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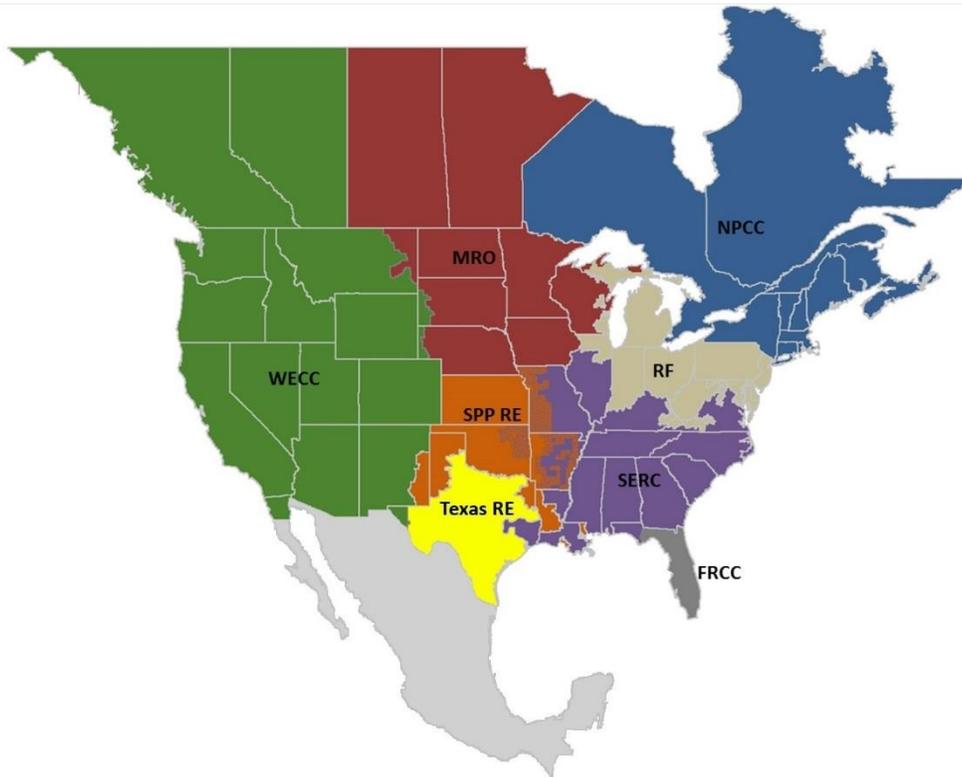
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

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Executive Summary

This assessment provides an analysis of the potential impacts to BPS reliability as a result of a large disruption on the natural gas system. As reliance on natural gas to meet electric generation requirements increases, additional planning measures, and risks must be considered to better understand the implications of the complex interdependency between the natural gas system and the BPS.

North America is experiencing a large shift in its electric generating resources with ongoing retirements of coal-fired and nuclear capacity coupled with growth in natural gas, wind, and solar resources. Regulatory rulings and state renewable portfolio standards are significant drivers for the development of more renewable energy resources while historically low natural gas prices and other factors are contributing to a large increase in the development of natural-gas-fired resources. Some areas within North America now meet their peak electric demand with greater than 60 percent of that sourced from natural-gas-fired electric generation.

This growing interdependence of the natural gas and electric infrastructure has resulted in new operational and planning reliability challenges. For example, the Aliso Canyon natural gas storage facility leak underscored not only the reliance on natural gas to meet electric demand but also how the disruption of a key natural gas infrastructure component can impact BPS reliability. In addition to natural gas storage, pipelines, compressor stations, and liquefied natural gas (LNG) facilities are also critical components of the natural gas infrastructure that the electric industry relies on to meet its load-serving obligations. While the natural gas industry has demonstrated a high degree of reliability, the natural gas leak at Aliso Canyon raised awareness of the BPS's dependency on natural gas infrastructure and calls for a closer look at the facilities that support fuel deliveries to electric generation.

This assessment identifies major clusters of natural gas generation and conducts a screening analysis to determine at a high level whether there are further issues that need investigation.

Key Findings

NERC's assessment identifies the following key findings:

- **Natural gas facility disruptions can have varying impacts depending on geographical location and overall infrastructure dynamics.**
Disruptions to natural gas facilities that impact BPS reliability are highly dependent on a variety of area-specific issues, including the amount and distance from natural gas supply sources, the amount of natural-gas-fired generation commonly connected to the pipeline system, resilience and preparation measures, and market and regulatory requirements. For example, in New England and Southwest California–Arizona, an outage of nearly any major natural gas facility (e.g., one interstate pipeline, key compressor station, or LNG terminal) during electric summer or winter peak conditions would likely lead to some level of electric generation outages. In contrast, the pipeline system in areas such as Texas–Oklahoma–Louisiana is highly interconnected, resembles more of a grid structure, is close in proximity to many supply sources, and is less vulnerable to transportation disruptions.
- **NERC's power flow simulation demonstrates that 18 out of 24 groups of gas-dependent generators studied experience transmission challenges during an extreme event.**
NERC conducted a power flow simulation screening assessment that evaluated the electric transmission system under extreme conditions that were based on the loss of significant electric generation due to failures of natural gas facilities within a relatively local area. The analysis identified approximately 40 “clusters” of natural gas generation representing at least 2,000 MW within a 200 mile radius. After applying criteria for dual fuel or service by multiple pipelines, there were 14 clusters that met the criteria for further examination and were included in the power flow study. Within these 14 clusters, 19 groups

of generation were selected for screening. As well, five other groups were screened based upon the potential impact they would experience due to the loss of a large natural gas storage facility. A power flow simulation was conducted on these 24 groups of generation facilities. There were 18 out of 24 groups of generation facilities identified where transmission upgrades or operational procedures may be necessary to mitigate extreme generator outages.

- **The demand for natural gas storage has increased significantly and has altered the traditional operations of these facilities in order to meet electric demand along with the traditional demands of the natural gas industry.**

The operational characteristics of some natural gas storage facilities throughout North America have evolved in recent years to accommodate increased natural gas demand. Whereas depleted reservoirs have traditionally operated in a seasonally cyclical manner of injections and withdrawals, the new paradigm of year-round injections and withdrawals has introduced new operational conditions to natural gas storage facilities. In particular, some storage facilities are providing intraday flexibility to support natural gas generation cycling. This is largely caused by the need to offset wind and solar variable energy production. Regulators and market operators need to consider potential fuel reliability and security impact when developing new or revised regulations or market rules regarding generation dispatch and natural gas availability.

- **Aliso Canyon has different characteristics than most traditional natural gas storage facilities.**

The Aliso Canyon natural gas storage facility outage is a relatively unique situation; rather than being located on the interstate natural gas pipeline system, Aliso Canyon is located within the SoCalGas distribution footprint. The unique demands of the SoCalGas system and its reliance on this storage field differs significantly from typical storage located on the interstate pipeline system and upstream of the local distribution companies. Given Southern California's high reliance on natural gas generation, increasing ramping requirements to offset variable energy resource production, reducing oil back-up inventory due to environmental regulations, and the changing of local policies, the Aliso Canyon outage poses additional reliability concerns in Southern California.

- **Firm natural gas pipeline transportation, in addition to dual fuel capability and ample infrastructure, provide the highest level of reliability for natural gas delivery.**

Firm fuel agreements from supply source to burner tip provide the highest level of reliable natural gas delivery. However, pipelines are not typically constructed or planned using "N-1" or other similar reliability requirements. The more natural gas infrastructure is put in service, the more resilient the totality of that infrastructure. Pipeline systems in restructured wholesale electric market areas generally have less firm transportation agreements for natural gas supply, pipeline transportation, and underground storage service compared to systems in vertically integrated markets.

- **Many mitigation strategies have been and can be employed to reduce potential impacts of a natural gas disruption.**

Electric transmission upgrades, dual fuel capability, electric power imports, the addition of incremental and diverse generating resources, firm fuel agreements, and battery storage can serve as key strategies to mitigate the risks from the disruption of natural gas infrastructure. However, there is presently a decline in the number of dual fuel units as many new projects are foregoing the added cost of developing dual fuel capability lessening its use as a mitigation strategy.

- **Natural gas supply sources have become more diversified, reducing the likelihood of natural gas infrastructure outages affecting electric generation.**

Most forced outages of natural gas infrastructure are human-caused, such as damage to pipelines from excavation. However, natural events (including earthquakes, hurricanes, other weather events, LNG import/export dynamics) could affect both supply and operations. With the increase in shale production in other areas of North America, the risk of Mexico hurricanes impacting natural gas deliveries to electric generation has been significantly reduced.

- **Recent FERC Orders continue to promote natural gas/electric coordination.**
FERC Orders 787 and 809 have supported natural gas/electric system coordination by increasing the synchronization of operations between the two industries.
- **Comprehensive planning by Planning Coordinators can significantly increase system resilience.**
NERC Planning Coordinator studies show that comprehensive planning and evaluation of significant risks on the natural gas system can result in a significant increase in available resilience measures to maintain reliability. Planning Coordinators that have documented these studies have found success in working with state regulators when requesting support for additional resilience measures (e.g., oil inventory, new natural gas generation is dual fuel capable, etc.).

Recommendations

NERC makes the following recommendations:

Regulators and Policy Makers

- **During the planning process, system planners should work with regulators to incorporate expeditious consideration of air permit waivers, which may be needed for resilience purposes; dual fuel, back-up pipeline capacity, and/or alternative sources of supply should be required in areas with significant risk.**

Dual fuel capability increases generation reliability and resilience, but it is currently limited by various federal, state, and provincial laws and regulations that restrict the duration power plants can run on oil. Temporary air permit waivers may be needed from environmental agencies in advance of an event of a sustained natural gas infrastructure disruption. Furthermore, the necessity for air permit waivers should be incorporated in resilience planning initiatives when they are required.

- **Regulators should consider fuel diversity as they evaluate electric system plans and establish energy policy objectives. Additionally, regulators and policy makers should expedite licensing of new transmission and natural gas facilities to diversify and distribute risk.**
- **Cyber and physical security needs to be diligently considered by regulators.**

Federal regulators and agencies should work with natural gas pipeline operators and evaluate potential cyber and physical security vulnerabilities on the natural gas system's infrastructure and control facilities. Policy makers should ensure gas infrastructure is as secure from cyber and physical threats as the grid it supplies. Additionally, gas industry regulators should be engaged to establish cyber security standards that match those of the NERC reliability standards.

- **The Department of Energy (DOE) should have the Energy Information Administration (EIA) collect data that quantify and assess the use of dual fuel storage for natural-gas-fired generation and whether that storage has inventory.**

Industry

- **NERC registered entities should consider the loss of key natural gas infrastructure in their planning studies.**

Entities should assess and develop criteria to evaluate large-scale BPS reliability impacts due to loss of pipelines, LNG, compressor stations, or natural gas storage facilities in the extreme event list as detailed in the Transmission Planning NERC Reliability Standard (TPL-001-4).¹ The criteria should also consider capacity and energy limitations, including seasonal replenishment requirements. Pipeline systems should be planned with the equivalent of N-1 to assure deliverability in the event of a pipeline, LNG, or storage

¹ <http://www.nerc.com/files/tpl-001-4.pdf>

outage. Where areas were identified in this assessment of needing more granular analysis, planners in those identified areas should be tasked with reviewing this work, assessing the more detailed implications, and where appropriate developing contingency plans to mitigate potential natural gas interruptions, and report back to NERC on what has been done.

- **Owners and operators of dual fuel capable generators must ensure operability of secondary fuel.**

Generator Owners and Operators of units with dual fuel capability should maintain and regularly test operational capabilities and back up fuel inventories at units to ensure that dual fuel capable units provide adequate resilience in the event of a natural gas outage.

- **Natural gas and electric industries must continue to advance coordination as the electric industry continues to become a larger percentage of total natural gas throughput.**

The natural gas and electric industries should increase coordination and information sharing of nonpublic operational information to promote reliability and interdependent system integrity. This coordination should include cyber and physical security as well. Additionally, as our power supply becomes increasingly dependent on natural gas, industry must ensure this just-in-time fuel is as reliable and secure as the power plants that need the fuel to operate.

NERC

- **NERC should enhance its reliability guidelines and/or standards.**

NERC, with industry's support, should enhance its Reliability Guidelines and/or Standards as necessary to include additional planning and operating requirements for analyzing disruptions to the natural gas infrastructure and their impacts on the reliable operation of the BPS. The standards should include developing and deploying mitigation plans to address reliability risks caused by outages of significant natural gas infrastructure.

- **NERC should enhance its Generator Availability Data System (GADS) database.**

The NERC GADS database should be modified to provide additional information on duration as well as frequency and cause codes for natural gas outages so that a more specific causality can be formulated around natural gas generator outages. This information should be used to work toward mitigation of common causes of failure.

This assessment, which builds on earlier NERC assessments, identifies the need to further improve coordination between the electric and natural gas industries to support the electric system's reliability and resilience. Differing regulatory frameworks and requirements increase the complexity between the interdependence of the two industries. Inter-industry coordination is needed at the regional level due to existing significant operational differences, regulatory rules, and market structures.

Chapter 1: Background

NERC has conducted previous assessments on natural gas and electric interdependence, including the *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power*² and its 2011 *Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependencies in the United States*.³ In 2016, NERC conducted a special assessment, titled *Operational Risk Assessment with High Penetration of Natural Gas Generation*,⁴ underscoring increased operational risk with an increase in natural-gas-fired generation.

Despite substantial progress in coordination between the electric and natural gas industries, the growing reliance on natural gas continues to raise the need to identify and mitigate the risks that result from the growing interdependence of the industries. This assessment focuses on the adequacy of the natural gas infrastructure to support the sustained delivery of natural gas to electric generation. The large growth in natural gas use for electric generation is discussed in this chapter along with an overview of potential increased risks to bulk power system (BPS) reliability.

Previous NERC Reliability Assessment Key Findings and Recommendations

Key Findings

The following are key findings from previous NERC Reliability Assessments:

- Natural gas use is expected to continue to increase in the future both in absolute terms and as a share of total power generation and capacity. Unlike coal and fuel oil, natural gas is not easily stored on-site; as a result, real-time delivery of natural gas through a network of pipelines and bulk natural gas storage is critical to support electric generators.
- Natural gas is widely used outside the power sector, and the demand from other sectors—particularly coincident end-user natural gas peak heating demand during cold winter weather—critically affects the ability to deliver interruptible transportation service in the power sector. Additionally, demand for natural gas is expected to grow in other sectors (e.g., transportation, exports, and manufacturing).
- While extremely rare, disruptions in natural gas supply and/or transportation to power generators have prompted industry to seek an understanding of the reliability implications associated with increasing natural-gas-fired generation. Contracts for firm natural gas supply and transportation affect the risk profile of each power plant (or group of power plants).
- Natural gas generation is expected to play a growing role in offsetting the variability and uncertainty associated with renewable resources. As variable generation increases, swings in variable generation may call for dispatch of natural gas-fired generation at a larger and less predictable rate.

Recommendations

Policy makers, market operators, and asset owners should consider factors that reduce risk, such as the following:

- **Maintaining Alternative Fuel Capabilities:** Evaluate capabilities across generator fleet, maintain back-up fuel inventories at key stations, and annually test fuel switching capability

² <http://www.pnucc.org/sites/default/files/NERC%20Phase%20II%20Accommodating%20an%20Increased%20Dependence%20201305.pdf>

³ <https://www.columbiagrid.org/client/NERC%20Gas%20Study.pdf>

⁴ http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf

- **Enhancing Market and Regulatory Rules:** Provide additional incentives for behavior and investments that support reliability and resilience
- **Evaluating Single Points of Disruption:** Assess reliability under extreme conditions, loss of major pipeline infrastructure, or supply
- **Continuing Pipeline Expansion:** Keep pace with generation expansion and increasing electricity production
- **Limiting Exposure to Production Area Failures:** Increase resilience by maintaining alternative supply chains and paths
- **Maintaining Situational Awareness:** Maintain awareness of pipeline conditions and the potential unavailability of generators
- **Communicating Risks to Policymakers:** Share and clarify results and conclusions of studies that evaluate electric reliability
- **Maintaining Fuel Diversity:** Maintain fuel diversity in order to provide resilience to common-mode failures

Reliability Guideline on Gas and Electrical Operational Coordination

The NERC Operating Committee is establishing a Reliability Guideline on Gas and Electrical Operational Coordination. The guideline provides operational practices that should increase system resilience and adaptability during extreme conditions. The guideline provides insights on establishing gas and electric industry coordination mechanisms; preparation, supply rights, training, and testing; establishing and maintaining open communication channels; and best practices for intelligence and situational awareness.

The guideline provides examples of proactive measures that should be taken to prepare for the potential of adverse conditions on the pipeline system. For example, preparing the gas and electric system for coordinated operations benefits from early assessments and activities to ensure that system operators are prepared and can effectively react when real-time events occur. Activities that increase system resilience include developing a detailed understanding of where and how gas infrastructure interfaces with the electric industry, such as the following:

- Identifying each pipeline (i.e., interstate and intrastate) that operates within the electric footprint and mapping the associated electric resources that are dependent upon those pipelines.
- Identifying the level and quantity of pipeline capacity service (i.e., firm or interruptible, primary or secondary) and any additional pipeline services (e.g, storage, no-notice) being used by each natural-gas-fired generator.
- Developing a model of the non-electric generation load that those pipelines and local distribution companies (LDCs) serve and will protect when natural gas curtailments are needed.
- Identifying natural gas single-element contingencies and how those contingencies will impact the electric infrastructure. For instance, although most natural-gas-side contingencies will not impact the electric grid instantaneously they can be far more severe than electric side contingencies over time; this is because natural gas contingencies may impact several generation facilities. When identifying natural gas system contingencies, the electric entity should consider what the natural gas operator will do to secure its firm customers including the potential that the natural gas system will invoke mutual aid agreements with other interconnected pipelines; this may involve curtailment of non-firm electrical generation from the unaffected pipeline to aid the impacted pipeline.

- Understanding how natural gas contingencies may interact with electric contingencies during a system restoration effort.

Increasing Use of Natural Gas

NERC's 2016 Long-Term Reliability Assessment⁵ reported that natural gas generation is the leading fuel type for capacity additions. Since 2008, the amount of natural gas generation capacity in NERC's footprint has increased by 86 GW—from 336 GW to 422 GW—and is expected to substantially increase over the next ten years. In addition, the use of natural gas generation to serve electric load is increasing. Natural gas combined-cycle units have increased from 43 percent of peak load requirements in 2011 to 56 percent in 2016. The upward trends in both the net generation and the natural-gas-fired combined-cycle annual capacity factor highlight natural gas' growing contribution to meet base load demand, which is a shift from historically serving peak and intermediate loads. For example, Florida, California, and Texas, now rely on natural gas to meet the electric generation requirements of over 60 percent of their on-peak demand. **Table 1.1** shows natural-gas-fired generation as a percentage of on-peak demand in NERC assessment areas.

Table 1.1: Natural Gas Percentage of Peak Season Total Anticipated Capacity

	2017 (MW)	2021 (MW)	2017 Gas of Total Capacity (%)	2021 Gas of Total Capacity (%)
FRCC	35,583	39,598	66.19%	69.05%
WECC-CAMX	40,299	42,536	68.39%	68.23%
Texas RE-ERCOT	45,842	51,867	60.34%	63.26%
NPCC-New England	14,331	16,308	48.17%	52.33%
WECC-SRSG	16,530	16,774	51.24%	51.84%
WECC-AB	8,514	8,514	52.02%	51.79%
SERC-SE	30,256	30,262	48.53%	46.88%
MRO-SaskPower	1,835	2,087	42.90%	43.97%
SPP	30,413	29,446	45.92%	45.22%
SERC-N	19,250	21,160	37.96%	40.68%
MISO	59,566	60,026	41.74%	42.26%
NPCC-New York	16,030	16,708	41.07%	41.98%
PJM	66,760	76,335	35.80%	38.71%
WECC-RMRG	6,695	6,914	36.36%	38.51%

⁵ <http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf>

Table 1.1: Natural Gas Percentage of Peak Season Total Anticipated Capacity				
	2017 (MW)	2021 (MW)	2017 Gas of Total Capacity (%)	2021 Gas of Total Capacity (%)
WECC-NWPP-US	20,860	20,565	34.67%	34.80%
SERC-E	15,762	17,754	30.67%	32.25%
NPCC New York	6,568	7,340	22.99%	24.91%
NPCC-Maritimes	856	856	12.56%	12.66%
MRO-Manitoba Hydro	311	404	5.51%	6.33%
WECC-BC	434	442	3.45%	3.48%
NPCC-Québec	570	570	1.33%	1.33%

Figure 1.1 shows natural-gas-fired generation in aggregate along select major natural gas pipeline systems in North America underscoring the significant critical mass of natural-gas-fired generation and its dependence on the natural gas pipeline system.

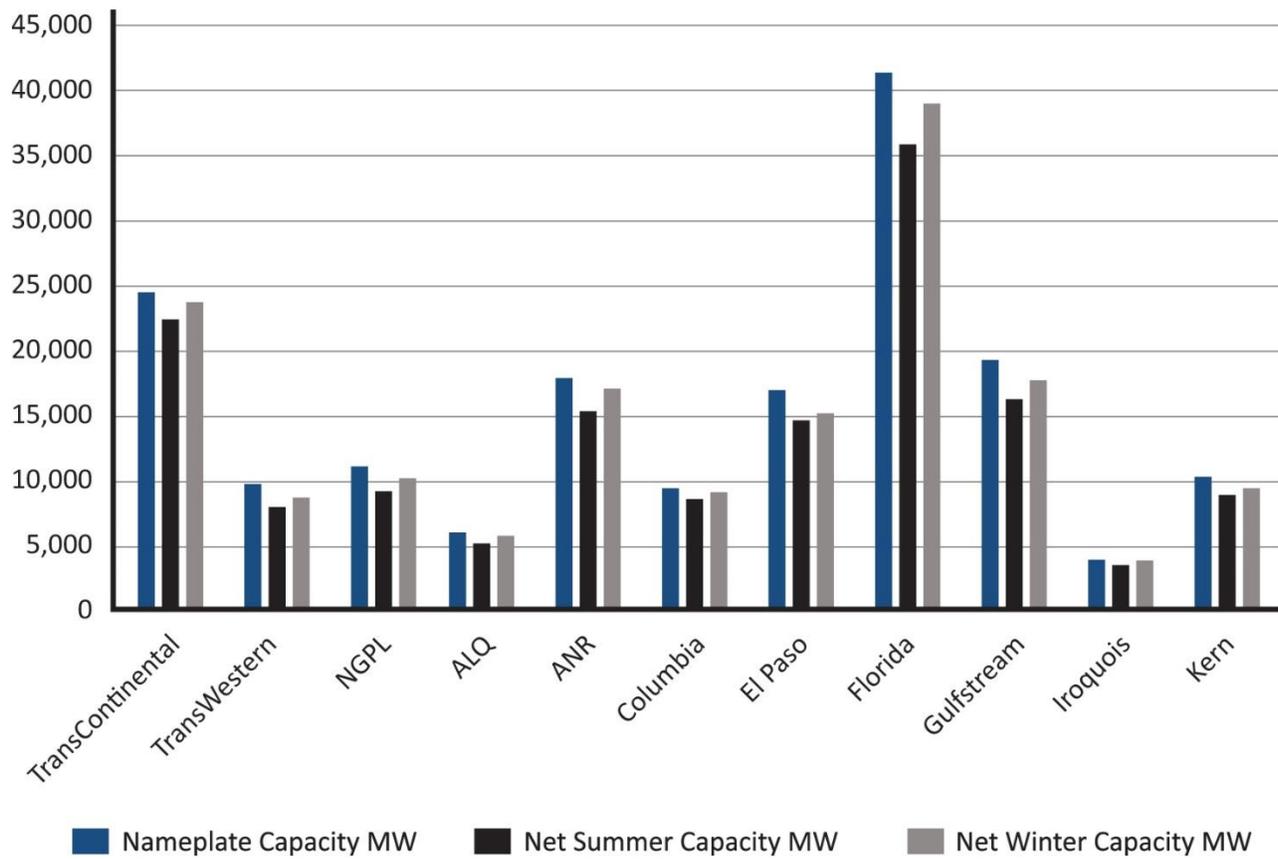


Figure 1.1: Directly Connected Electric Generation on Selected Pipelines

The large growth in natural gas use for electric generation can in part be attributed to its low cost coupled with the reduction in coal use resulting from regulatory rulings in the United States, such as Mercury and Air Toxics Standards and the Cross-state Air Pollution Rule as well as Canadian coal regulations. Natural gas production has increased significantly and is coupled with a decline in natural gas prices, both resulting from newly discovered shale formations and drilling technological advances, such as hydraulic fracturing. **Figure 1.2** shows the decrease in natural gas prices, which has largely contributed to the trend in increased natural-gas-fired electric generation. **Figure 1.3** depicts the large increase in North American natural gas production since the 1990's, which has also been a driving factor in the large increase of natural-gas-fired generation.

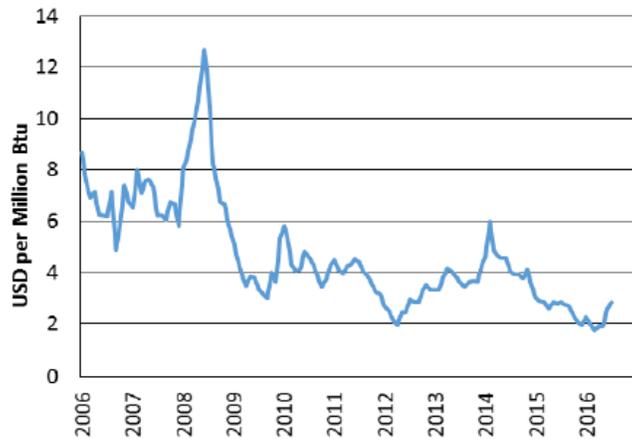
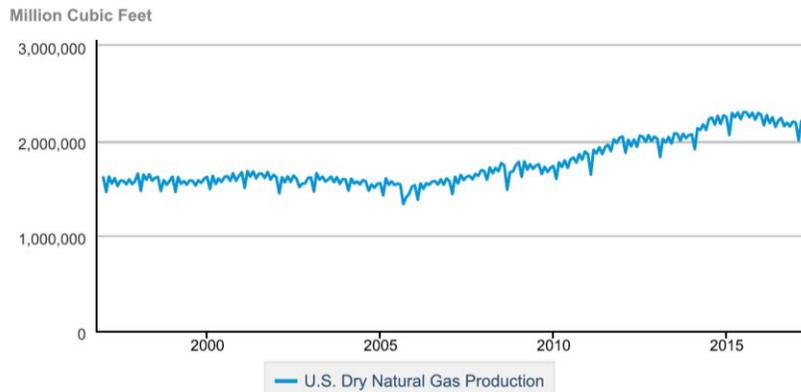


Figure 1.2: U.S. Natural Gas Prices



Source: U.S. Energy Information Administration

Figure 1.3: U.S. Natural Gas Production

Regional Risk Profiles

Natural gas generation and its impacts on BPS reliability are diverse and varied across North America. Some of the differentiating factors in various areas that are important to understand prior to a deeper analysis are described below in **Table 1.2**.

Table 1.2: Differentiating Factors

Area	Risk Description
Northwest	The northwest does not have significant natural gas storage but also has less reliance on natural gas generation. This area is able to bring in Canadian natural gas supplies as well as domestic supplies in order to meet its natural gas needs.
Southern California and Arizona	This area has a high degree of dependence on storage, notably the Aliso Canyon storage facility. Ramping needs, due to an increased penetration of distributed energy resources and utility-scale solar photovoltaic, have made storage needs more significant in this area. Limited dual fuel capability adds additional reliability concerns to the reliance on natural gas infrastructure in this area. Natural gas storage may be limited geographically in Arizona due to its proximity to a sole source aquifer for water use.
East Texas, Louisiana, and Oklahoma	This area benefits from significant levels of natural gas production and a well-developed system of both interstate and intrastate natural gas pipeline facilities. Additional production area storage facilities provide added deliverability to the area.
Southeast	The southeast has significant amounts of storage, production, and pipeline capacity. A sizable amount of electric generation in this area is backed by firm contracts as well as having dual fuel capability.
Florida	Florida relies heavily on natural gas generation with close to 70 percent of its peak requirement relying on natural-gas-fired generation. Firm fuel and dual fuel capabilities provide effective mitigation for this area. Florida has no market area storage and relies on out-of-area supply to meet their demand requirements and out-of-area storage facilities to mitigate supply disruptions or extreme peak conditions
New England	New England has no storage facilities while relying significantly on natural gas and liquefied natural gas supplies. It has limited infrastructure compared to the demand of natural gas in the area for electric generation. Disruption to any of the major trunk lines or deliveries would likely force generation out of service. Under peak conditions demand may not be served; however, under light load conditions some of these outages can be managed by system operators. Lack of firm transportation by electric generators in this area contribute to its risk profile.

Canadian Natural Gas Market

Some areas within Canada rely significantly on natural gas in order to meet peak electric demand requirements. SaskPower, for example, sources 42 percent of its peak generation from natural-gas-fired generation. Conversely, Québec, partly due to its abundance of hydro assets, currently has no natural-gas-fired electric generation. Canada, similar to the United States, also relies on underground natural gas storage facilities to meet deliverability requirements of natural gas for electric generation. Presently, Canada has approximately 10 underground natural gas storage facilities with working capacity of 440 billion cubic feet (bcf) and deliverability of 7 bcf per day. The majority of Canada's natural gas is transported on a Trans-Canada pipeline that carries natural gas through Alberta, Saskatchewan, Manitoba, Ontario, and Quebec. As a result, Canadian markets are particularly vulnerable to any supply disruptions on the Trans Canada pipeline.

Aliso Canyon Storage Facility Outage

The Aliso Canyon underground storage facility, one of more than 400 storage facilities in the United States, experienced a significant leak in 2015 resulting in a temporary closure of this facility. This closure underscores the potential reliability issues resulting from a reliance on a particular generation fuel type. The Aliso Canyon outage has also accentuated the need for a better understanding of risks associated with the growing dependence on natural gas and the need to take appropriate actions to assess and mitigate those risks.

While the natural gas industry has demonstrated a high degree of reliability that includes a system of natural gas pipelines, compressor stations, storage, pipeline looping, and liquefied natural gas deliverability, the Aliso Canyon storage facility shut-down in Southern California in the winter of 2015 underscores the significant threats that a single point of disruption can pose to the reliability of the BPS. The rapid increase in the growth of reliance on natural gas for electric generation necessitates that system planners and operators fully understand their exposures to a potential natural gas disruption and have contingency plans in the event of disruption.

In July 2017, the Division of Oil and Gas and Geothermal Resources (a division of the state of California Department of Conservation) and the California Public Utilities Commission concurred that natural gas injection may resume at the Aliso Canyon storage facility. Since the leak was plugged 17 months prior, significant improvements and upgrades had been made to infrastructure, testing, operations, and monitoring to ensure safe operations. The facility will operate at a significantly reduced storage capacity and injection pressures.⁶

Considerations for Bulk Power System Reliability

Natural-gas-fired generation mostly relies on “just-in-time” fuel delivery from the natural gas industry. Disruptions to the fuel delivery can lead to multiple electric generating units becoming unavailable. This is compounded as multiple plants are connected through the same natural gas infrastructure. Disruptions to the fuel delivery results from adverse events that may occur such as line breaks, well freeze-offs, or storage facility outages. Similarly, the pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor driven compressors). In consideration of potential risks associated with pipeline systems, NERC has identified natural gas generators that are dependent on major trunk lines or are restricted to one pipeline connection in various areas. These are described in [Table 1.3](#) below.

Region	Number of Generators with One Connection	Generation Capacity with One Connection (MW)	Number of Major Supply “Trunk” Lines Serving Area
Northwest	16	4,963	24
Southern California and Arizona	20	11,430	13
East Texas, Louisiana, and Oklahoma	1	656	60
Southeast	68	46,124	35
Florida	38	31,049	7
Middle Atlantic	22	12,244	9
New England	35	13,103	6

As natural gas generation transitions from a “peaking” resource to a more “baseloaded” resource, a disruption of the delivery of natural gas resulting from a single loss of a natural gas infrastructure facility exposes the electric industry to a much greater level of risk and loss of resilience.

There are two important and distinct reliability risks associated with natural gas supply that need to be considered in BPS planning (see [Figure 1.4](#)). The first is Interruption Risk. When electric generator customers do not procure “firm” supply and transportation for their fuel, their service is likely to be interrupted when firm customers schedule their full entitlements—particularly in constrained pipeline areas such as New England. This report does

⁶ <http://www.conservation.ca.gov/dog/pages/AlisoCanyon.aspx>

not assess these more “typical” interruptions that may impact individual generators based on their fuel service agreements.

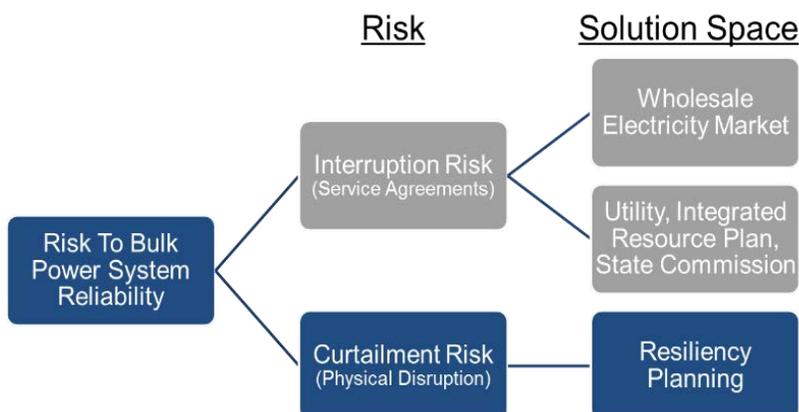


Figure 1.4: Natural Gas Disruption Risk Paradigm

The second is Curtailment Risk, which occurs when “firm” service is disrupted through a *force majeure* event. Curtailments occur when facility outages impact the scheduled flow of natural gas for any reason.

Understanding the distinction between these two risks is important due to their solutions being very different. For example, electric generation with “firm” fuel service agreements can still be curtailed but can be off-set by dual fuel capability.

Interruption Risk is generally considered in NERC’s annual reliability assessments. Through the assessments, NERC puts a spotlight on generator availability risks that may be impacting their ability to meet peak seasonal demand. However, issues related to generator interruptions are likely to be resolved through integrated resource plans, state or provincial regulatory requirements, and implementation of mitigation strategies—such as dual fuel capability and electricity markets (where they exist). Each of these solutions has a mechanism to consider the reliability needs of the system.

For this assessment, NERC focused on Curtailment Risk, which involves resilience planning. Resilience planning is generally defined as preparatory actions to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive events. These activities often are supplemental to “normal” planning activities but serve to provide awareness and mitigation of potential risks to both industry and regulators. **Figure 1.5** demonstrates the paradigm between reliability and fuel assuredness.

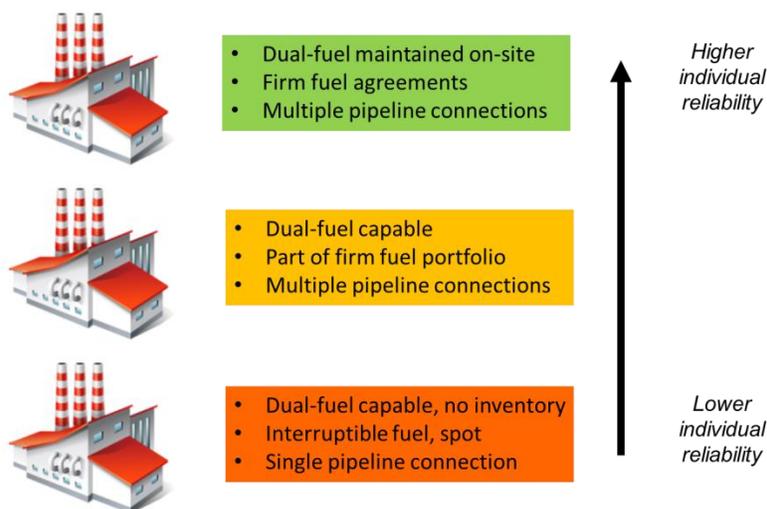


Figure 1.5: Generalized Risk Profiles and Generator Vulnerabilities

Chapter 2: Assessment Objectives and Approach

This assessment evaluates impacts to the bulk power system reliability as a result of fuel delivery disruptions resulting from the loss of major natural gas infrastructure facilities (e.g., storage facilities, key pipeline segments, liquefied natural gas terminals). Electric power system and transmission screening analysis provides insights on transfer capability as a result of a large loss of generation. Additionally, the assessment offers recommendations for reducing bulk power system exposure to natural gas infrastructure disruptions through planning and preparation.

An advisory group comprised of electric industry experts provided guidance to NERC throughout this assessment activity. NERC, in coordination with the Regional Entities, Argonne National Laboratory, and industry experts identified natural gas storage facilities and major pipelines that, if inoperable, could have an impact on electric reliability. The location of generation affected, dual fuel capability of resources, and electric transmission system adequacy are considered in this assessment. This assessment also uses data acquired from Transmission Planners and Planning Coordinators as well as from public sources.

Objectives

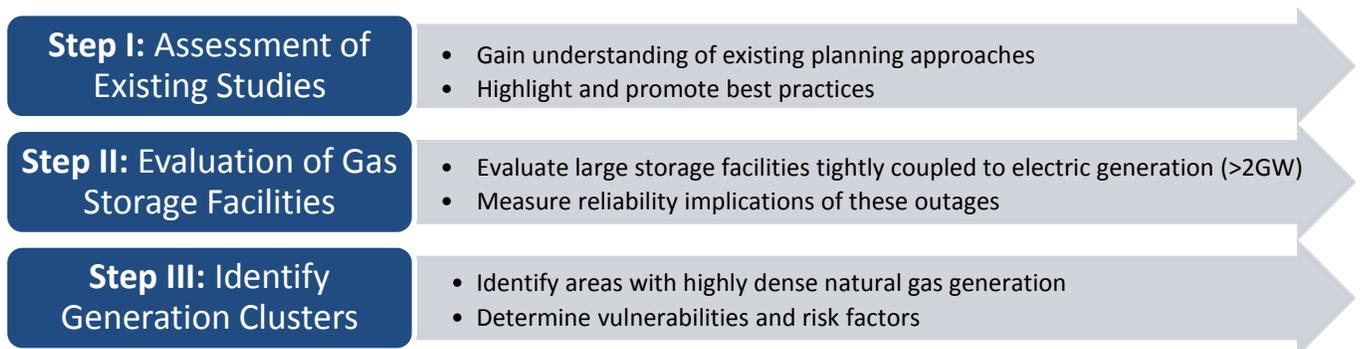
The assessment's objective are as follows:

- Identify natural gas infrastructure facilities that are important for the operation of large amounts of generation capacity
- Assess current studies performed by industry that evaluate large disruptions to natural gas facilities
- Evaluate the transmission system given the loss of generation from natural gas supply disruptions
- Make recommendations on mitigating natural gas infrastructure risks to bulk power system reliability

Approach

Steps I, II, and III

This assessment is structured in the following three steps:



[Step I – Appendix E.](#)

[Step II - Chapter 4.](#)

[Step III - Chapter 5.](#)

The assessment process involves evaluating the electric system's ability to operate reliably under a variety of scenarios in which natural gas infrastructure is significantly disrupted. This includes disruptions to facilities that have not occurred historically but can conceivably materialize due to a variety of reasons, including (but not limited to) natural events, accidents, or regulatory action.

Chapter 3: Reliability Considerations, Risk Factors, and Previous Studies

Electric Reliability

NERC defines the reliability of the interconnected bulk power system (BPS) in terms of the following two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components.

Note: Fuel adequacy is a function of fuel security. For example, if an electric generator does not have fuel, it is not available to generate electricity, which reduces the capability of the system.

Reliability Considerations for Natural Gas Generation

Natural-gas-fired generation mostly relies on “just-in-time” fuel delivery from the natural gas industry. Disruptions to the fuel delivery can quickly lead to multiple electric generating units becoming unavailable. This is compounded where multiple plants are connected through the same natural gas infrastructure. Disruptions to the fuel delivery results from adverse events that may occur such as line breaks, well freeze-offs, hurricanes, floods, storage facility outages, or infrastructure attacks. Similarly, the pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor-driven compressors). Whereas the ability to use alternate fuel provides a key mitigation effect, only 27 percent of U.S. natural-gas-fired generation capacity added in 1997 and later is “dual fuel.”⁷

Factors Impacting the BPS’s Risk Exposure

The following inputs can be used by Planning Coordinators and Transmission Planners to ascertain the natural gas generation fleet’s potential exposure to Curtailment Risk:

⁷ Testimony of the Foundation for Resilient Societies By Thomas S. Popik, June 19, 2017

Fuel Service Agreements	<ul style="list-style-type: none"> • What level service does each generator maintain?
Alternative Fuel Capabilities	<ul style="list-style-type: none"> • What are the fuel-firing capabilities of the unit? Is back-up oil maintained on-site? Is it tested?
Pipeline Connections	<ul style="list-style-type: none"> • How many direct connections are available to the generator and are they served by different supply sources?
Market and Regulatory Rules	<ul style="list-style-type: none"> • What are the regulatory obligations under a force majeure? What tools exist to prepare and plan for a large disruption?
Vulnerability to Disruptions	<ul style="list-style-type: none"> • What is the generation fleet's risk profile as it relates to reliance on natural gas storage and limited transportation sources?
Pipeline Expansion	<ul style="list-style-type: none"> • Where growth in natural gas generation is occurring, is pipeline expansion also occurring?

Increased dependence on natural gas for generating capacity can amplify the bulk power system’s exposure to interruptions in natural gas supply and delivery. Strategies—such as storage, firm fuel contracting, alternate pipelines, dual fuel capability, generators using other fuel sources with on-site fuel availability, sufficient pipeline capacity to support normal and emergency operations, access to multiple natural gas basins, or additional electric transmission lines from other areas—can help mitigate and manage potential risks to reliability. An important mitigation approach includes high levels of coordination between the electric and natural gas industries, which can lead to a more resilient bulk power system and increased situational awareness of potential fuel supply shortages. Regional solutions will likely include a mix of mitigating strategies, increased natural gas and/or electric infrastructure, electric market products, a diverse fuel mixture, and dual or back-up fuel capability

Assessment of Existing Studies ([Step 1](#))

NERC reviewed previous studies conducted by Argonne National Laboratories, Eastern Interconnection Planning Collaborative (EIPC), ERCOT, Southern Company, and Columbia Grid Reports as well as the Aliso Canyon Risk Assessment Technical Reports. From the review of these reports and key lessons learned, NERC has developed the following key takeaways and recommendations.

Key Takeaways

The results of the survey conducted by NERC identified several key findings several key findings that may be useful as the electric and natural gas industries identify ways to assess the impacts of potential extreme disruptions. The following are some key takeaways from the survey:

- The importance of an assessment of interdependence varies by company and Region due to individual resource mix, topology, and the availability of dual fuel generation capacity.
- Several companies are already either conducting studies or developing processes that will lead to studies to assess natural gas infrastructure disruptions.
- The identification of wide-area transmission impacts (i.e., voltage and thermal constraints) due to loss of a large natural gas underground facility or a segment of a pipeline are typically not studied; the majority of the focus is put on resource adequacy and resource availability. Transmission reliability and contingency analysis in the event of loss of a major pipeline/storage facility is paramount in developing mitigation plans and emergency operational procedures.

- Many respondents indicated that there were no natural gas storage facilities within their systems to evaluate. However, the loss of a large natural gas facility can impact electric generation downstream and beyond the boundaries of a Planning Coordinator. Determining whether natural gas system outages could create a regional or local electric reliability risk will warrant a coordinated and detailed analysis among neighboring Planning Coordinators.
- Electric Registered Entities, in coordination and collaboration with their neighbors and natural gas sector, should determine which power plants would be affected in the event of a disrupted natural gas facility. Alternative fuel capability, mitigation plans, emergency operating procedures, evolving ramping capability requirements to manage VERs, and the wide-area reliability impacts to the BPS should be further studied.

Recommendations

Comprehensive studies by Planning Coordinators that assess specific disruptions to important natural gas facilities should identify and characterize adverse impacts to electric reliability. These disruptions are typically beyond the “design basis” of the power system required by NERC Reliability Standards as well as any regional or local planning requirements; because of this, these reliability risks are generally not incorporated into the planning requirements. In many cases, the resulting reliability impacts are due to a lack of capacity on existing infrastructure. As the BPS relies more heavily on natural gas generation, policy makers and regulators need to be aware of these risks—how likely they are as well as the potential impact. While many pipeline-related infrastructure impacts can be rectified within a week or two, natural gas storage facilities, as observed with Aliso Canyon, can be out for significant periods of time.

The recommended approach for Planning Coordinators can be broken down in the following four general steps:

1. Identify potential natural gas system contingencies and their frequency of occurrence.
2. Assess the impacts for each of the identified contingencies in terms of duration and amount of natural gas supply disrupted.
3. Apply the contingency disruptions to the natural gas supply capabilities to calculate the impact on total natural gas supplies and, more specifically, the amount of natural gas available to electric generators.
4. Determine the transmission systems ability to transport power to load under these extreme conditions.

With this information, policy makers, regulators, and industry can effectively identify and determine solutions that help support reliability depending on their individual risk tolerances.

A further description of these studies is outlined in [Appendix E: Assessment of Existing Studies](#).

Chapter 4: Evaluation of Natural Gas Storage Facilities

Step II

[Step I](#) of NERC’s study approach was an assessment of existing studies which can be found in [Appendix E](#). This chapter (which is [Step II](#) of NERC’s study approach) provides an evaluation of natural gas storage facilities. It documents the second part of NERC’s assessment approach and details methods, assumptions, and results from the evaluation of natural gas storage facilities and the identification of coupled clusters of generation.

Natural Gas Storage

Underground storage of natural gas is an integral component of the natural gas supply chain, but its function is different from the other components of that supply chain, which are production, pipeline transportation, and distribution. Storage serves as a substitute for natural gas production, but the location of a storage facility can also provide operational flexibility for the natural gas delivery infrastructure. There are 385 underground storage facilities in the lower 48 states with a total of 4,688 bcf of working natural gas design capacity.⁸ As a substitute for production, storage enables local distribution companies to offer natural gas to consumers throughout the year with reliable service and stable prices. Natural gas storage enables companies to adjust for daily and seasonal fluctuations in demand throughout the year while natural gas production remains relatively constant year-round. For those generators that rely on storage, a storage outage could result in potential supply shortages. Without storage, customers (including electric generators and residential users) would be faced with potential supply shortages. Not all natural gas storage facilities are designed for “rapid turn” to service the power sector. Rapid turn is found in salt domes, which have a greater ability to inject and withdraw throughout the year than depleted reservoirs do providing salt dome storage facilities with greater ability to handle the swings and non-ratable takes of electric generators.

Following the events at Aliso Canyon, federal officials (including members of Congress), sought to understand and identify opportunities to improve the overall safety and environmental impacts of natural gas storage infrastructure. To support these efforts, the federal government, formed an Interagency Task Force on Natural Gas Storage Safety in April 2016. Detailed in the Final Report of the Interagency Task Force on Natural Gas Storage Safety,⁹ the analysis identified a small number of underground natural gas storage facilities other than Aliso Canyon that have the potential to affect energy reliability. As the electric and natural gas industries become more interdependent, it was also recommended that electric power system planners and operators, working with their natural gas counterparts, should study and understand the electric reliability impacts of prolonged disruptions of large-scale natural gas infrastructure (e.g., storage facilities, processing plants, key pipeline segments and compressor stations, liquefied natural gas terminals). They should share their analyses with State and Federal officials to ensure that policy makers fully understand the risks to electric reliability and can develop appropriate mitigation policies and strategies. In summary, the task force concluded that, while incidents at U.S. underground natural gas storage facilities are rare, the potential consequences of those incidents can be significant and require additional actions to ensure safe and reliable operation over the long term.

In November of 2016, NERC formed an advisory group comprised of Planning and Operating Committee members, electric industry experts, select natural gas sector association representatives, and Regional Entity staff to perform a special reliability assessment¹⁰ on the screening of single points of disruption to natural gas infrastructure. The loss or disruption of the natural gas infrastructure could directly affect the operations, reliability, and resilience of the North American bulk power system. The growing interdependence has created more frequent reliability

⁸ [Underground Natural Gas Working Storage Capacity](#).

⁹ [Ensuring Safe and Reliable Underground Natural Gas Storage](#)

¹⁰ The Special Reliability Assessments are intended to be topic-driven around specific risks (e.g., drought, fuel availability, natural gas, electric interdependency) to the bulk power system (BPS). See NERC Rules of Procedure (Section 800).

challenges in recent years in which power generators have to curtail electricity production due to fuel unavailability. Interdependency issues often become more pronounced during extreme weather events, electric system outages, or natural gas supply disruptions.^{11, 12, 13, 14}

Data Gathering, Methods, and Assumptions

Argonne National Labs conducted an assessment that identified 12 underground natural gas storage facilities that can potentially have a significant impact on electric generation capacity if they become inoperable. **Table 4.1** provides an overview of these underground natural gas storage facilities. NERC used this assessment and added additional five natural-gas-fired generation facilities to develop further analysis that analyzes risks associated with losing a group of natural gas-fired electric generation facilities simultaneously due to a lack of natural gas deliverability.

UGS Rank	Underground Storage Facility (UGS)	UGS Type	Maximum Daily Deliverability (Mcf/d)	Nameplate Capacity At-Risk (MW)	Distance of Farthest Plant (Miles)	Number of Plants At-Risk
1	Storage Facility XYZ	Salt Cavern	2,665,000	13,800	490	19
2	Storage Facility XYZ	Salt Cavern	2,500,000	13,700	480	17
3	Storage Facility XYZ	Depleted Reservoir	550,000	9,100	270	14
4	Storage Facility XYZ	Salt Cavern	3,200,000	9,200	340	14
5	Storage Facility XYZ	Salt Cavern	2,300,000	9,000	240	16
6	Storage Facility XYZ	Depleted Reservoir	1,860,000	7,820	40	16
7	Storage Facility XYZ	Depleted Reservoir	1,680,000	7,600	50	18
8	Storage Facility XYZ	Salt Cavern	765,000	3,800	290	5
9	Storage Facility XYZ	Depleted Reservoir	275,000	3,600	330	6
10	Storage Facility XYZ	Depleted Reservoir	800,000	3,400	350	7
11	Storage Facility XYZ	Salt Cavern	2,400,000	2,500	320	6
12	Storage Facility XYZ	Depleted Reservoir	1,555,000	2,200	170	4

The U.S. Natural Gas Storage Risk-Based Ranking Methodology and Results report,¹⁵ published by Argonne National Laboratory, summarizes the methods and models developed to assess the risk to energy delivery from the potential loss of underground natural gas storage facilities located within the United States. The U.S. has a total of 418 existing storage fields of which 390 are currently active. Argonne National Laboratory has developed three distinct models to estimate the impacts of a disruption of each of the active underground natural gas facilities on their owners and operators: 1) local distribution companies (LDCs), 2) directly connected transporting pipelines and thus on the customers in downstream States, and 3) third-party entities and thus on contracted customers expecting the natural gas shipment and measured impacts across all natural gas customer classes.

¹¹ [A Primer of the Natural Gas and Electric Power Interdependency in the United States](#)

¹² [Accommodating an Increased Dependence on Natural Gas for Electric Power. Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System](#)

¹³ [Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation](#)

¹⁴ [NERC 2014 Polar Vortex Review](#)

¹⁵ <https://anl.app.box.com/s/ki95gqa3xzein3h11ef2sst4xq4ggdho>

For the electric sector, the impacts were quantified in terms of natural-gas-fired electric generation capacity potentially affected from the loss of an underground natural gas storage facility. All models and analyses are based on publicly available data.

Figure 4.2 illustrates the three underground storage supply-to-customer processes that were modeled. The consequence of an underground gas storage (UGS) disruption was estimated using Excel-based models developed internally by Argonne specifically for its assessment. In each model, a compensated mode is run in which mitigation measures are assumed to be implemented whenever a supply shortfall is estimated. Such mitigation measures include increased withdrawals from unaffected UGS facilities owned by the UGS operators, additional contributions from liquefied natural gas storage facilities (if available), raised output from natural gas production fields, and increased contributions from other interstate transmission pipelines via interconnection points.

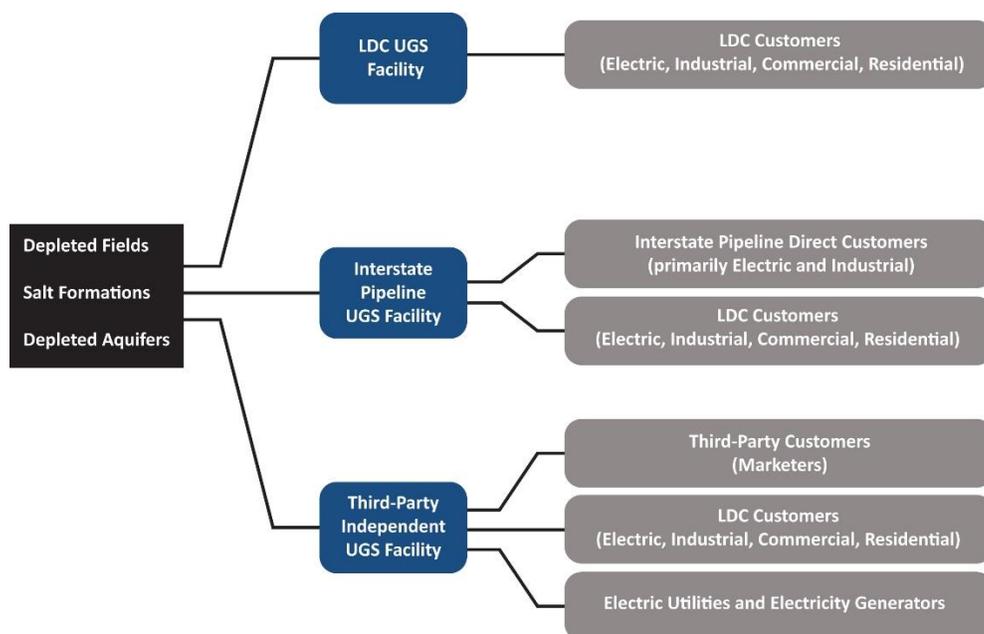


Figure 4.2: Underground Storage Supply-to-Customer Processes

The process for determining at-risk power plants from underground natural gas facility disruptions uses information on the maximum daily storage quantity of natural gas that each UGS facility is obligated to store and supply for a shipper (i.e., electric utility, LDC, marketer) under each contract. The overall procedure to determine the potentially affected power plants is as follows:

1. NERC used the FERC Index of Customers to determine which organizations (e.g., natural gas LDCs, natural gas marketer, electric utility, interstate transmission natural gas pipeline) have contracted with a given UGS company for natural gas supply.
2. Data from EIA Form 923 was used to establish the natural gas supplier to each electric power plant and the type of supply and transport contracts (firm, interruptible) and to identify which power plants could be affected by a disruption in natural gas supply for a given UGS facility.
3. NERC used data from EIA Form 860 to establish the natural gas pipeline(s) connected to each natural-gas-fired generator and the FERC Index of customers is then examined to determine whether the pipeline has a storage or asset management contract (and what type of contract), which could be affected by a disruption of a given UGS facility.
4. Based on the above, compensated supply-demand models specific to each UGS owner type (i.e., LDC, Interstate Pipeline, Third Party) determine the total electric capacity that is potentially affected by the

disruption of natural gas supply from a UGS facility.

5. NERC then developed a list of potentially affected power plants for each UGS facility that identifies the supplier, type, potentially affected electric capacity (MW), and natural gas contract. The estimated shortfall in natural gas supply from a given UGS facility is compared with the monthly consumption of each natural-gas-fired generator that receives natural gas during each month. It is assumed that power plants with interruptible contracts will be affected before those with firm contracts. In addition, the power plants closest to the UGS facility will be disrupted first as power plants farther away from the UGS facility may have a higher probability of finding another source of natural gas.

Chapter 5: Identification of Generation Clusters

Step III

This chapter (which is [Step III](#) of NERC's study approach) identifies large generation clusters that would be most susceptible to a natural gas disruption. This was conducted to determine vulnerabilities and risk factors necessary to consider in resilience planning.

Background

In addition to the underground natural gas facility interruptions to electric generation availability, NERC identified approximately 40 generation clusters in 7 main geographical areas. Each cluster represents at least 2 GW of natural-gas-fired power plants. See [Figure 5.1](#).

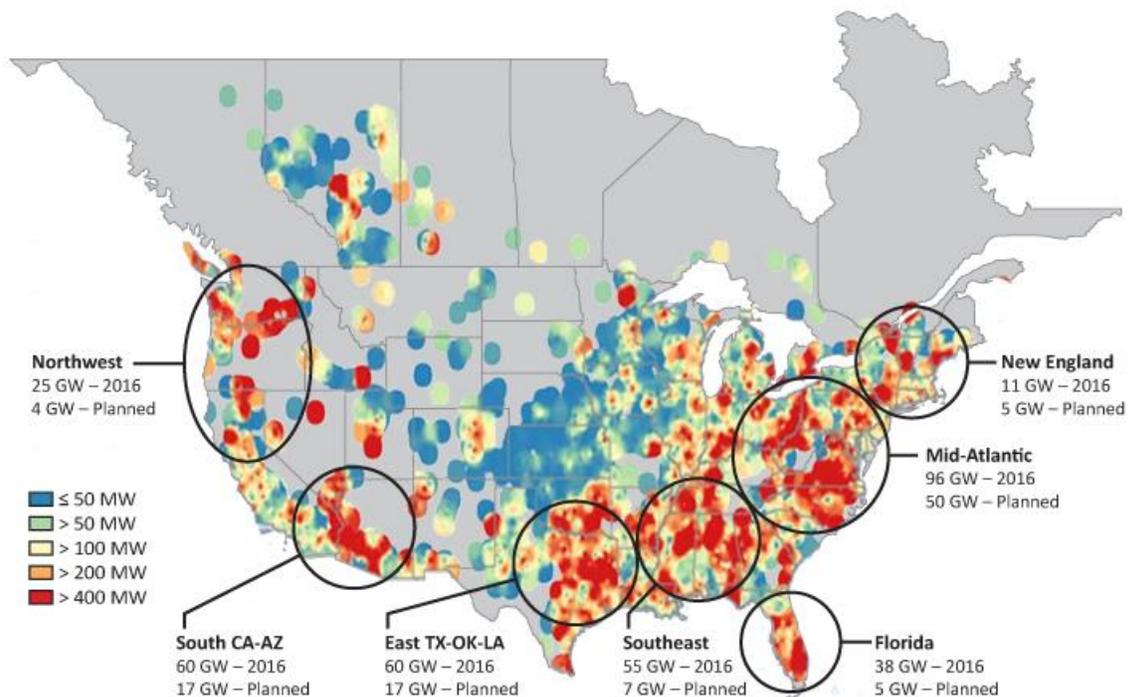


Figure 5.1: Natural Gas Generation Clusters

A data request was sent to Generator Owners/Operators, Balancing Authorities, and/or Planning Coordinators through the Regional Entities to collect information, including dual fuel capability/capacity, seasonal generating capacity, fuel contract type, power system model bus number, and natural gas pipeline connectivity. Not all of the generating plants identified within a cluster were BES elements (e.g., behind the meter, industrial generation for internal processes) and were not modeled.

The assumptions considered in the identification are as follows:

- All generation with an alternative source of fuel was assumed available (with no fuel-switching down time period). This generation's dispatch was modified to reflect the generating capacity with the secondary fuel burn.
- All generation and transmission facilities are on-line and available to serve load.

- Non-hydro renewable generation (solar and wind) was dispatched at their de-rated capacity at peak demand.
- Based on available data when this study was performed, this study does not consider the addition of new pipeline capacity.¹⁶

The generation was reviewed with the natural gas industry members serving on the NERC Technical Advisory Group to ensure the identified generation is connected to a segment of a pipeline. The identification excluded Aliso Canyon and areas where Planning Coordinators have performed extensive assessments to re-dispatch electric generation to evaluate loss of natural gas facilities.

From the originally identified 40 clusters, 14 clusters met the criteria (2 GW or more are at risk of being lost, excluding alternative fuel generation capacity) for power flow screening. Within the clusters there were some where multiple pipelines fed the generation fleet within the identified geographical area. In some instances there were more than one set of generating stations identified within a cluster that met the screening criteria of 2GW or greater that were supplied by one pipeline. In aggregate, 19 groups of generation were selected within the 14 clusters in addition to the 5 groups of natural-gas-fired generation from the loss of a large natural gas underground natural gas storage facility for further power system analysis. Results of this screening are included in the next chapter.

¹⁶ The assessment was conducted using existing case studies that may not include recent incremental projects, such as the Sabal Trail and Florida Southeast Connection pipelines, which went into service in Florida in the summer of 2017.

Chapter 6: Transmission Power Flow Screening

Using the information provided by Argonne National Laboratory as well as the information received from Planning Coordinators, NERC conducted a transmission power flow screening.

In addition to the 19 sets of generation that met the criteria (as described in the previous chapter), an additional five sets of generating stations that were not captured during the geographical location assessment performed by NERC were also included. These five sets were identified as being vulnerable to a loss of underground storage as assessed in Chapter 4 above. From the Argonne National Laboratory analysis due to loss of an underground natural gas storage facility that were not captured during the geographical location assessment performed by NERC. These 24 sets of potential electric generation outages greater than 2 GW were selected for the power flow screening.

Steady-State Power System Screening Approach

The screening process examined if the system could support the import of replacement power equal to the loss of generation that resulted from a natural gas supply disruption. The screening process undertook an extreme scenario of a large natural gas supply disruption combined with peak load conditions during a non-coincident peak. The screening analysis is intended to provide NERC, Regional Entities, and Planning Coordinators insights as to where more granular evaluation of the transmission system is needed.

The analysis determined if the transmission system is capable of meeting demand using the existing system and resources or if reliance on neighboring systems can support the required deliverability of resources.

NERC's study is limited to existing interconnection-wide models, such as the Multi-Area Modeling Working Group (MMWG) and WECC interconnection models. Therefore, NERC can only perform a screening analysis since more detailed models with known operational procedures also need to be evaluated.

The study approach used replacement power that was first sourced from the Planning Coordinator area and then from the neighboring systems. The screening was performed with DSA Tools and is shown in [Figure 6.1](#) and summarized below:

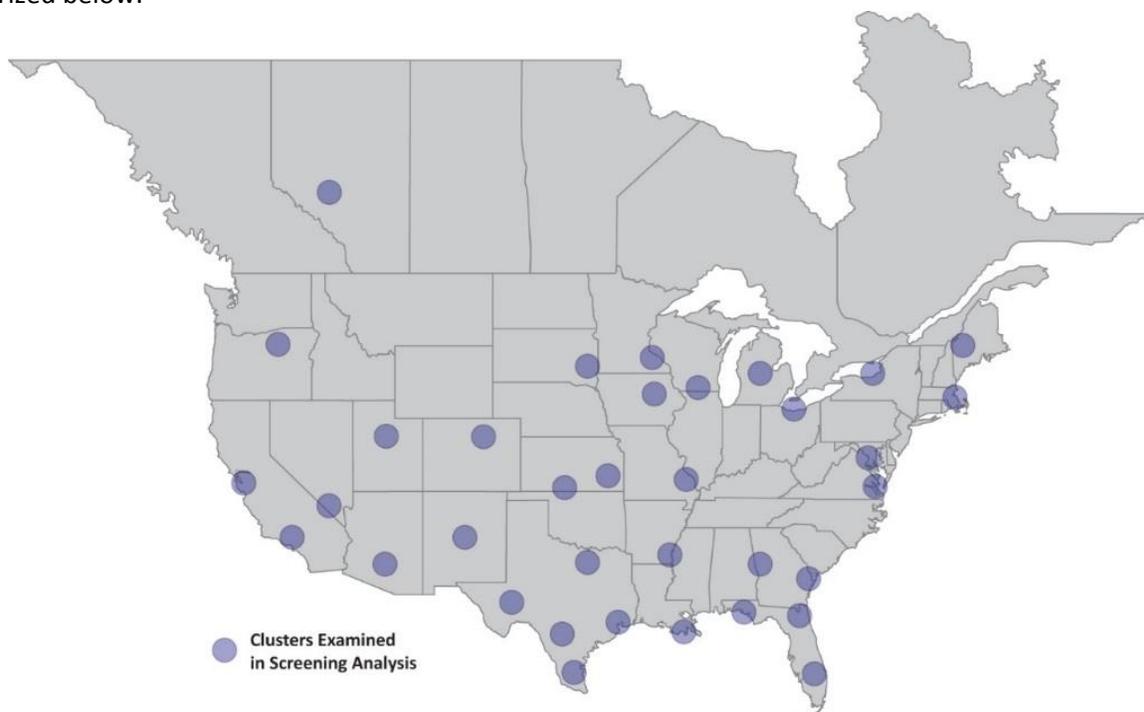


Figure 6.1: Clusters Examined in Screening Analysis

- Reliance on generation capacity internal to a Planning Coordinator area:
 - Non-natural-gas-fired generation (source) is set to increase their output to the maximum generating capacity within the Planning Coordinator area.
 - The natural-gas-fired generation (sink) impacted by the loss of a natural gas facility is scheduled to be reduced to minimum capacity and turned off if the minimum is reached.
 - Generation was transferred from other sources as impacted natural-gas-fired generation was reduced in increments of 5 MW and a power flow solution was obtained.
 - The transfer was continued until the impacted natural-gas-fired generation reached zero output or the system could no longer support the delivery of the makeup power.
- Reliance on neighboring Planning Coordinators to transfer power:
 - In the event that generation capacity internal to a Planning Coordinator area reaches its maximum capacity before the impacted natural-gas-fired generation reached zero output, an interface area is defined at the Planning Coordinator boundaries and transfers are allowed.
 - The transfer continued until thermal limits at tie-lines are reached or voltage criteria is violated.

Screening Results

The results of the screening indicate that 18 out of 24 groups of generation facilities would experience voltage and stability issues in the absence of additional operational remedies when (>2GWs) of natural-gas-fired generation were to be disrupted. This is shown in [Figure 6.2](#).

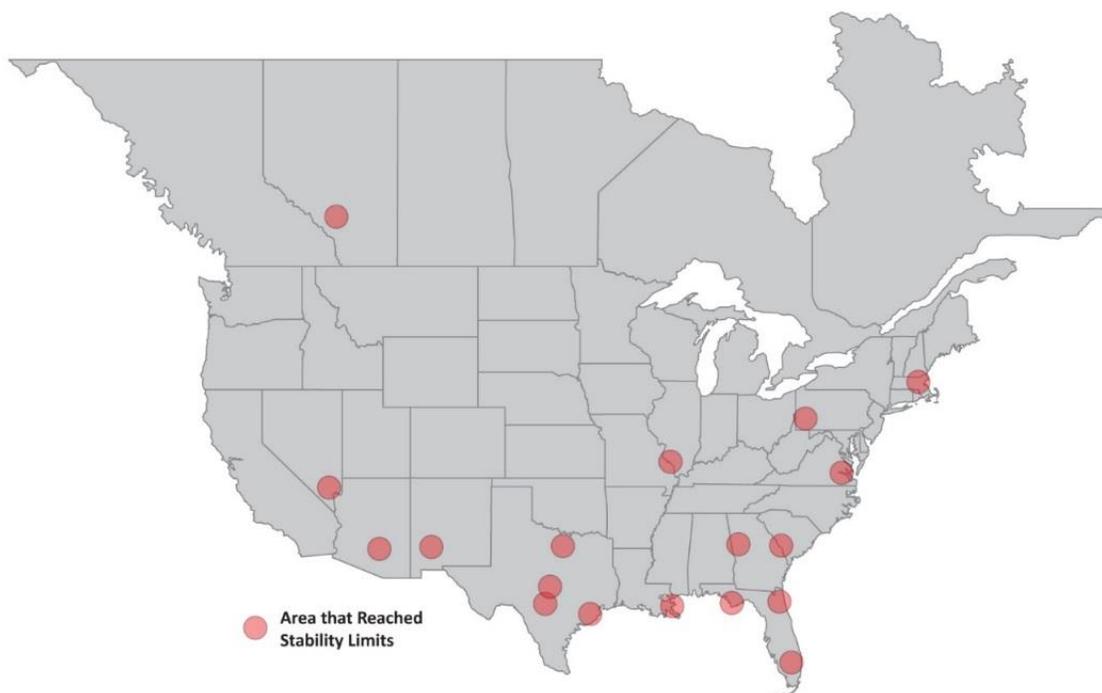


Figure 6.2: Clusters Where Power Flow Issues were identified

Recommendations

DOE, NERC, and its Registered Entities should collaborate to confirm with plant owners and operators which power plants would be affected, whether they have existing dual fuel capability (with available alternative fuel) or other mitigation options, and what the reliability impact is to the bulk power system, considering a variety of conditions and sensitivities. Coordination between electric sector utilities and Registered Entities should be expanded to include assessments where reserve sharing facilities are available, where maintenance of large generation/transmission facilities could impact import capabilities, and where generation availability can span within a large area.

Chapter 7: Liquefied Natural Gas and Other Supply Disruptions

In addition to the potential for natural gas pipeline disruptions and natural gas storage disruptions, liquefied natural gas (LNG) disruptions and other supply disruptions can pose reliability challenges to the bulk power system. LNG can either be a source or a demand on the natural gas system. The location of LNG facilities within the natural gas pipeline system and distances between wellheads, import facilities, and electric generating stations need to be considered.

Potential Loss of Liquefied Natural Gas Supplies

Due to pipeline constraints, LNG imports in New England during the winter heating season (or to supplement natural gas supplies in response to a pipeline contingency) are critical to maintain bulk power system reliability. In other areas, the potential for a dramatic increase in the volumes of LNG exported from the United States has raised concern over its impact on the natural gas markets in the US—in particular the impact on the power generation market where natural gas fueled generators are being used to replace aging coal fired plants to provide more electricity to meet increasing overall demand.

Shortages of natural gas led to the building of LNG importation facilities in the 1970s. Subsequent global trade changes led to dramatic reductions in LNG importation into the US followed shortly after the year 2000 by increased demand for more natural gas. Mothballed LNG importation facilities were reactivated and new importation facilities were built to meet this new shortage of natural gas in the U.S. Increased natural gas production has led to a reduction in the price of natural gas, which has boosted the demand in industrial and electric power markets. **Figure 7.1** shows current LNG plants that are connected to natural gas pipeline systems.

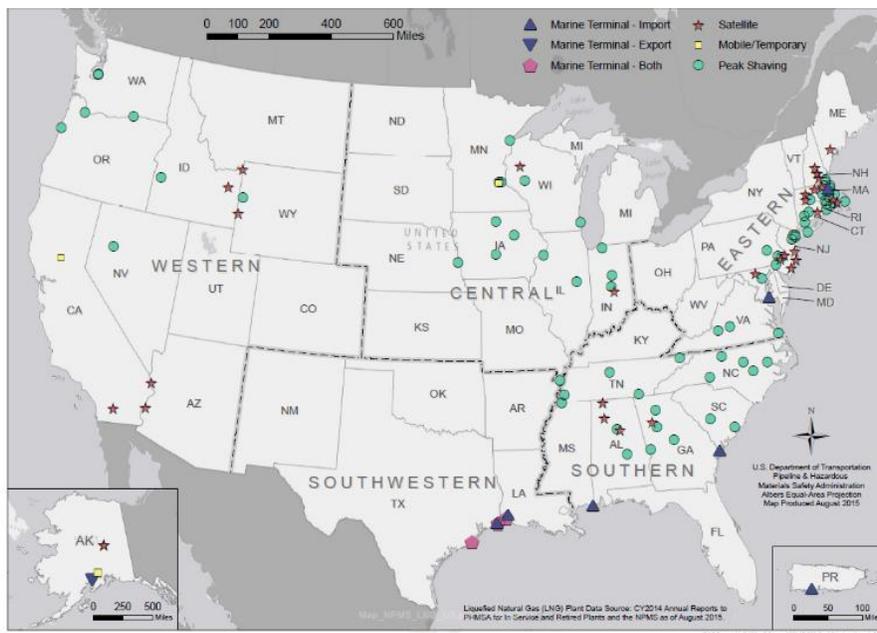


Figure 7.1: U.S. LNG Plants Connected to Natural Gas Pipeline Systems

Similarly, LNG is beginning to play a larger role in Canada in meeting peaking needs as well as serving to export natural gas to the United States. The Canaport LNG facility in Saint John, New Brunswick, has a maximum send out of 1.2 bcf/day enabling it to supply deliveries to the Northeast United States as well as within Canada.

Regional Natural Gas Supply Chain Impacts

The location of natural-gas-fired generation facilities in relation to the pipelines that transport natural gas to their facility is a critical part of the analysis of the impact on power generation during any significant outages in the natural gas supply chain. The location of LNG facilities within that natural gas pipeline system is just one component that must be considered.

With the locations of shale natural gas formations being remote from the traditional areas of natural gas production, there are shifts in the direction of flow of natural gas through the existing and proposed natural gas pipeline systems that will impact the reliability of natural gas supply across the United States. Historically, there was a long chain of natural gas pipelines that moved natural gas north from the Gulf of Mexico as far as New England. Now, a major source of natural gas is located at the midpoint known as the Marcellus shale production zone. Thus, natural gas no longer has to flow from the Gulf to the Northeast and New England with Marcellus volumes satisfying much of the demand. The natural gas produced in the Gulf areas can now, to a greater degree, stay in that area to support increased power generation and the growth/expansion of industrial markets. Similar shifts are occurring or will occur in other areas of the United States.

New England and Northeast Natural Gas Markets

In the New England area, there is a higher degree of concern with the limited natural gas system flexibility to address the interstate pipeline constraints. This means there are fewer options for alternate sources of natural gas supply should any part of the natural gas supply system experience a major outage other than increased imports from LNG facilities.

LNG remains an important fuel for New England, providing from 20 percent to over 40 percent of design-day supply in the winter for several local natural gas organizations. Without these LNG supplies, there would not be enough natural gas available for electric generation on a winter peak design-day even with the natural gas pipeline systems operating at full capability. LNG provides about 8 percent of New England's total annual natural gas supply. There is no underground storage located in New England primarily due to geologic unsuitability. LNG is thus an important part of the Region's supply and deliverability network. There are liquefaction and satellite storage tanks in localities in the Region that are owned and operated by the LDC. In 2016, according to the Northeast Gas Association (NGA), the LNG storage capacity in New England among the LDCs was 16.1 bcf.

Just as a disruption on a natural gas pipeline could impact delivery of U.S. natural gas supplies to New England, a disruption at an LNG import terminal, or a pipeline serving that terminal, would limit LNG supplies serving the Region. Due to New England's inadequate pipeline capacity and its reliance on LNG in order to meet peak day natural gas requirements, ISO New England has implemented significant measures to reduce risk of a loss of bulk power system reliability. ISO New England has developed the following actions to date:

- Non-Market Enhancements:
 - ISO New England has developed a systematic plan of coordination between ISO New England and the pipeline operators. Changes to the ISO New England Information Policy allows communications with pipeline operations staff about specific generators.
 - ISO New England maintains situational awareness of the natural gas system using newly developed tools that monitors the capability and demand on the natural gas system. This includes evaluating a generator's daily natural gas arrangements versus expected natural gas requirements to meet the generator's daily schedule. Oil and coal inventory surveys are also conducted monthly and are updated weekly or daily during times of high demand.
- Market Enhancements:

- ISO New England implemented enhancements to its energy and ancillary services markets to better reflect the intra-day price volatility of natural gas and operating reserve deficiencies
- FERC Order 809 providing more flexibility for scheduling natural gas as well as adding a new intraday nomination cycle has served to mitigate some the electric and natural gas interdependency concerns.
- ISO New England will be implementing a pay-for-performance incentive in its forward capacity market. This is designed to provide stronger incentives for resources to perform during shortage conditions.

Until the pay-for-performance incentives go into effect on June 1, 2018, ISO New England has implemented a winter reliability program. This winter program is designed to provide the incentive for generators to increase their fuel inventories prior to the winter.

Even with these enhancements, the deficiency of infrastructure (combined with a lack of natural gas firm transportation for electric generation) exacerbates the effects of a single point of disruption. The natural gas system in New Jersey, New York, and New England is expected to become more constrained in the coming years. In addition, the planned and targeted closures of nuclear plants in the Northeast will increase the demand for natural gas to fuel the electric generation needed to address the emerging supply gap.¹⁷

¹⁷ US Chamber of Commerce Institute For 21st Century Energy: Energy Accountability Series

Chapter 8: Other Contributing Factors to Natural Gas Disruptions

It is necessary to identify the types of contingencies that can occur in the natural gas system's infrastructure and to compile data on their frequencies, duration, and consequences that can be used in reliability assessments. There are a wide range of events that could result in the loss of natural gas service, including physical/operational, technical/cyber, natural, and man-made causes.

A list of some of the potential natural gas system vulnerabilities includes the following:

- Physical/Operational
 - Mechanical or operational malfunction of a specific natural gas system equipment, such as a compressor station
 - Pipeline leakage or burst due to stress or corrosion cracking
 - Storage well degradation or failure due to scaling, water penetration, or other factors
 - Pipeline capacity outages due to scheduled construction, maintenance, and testing
- Technical/Cyber
 - SCADA system malfunction
 - Electrical failure of supporting computer and control systems
 - Database corruption
 - Hacking or tampering with supporting software and information for control systems
 - Failure or malfunction of operational flow control systems
- Natural
 - Damage to compressor stations from flooding
 - Damage to pipelines due to flooding, erosion, river scouring
 - Damage to facilities due to hurricanes or high winds
 - Well freeze-offs in production and storage systems
 - Damage to facilities due to earthquakes
- Man-made
 - Damage resulting from terrorist activities
 - Pipeline damage due to excavation
 - Damage due to negligence

Physical and Cyber Protection

NERC and the American Gas Association have launched a new grid and energy delivery security partnership that takes advantage of the growing interdependency and collaboration of the natural gas and electricity industries. Under this partnership, staff from the Downstream Natural Gas Information Sharing and Analysis Center (DNG-ISAC) have joined the Electricity Information Sharing and Analysis Center (E-ISAC) in Washington, D.C., to improve

coordination on potential security risks related to critical electricity and natural gas pipeline infrastructure.¹⁸ The partnership between the E-ISAC and the DNG-ISAC builds on the long-standing efforts of the natural gas and electricity industries to address supply interdependencies by developing a robust information exchange on shared security risks.

Threats to bulk power system reliability increase as physical and cyber threats grow, underscoring the need for additional coordination between the natural gas and electric industries in regards to physical and cyber security. NERC recommends that natural gas industry regulators should be engaged to establish cyber security standards that match those of the NERC reliability standards.

¹⁸ [NERC, AGA Launch Security Information Sharing Effort](#)

Chapter 9: Conclusion

North America is experiencing a large shift in its electric generating resources with ongoing retirements of fossil-fired and nuclear capacity coupled with growth in natural gas, wind, and solar resources. With this, it is becoming even more important to evaluate system resilience and effective operational coordination particularly when some fuels are being relied on more than others. The Aliso Canyon natural gas storage facility outage in Southern California underscores not only the reliance on natural gas to meet electric demand but also how the disruption of key infrastructure can impact bulk power system reliability.

Whereas increased synchronization between natural gas and electric industries incremental resources (e.g., battery storage and transmission upgrades, dual fuel capability, diverse resources, storage, and increased incentives to secure firm transportation) can serve to mitigate risks, entities should assess and develop criteria to evaluate bulk power system potential reliability impacts due to a loss of a pipeline, liquefied natural gas facility, or storage facility.

The electric and natural gas industries should continue to increase coordination, particularly with the increased threats of cyber and physical attacks. Additionally, it is important that Generator Owners seek necessary air permit waivers and a protocol for calling on those in the event that alternate fuel is necessary. As natural-gas-fired generation continues to grow, particularly in order to meet peak demand, regulators and policy makers should evaluate existing natural gas industry standards, including cyber and physical standards, and evaluate whether those standards should be mandatory.

NERC's power flow analysis determined that many areas in North America could incur power flow and stability issues if they were to experience significant losses of natural gas infrastructure. This accentuates the need for system operators and planners to conduct their own system studies around loss of pipeline infrastructure and to develop contingency plans.

More transparent data and more thorough data analysis is needed to formulate key decisions around the bulk power system reliability. NERC should expand its GADS data base to provide more specific cause codes for natural gas outages so that more precise causes can be determined in order to formulate adequate remedies to reduce outages.

Appendix A: Overview of Natural Gas Storage—Aliso Canyon Outage

Background and Overview

In October 2015, a natural gas leak was detected in one of the Aliso Canyon underground natural gas storage facility wells¹⁹ in southern California. The facility is one of the largest natural gas storage facilities in the United States, serving approximately 11 million customers and providing fuel to 18 power plants with approximately 10 GW of capacity. The natural gas pipeline and storage network in California that includes the Aliso Canyon facility is different from other Regions, so impacts of the Aliso Canyon facility shutdown would not be duplicated elsewhere. Nevertheless, this storage outage underscores the potential effects that a single point of disruption can have on bulk power system reliability.

Through November and December 2015, SoCalGas worked to stop the leak, and the amount of working natural gas storage in Aliso Canyon was reduced from 86 bcf to 15 bcf. SoCalGas sealed the leak in February 2016; however, additional injection of natural gas into the facility was prohibited pending a comprehensive inspection of the 114 storage wells at the facility.

A technical assessment group was formed to study and identify risks posed to electric and natural gas reliability as a result of the loss of Aliso Canyon.²⁰ The group conducted a study of potential risks and developed an action plan that outlined a number of mitigation measures. In response to the potential operational concerns, entities led by the California ISO (CAISO), California Public Utility Commission (CPUC), California Energy Commission (CEC), and the Los Angeles Department of Water and Power (LADWP) prepared and implemented coordinated operating plans.

The unavailability of Aliso Canyon significantly impacted system operations during Summer 2016 and Winter 2016/2017. However, due to mild weather and other factors that resulted in reduced electricity demand, there was no loss of load during this time. Increased hydroelectric generating availability further mitigated potential impacts in system operations during the summer of 2017.

A second study²¹ on Aliso Canyon is expected to be issued by the CEC in December, 2017, to fully address how the CAISO has worked with utilities and other parties to address the 2016–2017 events.

2016–2017 Seasonal Operations Overview

Summer 2016

Through extensive coordination among operating entities, there were no electric load interruptions as a direct result of unavailability of the Aliso Canyon storage facility. The summer temperatures were mild with the exception of system peak demand on June 20, 2016. In addition, outages caused by wildfires did not impact major transmission paths and were mitigated adequately through real-time system operations. During the summer season, there were three natural gas curtailment incidents with no impact to electric generation availability. Flex Alerts²² were used successfully to change consumer behavior and reduce demand at key times.

¹⁹ Owned by Southern California Gas Company (SoCalGas)

²⁰ The technical assessment group consisted of members from the California Public Utility Commission (PUC), California Energy Commission, California ISO, Los Angeles Department of Water and Power (LADWP) and SoCalGas.

²¹ “[CCST study](#)” led by California Energy Commission with California Council on Science and Technology. The scoping description gives the report name as “Long-Term Viability of Gas Storage Study”. The study has participation from multiple agencies including California Air Resources Board, Division of Oil and Gas and Geothermal Resources with the Department of Conservation and is expected to be issued by late December, 2017. Details may be found at.

²² [California ISO Flex Alerts](#)

During the Aliso Canyon outage, CAISO and SoCalGas modified several tariffs to allow the natural gas company to push selected electric generation up in curtailment priority to help maintain both natural gas and electric system reliability. Tariff changes and improved coordinated planning between the CAISO and So CalGas provided the flexibility needed to avoid unserved electric load due to the unavailability of the Aliso Canyon Storage facility.

Winter 2016/2017

On January 24 and 25, 2017, due to increased system demand driven by cold weather conditions, SoCalGas began withdrawing natural gas from Aliso Canyon to support reliability of the Region’s natural gas and electricity systems with no electric service curtailments. Over the two days, approximately 50 MMcf of natural gas was withdrawn, leaving 14.8 bcf of working natural gas inventory in the field.

SoCalGas did issue curtailment watches each day from January 23 through January 26, 2017, and CAISO used their generation natural gas constraint nomogram in the day-ahead market to limit natural gas usage in the Southern California Edison and San Diego Gas and Electric areas. The nomogram limits the use of generating resources in the impacted area reducing their output to conserve natural gas supply in preparation for potential shortfall in real-time operations.

Summer 2017

On July 19, 2017 the California Department of Conservation announced that injections would be able to resume at Aliso Canyon. Following months of rigorous inspection and analysis of wells at the Aliso Canyon natural gas storage facility and the implementation of multiple new safety protocols, state engineering and safety enforcement concluded the facility would be safe to operate and could reopen at a greatly reduced inventory capacity in order to protect public safety and prevent an energy shortage in Southern California.

Under Senate Bill 380 (SB 380), the Division of Oil, Gas and Geothermal Resources and the California Public Utilities Commission were required to concur that the facility was safe before natural gas injection could resume. This will continue to limit the withdrawal capacity of these facilities, resulting in reduced natural gas availability to meet both natural gas and electric generation needs.

The National Oceanic and Atmospheric Administration forecasted a warmer than normal Summer 2017 in California and increased risk of fire with thick undergrowth fed by spring rains. Compared to Summer 2016, the electric generation was less reliant on Aliso Canyon due to hydroelectric generation availability in both northern California and the Pacific Northwest, dual fuel capability in the LA basin, increased non-natural-gas-fired generation and transmission resources, and incremental participation in the western Energy Imbalance Market (EIM).

Through coordination and cooperation among operating entities in southern California, there were no load interruptions during Summer 2017. The CAISO, SoCalGas, LADWP, Peak Reliability Coordinator, and Western Electricity Coordinating Council continued to communicate through Peak-day calls, weekly calls with Peak Reliability Coordinator, and daily natural gas coordination calls with SoCalGas.

2016 and 2017 Technical Assessments

Summer 2016 and Winter 2016/2017 Assessment Summary

In April 2016, a technical assessment group released the Aliso Canyon Risk Assessment Technical Report,²³ which provided findings from analysis of the potential natural gas and electric system reliability impacts. The report outlined four key factors that contributed to reliability risks during the Summer 2016 operating season:

- Rapid ramping of electric generation that exceeds the dynamic capability of the natural gas system

²³ [Aliso Canyon Risk Assessment Technical Report](#)

- Mismatches between scheduled natural gas and actual demand
- Planned and unplanned outages on the natural gas storage and delivery system, outside of Aliso Canyon
- Interruptions in natural gas supply to California (e.g., very cold weather in the east)

In May 2016, the Technical Assessment Group also created an Aliso Canyon Action Plan²⁴ that presented measures²⁵ to mitigate the risk of large natural gas curtailments that could result in electricity interruptions. The five mitigation plan categories are as follows:

- Prudent use of Aliso Canyon
- Tariff changes
- Operational coordination
- Demand-side reduction for natural gas and electricity
- Reduction of natural gas maintenance outages

Summer 2017 Assessment Summary

The Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment was released in May of 2017.²⁶ The assessment report outlines the study work and findings related to potential risks to southern California electric reliability with reduced natural gas availability within the SoCalGas system. Based on the hydraulic modeling conducted, the maximum natural gas send-out that SoCalGas facilities (excluding Aliso Canyon) can support is 3.638 bcf per day (bcfd) of which 2.2 bcfd is available for electricity generation. This assumes ideal conditions with 100 percent receipt point utilization and storage capability. Studies conducted by the CAISO and LADWP indicated that 1.47 bcfd during peak conditions would meet expected electric demand.

Mitigation measures detailed in the Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment²⁷ are as follows:

- **Battery Storage:** The outage of Aliso Canyon drove the expedited procurement of nearly 100 MW of battery storage in the Southern California Edison and San Diego Electric and Gas footprints. LADWP has expedited its beacon 20 MW battery project, which should be operational in 2018.
- **Transmission Capacity:** Several transmission upgrades made over the last year will provide additional reliability to the transmission system feeding southern California. Some of the larger improvements include the 500 kV Vincent-to-Mira Loma line, phase shifters installed in the Imperial Irrigation District footprint, synchronous condensers installed in the SCE and SDGE footprints, and series reactors installed by Pacific Gas and Electric (at their Midway substation).
- **Solar Capacity:** LADWP recently brought 144 MW of solar on line bringing their total to approximately 1 GW. They plan to bring an additional 106 MW on-line in Summer 2017.
- **Dual fuel capability:** In 2016, LADWP secured temporary variances that allow the burning of diesel fuel at three of its plants (totaling approximately 1.3 GW). These variances permit the burning of diesel fuel under specific conditions as a last resort (i.e., as a last step to prevent a rolling blackout).

During peak demand or system element contingencies, additional generation may be needed to meet electric reliability. If natural gas supply cannot accommodate additional generation, southern California entities may need

²⁴ [Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin](#)

²⁵ [Aliso Canyon Mitigation Measures May 19, 2017](#)

²⁶ [Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment](#)

²⁷ *Ibid.*

to rely on assistance from neighboring Balancing Authorities. This assumes ample supply outside southern California and adequate transmission capacity to move that power into the southern California system. A reduction of import capability will require more natural gas supply to meet the energy shortfall. If that natural gas is not available from other SoCalGas facilities, natural gas may have to be withdrawn from Aliso Canyon. A reduction in import capability or demand response in southern California coupled with a reduction of natural gas storage withdrawal or flowing natural gas supply may result in electric load shedding.

California’s Underground Natural Gas Storage Facility Current Status

The CPUC has ordered other SoCalGas underground natural gas facilities to upgrade the wells (particularly at Honor Rancho and La Goleta) and to store natural gas in preparation for the summer season.

The recent unavailability of Aliso Canyon has increased the coordination and communication between operating entities in both the electric and natural gas industries. The cooperation between electric entities is paramount to ensure the reliability of the Bulk Electric System. The coordination has also expanded beyond the impacted entities throughout the Western Interconnection.

The Aliso Canyon outage underscores the possibility that this outage may be more than an isolated incident. With the large increase in natural gas generation and the reliance on natural gas storage to meet those needs, natural gas storage is paramount to the reliability of the bulk power system

Appendix B: Natural Gas System Operations

Most areas in the United States and Canada are served by many different pipeline systems that are relied on to transport natural gas into and out of each area. The North American natural gas pipeline network is a highly integrated system with many connections that enable the transfer of natural gas between the different pipeline systems. In addition, there are numerous connections with natural gas utilities and natural-gas-fired power plants that receive natural gas. In many cases, multiple connections from multiple pipelines create both flexibility and reliability in natural gas deliveries. Further, underground natural gas storage is connected to the pipelines supporting reliable natural gas delivery. Market area natural gas storage makes it possible for firm peak month and peak day deliveries to be satisfied with a greater degree of certainty and reliability. Natural gas utilities further augment underground storage supplies with storage from above-ground facilities, most notably liquefied natural gas peak shaving, and propane-air facilities. In short, the natural gas infrastructure is extensive and diverse, making the system for serving firm loads very reliable. Nevertheless, contingencies that negatively impact natural gas service can and do occur. On rare occasions, these contingencies threaten firm service. More often, these contingencies may reduce the capacity available for interruptible service that many generators use that the pipeline has no contractual obligation to provide and only is available when firm shippers are not using their capacity.

Natural gas production, transmission, and distribution systems have inherent attributes that provide for a high degree of reliability and resilience. Unlike electricity, which travels near the speed of light and flows along a path of least resistance, natural gas moves by pressure. Natural gas moves through a transportation system with the use of compressors that reduce the volume and pressurize it, allowing the molecules to travel long distances. Compressors are placed at regular intervals to continue the forward movement. As a result, natural gas physically moves slowly through a pipeline at speeds up to 30 mph and its flow can be controlled. The slower speed of natural gas movement along a pipeline allows time for pipeline operators to control the flow of natural gas and to adjust their operations in the event of a disruption. As a result of these characteristics of natural gas and the natural gas transportation system, a failure at one point on the system typically has only a localized effect.²⁸ However, even a local effect can cause some disruption of power generation.

Another important characteristic of natural gas is its ability to be stored after production. Natural gas is most commonly stored underground in depleted aquifers and oil and natural gas fields as well as in salt caverns. Not all states have geology suited for natural gas storage in depleted aquifers or oil and natural gas wells. Increasingly some states are reluctant to use water aquifers for natural gas storage. Natural gas can also be stored above ground in storage tanks as liquefied natural gas for use at import and export facilities and at peak shaving plants or as compressed natural gas for industrial and commercial uses. Although storage is important as a supply cushion, it also provides important operational flexibility in the event of constraints in the pipeline and distribution network because storage facilities are widely dispersed on those networks. According to an April 2017 Interstate Natural Gas Association of America survey of 51 interstate pipelines, over the ten-year period (2006–2016), pipelines delivered 99.79 percent of firm delivery contractual commitments to their firm shippers. However, this is not a guarantee that contractual commitments to shippers prevent all single point disruptions. Further, until recently, the electric sector was not as reliant upon natural gas nor was the sector using as many variable energy resources that require frequent ramping of generation during the Electric Peak demand.

The wide geographic dispersion of production areas may reduce the vulnerability of the supply to localized weather events. Additionally, most natural gas production now occurs in onshore areas with offshore production making up only 5 percent of total natural gas production as compared to 20 percent in 2004.²⁹

²⁸ More detail about the physical, operational characteristics of the natural industry segments can be found in the Appendices to the 2011 Southwest Cold Weather Event report prepared by the staffs of FERC and NERC. Report on Outages and Curtailments During Southwest Cold Weather Event of February 1-5, 2011 (August 2011), Appendices 8-10 (“Southwest Cold Weather Report”).

²⁹ EIA – Natural Gas Monthly December 2007 and Natural Gas Monthly April 2017: https://www.eia.gov/naturalgas/monthly/pdf/table_07.pdf.

The natural gas transportation network is comprised of an extensive network of interconnected pipelines that offer multiple pathways for rerouting deliveries in the event of a physical disruption. In addition, pipeline capacity is often increased by installing two or more parallel pipelines in the same right-of-way (called pipeline loops), making it possible to shut off one loop for planned maintenance or minor disruption. This leaves parallel loops in service. In the event of one or more compressor failures, natural gas pipelines can usually continue to operate at pressures necessary to maintain deliveries to shippers (at least outside the affected segment). The use of line pack in the pipelines can be used if needed to provide operational flexibility as noted in the Southwest Cold Weather Report.³⁰

However, line pack is not a substitute for storage facilities for multiple baseload natural-gas-fired power plants in a region. As noted previously, because of the inherent characteristics of natural-gas and the interconnected pipeline system, operators can control and redirect the flow around an outage in one segment. The existence of geographically dispersed production and storage, and its location on different parts of the pipeline and distribution system, also provides flexibility for operators to maintain service in the event of a disruption on parts of the transportation and distribution system. These attributes have all positively contributed to the natural gas system's historic reliability and resilience.

State statutes and public utility regulations may allow a local distribution company (LDC) to curtail services to some customers in the event of extreme situations for reasons that include the need to maintain the operational integrity of the system and/or to maintain natural gas service to designated high priority customers, including "essential human need" customers. Historically, these regulatory requirements give the highest priority for the reliability of service to residential and commercial customers without short-term alternatives. As a result, a generator that relies on an LDC distribution system (particularly on an interruptible basis) as part of the generator's fuel supply chain needs to take into account these regulatory obligations of the LDC and, for example, plan for the use of alternate fuels, maintain on-site fuel storage (such as liquefied natural gas or compressed natural gas), or contract for a higher level of service from the LDC (such as firm transportation or emergency service).

³⁰ Southwest Cold Weather Report at 68-70.

Appendix C: Natural Gas Industry Regulatory Construct

Following FERC orders 436³¹ and 636,³² the natural gas industry has not been vertically integrated, and each distinct industry segment has been subject to a different regulatory construct. The industry consists of three general segments: 1) upstream natural gas production, gathering, and processing, 2) pipeline transportation and storage, and 3) local distribution.³³ Price regulation for natural gas sold by producers was removed in the Wellhead Decontrol Act of 1989, which was followed later by FERC's removal of all price regulation for the sale of natural gas in the wholesale market. Gathering and processing are also not subject to price regulation by the Federal Government. However, the price and terms and conditions of the interstate transportation and storage of natural gas continue to be regulated by FERC. Pure intrastate transportation and storage of natural gas is subject to state regulation and Public Utility Commissions. The local distribution of natural gas by local distribution companies (LDCs) is also subject to state regulation. All pipelines are subject to safety regulation by the U.S. Department of Transportation, Pipeline and Hazardous Safety Administration, or state agencies.

FERC's regulation of interstate transportation and storage is contract-based. The pipeline or storage companies' contract with its shipper customer, and how the shipper nominates service under that contract, determines the scheduling and curtailment priorities in the event of a pipeline restriction or *force majeure* event. FERC regulations preclude interstate pipelines from undue discrimination in providing service based on the classification of customers. This means that the identity of the customer, whether it is an LDC, electric generator, or a producer, cannot have any bearing on priority of service. In addition, the pipeline is required to honor all firm service contracts as long as there has been no *force majeure* event.³⁴

Pipelines schedule capacity based on nominations, and when necessary, restrict service based upon the type of service contracted. There are two main types of service that pipeline and storage operators provide: 1) firm service: whereby a shipper pays a monthly reservation charge to the pipeline, which entitles it to transport or store a certain quantity of natural gas daily assuming the shipper nominates the quantity and it delivers to the pipeline the equivalent amount of natural gas at the receipt points specified in the contract, and 2) interruptible service: which is a lower quality service provided by the pipeline when it has available capacity that is either not under firm contracts or not being used that day by firm transportation customers. Within firm service, many pipelines and storage facilities provide no notice service; no notice service allows for the highest level of firm service that a customer can contract. It allows for the reservation of pipeline capacity throughout the 24-hour natural gas day. This reservation of capacity allows for the electric utility or customer to nominate its firm service on a primary basis throughout the day offering the highest level of flexibility available on a pipeline.

Under the FERC regulations,³⁵ a firm service shipper is entitled to "segment" its capacity daily and utilize other delivery points within the path to its delivery point if capacity is available, which are called "secondary firm points." Once scheduled by the pipeline, the transportation capacity to secondary receipt and delivery points is as firm as primary firm. Primary firm service shippers receive the most reliable service because they have the highest priority when scheduling and are the last to be curtailed in *force majeure* situations. Secondary firm service shippers are next in priority for scheduling, but once scheduled, they are curtailed pro rata with other firm service. Interruptible shippers, if scheduled, can be bumped by higher priority firm shippers; interruptible shippers are also curtailed first before any firm shippers. Many environmental laws and regulations limit oil use for electric generation.

³¹ 1985 FERC Order No. 436 required that natural gas pipelines provide open access to transportation services, enabling consumers to negotiate prices directly with producers and contract separately for transportation

³² [FERC Order No. 636](#)

³³ A more detailed diagram of the natural gas industry segments appears at the end of these comments.

³⁴ FERC natural gas regulations define "service on a firm basis" as a service that is "not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm services." 18 C.F.R. § 284.7(a) (3).

³⁵ 18 C.F.R. § 284.7(d).

LDCs are regulated by most states as utilities with an obligation to serve their firm core retail customers. As a result, LDC systems are built to serve their firm core customer base to ensure reliable service to these firm customers and others on a “design day” (or a forecasted peak day load based on historical weather conditions). Natural gas utilities may offer an interruptible “bundled” sales service (which includes commodity supply and the transportation of the supply on the local distribution system) and/or a stand-alone interruptible transportation service for the transportation of customer-owned natural gas on the local distribution system. The LDC systems are sized to serve core customer needs, and as a result the LDC may not be able to maintain interruptible transportation service at all times. During periods of high usage and system constraints, prevalent on the coldest winter days, LDCs may call on interruptible customers to cease natural gas usage temporarily, upon which these customers generally switch to a back-up fuel, such as fuel oil.³⁶

The National Energy Board regulates pipelines in Canada, including the TransCanada pipeline, which transports natural gas through Alberta, Saskatchewan, Manitoba, Ontario, and Quebec. The regulatory construct in Canada is similar to that of the United States in which firm transportation carries the highest priority. Natural gas-electric coordination, particularly information sharing between the natural gas generators and natural gas pipeline companies, is also an issue of significant importance in Canada. The Ontario Independent Electricity System Operator (IESO) has supported a broader review of FERC Order 787 to determine if IESO can benefit from similar coordination efforts.³⁷

Although not to the same level as many areas in the United States, Canada relies significantly on natural gas in order to meet peak electric demand requirements. SaskPower, for example, sources 42 percent of its peak generation from natural-gas-fired generation. Conversely, Quebec, partly due to its abundance of hydro assets, has no natural-gas-fired electric generation. Canada, similar to the United States, also relies on underground natural gas storage facilities to meet deliverability requirements of natural gas for electric generation. Presently, Canada has approximately 10 underground natural gas storage facilities with working capacity of 440 bcf and deliverability of 7 bcf per day.³⁸

³⁶ The tradeoff for these customers is a discounted rate for the interruptible natural gas delivery service, compared with firm service rates, and the customers enter into these interruptible contractual arrangements with that prior knowledge.

³⁷ <http://www.ieso.ca/sector-participants/engagement-initiatives/engagements/completed/gas-electric-coordination-enhancements>

³⁸ INGAA

Appendix D: FERC Natural Gas-Electric Coordination

Recognizing the increased use of natural gas to generate electricity, FERC has encouraged natural gas-electric coordination.

Stemming from the Southwest outage in February 2011, FERC hosted a series of regional technical workshops and solicitation of written comments to collect input from every sector nationally and in each Region, relevant to electric reliability as show below:

- Electric utilities
- Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)
- Industrial consumers
- State regulators
- Natural gas pipelines, marketers, suppliers, and natural gas distribution companies
- The North American Energy Standards Board (NAESB)

Starting from this and other input, FERC initiated natural gas scheduling rulemakings in order to better synchronize operations between the natural gas and electric industries. FERC followed with various individual actions among the regulated ISO/RTOs. The natural gas rulemakings resulted in Order Nos. 787³⁹ and 809.⁴⁰

Order Nos. 787 and 809 are described in more detail below:

- Order No. 787 (Communication between power generators and natural gas pipelines):
 - The final rule allows interstate natural gas pipelines and electric transmission operators to share nonpublic operational information to promote reliability and integrity of their systems (ensures robust communications).
- Order No. 809 (Pipeline Scheduling Time Line):
 - The final rule addresses the differences between nationally standardized natural gas pipeline scheduling and regional electric dispatch time lines. The order adopted two proposals submitted by NAESB (after FERC directed work to find consensus) to revise the interstate natural gas nomination time line and make conforming changes to the NAESB standards in FERC's regulations.
 - The revised regulations modify the scheduling practices used by interstate pipelines to schedule natural gas transportation service and provide additional contracting flexibility to firm natural gas transportation customers that use multi-party transportation contracts.
 - Effective April 2016, the order shortened the gap between the deadlines for nominations and the start of natural gas flow from those nominations and added a new intraday nomination cycle, all to allow shippers including electric generators to better match their nominations to the dispatch decisions of power markets and to the trading cycles of commodity natural gas markets.
 - FERC had initially proposed to move the start of the "Gas Day" from 9:00 a.m. Cocos Islands Time to 4:00 a.m. Cocos Islands Time to better match the morning ramp-up of generation load.

³⁹ FERC Order No. 787, Communication of Operational Information between Natural Gas Pipelines and Transmission Operators, (Docket No. RM13-17-000, November 15, 2013)

⁴⁰ FERC Order No. 809, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (Docket No. RM14-2, April 16, 2015)

However, in Order No. 809, FERC decided not to require a change to the start time of the Gas Day, finding that *“there is limited evidence to support the premise in the NOPR that the current start of the Gas Day results in natural-gas-fired generators de-rating during the morning ramp due to exhausting nominated natural gas transportation.”* *“In addition, evidence in the record provided through the ISO and RTO data responses did not provide sufficient support for changing the nationwide Gas Day.”*⁴¹

Several observations arose out of the FERC proceeding: ISO-NE and several other grid operators provided data that they believe supported a change in the start of Gas Day. ISO-NE stated that during 2013 and 2014, there were 173 reported natural-gas-fired generator de-rates due to fuel limitations and 67 of those were logged between 3:00 a.m. and 9:00 a.m. Cocos Islands Time. The morning de-rates affected 49 days. In 2013 and 2014, there were 20 natural-gas-fired generator de-rates due to fuel limitations, over 14 days, that had an identified ending time that coincided with the start of the next Gas Day at 9:00 a.m. Cocos Islands Time. While ISO-NE stated that it was not certain the de-rates occurred solely due to the exhaustion of natural gas pipeline nominations given the 9:00 a.m. Cocos Islands Time end time, this is likely the cause. The proceeding highlighted the regional differences and complexities between the natural gas and electric markets and the operational characteristics of both systems and the need for improved GADS reporting so that RTOs have improved information for the causes of de-rates in the future.⁴²

The electric markets in the East were stressed during each of the cold weather events in 2014. During these events, electric demand was at historic levels due to the extremely cold weather. New winter peaks were set in MISO, PJM, NYISO, and SPP. During the cold weather events later in January, regional demand in the eastern Regions was high but not at the levels set in early January.⁴³ However, the latter periods did experience stresses primarily because of higher natural gas prices as a result of historic demand levels, fuel delivery disruptions, and generator outages.⁴⁴ Despite the unprecedented performance levels required, the natural gas industry was able to honor all firm fuel supply and transportation contracts.⁴⁵

As part of FERC’s ongoing efforts, the Commission asked NAESB in an order on rehearing of Order No. 809 to explore the potential for faster computerized scheduling to provide shippers with more opportunities to reschedule natural gas. NAESB reconvened its natural gas-electric harmonization task force to conduct industry-wide fact-finding. After those discussions concluded, NAESB reported to FERC that no recommendations achieved consensus on standards.⁴⁶ During the NAESB deliberation, the importance of pipeline service menus was discussed, but participants recognized that service development has occurred and continues to occur naturally in the marketplace and that it is not within NAESB’s scope to recommend such service policy changes to FERC.⁴⁷

Order Nos. 787 and 809 provided a forum for dialogue and proposed regulatory changes to increase natural gas and electric coordination, including a more compatible scheduling paradigm. The industries continue to have

⁴¹ Paragraphs 63 and 64 of Order No. 809.

⁴² While these data do not show specifically whether the generators exceeded their firm natural gas transportation schedule for the day, ISO-NE states that the data suggests that the de-rates likely resulted from the exhaustion of natural gas transportation service, because the generators could come back on line at the start of the new Gas Day. Docket No. RM14-2-000

⁴³ See <http://www.ngsa.org/winter-2013-14-market-conditions-frequently-asked-questions/#jumpone>.

⁴⁴ See FERC Staff Presentation “Recent Weather Impacts on the Bulk Power System” January 16, 2014, <http://www.ferc.gov/CalendarFiles/20140116102908-A-4-Presentation.pdf>.

⁴⁵ See <https://www.ferc.gov/media/news-releases/2014/2014-4/10-16-14-A-4-presentation.pdf> and “During each of these cold events, customers who had firm transportation capacity on natural gas pipelines generally managed to secure natural gas deliveries.” Also see <https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf> at Slide 4.

⁴⁶ The July 29, 2016 NAESB Status Report for Submittal to the Commission Concerning FERC Order No. 809 is available at the following link: https://www.naesb.org/pdf4/ferc072916_naesb_order809_status_report.pdf.

⁴⁷ Letter to NAESB in FERC Docket No. RM14-2-000.

discussions in various forums as needed regarding areas where further communication and coordination may be useful.

Appendix E: Assessment of Existing Studies

Step I

This appendix ([Step I](#) of NERC’s study approach) provides an overview of existing studies conducted by industry. The purpose of this is to gain an understanding of existing planning approaches as well as to highlight and promote best practices.

NERC Survey Response Summary

In an effort to understand electric industry efforts in planning to prepare for events similar to the Aliso Canyon outage, NERC conducted a survey of Planning Coordinators in North America. The survey questions were focused on assessments, analysis, and studies conducted within the last five years on evaluating the loss of large natural gas facilities (e.g., storage facilities, key pipeline segments, liquefied natural gas terminals). In addition, the survey also included questions on specific procedures and guidelines to ensure adequate back-up fuel supplies, firm or interruptible natural gas supply and transportation to generating facilities as well as transmission deliverability considerations if assessments resulted in resource shortfalls within the Planning Coordinator area. The goal of the survey was to determine what, if any, natural gas dependent analysis industry planners were performing and to review the methods and assumptions used for supporting studies. The purpose of this section is to provide a high-level summary of the responses to that survey and provide some key takeaways for consideration by the industry. [Figure E.1](#) provides a breakdown of responses received from Planning Coordinators and Balancing Authorities. This figure demonstrates a significant number of cases where no existing studies or analysis have been performed.

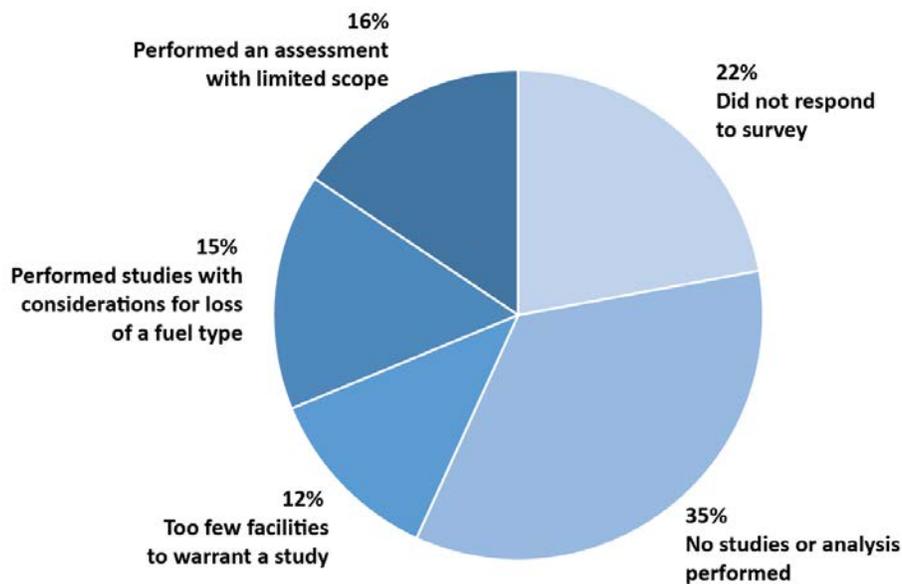


Figure E.1: Planning Coordinator and Balancing Authority Survey

The scope, frequency (i.e., seasonal, per annum, or every 3–5 years), and framework of assessments and studies conducted varies by entity. Most respondents refer to TPL-001-4⁴⁸ extreme event category detailed requirements R3 and R4, which evaluate simulations with removal of elements based upon operating experiences that may result in wide-area disturbances or loss of two generating stations resulting from conditions, such as loss of a large natural gas pipeline. The NERC Reliability Standard also require an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) if the analysis concludes there is cascading caused by the occurrence of extreme events.

⁴⁸ [Standard TPL-001-4 — Transmission System Planning Performance Requirements](#)

Few entities have developed their own assumptions and criteria or participated in a joint effort with neighboring entities where transmission constraints were often a secondary concern in favor of focusing more on issues of resource adequacy. Less than 10 percent of respondents were aware of or anticipated impacts to reliability should their primary source for natural gas be unavailable. Mitigation plans included the following: 1) the reliance on backup fuel for generating resources with dual fuel capability, allowing them to continue to supply electric power to their customers without interruption of service; 2) reliance on importing power from neighboring utilities; and 3) the increase in generation from other types of fuel (e.g., nuclear, hydro, coal).

Summary of Existing Assessments

A summary of existing analyses and results are detailed below. These reports were reviewed for insights into how those studies were conducted and their respective methods and assumptions.

Argonne National Laboratory Pipeline Disruption Analysis

The United States Department of Energy commissioned Argonne National Laboratory to analyze the potential impacts of an abrupt and protracted loss of natural gas deliverability due to some disabling event at each of the Nation's interstate natural gas pipelines. The method ANL used in this analysis required the estimation of the consequences of such a disruption. "Disruption" was defined as the total loss of deliverability at specific locations along the interstate natural gas pipeline for a period of at least a one-month duration, at the time of peak natural gas demand. The consequence analysis was performed using the Argonne-developed *NGfast* tool, which is a natural gas pipeline network model that enables the rapid assessment of impacts from disruptions and flow reductions in the nation's natural gas transmission pipeline network. Impacts were measured in terms of the extent of natural gas volume disrupted, states affected, local distribution companies (LDCs) affected, number and type of customers affected, and amount of natural gas-based power generation capacity affected.⁴⁹ All of the monthly data for the years 2014 and 2015 incorporated in *NGfast* were obtained from publicly accessible sources.

Potential Impacts of Interstate Natural Gas Pipeline Disruptions

The consequence of an interstate natural gas pipeline failure is expressed in terms of the number of customers affected per sector and the amount of natural gas flow lost. For the purposes of this study, customers in the electric sector are of particular interest because of the interdependency that exists between the electric and natural gas systems; the principal impacts in the electric sector are expressed in terms of megawatts potentially interrupted due to the lack of natural gas supply.

The analysis indicates that the largest potential impact from the loss of the natural gas supply from interstate natural gas pipeline would be on natural-gas-fired power plants. The impact on downstream residential and commercial customers was estimated to be minimal.

Potential Electric Sector Impacts

It was assumed that an unexpected loss of generation capacity would not affect electric reliability unless the loss is relatively large (2 GW or more).⁵⁰ The analysis of the interstate natural gas pipeline network was performed using *NGfast* under the following two sets of conditions:

- **A Worst-Case Scenario:** Assumes that mitigation measures are not available and that the only way to balance supply and demand after a disruption is to shed load. This scenario can be considered highly unlikely as the natural gas sector would apply a range of mitigation measures as available. Mitigation

⁴⁹ Edgar C. Portante, Brian A. Craig, Stephen M. Folga, "NGfast: A Simulation Model for Rapid Assessment of Impacts of Natural Gas Pipeline Breaks and Flow Reductions at U.S. State Borders and Import Points," *IEEE.org* 1118-26 (S.G. Henderson, B. Biller, M.-H. Hsieh, J. Shortle, J.D. Tew, and R.R. Barton, eds. 2007), <http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=4419711> (presented at the 2007 Winter Simulation Conference).

⁵⁰ DOE, 2016. *Ensuring Safe and Reliable Underground Natural Gas Storage*, available at <https://www.energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Report.pdf>, accessed July 13, 2017.

measures typically include additional withdrawals from in-state underground storage, liquefied natural gas facilities, and production fields as well as compensating flows from interconnected pipelines.

- **A Reasonable Best-Case Scenario:** Assumes mitigating measures, such as those suggested above, would be implemented to balance supply and demand after a disruption. This case also considers the abilities of LDCs that are interconnected to multiple pipelines to use their own pipelines and storage to provide alternate service to generators. However, this scenario does not take into account whether the mitigating actions would be cost-effective.

The results for the Worst-Case and Reasonable Best-Case scenarios are shown in **Figures E.2** and **E.3**, respectively. The two figures highlight the interstate natural gas pipelines which, if disrupted, would lead to potential electric sector impacts. The figures also show the states affected and the amount of natural-gas-fired power generation capacity potentially impacted, together with the quantity of the affected electric generating capacity that has co-fuel or dual fuel capability (i.e., the ability to switch from natural gas to another fuel such as distillate fuel oil, if needed).

The majority of the potentially affected electric generating capacity has co-fuel backup capability. As expected, the results for the Worst-Case scenario are greater than those of the Reasonable Best-Case scenario. Assuming the industry can deploy all mitigation measures as discussed above, the potentially affected capacity in states in the Northeast, Northwest, and Oklahoma identified in the Worst-Case scenario are reduced in the Reasonable Best-Case scenario, below the 2GW threshold.

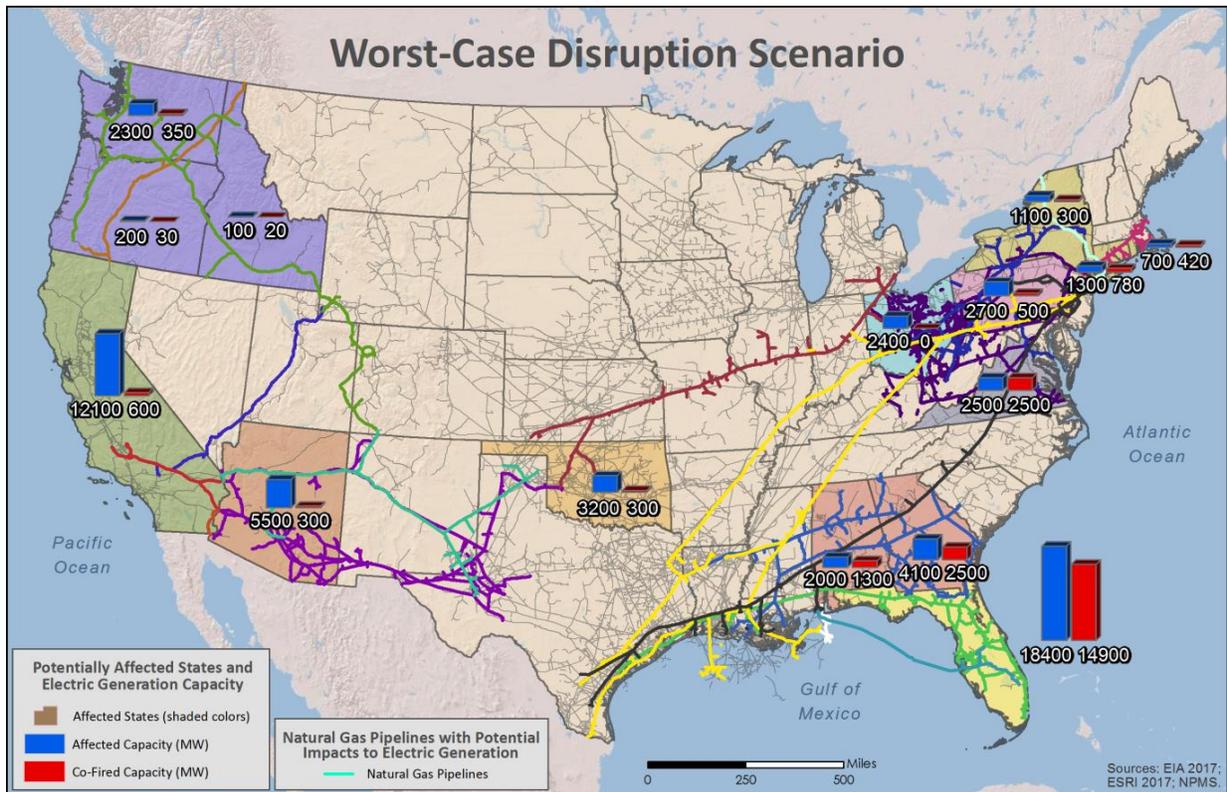


Figure E.2: Summary of NGfast Simulation Results for the Worst-Case Scenario

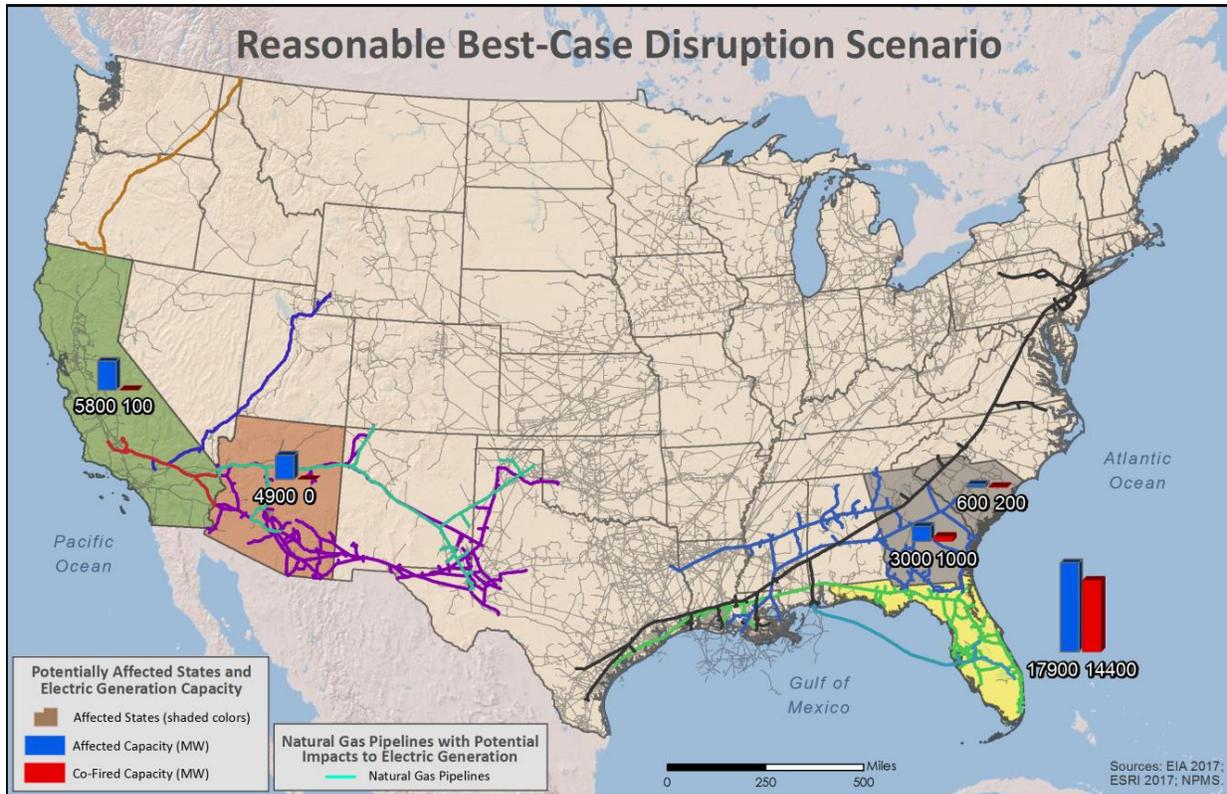


Figure E.3: Summary of NGfast Simulation Results for the Reasonable Best-Case Scenario

EIPC Natural Gas-Electric System Interface Study Summary

The Eastern Interconnection Planning Collaborative Gas-Electric System Interface Study⁵¹ was conducted in 2013 and 2014 with the cooperation of six stakeholders: IESO, ISO New England, MISO, NYISO, PJM, and TVA. The study includes four “Targets.” They are as follows:

- **Target 1:**⁵² Develop a baseline assessment that includes descriptions of the natural gas-electric system interfaces and how pipeline, storage, and LDC infrastructure impact each other.
- **Target 2:**⁵³ Identify the specific drivers of the pipeline/LDC planning processes affecting the availability and operational risks borne by natural-gas-fired generators across the study region.
- **Target 3:**⁵⁴ Evaluate the current level of operational planning interaction between the bulk electric generation and natural gas supply systems.
- **Target 4:**⁵⁵ Assess regulatory, commercial, and operational attributes of the natural gas/electric interfaces affecting the performance of natural-gas-fired generation.

Targets 1 and 2 focused on data-gathering pertaining to the operation and capabilities of the natural gas infrastructure in the Region under study for residential, commercial, and industrial customers. This information was then used to achieve the goal of Target 3, which considered the theoretical loss of an important natural gas pipeline, an important compressor station, or a major liquefied natural gas supply source during a winter and

⁵¹ [EIPC - Gas-Electric Documents](#)

⁵² [Gas-Electric System Interface Study - Existing Natural Gas-Electric System Interfaces](#)

⁵³ [Gas-Electric System Interface Study - Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the electric Systems](#)

⁵⁴ [Gas-Electric System Interface Study - Natural Gas and Electric System Contingency Analysis](#)

⁵⁵ [Gas-Electric System Interface Study - Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives](#)

summer peak day in 2018 and 2023. The study allowed dual fuel units to dispatch on their secondary fuel and considered the time necessary to re-dispatch unaffected units. However, *“specific analysis of overall reliability of the electric grid within the Study Region was outside the scope of the Target 3 inquiry.”* Of the six study participants, two indicated in their survey response that the results of the EIPC study suggested there are potential reliability impacts for the pipeline contingencies considered. The study indicates that the biggest risk is during the winter for generators who do not have firm natural gas delivery when more natural gas is being utilized by residential customers during these periods.

Columbia Grid Reports (Northwest/Northern California Area)

The Columbia Grid Reports⁵⁶ completed in 2012⁵⁷ and 2013⁵⁸ investigated *“whether large scale limitations in the availability of natural gas to area generation could lead to transmission reliability issues during peak winter loads.”* Traditional planning studies assume that the natural gas supply to natural-gas-fired plants is available when needed and is unlimited. The Gas-Electric Interdependencies Study Team was formed to investigate whether this assumption on natural gas availability is appropriate. In addition, if there are situations where the natural gas system may be limited in its ability to deliver natural gas to the power plants, the study team assessed whether these limitations could lead to electric system reliability issues. The focus of the study was to determine whether transmission system changes, or other actions, should be investigated to help protect against limitations in the availability of natural gas to generation in a specified transmission corridor. The study relied upon imports while considering known import limitations. Units with dual fuel capability were allowed to replace the lost natural gas generation but were assumed to have no supply limitations during the period under study. Voltage stability, steady-state voltage, and thermal loading were monitored during the simulations and no performance issues were observed; however, contingency mitigation efforts on overloaded branches and more sensitivity scenarios on the most limiting contingencies were recommended for future assessments.

ERCOT Natural Gas Curtailment Risk Study

The Electric Reliability Council of Texas (ERCOT) study⁵⁹ was completed in 2012 and presents the risk of natural gas supply curtailment to electric generators for a 1-year, 5-year, and 10-year time horizon. The study used historical data to implement a probabilistic approach in determining the risks associated with freezing weather, pipeline disruptions, and tropical cyclones as they pertained to the reliability of the natural gas infrastructure in the Region. At least 60 percent of ERCOT’s electric generators indicated “interconnects” with more than one pipeline, and the study concluded that this redundancy could help to mitigate the risks associated with a pipeline disruption. The scope of the study did not extend to an analysis of the reliability of the electric transmission network in ERCOT’s territory.

Aliso Canyon Risk Assessment Technical Reports

The Aliso Canyon Risk Assessment Technical Reports released in April of 2016⁶⁰ and May of 2017⁶¹ were conducted for 2016 summer and 2016/2017 winter seasons and assessed the risks to energy reliability in the Greater Los Angeles and Southern California area without the use of the Aliso Canyon natural gas storage facility. Generating facilities served by Aliso Canyon represent more than half of the local capacity resources in the CAISO and LADWP areas. The assessments determined the minimum level of local generation needed to maintain grid reliability. In the event of a natural gas shortage, imports could be used to meet demand in the area. However, neighboring utilities may not have generation to export as they may be experiencing the same high loading conditions during peak hours, and the import capability may also be limited by the lack of remaining capacity in the tie lines. The analysis considered N-1 transmission contingencies and found that resource adequacy and

⁵⁶ [Gas-Electric Interdependencies Study Team Overview](#)

⁵⁷ [Gas-Electric Interdependencies Status Report](#)

⁵⁸ [Gas-Electric IS Gas Curtailment Study](#)

⁵⁹ [The Electric Reliability Council of Texas – Gas Curtailment Risk Study](#)

⁶⁰ [Aliso Canyon Risk Assessment Technical Report](#)

⁶¹ [Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment](#)

electric system stability issues could result in a supply interruption to load. **Figure E.4** shows the geographic area impacted by Aliso Canyon.

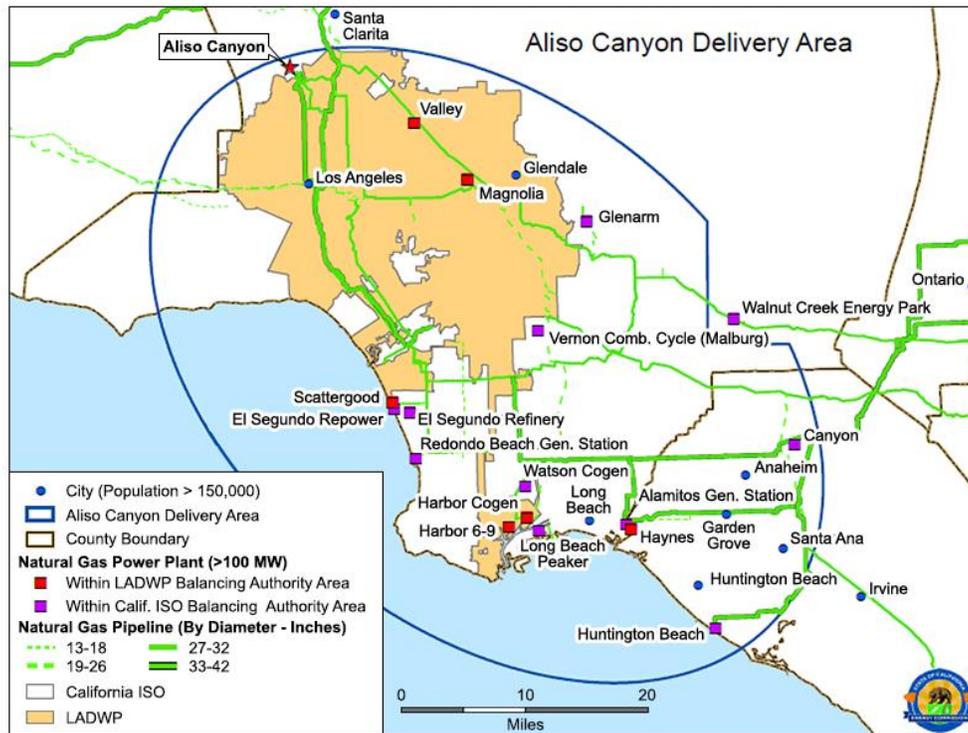


Figure E.4: Electric Generation Plants Impacted by Aliso Canyon

Southern Company Natural Gas Dependency and Potential Disruption Analysis

Southern Company's assessment analyzed the potential impacts to the Southern Balancing Authority Area Generation and Transmission System for a hypothetical pipeline failure event between two major supply source pipelines and the generating plants fed from the pipelines. Southern Company's assessment sought to identify potential system impacts due to operating procedures, fuel storage practices, and other mitigation actions Southern Company has established in the event a single pipeline failure were to occur.

This hypothetical pipeline failure event was modeled in a three-stage approach in which Southern Company assesses the transmission system in the following three periods: 1) prior to the pipeline failure event, 2) hours after the pipeline failure has occurred, and 3) days following the pipeline failure until the pipeline is returned to normal service. Southern Company made several assumptions about resource availability at each stage. Transmission constraints were identified based on a single contingency condition at each stage. Southern Company's assessment will be performed at both Summer Peak and Winter Peak load levels for the upcoming peak season. Primarily due to its backup fuel capabilities, Southern Company can maintain reliability on the transmission system for a pipeline disruption event. Southern Company's assessment demonstrates its own steps to prevent an operational problems. However, some power sector companies do not have all of the visibility and controllability into supply, transportation, generation and distribution as Southern Company or other vertically oriented companies do.

Key Takeaways

The results of the survey conducted by NERC identified several key findings that may be useful as the electric and natural gas industries identify ways to assess the impacts of potential extreme disruptions. The following are some key takeaways from the survey:

- The importance of an assessment of interdependence varies by company and Region due to individual resource mix, topology, and the availability of dual fuel generation capacity.
- Several companies are already either conducting studies or developing processes that will lead to studies to assess natural gas infrastructure disruptions.
- The identification of wide-area transmission impacts (i.e., voltage and thermal constraints) due to loss of a large natural gas underground facility or a segment of a pipeline are typically not studied; the majority of the focus is put on resource adequacy and resource availability. Transmission reliability and contingency analysis in the event of loss of a major pipeline/storage facility is paramount in developing mitigation plans and emergency operational procedures.
- Many respondents indicated that there were no natural gas storage facilities within their systems to evaluate. However, the loss of a large natural gas facility can impact electric generation downstream and beyond the boundaries of a Planning Coordinator. Determining whether natural gas system outages could create a regional or local electric reliability risk will warrant a coordinated and detailed analysis among neighboring Planning Coordinators.
- Electric Registered Entities, in coordination and collaboration with their neighbors and natural gas sector, should determine which power plants would be affected in the event of a disrupted natural gas facility. Alternative fuel capability, mitigation plans, emergency operating procedures, evolving ramping capability requirements to manage VERs, and the wide-area reliability impacts to the BPS should be further studied.

Recommendations

Comprehensive studies by Planning Coordinators that assess specific disruptions to critical natural gas facilities should identify and characterize adverse impacts to electric reliability. These disruptions are typically beyond the “design basis” of the power system required by NERC Reliability Standards as well as any regional or local planning requirements; because of this, these reliability risks are generally not incorporated into the planning requirements. In many cases, the resulting reliability impacts are due to a lack of capacity on existing infrastructure. As the BPS relies more heavily on natural gas generation, policy makers and regulators need to be aware of these risks—how likely they are as well as the potential impact. While many pipeline-related infrastructure impacts can be rectified within a week or two, natural gas storage facilities, as observed with Aliso Canyon, can be out for significant periods of time.

The recommended approach for Planning Coordinators can be broken down in the following four general steps:

1. Identify potential natural gas system contingencies and their frequency of occurrence.
2. Assess the impacts for each of the identified contingencies in terms of duration and amount of natural gas supply disrupted.
3. Apply the contingency disruptions to the natural gas supply capabilities to calculate the impact on total natural gas supplies and, more specifically, the amount of natural gas available to electric generators.
4. Determine the transmission systems ability to transport power to load under these extreme conditions.

With this information, policy makers, regulators, and industry can effectively identify and determine solutions that help support reliability depending on their individual risk tolerances.

Exhibit E



U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017

Ran Fu, David Feldman, Robert Margolis,
Mike Woodhouse, and Kristen Ardani
National Renewable Energy Laboratory

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List of Acronyms

AC	alternating current
BOS	balance of system
DC	direct current
EPC	engineering, procurement, and construction
FICA	Federal Insurance Contributions Act
GW	gigawatt
ILR	inverter loading ratio
ITC	investment tax credit
LCOE	levelized cost of energy
MACRS	Modified Accelerated Cost Recovery System
MLPE	module-level power electronics
NEC	National Electric Code
NEM	net energy metering
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PERC	passivated emitter and rear cells
PII	permitting, inspection, and interconnection
PV	photovoltaic(s)
Q	quarter
R&D	research and development
SAM	System Advisor Model
SG&A	sales, general, and administrative
TPO	third party ownership
USD	U.S. dollars
Vdc	volts direct current
Wac	watts alternating current
Wdc	watts direct current

Executive Summary

This report benchmarks U.S. solar photovoltaic (PV) system installed costs as of the first quarter of 2017 (Q1 2017). We use a bottom-up methodology, accounting for all system and project-development costs incurred during the installation to model the costs for residential, commercial, and utility-scale systems. In general, we attempt to model the typical installation techniques and business operations from an installed-cost perspective. Costs are represented from the perspective of the developer/installer; thus, all hardware costs represent the price at which components are purchased by the developer/installer, not accounting for preexisting supply agreements or other contracts. Importantly, the benchmark also represents the sales price paid to the installer; therefore, it includes profit in the cost of the hardware,¹ along with the profit the installer/developer receives, as a separate cost category. However, it does not include any additional net profit, such as a developer fee or price gross-up, which is common in the marketplace. We adopt this approach owing to the wide variation in developer profits in all three sectors, where project pricing is highly dependent on region and project specifics such as local retail electricity rate structures, local rebate and incentive structures, competitive environment, and overall project or deal structures. Finally, our benchmarks are national averages weighted by state installed capacities. Table ES-1 summarizes the first order benchmark assumptions.

Table ES-1. Benchmark Assumptions

Unit	Description
Values	2017 U.S. dollars (USD)
System Sizes	In direct current (DC) terms; inverter prices are converted by DC-to-alternating current (AC) ratios.

PV Sector	Description	Size Range
Residential	Residential rooftop systems	3–10 kW
Commercial	Commercial rooftop systems, ballasted racking	10 kW–2 MW
Utility-Scale	Ground-mounted systems, fixed-tilt and one-axis tracker	>2 MW

Based on our bottom-up modeling, the Q1 2017 PV cost benchmarks are:

- \$2.80 per watt DC (Wdc) (or \$3.22 per watt AC [Wac]) for residential systems
- \$1.85/Wdc (or \$2.13/Wac) for commercial systems
- \$1.03/Wdc (or \$1.34/Wac) for fixed-tilt utility-scale systems
- \$1.11/Wdc (or \$1.44/Wac) for one-axis-tracking utility-scale systems.²

¹ Profit is one of the differentiators between “cost” (aggregated expenses incurred by a developer/installer to build a system) and “price” (what the end user pays for a system).

² This year, we use the same DC-to-AC ratio (1.3) for both fixed-tilt and one-axis-tracking utility-scale PV systems (see Section 2.5).

Overall, modeled PV installed costs declined, year over year, in Q1 2017 for all three sectors, as they have done each year since we began modeling PV system costs.

Figure ES-1 puts our Q1 2017 benchmark results in context with the results of previous NREL benchmarking analyses. When comparing the results across this period, it is important to note the following:

1. Values are inflation adjusted using the Consumer Price Index. Thus, historical values from our models are adjusted and presented as real USD instead of nominal USD.
2. Cost categories are aggregated for comparison purposes. “Soft Costs – Others” represents permitting, inspection, and interconnection (PII); land acquisition; sales tax; and engineering, procurement, and construction (EPC)/developer overhead and net profit.
3. The “Utility-Scale PV, One-Axis Tracker (100 MW)” consists of our previous bottom-up results (2010 and 2013–2016) and interpolation estimates for 2009 and 2011–2012.
4. A comparison of Q1 2016 and Q1 2017 is presented in Table ES-2.

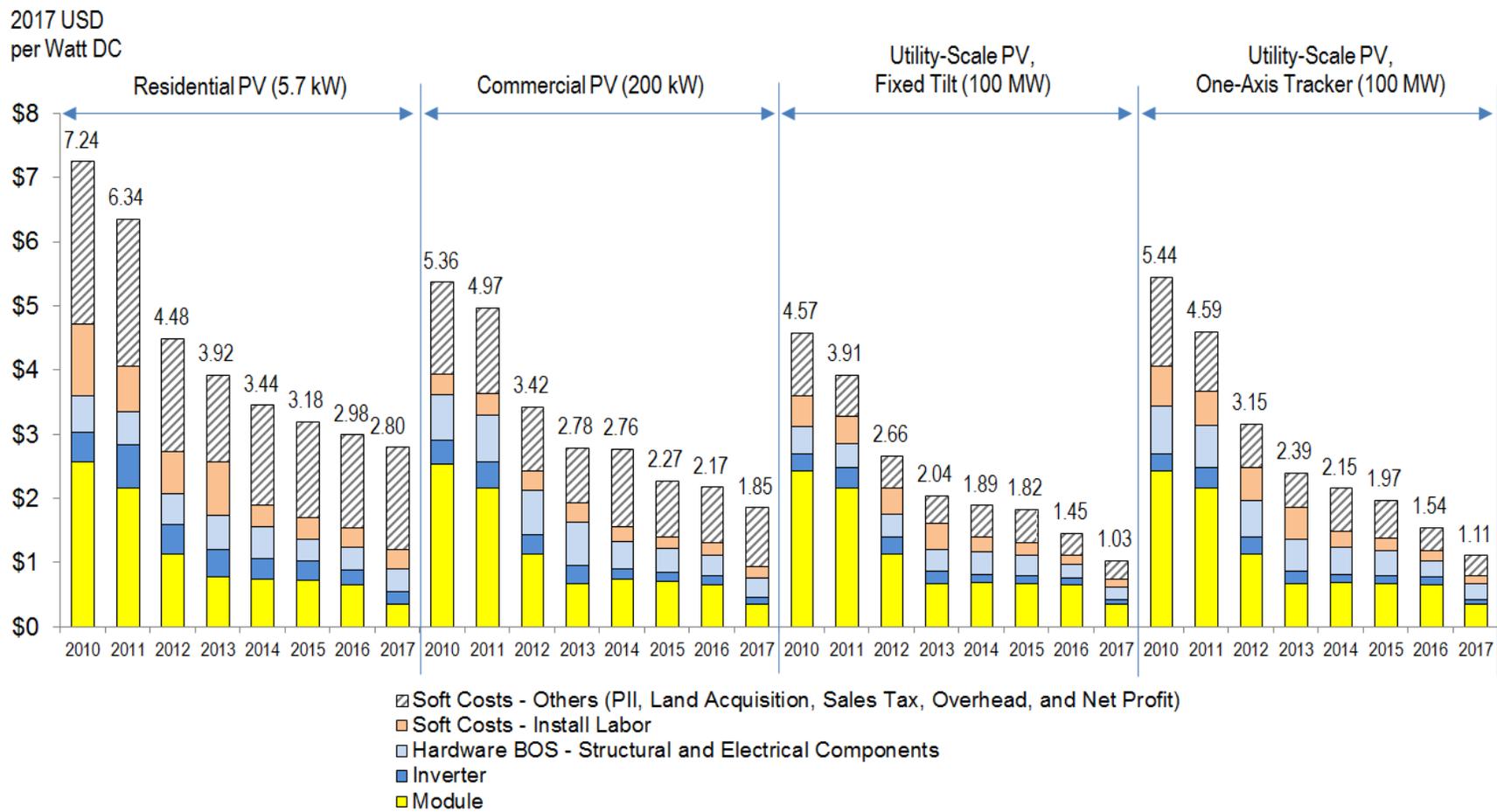


Figure ES-1. NREL PV system cost benchmark summary (inflation adjusted), 2010–2017

The inflation-adjusted system cost differences between Q1 2016 and Q1 2017 are \$0.18/Wdc (residential), \$0.32/Wdc (commercial), and \$0.42/Wdc (fixed-tilt utility-scale). Table ES-2 shows the benchmarked values for all three sectors and drivers of cost decrease and increase.

Table ES-2. Comparison of Q1 2016 and Q1 2017 PV System Cost Benchmarks

Sector	Residential PV	Commercial PV	Utility-Scale PV, Fixed-Tilt
Q1 2016 Benchmarks in 2016 USD/Wdc	\$2.93	\$2.13	\$1.42
Q1 2016 Benchmarks in 2017 USD/Wdc	\$2.98	\$2.17	\$1.45
Q1 2017 Benchmarks in 2017 USD/Wdc	\$2.80	\$1.85	\$1.03
Drivers of Cost Decrease	<ul style="list-style-type: none"> • Lower module price • Lower inverter price • Higher module efficiency • Lower electrical BOS commodity price • Higher small installer market share • Lower sales & marketing costs • Lower overhead (general & administrative) 	<ul style="list-style-type: none"> • Lower module price • Lower inverter price • Higher module efficiency • Smaller developer team 	<ul style="list-style-type: none"> • Lower module price • Lower inverter price • Higher module efficiency
Drivers of Cost Increase	<ul style="list-style-type: none"> • Higher labor wages • Higher advanced inverter adoption • More BOS components for rapid shutdown • Higher supply-chain costs 	<ul style="list-style-type: none"> • Higher labor wages • Higher PII costs • Higher net profit to EPC/developer 	<ul style="list-style-type: none"> • Higher labor wages • Higher net profit to EPC/developer

As Figure ES-1 shows, hardware costs—and module prices in particular—declined substantially in Q1 2017 owing to an imbalance in global module supply and demand. This has increased the importance of non-hardware, or “soft,” costs.³ Figure ES-2 shows the growing contribution from soft costs.⁴ Soft costs and hardware costs also interact with each other. For instance, module efficiency improvements have reduced the number of modules required to construct a system of a given size, thus reducing hardware costs. This trend has also reduced soft costs from direct labor and related installation overhead.

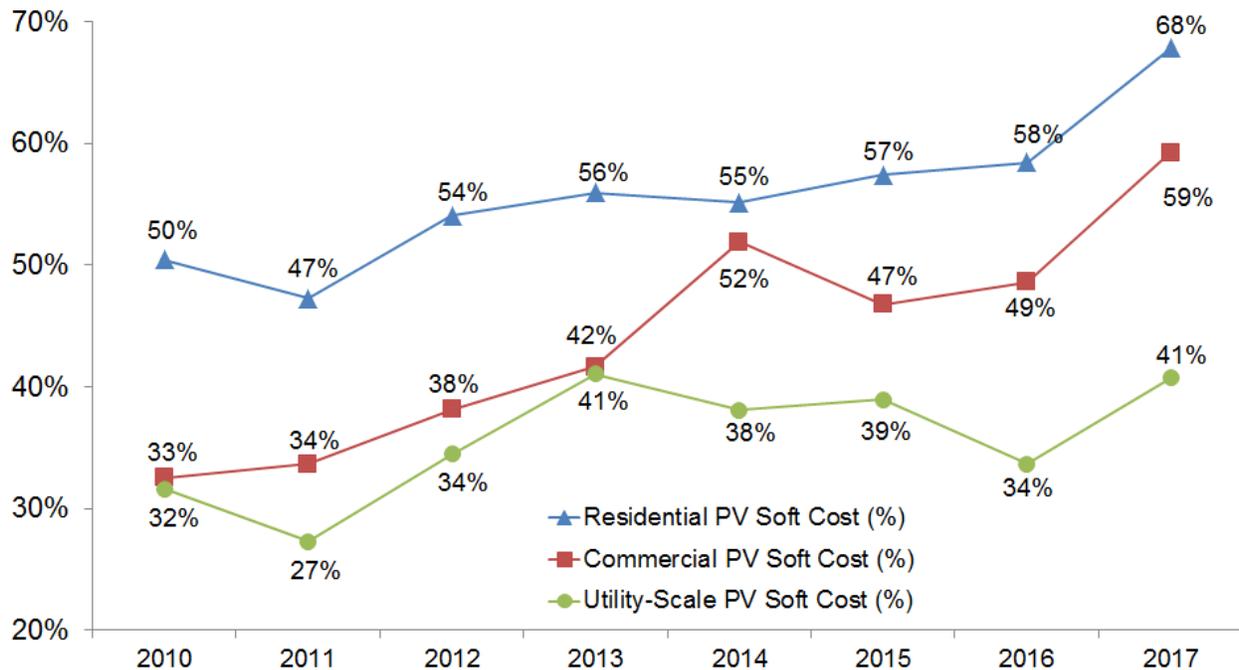


Figure ES-2. Modeled trend of soft cost as a proportion of total cost by sector, 2010–2017

Also, our bottom-up system cost models enable us to investigate regional variations, system configurations (such as MLPE vs. non-MLPE, fixed-tilt vs. one-axis tracker, and small vs. large system size), and business structures (such as installer vs. integrator, and EPC vs. developer). Different scenarios result in different costs, so consistent comparisons can only be made when cost scenarios are aligned.

Finally, the reductions in installed cost, along with improvements in operation, system design, and technology have resulted in significant reduction in the cost of electricity, as shown in Figure ES-3. U.S. residential and commercial PV systems are 86% and 89% toward achieving SunShot’s 2020 electricity price targets, and U.S. utility-scale PV systems have achieved their 2020 SunShot target three years early.

³ Soft cost = total cost - hardware (module, inverter, structural and electrical BOS) cost.

⁴ An increasing soft cost proportion in Figure ES-2 indicates soft costs declined more slowly than did hardware costs; it does not indicate soft costs increased on an absolute basis.

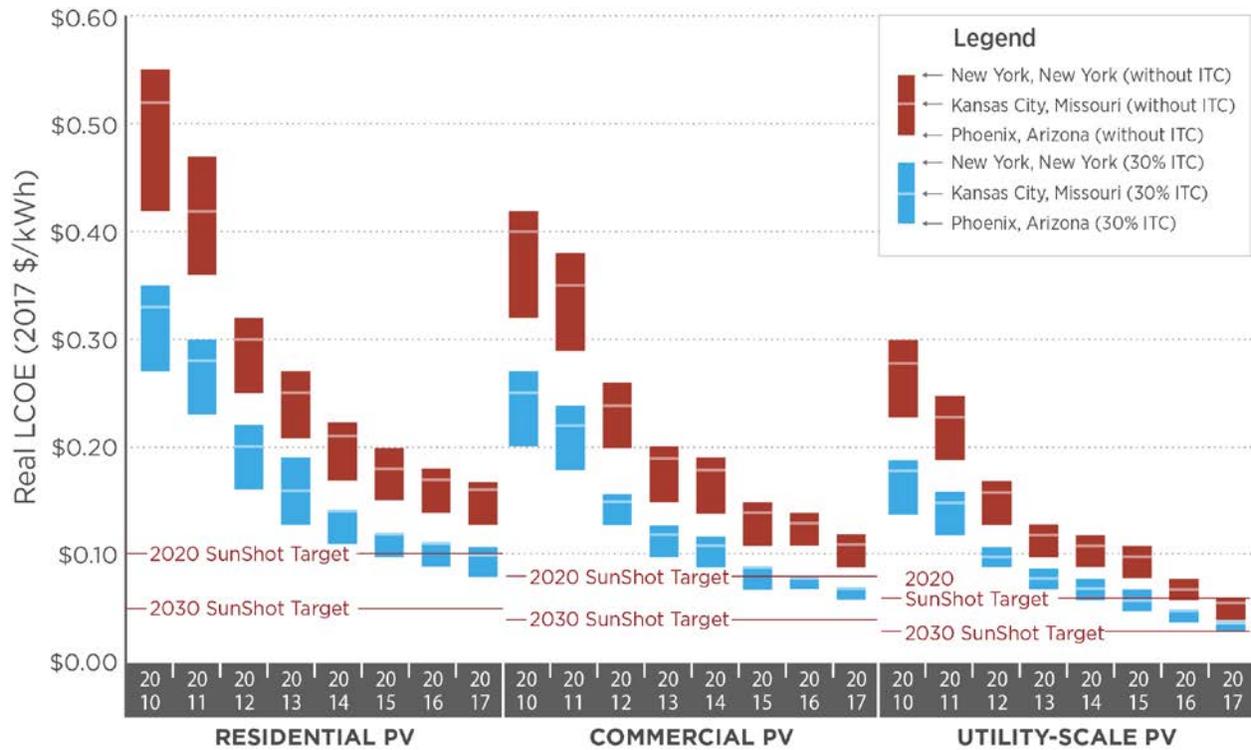


Figure ES-3. NREL PV LCOE benchmark summary (inflation adjusted), 2010–2017

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1 Introduction

Solar photovoltaic (PV) deployment has grown rapidly in the United States over the past several years. As Figure 1 shows, in 2016 new U.S. PV installations included 2.3 gigawatts (GW) in the residential sector, 1.1 GW in the commercial sector, and 10.2 GW in the utility-scale sector—totaling 13.7 GW across all sectors (Bloomberg 2017). At the same time, PV system costs have continued to decline. Previous modeling (Fu et al. 2016) by the National Renewable Energy Laboratory (NREL) shows system cost reductions of about 60%–80% across sectors between the fourth quarter of 2009 (Q4 2009) and Q1 2016.

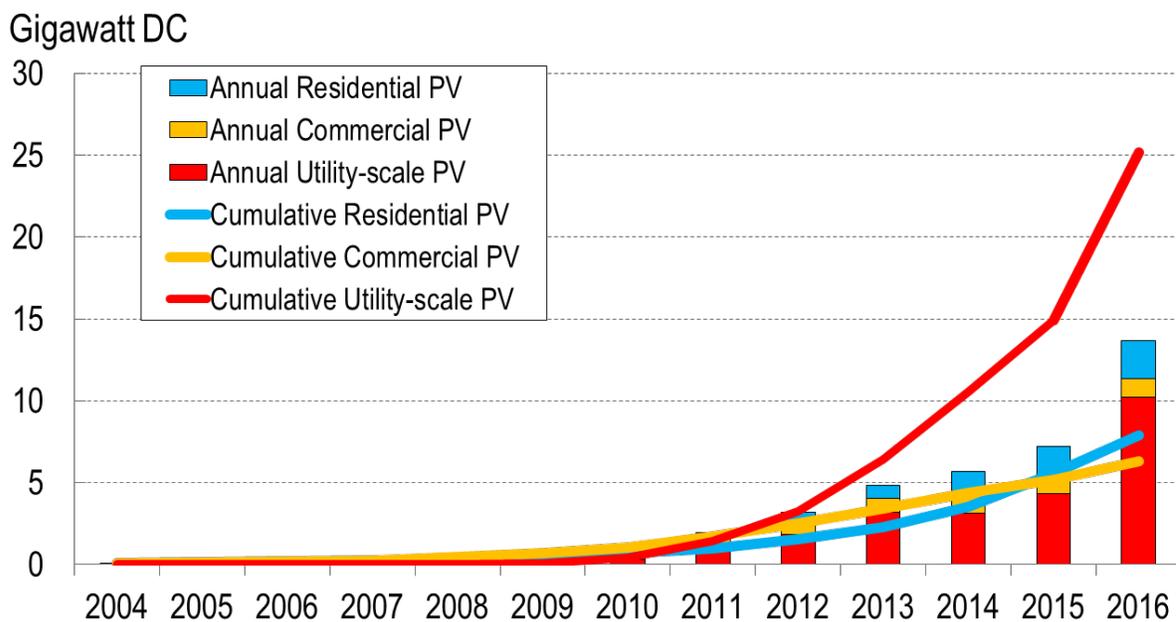


Figure 1. U.S. PV market growth, 2004–2016, in gigawatts of direct-current (DC) capacity (Bloomberg 2017)

This report continues tracking cost reductions by benchmarking costs of U.S. PV for residential, commercial, and utility-scale systems built in Q1 2017. It was produced in conjunction with several related research activities at NREL and Lawrence Berkeley National Laboratory, which are documented in Barbose and Darghouth (2016), Bolinger and Seel (2016), Chung et al. (2015), Feldman et al. (2015), and Fu et al. (2016).

Our methodology includes bottom-up accounting for all system and project-development costs incurred when installing residential, commercial, and utility-scale systems, and it models the Q1 2017 costs for such systems excluding any previous supply agreements or contracts. In general, we attempt to model the typical installation techniques and business operations from an installed-cost perspective, and our benchmarks are national averages of installed capacities, weighted by state. The residential benchmark is further averaged across installer and integrator business models, weighted by market share. All benchmarks assume non-union construction labor, although union labor cases are estimated for utility-scale systems.

Our modeled costs can be interpreted as the sales price an engineering, procurement, and construction (EPC) contractor/developer might charge for a system before any developer fee or price gross-up. We use this approach owing to the wide variation in developer profits in all three sectors, where project pricing is highly dependent on region and project specifics such as local retail electricity rate structures, local rebate and incentive structures, competitive environment, and overall project or deal structures.

The remainder of this report is organized as follows. Section 2 describes our model inputs and sources. Sections 3, 4, and 5 show specific model inputs and outputs for the residential, commercial, and utility-scale PV sectors, including historical trends in system costs and the levelized costs of energy (LCOE). Section 6 includes three additional applications of our cost modeling: system cost reduction from economies of scale, module efficiency impacts, and regional LCOEs. Finally, Section 7 puts the results in context with each other and offers conclusions.

2 Model Inputs and Sources

This section describes our model inputs and sources. Section 2.1 describes our main data source, California’s Net Energy Metering (NEM) Interconnection Applications Data Set. Sections 2.2 through 2.6 detail the inputs for the various components affecting PV system cost, and Section 2.7 describes how we allocated installations to installers versus integrators in the residential PV model.

2.1 California’s NEM Interconnection Applications Data Set

Previous NREL analyses used the California Solar Initiative Data Set (CSI 2017), but, as that program has wound down, the number of new PV incentive applications—and consequently the data collection—has decreased substantially. As a result, in last year’s report, we began using the more robust California NEM Interconnection Applications Data Set instead (Go Solar CA 2017). This database is updated monthly and contains all interconnection applications in the service territories of the state’s three investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric). We use the database to benchmark generic system characteristics, such as system size, module power and efficiency, and choice of power electronics. Although there are other databases for other markets, such as Massachusetts and New York, we use only the California NEM database to inform these general benchmark characteristics because of its higher granularity and greater consistency. Notably, we do not use the California NEM database for regional cost analyses. Inputs and sources for regional analyses are described in subsequent sections of this report.

As shown in Figure 2, the California NEM database captures most residential capacity in California (79% of installed capacity in 2015 and 80% in 2016) and a sizable portion of commercial capacity (91% of installed capacity in 2015 and 35% in 2016). Note that:

- We analyze only rooftop systems in the database for the residential and commercial sectors. We exclude ground-mounted systems.
- We exclude systems with only alternating-current (AC) power records.
- We exclude systems that were still in the validation phase.
- We use GTM (2017) data to represent total installed capacities.

Annual Installation in California (MW DC)

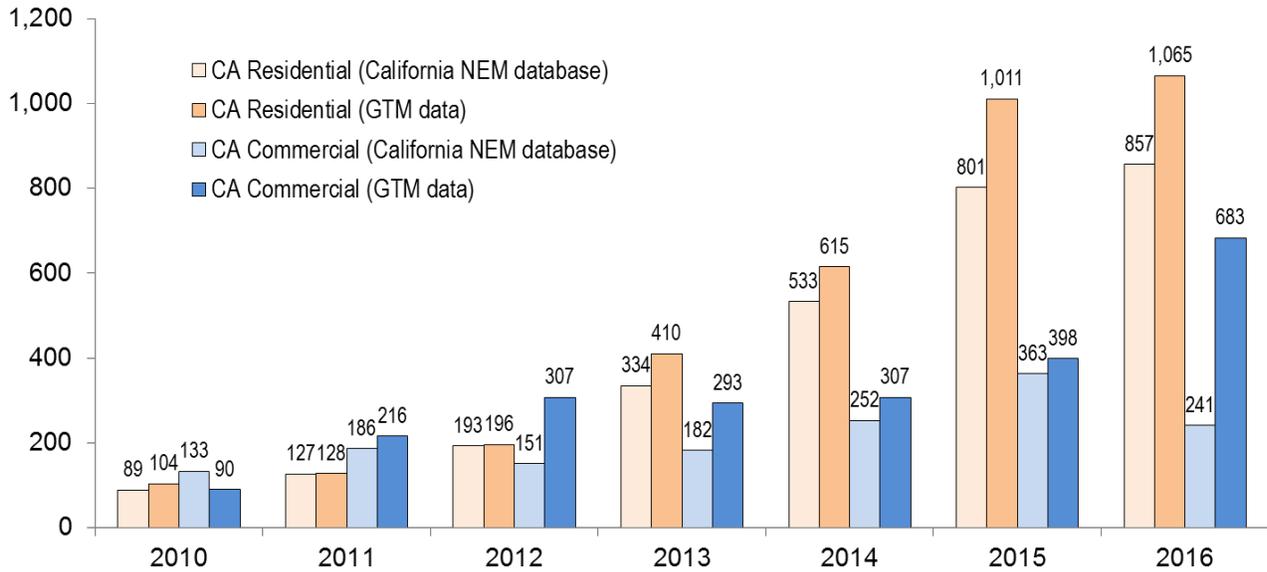


Figure 2. Installed capacities of residential and commercial PV systems covered by the California NEM database (Go Solar CA 2017) compared with GTM data (GTM Research 2017), 2010–2016

2.2 Module Power and Efficiency

Figure 3 displays module power and efficiency data from the California NEM database. Since 2010, module power and efficiency in both sectors have been steadily improving. We use the values of 16.2% (residential) and 17.5% (commercial and utility-scale) module efficiency in our models. Also note that since module selection may vary in different regions, the actual module efficiencies in other regions than CA may be different.

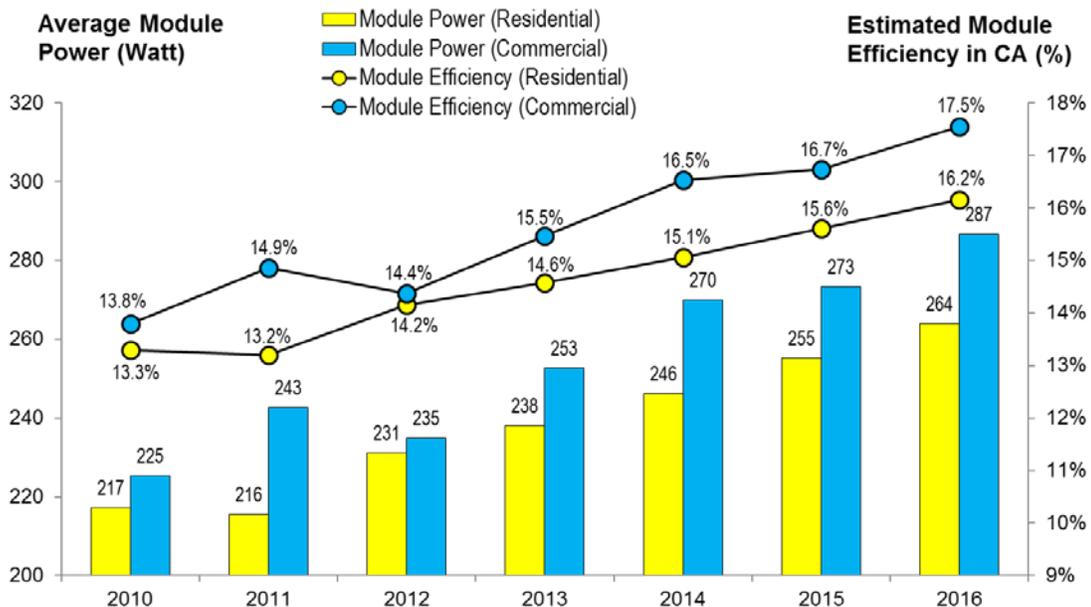


Figure 3. Module power and efficiency trends from the California NEM database (Go Solar CA 2017), 2010–2016

2.3 PV System Size

Figure 4 displays average system sizes from the California NEM database. Average residential system sizes have not changed significantly over the past 6 years. We use the 2016 value of 5.7 kW as the baseline case in our residential cost model. Conversely, commercial system sizes have changed more frequently, likely reflecting the wide scope for “commercial customers,” which include schools, office buildings, malls, retail stores, and government projects. We use 200 kW as the baseline case in our commercial model.

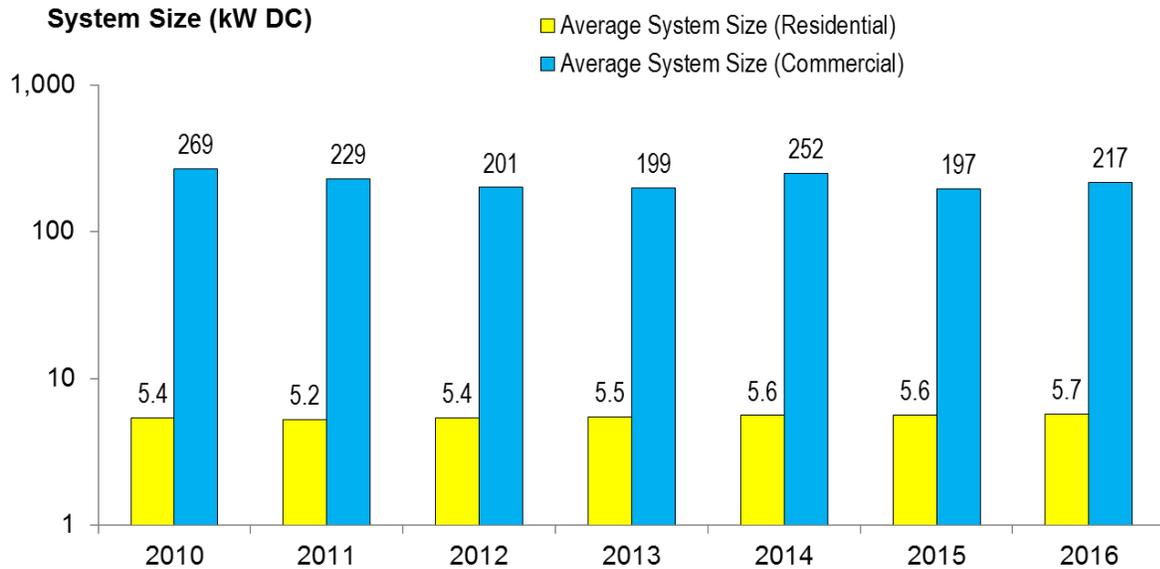


Figure 4. PV system size trends from the California NEM database (Go Solar CA 2017), 2010–2016

2.4 Module-Level Power Electronics

Microinverters and DC power optimizers are collectively referred to as module-level power electronics (MLPE). By allowing designs with different roof configurations (orientations and tilts) and constantly tracking the maximum power point for each module, MLPE provide an optimized design solution at the module level. Table 1 provides a brief comparison of traditional string inverters and MLPE.

Table 1. Comparison of Inverter Solutions: String Inverter, DC Power Optimizer, and Microinverter

	String Inverter	DC Power Optimizer	Microinverter
Function	PV modules are connected in parallel by one or multiple strings and then directly connected to the string inverter for DC-to-AC conversion. If one module is shaded, the whole string is impacted.	Each PV module has one power optimizer for DC-to-DC conversion, so the traditional junction box is replaced, and all modules are connected by string inverter for DC-to-AC conversion. Shading only impacts individual modules.	Each PV module has one microinverter for DC-to-AC conversion, and thus no string inverter is used. Shading only impacts individual modules.
Relative product price	Low (without rapid shutdown) Medium (with rapid shutdown)	Medium	High
Performance in shading	Poor	More efficient	More efficient
Performance in various directions or on irregular roofs	Low	Medium	High
Module-level monitoring and troubleshooting	No	Yes (e.g., SolarEdge Cellular Kit)	Yes (e.g., Enphase “Envoy + Enlighten”)
Improved energy yield from module mismatch reduction	No	Yes	Yes
Number of electronic components	Normal	Greater (thus may have some component risks)	Greater (thus may have some component risks)
Safety for installation	Normal	Safer; easier wiring work	Safest; use only AC cable with no high-voltage DC power

According to the California NEM database, market uptake of MLPE has been growing rapidly since 2010 in California’s residential sector (Figure 5). This increasing market growth may be driven by decreasing MLPE costs and by the “rapid shutdown” of PV output from buildings required by Article 690.12 of the National Electric Code (NEC) since 2014—MLPE inherently meet rapid-shutdown requirements without the need to install additional electrical equipment.

In 2016, MLPE—represented by the combined share of Enphase and SolarEdge inverter solutions—reached 53% of the total California residential market share (Figure 5). Therefore, in our residential system cost model, string inverter, power optimizer, and microinverter options are modeled separately and their market shares (47%, 26%, and 27%) are used for the weighted average case. Conversely, MLPE growth (represented by Enphase and SolarEdge) has been slow

in California’s commercial sector, reaching a share of only 12% in 2016 (Figure 6). Thus, we do not include MLPE inverter solutions into our commercial model.

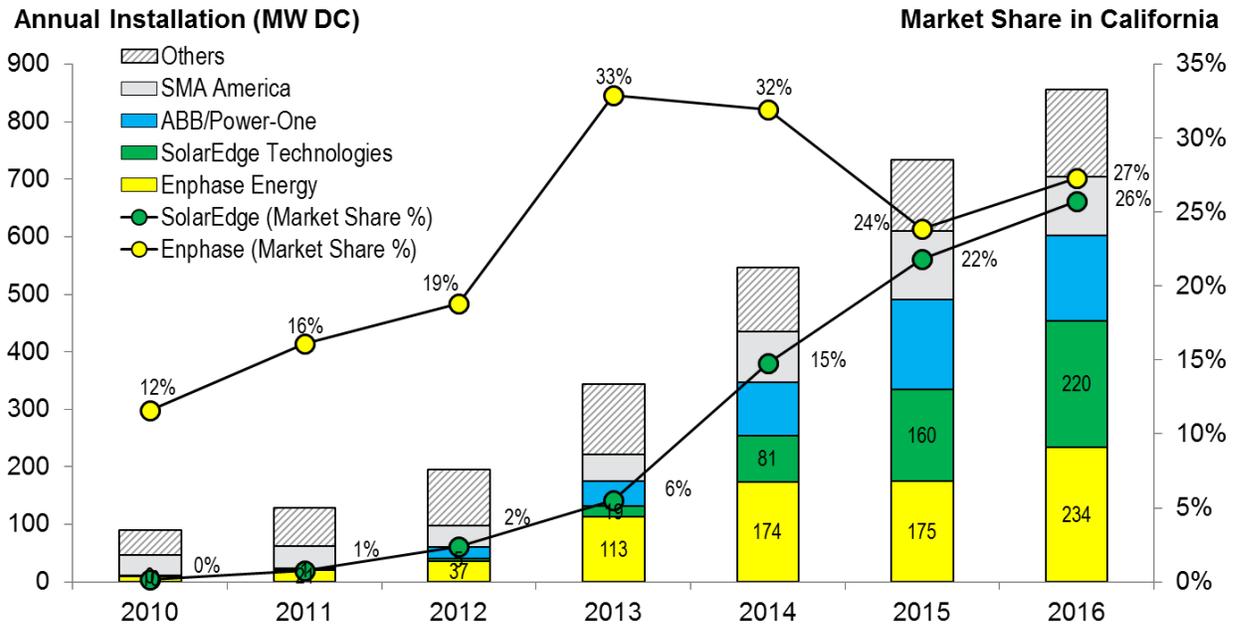


Figure 5. Residential inverter market in California from the California NEM database (Go Solar CA 2017), 2010–2016⁵

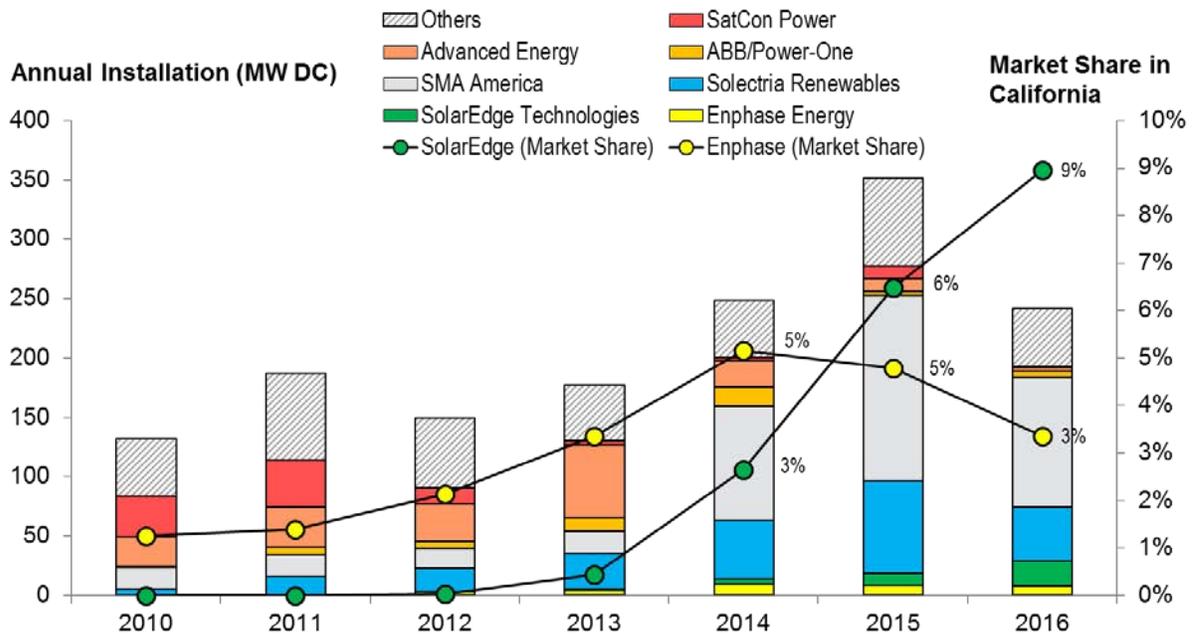


Figure 6. Commercial inverter market in California from the California NEM database (Go Solar CA 2017), 2010–2016

⁵ “Others” represents other companies with small market shares. Although some companies may also have MLPE-based inverter products, we assume that SolarEdge and Enphase represent MLPE inverter manufacturers.

For safety reasons, rapid-shutdown codes⁶ are prevalent in most of the top residential PV markets, and they typically include language from NEC 2014 (Article 690.12).⁷ As of January 1, 2017, the 2017 NEC rapid-shutdown code was in effect in one state, the 2014 NEC was in effect in 35 states, the 2011 NEC was in effect in five states, and the 2008 NEC was in effect in six states (Table 2). Our cost model uses the 2014 NEC, which is the most widely adopted version and includes the rapid-shutdown requirement. Table 3 presents the rapid-shutdown technical solutions and cost impacts for various inverter options. Because of the increase in rapid shutdown requirements, the cost difference between string inverter and power optimizer configurations became smaller this year.⁸ The model for our Q1 2016 benchmark did not include rapid shutdown.

Table 2. Rapid-Shutdown Codes—Progress by State

Code	Rapid-Shutdown Requirement	State
2017 NEC	Yes	Massachusetts
2014 NEC	Yes	Alabama, Alaska, Arkansas, California, Colorado, Connecticut, Delaware, Georgia, Idaho, Iowa, Kentucky, Maine, Maryland, Michigan, Minnesota, Montana, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, Rhode Island, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, West Virginia, Wyoming
2011 NEC	No	Florida, Louisiana, Virginia, Wisconsin, Nevada
2008 NEC	No	Hawaii, Illinois, Indiana, Kansas, Pennsylvania, Tennessee
No statewide NEC adoption	No	Arizona, Mississippi, Missouri

⁶ During a power shutdown (e.g., during a building fire or utility power loss), DC conductors in each PV array string are most dangerous to first responders such as fire fighters because the DC side can still be energized even if the inverter is shut down. Rapid-shutdown codes require a set distance between PV system conductors and PV arrays, so the conductors are de-energized to a safe level and risks to first responders are reduced.

⁷ For example, a segment of the NEC language that is used says, “Conductors more than 5 feet inside a building or more than 10 feet from an array will be limited to a maximum of 30 V and 240 VA within 10 seconds of shutdown.” This only applies to PV system circuits “on or in buildings,” thus ground-mounted systems are not required to have rapid-shutdown capability.

⁸ The costs were \$2.78/W (string inverter) vs. \$2.94/W (power optimizer) in Q1 2016 when rapid shutdown was not included in our cost models, compared with \$2.90/W (string inverter) vs. \$2.95/W (power optimizer) if rapid shutdown is included in Q1 2016 benchmark.

Table 3. Rapid Shutdown—Different Inverter Solutions

	String Inverter	DC Power Optimizer	Microinverter
Solution for rapid-shutdown requirement	<p>A rapid-shutdown box must be mounted directly to the PV mounting rail and fit under the PV modules.</p> <p>A rapid-shutdown controller must be mounted so it is visible and freely accessible to first responders.</p>	<p>A rapid-shutdown cable must be installed in the inverter box. No additional roof-mounted devices are required.</p>	<p>Microinverters inherently meet rapid-shutdown requirements without any additional electrical equipment, because the DC side (which has low voltage) is de-energized as soon as the grid or power from the grid is interrupted.</p>
Additional balance-of-system (BOS) costs	<p>Rapid shutdown box</p> <p>Rapid shutdown controller</p> <p>Cable between box and controller</p> <p>Total BOS increase = \$0.08/W</p>	<p>One rapid shutdown cable in each inverter</p> <p>Total BOS increase = \$0.01/W</p>	None
Additional direct labor costs	<p>Electrician for cabling between box and controller</p> <p>Common labor for racking box and controller</p> <p>Total labor increase = \$0.01/W</p>	<p>Electrician for setting up internal cable in each inverter</p> <p>Total labor increase = \$0.01/W</p>	None
Q1 2016 – Benchmark (no rapid shutdown consideration)	\$2.78/W	\$2.94/W	\$3.28/W
Q1 2016 – Benchmark (if rapid shutdown is considered)	\$2.90/W	\$2.95/W	\$3.28/W
Cost change in 2016 models due to rapid shutdown only	0.12/W = 0.08/W (electrical BOS) + 0.01/W (direct labor) + 0.03/W (other related costs)	0.01/W = 0.01/W (electrical BOS and direct labor)	No change

2.5 Inverter Price and DC-to-AC Ratios

As shown in Figure 7, we source non-MLPE inverter prices from the PVinsights (2017) database, which contains typical prices between Tier 1 suppliers and developers in the market. For MLPE inverter prices, we use data from public corporate filings, shown in Figure 8 (Enphase 2017; SolarEdge 2017).⁹ Enphase’s Q1 2017 revenue was \$0.40/Wac, which represents the typical microinverter price. SolarEdge’s Q1 2017 revenue was \$0.25/Wac, including sales from DC power optimizers, string inverters, and monitoring equipment, which are typically included in one product offering. GTM Research estimates a DC power optimizer cost of \$0.08/Wac (GTM Research 2017), implying a string inverter and monitoring equipment price of \$0.17/Wac. This is close to the Q1 2017 non-MLPE string inverter costs of \$0.15/Wac shown in Figure 7 (assuming a \$0.02–\$0.03/Wac cost for monitoring equipment) (GTM Research and SEIA 2017).

We convert the USD/Wac inverter prices from Figure 7 and Figure 8 to USD per watt DC (Wdc) using the DC-to-AC ratios shown in Table 4. In our benchmark, we use USD/Wdc for all costs, including inverter prices.

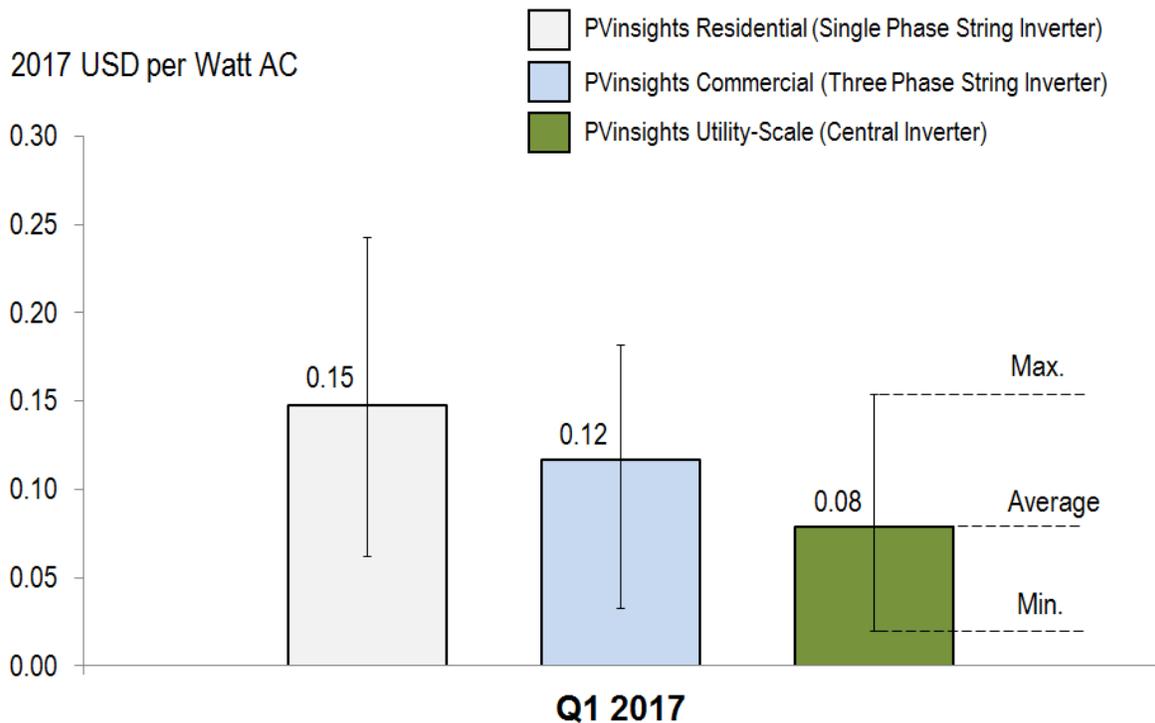


Figure 7. Non-MLPE inverter prices (USD/Wac) from PVinsights (2017), Q1 2017

⁹ All sourced inverter prices are quoted in U.S. dollars (USD) per watt AC (Wac).

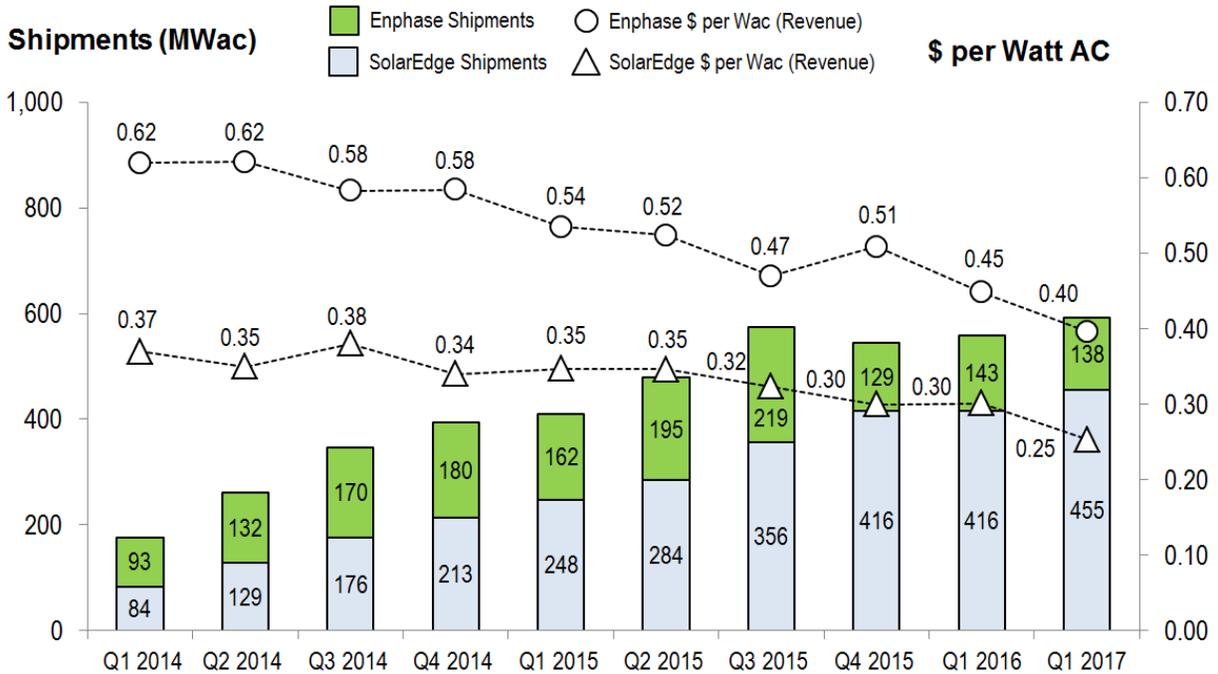


Figure 8. MLPE inverter shipments and prices (USD/Wac) from public corporate filings (Enphase 2017, SolarEdge 2017), Q1 2014–Q1 2017

Table 4. Inverter Price Conversion (2017 USD)

Inverter Type	Sector	USD/Wac	DC-to-AC Ratio ^a	USD/Wdc
Single-Phase String Inverter	Residential PV (non-MLPE)	0.15	1.15	0.13
Microinverter	Residential PV (MLPE)	0.40	1.15	0.34
DC Power Optimizer String Inverter	Residential PV (MLPE)	0.17	1.15	0.15
Three-Phase String Inverter	Commercial PV (non-MLPE)	0.12	1.15	0.10
Central Inverter	Utility-scale PV (fixed-tilt)	0.08	1.3 (oversized) ^b	0.06
Central Inverter	Utility-scale PV (1-axis tracker)	0.08	1.3 (oversized)	0.06

^a We updated the central inverter DC-to-AC ratios using Lawrence Berkeley National Laboratory data (Bolinger and Seel 2017); for the other ratios, we use the estimates from our 2016 report (Fu et al. 2016) based on interview feedback (NREL 2017).

^b A DC-to-AC ratio larger than one means that the PV array's DC rating is higher than the inverter's AC rating. This increases inverter utilization, although it also results in some PV energy curtailment, or "clipping," during the sunniest periods when PV output exceeds the inverter's capacity. PV module prices

have dropped more rapidly than inverter prices have, and many utility-scale PV developers have found it economical to oversize their PV arrays. The resulting AC-generation gains during periods of less-than-peak PV production more than offset the losses from occasional peak-period clipping (Bolinger and Seel 2016).

2.6 Module Prices

We use \$0.35/W—the spot price of U.S. crystalline-silicon modules in March 2017—to represent the ex-factory gate price between Tier 1 module suppliers and first buyers¹⁰ in all sectors, based on Bloomberg (2017) data (Figure 9). Because we model ex-factory gate price in Q1 2017, actual market pricing may vary owing to previously signed supply agreements or installer/distributor inventory lags.¹¹ In addition, the actual market price may vary by market segment because of increased supply-chain costs as well as the price premium for small-scale procurement. Compared with module spot prices in 2016, module spot prices in 2017 have also been influenced by changes in currency exchange rates. The USD appreciated against the Chinese Yuan by approximately 6% between Q1 2016 and Q1 2017 (XE Currency Charts 2017).

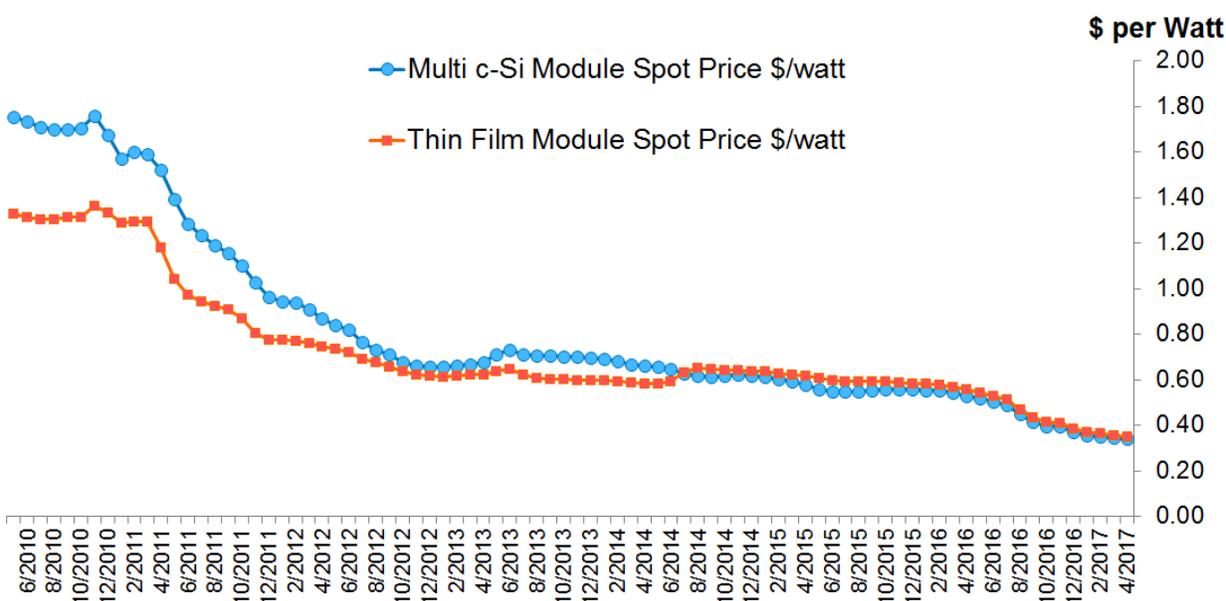


Figure 9. Ex-factory gate price (spot prices) for U.S. crystalline-silicon modules from Bloomberg (2017) data

Despite a \$0.35/W factory gate module price, additional module costs increase national integrators’ total module costs to \$0.65/W (86% price premium) and small installers’ total module costs to \$0.73/W (109% price premium). These additional costs in Figure 10 consist of shipping and handling (a 15% price premium above factory gate pricing for national integrators and small installers, respectively [NREL 2017]), historical inventory (a 60% price premium

¹⁰ The first buyers of modules ex-factory gate can be developers, EPC contractors, installers, distributors, retailers, or other end users. In our cost model, first buyer price—that is, ex-factory gate price—is used as the “module price” component of the total system cost in the residential, commercial, and utility-scale sectors.

¹¹ The effect of inventory lags and previous supply agreements on system pricing in the latter half of 2016 and the first quarter of 2017 may be particularly high, because the actual market module price had not dropped so precipitously since 2011 and 2012.

above factory gate pricing [NREL 2017]), a sales-tax of 6.7%, and, for small installers, a 20% price premium above factory gate pricing due to small-scale procurement (Bloomberg 2017).

In Q1 2017 historical inventory represented the largest supply-chain cost for residential installers. While we do not include pre-existing supply agreements or other contracts into our benchmark, historical inventory is a necessary cost for residential installers. Because homeowners of residential rooftop PV systems have different preferences for module brand, both small installers and national integrators tend to diversify their module procurement. Furthermore, since rooftop PV system sizes are relatively small (5.7 kW in our benchmark), the various module brands procured may not be fully consumed and installed instantly. Thus, the historical inventory price creates a price lag (approximately six months) for the market module price in the residential sector when the modules from previous procurement are installed in today's systems.

From 2012 to mid-2016 this price lag did not create a large price premium because the average spot price of modules did not change dramatically. However, from mid-2016 to early-2017 module spot price dropped by approximately \$0.25/W, or 41%, as shown in Figure 9. Thus, in the first quarter of 2017 residential installers must bear the costs of this \$0.21/W historical inventory. It is likely that this price premium will be much smaller next year as analysts expect the spot price curve to become flatter. However, many things may change within the market (e.g., tariffs) and make it challenging for residential players to forecast module price. Without historical inventory, total module costs would be \$0.43/W for national integrators and \$0.52/W for small installers (potentially reducing total residential PV costs to \$2.59/Wdc).

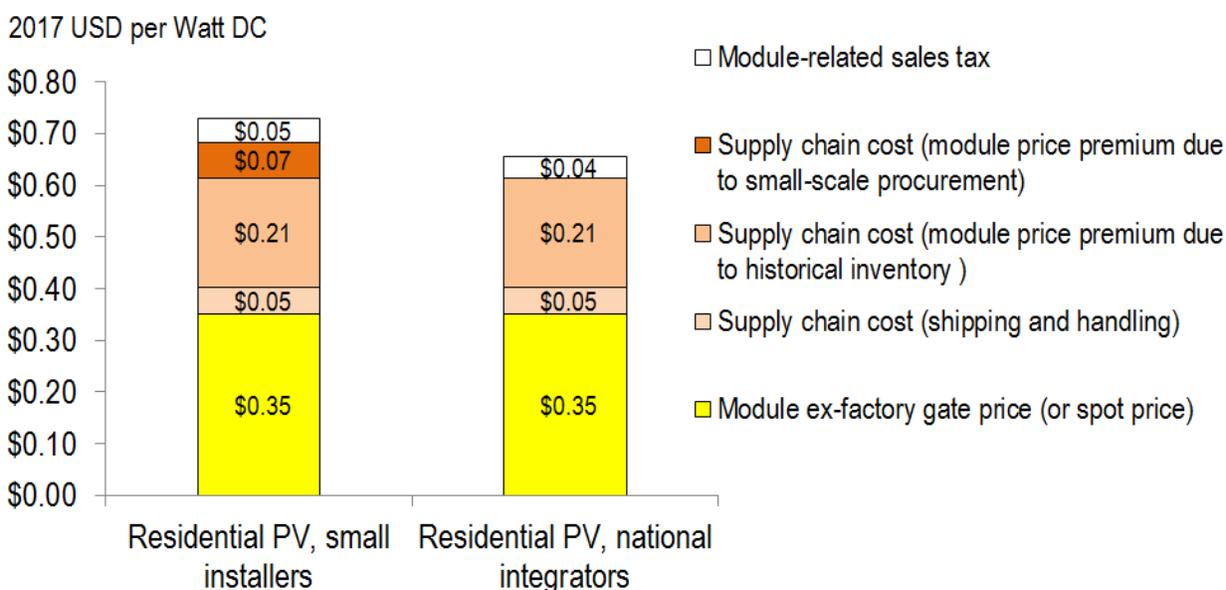


Figure 10. Actual market module prices (2017 USD)

Besides module spot price, actual module manufacturing cost is introduced here in order to demonstrate the technology improvement. We work across the spectrum of academic and national laboratory researchers, startup companies, and multinational corporations to understand the cost drivers and technology landscape of PV module production. Our bottom-up method entails an examination of each stage in the supply chain, including polysilicon, ingot, and wafer production, cell conversion, and module assembly. For each stage, we begin with the derivation

of detailed technology-manufacturing process flows. Then we work with equipment and materials suppliers, as well as integrated manufacturers already engaged in production, to collect and verify the costs for each step of the process. Finally, we sum the individual process steps to generate total costs for the intermediate materials (polysilicon, ingots, wafers, and cells) and finished PV modules.

Figure 11 shows our most recent module manufacturing cost analysis, for passivated emitter and rear cells (PERC) and modules manufactured in Southeast Asia. The dark blue bars show the Q1 2017 cost contributions for each step: about \$0.05/W for polysilicon, \$0.05/W for ingot and wafer production, \$0.08/W for cell conversion, \$0.13/W for module assembly, and \$0.03/W for an industry-average budget for research and development (R&D) plus sales, general, and administrative (SG&A). The all-in module manufacturing cost is about \$0.35/W.

Figure 11 also illustrates the magnitude of cost reductions since our last detailed module manufacturing analysis in 2014 and the first half of 2015, when we calculated an all-in module manufacturing cost of about \$0.63/W. This 45% reduction in costs over 2–3 years was enabled by improving silicon utilization (principally reducing kerf loss), converting from slurry-based wafer slicing to diamond-wire-based wafer slicing, and reducing costs for cell conversion and module assembly principally via improved efficiency and capital investment requirements (the depreciation expenses shown in the figure). In a forthcoming paper, we will detail additional technology-improvement opportunities that could lead to even lower costs in the future.

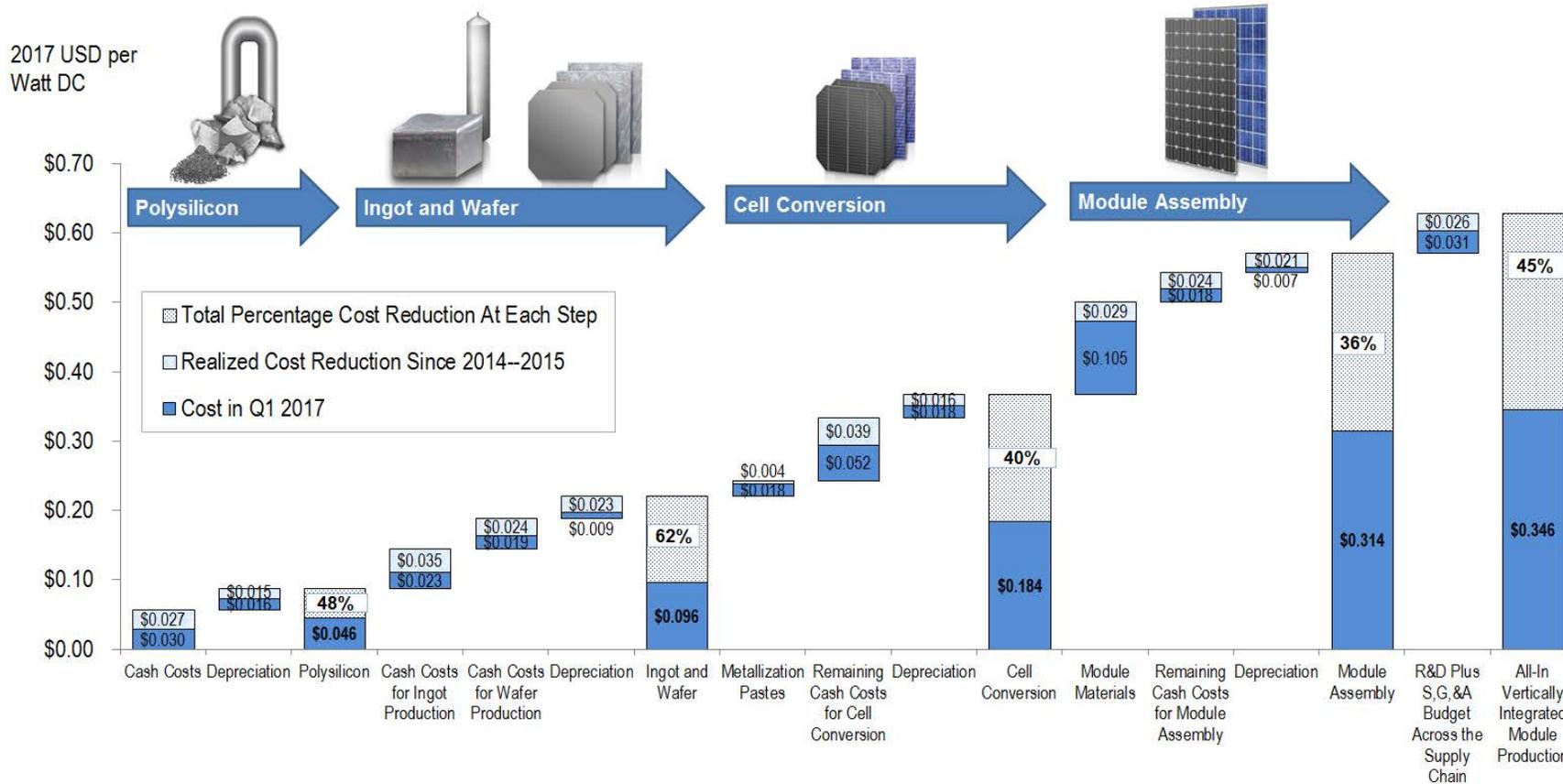


Figure 11. Updated bottom-up manufacturing cost model results for the full crystalline-silicon module supply chain from 2014/15 to Q1 2017¹²

¹² The results shown are for manufacturing PERC and modules in Southeast Asia.

2.7 Small Installers vs. National Integrators in the Residential PV Model

Our residential PV benchmark is based on two different business structures: “small installer” and “national integrator.” We define small installers as businesses that engage in lead generation, sales, and installation, but *do not* provide financing solutions. The national integrator performs all of the small installer’s functions, *and* provides financing and system monitoring for third-party-owned systems. In our models, the difference between small installers and national integrators is manifested in the overhead and sales and marketing cost categories, where the national integrator is modeled with higher expenses for customer acquisition, financial structuring, and asset management.

To estimate the split in market share between small installers and national integrators, we use data compiled from corporate filings (Sunrun 2017; Vivint Solar 2017) and GTM Research and SEIA (2017). As shown in Figure 12, small installers gained more market share than national integrators did during 2016, in part because the direct ownership business model, led by installers, remained more popular than third-party ownership. We use the 41% integrator and 59% installer market shares in our Q1 2017 model to compute the national weighted-average case in our residential PV model.

Table 5 summarizes overhead and sales and marketing costs for small installers and national integrators from our Q1 2016 and Q1 2017 reports. National integrators achieved lower per-watt sales and marketing and overhead costs in Q1 2017 compared with Q1 2016 because of lower reported total expenditures on those two categories. Small installers had higher total expenditures on sales and marketing and overhead as they prepared to grow their businesses in 2017, but they still achieved lower per-watt costs for sales and marketing in Q1 2017 compared with Q1 2016 because they installed more PV capacity in the later period.

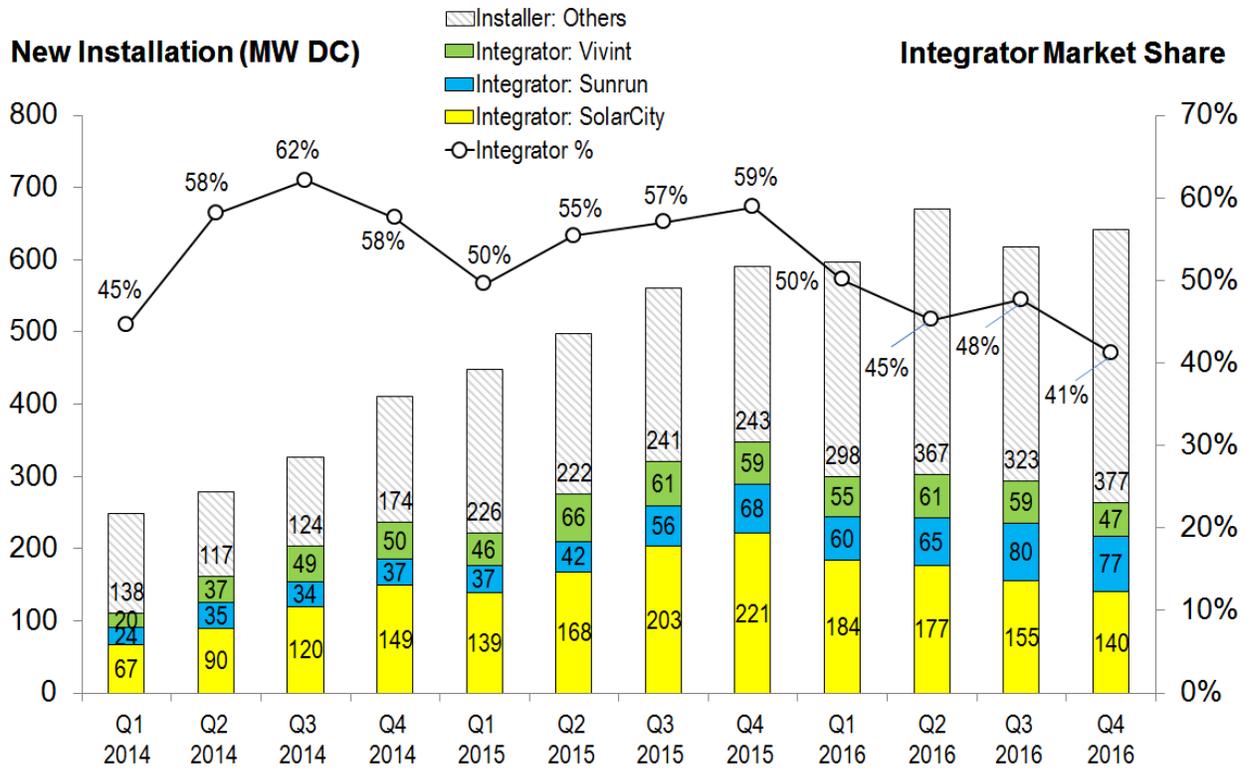


Figure 12. Residential PV market share: integrator vs. installer, Q1 2014–Q1 2016 (GTM Research and SEIA 2017; Sunrun 2017; Vivint Solar 2017)

Table 5. Installer and Integrator Cost Changes, Q1 2016–Q1 2017

	Q1 2016 Report	Q1 2017 Report
Sales & marketing (customer acquisition)	\$0.31/Wdc (small installer) \$0.43/Wdc (national integrator)	\$0.29/Wdc (small installer) \$0.42/Wdc (national integrator)
Overhead (general & administrative)	\$0.28/Wdc (small installer) \$0.38/Wdc (national integrator)	\$0.28/Wdc (small installer) \$0.35/Wdc (national integrator)

3 Residential PV Model

This section describes our residential model’s structure, inputs, and assumptions (Section 3.1), output (Section 3.2), and differences between modeled output and reported costs (Section 3.3).

3.1 Residential Model Structure, Inputs, and Assumptions

We model a 5.7-kW residential rooftop system using 60-cell, multicrystalline, 16.2%-efficient modules from a Tier 1 supplier and a standard flush mount, pitched-roof racking system. Figure 13 presents the cost drivers and assumptions, cost categories, inputs, and outputs of the model. Table 6 presents modeling inputs and assumptions in detail.

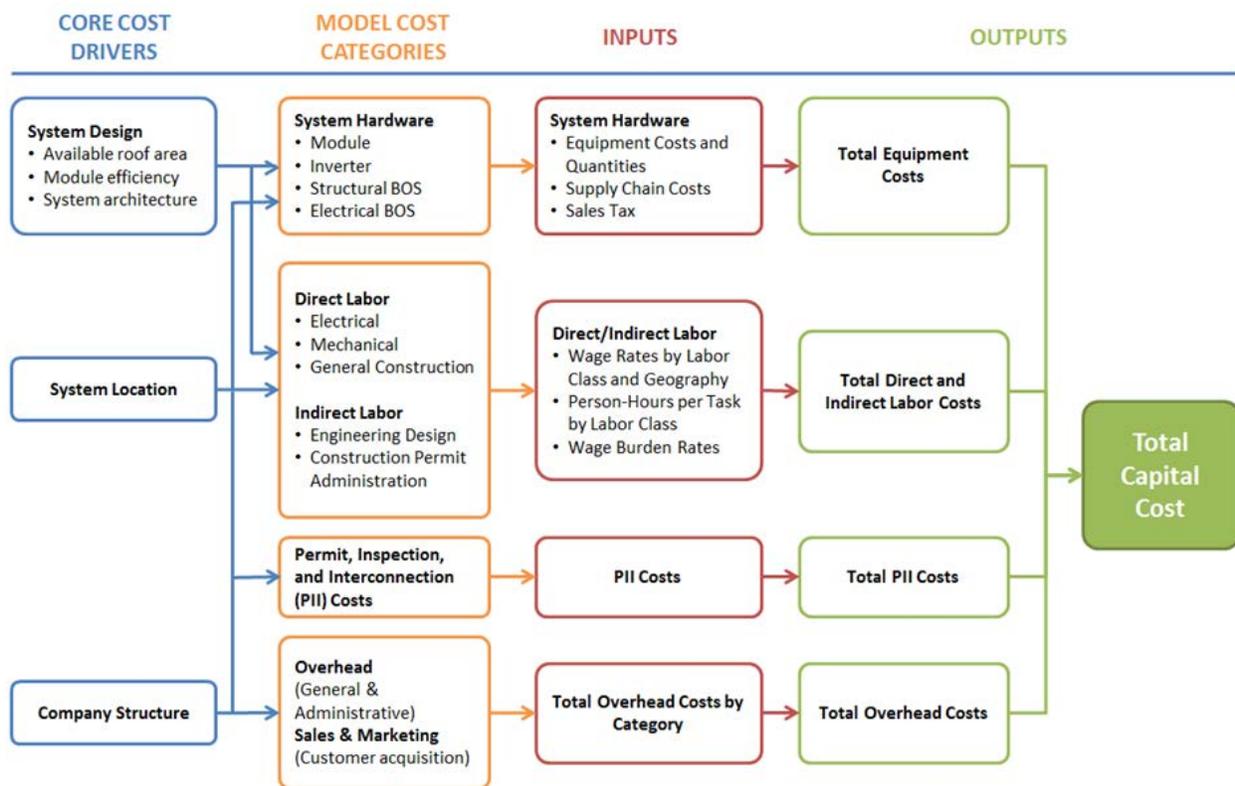


Figure 13. Residential PV: model structure

Table 6. Residential PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	5.7 kW	Average installed size per system	Go Solar CA (2017)
Module efficiency	16.2%	Average module efficiency	Go Solar CA (2017)
Module price	\$0.35/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	Bloomberg (2017), NREL (2017)
Inverter price	Single-phase string inverter: \$0.13/Wdc DC power optimizer string inverter: \$0.15/Wdc Microinverter: \$0.34/Wdc	Ex-factory gate (first buyer) prices, Tier 1 inverters	Go Solar CA (2017), NREL (2017), PVinsights (2017), corporate filings (Enphase 2017; SolarEdge 2017)
Structural BOS (racking)	\$0.11/Wdc	Includes flashing for roof penetrations	Model assumptions, NREL (2017)
Electrical BOS	\$0.20–\$0.33/Wdc Varies by inverter option	Conductors, switches, combiners and transition boxes, as well as conduit, grounding equipment, monitoring system or production meters, fuses, and breakers	Model assumptions, NREL (2017), RSMMeans (2016)
Supply chain costs (% of equipment costs)	Varies by installer type	15% costs and fees associated with shipping and handling of equipment multiplied by the cost of doing business index (101%) Additional 80% (60% historical inventory + 20% small-scale procurement) for module-related supply chain costs for small installers and 60% (historical inventory) for national integrators Additional 20% for inverter-related supply chain costs for small installers and 10% for national integrators	NREL (2017), model assumptions (2017)
Sales tax	Varies by location	Sales tax on the equipment; national benchmark applies an average (by state) weighted by 2016 installed capacities	DSIRE (2017), RSMMeans (2016)
Direct installation labor	Electrician: \$19.37–\$38.22 per hour; Laborer: \$12.64–\$25.09 per hour; Varies by location and inverter option	Modeled labor rate depends on state; national benchmark uses weighted average of state rates	BLS (2017), NREL (2017)

Category	Modeled Value	Description	Sources
Burden rates (% of direct labor)	Total nationwide average: 31.8%	Workers compensation (state-weighted average), federal and state unemployment insurance, Federal Insurance Contributions Act (FICA), builders risk, public liability	RSMMeans (2016)
Permitting, inspection, and interconnection (PII)	\$0.10/Wdc	Includes assumed building permitting fee of \$400 and six office staff hours for building permit preparation and submission, and interconnection application preparation and submission	NREL (2017), Vote Solar (2015), Vote Solar and IREC (2013)
Sales & marketing (customer acquisition)	\$0.29/Wdc (installer) \$0.42/Wdc (integrator)	Total cost of sales and marketing activities over the last year—including marketing and advertising, sales calls, site visits, bid preparation, and contract negotiation; adjusted based on state “cost of doing business” index	NREL (2017), Sunrun (2017), Vivint Solar (2017), Feldman et al. (2013)
Overhead (general & administrative)	\$0.28/Wdc (installer) \$0.35/Wdc (integrator)	General and administrative expenses—including fixed overhead expenses covering payroll (excluding permitting payroll), facilities, administrative, finance, legal, information technology, and other corporate functions as well as office expenses; adjusted based on state “cost of doing business” index	NREL (2017), Sunrun (2017), Vivint Solar (2017), Feldman et al. (2013)
Profit (%)	17%	Applies a fixed percentage margin to all direct costs including hardware, installation labor, direct sales and marketing, design, installation, and permitting fees	Fu et al. (2016)

3.2 Residential Model Output

Figure 14 presents the U.S. national benchmark from our residential model. The national benchmark represents an average weighted by 2016 state installed capacities. Market shares of 59% for installers and 41% for integrators are used to compute the national weighted average. String inverter, power optimizer, and microinverter options are each modeled individually, and the “mixed” case applies their market shares (47%, 26%, and 27%)¹³ as weightings.

Small installers have lower total costs than do large integrators; although small installers pay more for hardware, they have much lower overhead and sales and marketing costs. Notably, the cost difference between installer and integrator became smaller in Q1 2017 than in Q1 2016 (see Table 5). Because of rapid-shutdown requirements, the cost difference between string inverters and power optimizers also became smaller in Q1 2017 than in Q1 2016 (see Table 3).

¹³ This market share combination only reflects the California residential sector and may not reflect the actual national market shares.

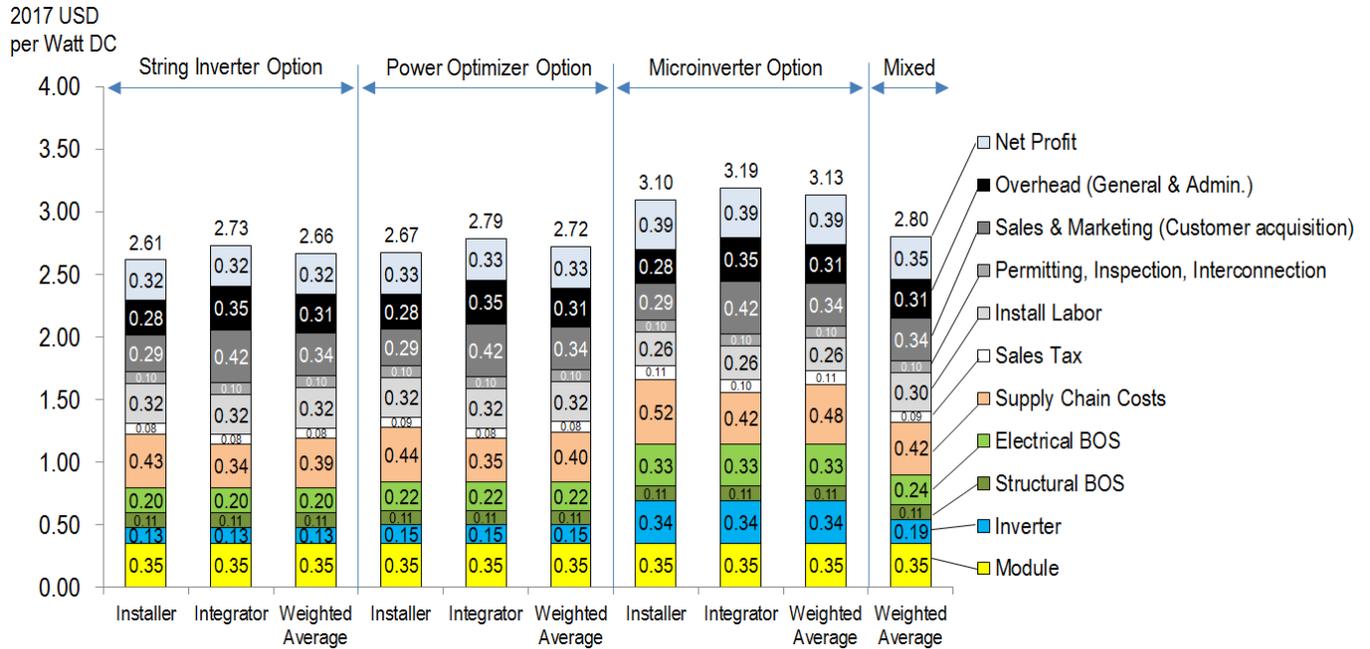


Figure 14. Q1 2017 U.S. benchmark: 5.7-kW residential system cost (2017 USD/Wdc)

Figure 15 presents the benchmark in the top U.S. solar markets (by 2016 installations), reflecting differences in supply chain and labor costs, sales tax, and SG&A expenses—that is, the cost of doing business (Case 2012).

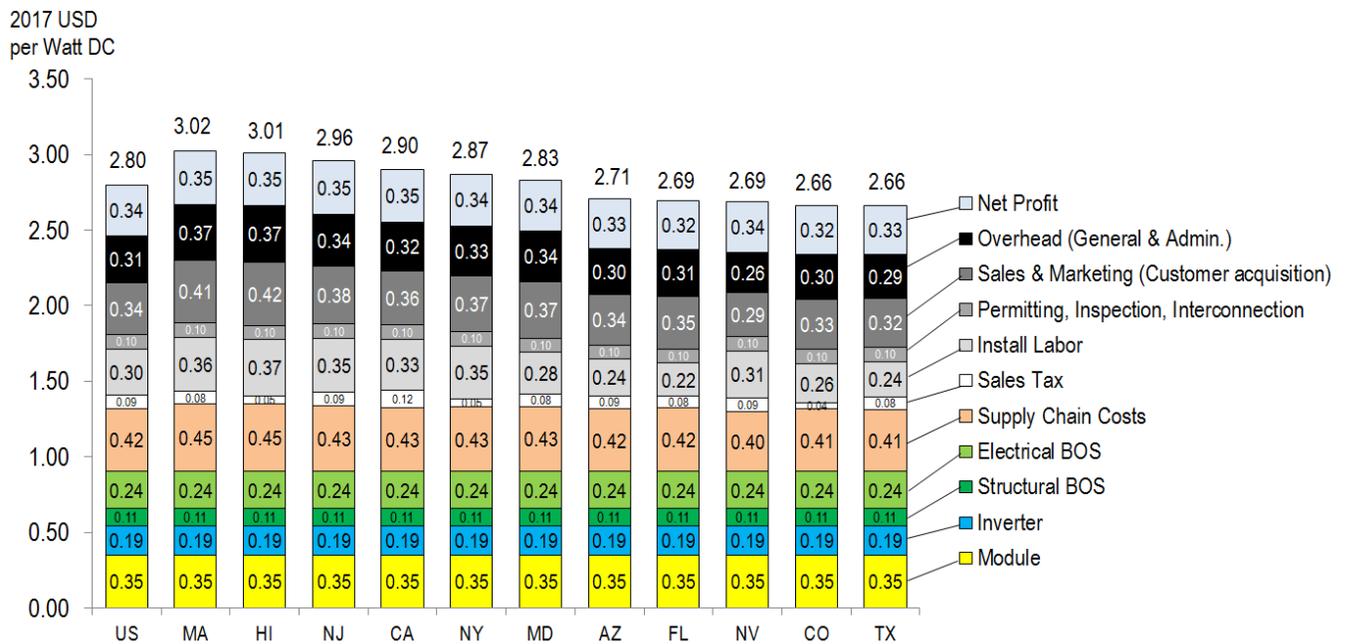


Figure 15. Q1 2017 benchmark by location: 5.7-kW residential system cost (2017 USD/Wdc)

3.3 Residential Model Output vs. Reported Costs

As shown in Figure 16, our bottom-up modeling approach yields a different cost structure than those reported by public solar integrators in their corporate filings¹⁴ (Sunrun 2017; Vivint Solar 2017). Because integrators sell and lease PV systems, they practice a different method of reporting costs than do businesses that only sell goods. Many of the costs for leased systems are reported over the life of the lease rather than the period in which the system is sold; therefore, it is difficult to determine the actual costs at the time of the sale. Although there are the corporate filings from Sunrun and Vivint Solar report system costs on a quarterly basis, the limited transparency in the public filings makes it difficult to determine the underlying costs as well as the timing of those costs. As indicated in Figure 16, our total modeled costs for national integrators are \$0.40–\$0.46/W below company-reported values. Because of the lack of transparency in the reported company costs, it is difficult to explain these differences entirely. Part of the difference in installation costs could come from integrators having preexisting contracts or older inventory that they used in systems installed in Q1 2017; this is particularly relevant owing to the rapid decline in module price in the second half of 2016. In addition, our sales and marketing costs are \$0.08–\$0.23/W below company-reported values, indicating either a difference in how costs are classified or additional costs not included in our model—a deeper exploration of this topic may prove valuable.

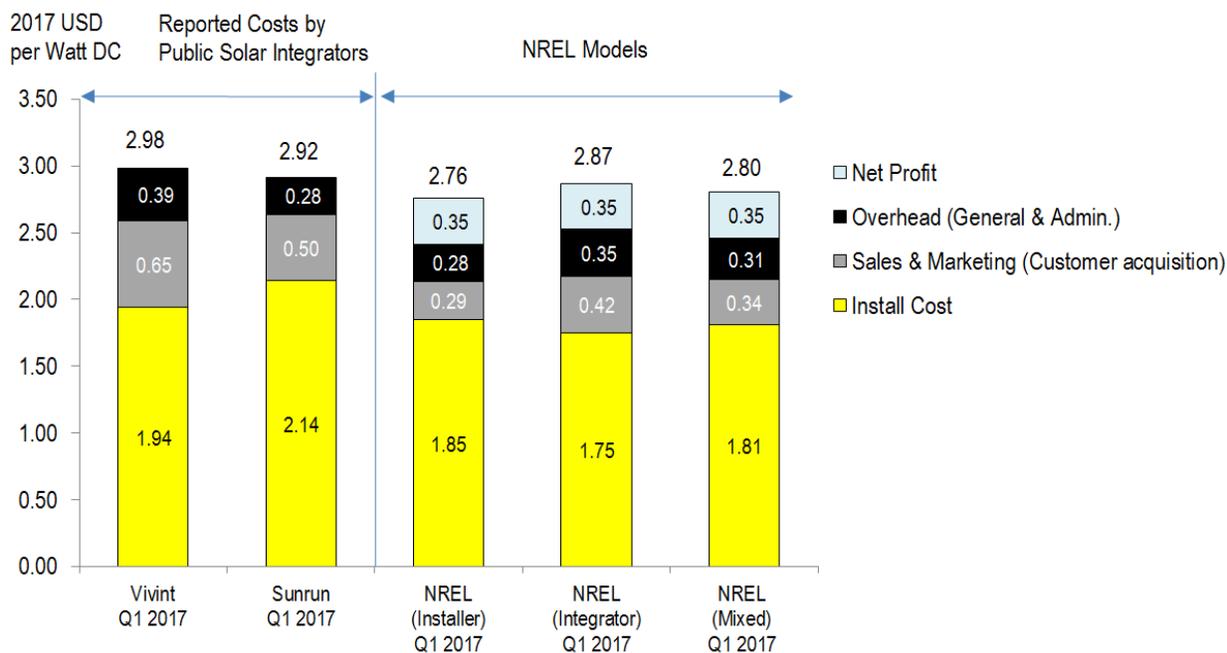


Figure 16. Q1 2017 NREL modeled cost benchmark (2017 USD/Wdc) vs. Q4 2016 company-reported costs

¹⁴ Because of the acquisition of SolarCity by Tesla, the quarterly corporate filings from SolarCity are not available this year.

3.4 Residential PV Price Benchmark Historical Trends

NREL began benchmarking PV system costs in 2010 in order to track PV system energy costs against the U.S. Department of Energy’s (DOE) SunShot Initiative targets, as well as examine cost reduction opportunities for achieving these goals.¹⁵ Since that time NREL has produced seven additional benchmarks, including a historical Q4 2009 benchmark. Figure 17 summarizes the reduction in residential PV system cost benchmarks between 2010 and 2017.¹⁶

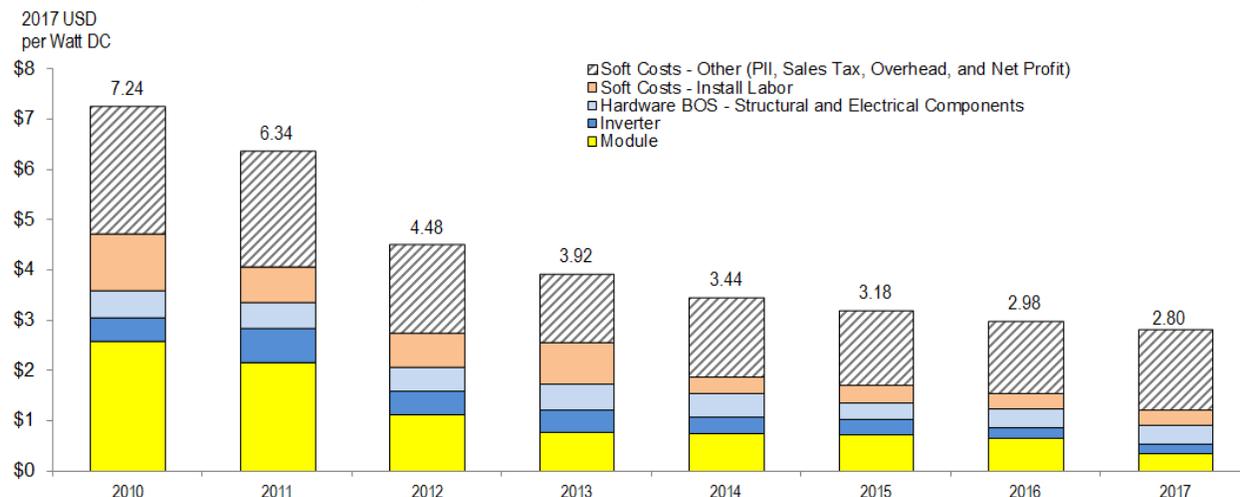


Figure 17. NREL residential PV system cost benchmark summary (inflation adjusted), Q4 2009–Q1 2017

As demonstrated in Figure 17, from 2010 to 2017 there was a 61% reduction in the residential PV system cost benchmark. Approximately 61% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 86% over that time period. An additional 18% can be attributed to labor, which dropped 73% over that time period, with the final 21% attributable to other soft costs, including PII, sales tax, overhead, and net profit.

Looking at this past year, from 2016 to 2017 there was a 6% reduction in the residential PV system cost benchmark. The majority of that reduction can be attributed to the 46% reduction in module factory gate price, moderated by the increase in module supply chain costs discussed earlier (shown here in “soft costs – other”).

¹⁵ The original overarching 2020 goal of the SunShot Initiative was for solar to reach cost parity with baseload energy rates, estimated to be 6 cents/kWh without subsidies, or a system installed cost of \$1/W. Commercial PV and residential PV were later separated to have their own goals of costs below retail rates, estimated to be 7 cents/kWh and 9 cents/kWh respectively, or system installed costs of \$1.25/W and \$1.50/W respectively (note: all 2020 targets are quoted in nominal USD). In recognition of the transformative solar progress to date and the potential for further innovation, in 2016 the SunShot Initiative extended its goals to reduce the unsubsidized cost of energy by 2030 to 3¢/kWh, 4¢/kWh and 5¢/kWh for utility-scale PV, commercial PV, and residential PV (note: all 2030 targets are quoted in nominal USD).

¹⁶ Each year’s PV system cost benchmark corresponds to the NREL benchmark calculated in Q4 of the previous year or Q1 of the current year (e.g. 2010 = Q4 2009; 2017 = Q1 2017).

3.5 Residential PV Levelized Cost of Energy Historical Trends

While LCOE is not a perfect metric to measure the competitiveness of PV within the energy marketplace, it incorporates many other PV metrics important to the energy costs beyond upfront installation costs. These benchmarks are summarized over time in Table 7, from Q4 2009 to Q1 2017 (^aSunShot Vision Study 2010, ^bOn the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; ^cOn the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); ^dTerms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), ^eU.S. Solar Photovoltaic System Cost Benchmark: Q1 2016).¹⁷

Table 7. Residential PV LCOE Assumptions, 2010–2017

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Installed cost	\$7.24	\$6.34	\$4.48	\$3.92	\$3.44	\$3.18	\$2.98	\$2.80
Annual degradation (%)	1.00% ^a	0.95%	0.90%	0.85%	0.80%	0.75% ^c	0.75%	0.75%
Inverter replacement price (\$/W)	\$0.41 ^a	\$0.36	\$0.31	\$0.26	\$0.21	\$0.15 ^c	\$0.14 ^e	\$0.13
Inverter lifetime (years)	10 ^a	11	12	13	14	15 ^c	15	15
O&M expenses (\$/kw-yr)	\$37 ^a	\$33	\$30	\$27	\$24	\$21 ^c	\$21	\$21
Pre-inverter derate (%)	90.0% ^a	90.10%	90.20%	90.30%	90.40%	90.5% ^c	90.5%	90.5%
Inverter efficiency (%)	94.0% ^a	94.80%	95.60%	96.40%	97.20%	98.0% ^c	98.0%	98.0%
System size (kw-DC)	5.0 ^a	5.0	5.1	5.1	5.2	5.2 ^c	5.6 ^e	5.7
Inverter loading ratio	1.1 ^a	1.11	1.12	1.13	1.13	1.14	1.15 ^e	1.15
Equity discount rate (real) ^e	9.0% ^c	8.6%	8.3%	7.9%	7.6%	7.3%	6.9% ^d	6.9%
Inflation rate	2.5% ^a	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate ^f	5.5% ^c	5.4%	5.3%	5.2%	5.0%	4.9%	4.8% ^d	4.8%
Debt fraction	34.2% ^b	35.2%	36.1%	37.1%	38.1%	39.0%	40.0% ^d	40.0%

¹⁷ In instances in which LCOE assumptions were not found from the selected literature in a given year, straight-line changes were assumed between any two values.

Other important assumptions: residential PV system LCOE assume a 1) system lifetime of 30 years^b, 2) federal tax rate of 35%^b, 3) state tax rate of 7%^b, 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)^b, 7) a three month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system^b, 8) a module tilt angle of 25 degrees, and an azimuth of 180 degrees, 9) debt with a term of 18 years^b, and 10) \$1.1MM of upfront financial transaction costs for a \$100MM TPO transaction of a pool of residential projects^d.

^e In instances in which LCOE assumptions were not found from the selected literature in a given year, straight-line changes were assumed between any two values.

^f The historical financial structure for a residential TPO system assumed in 2010 from Feldman and Bolinger 2016 does not assume a debt raise; however, the financial structure in 2016 from Feldman, Lowder, and Schwabe does assume back-leveraged debt. To make these assumptions uniform, the “debt interest rate” and “debt fraction” are taken from the utility-scale historical financial structure in Feldman and Bolinger 2016 that uses back-leveraged debt.

As demonstrated in Table 7, in addition to a 61% reduction in installed cost from 2010 to 2017, inverter replacement costs reduced 69%, O&M costs reduced 44%, annual degradation rates reduced 25%, the equity discount rate reduced 23%, the debt interest rate reduced 13%, and the debt fraction increased 17%.

Using these assumptions we calculated the LCOE, with and without the 30% federal investment tax credit (ITC), in Phoenix, AZ, Kansas City, MO, and New York, NY, corresponding to higher, medium, and lower resource areas in the United States and the locations used to calculate LCOE in the SunShot Vision Study. The calculated values are summarized in Figure 18.¹⁸

¹⁸ Because this analysis uses a more robust set of current and historical assumptions LCOE values may differ from previously reported benchmarked values.

2020 SunShot Goal: LCOE = 10 cents/kWh without ITC
2030 SunShot Goal: LCOE = 5 cents/kWh without ITC

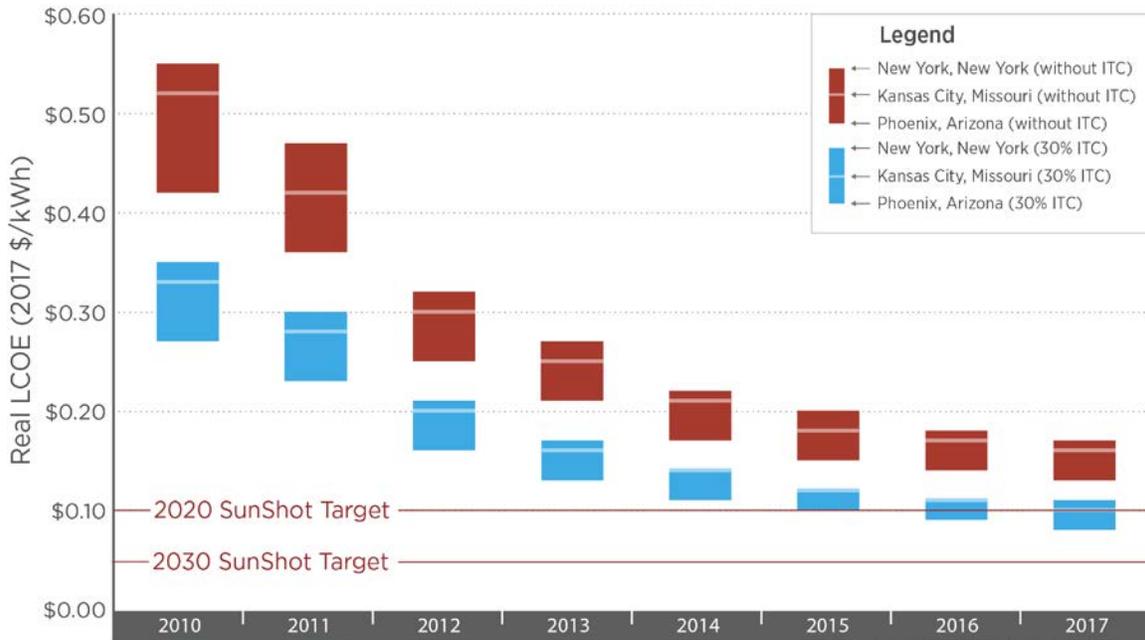


Figure 18. Levelized cost of energy for residential PV systems, by region and with and without ITC, 2010 –2017

As demonstrated in Figure 18, from 2010 to 2017 there was a 70% reduction in the residential PV system electricity cost benchmark (a 5% to 6% reduction was achieved from Q1 2016 to Q1 2017), bringing the unsubsidized LCOE between \$0.13/kWh to \$0.17/kWh (\$0.08/kWh to \$0.11/kWh when including the federal ITC). This reduction is 86% toward achieving SunShot’s 2020 residential PV LCOE goal.¹⁹

¹⁹ The SunShot 2020 target is adjusted from 2010 USD using the Consumer Price Index (CPI). A Summary of these values can be found in Appendix A and B. For LCOE Kansas City, MO, without ITC cases are \$0.52/kWh in 2010 and \$0.16/kWh in 2017 in 2017 USD from Appendix A and B. Thus, calculation is: $(0.52 - 0.16)/(0.52 - 0.10) = 86\%$.

4 Commercial PV Model

This section describes our commercial model’s structure, inputs, and assumptions (Section 4.1) and output (Section 4.2).

4.1 Commercial Model Structure, Inputs, and Assumptions

We model a 200-kW, 1,000 volts DC (Vdc), commercial-scale flat-roof system using multicrystalline 17.5%-efficient modules from a Tier 1 supplier, three-phase string inverters, and a ballasted racking solution on a membrane roof. A penetrating PV mounting system can have higher energy yield (kWh per kW) owing to wider tilt-angle range allowance. However, we do not model this system type, because its market share has declined owing to additional required flashing and sealing work, roof warranty issues, and the relative difficulty of replacing such a system in the future. Figure 19 presents a schematic of our commercial-scale system cost model. Table 8 presents the detailed modeling inputs and assumptions. We separate our cost estimate into EPC and project-development functions. Although some firms engage in both activities in an integrated manner, and potentially achieve lower cost and pricing by reducing the total margin across functions, we believe the distinction can help separate and highlight the specific cost trends and drivers associated with each function.

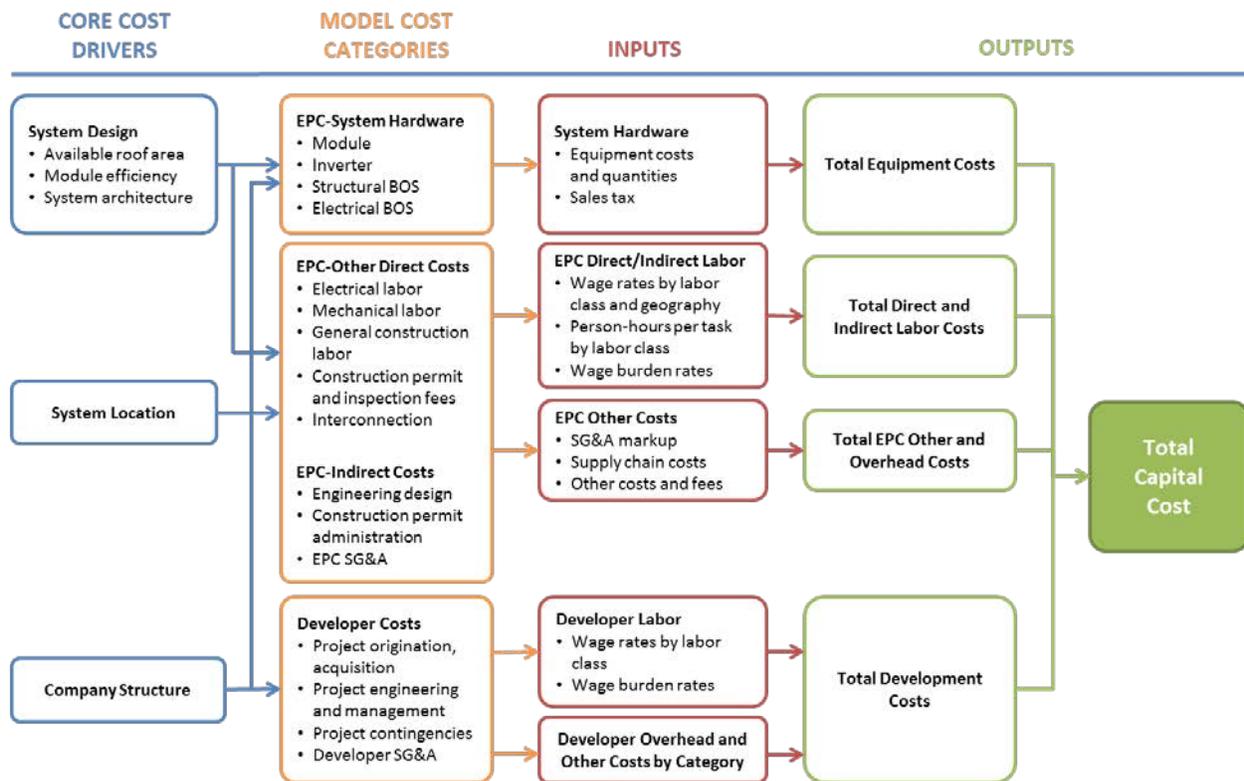


Figure 19. Commercial PV: model structure

Table 8. Commercial PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	10 kW – 2 MW	Average installed size per system	Go Solar CA (2017)
Module efficiency	17.5%	Average module efficiency	Go Solar CA (2017)
Module price	\$0.35/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	Bloomberg (2017), NREL (2017)
Inverter price	Three-phase string inverter: \$0.10/Wdc	Ex-factory gate prices (first buyer) price, Tier 1 inverters	Bloomberg (2017), NREL (2017)
Structural components (racking)	\$0.13–\$0.28/Wdc; varies by location and system size	Flat-roof ballasted racking system	ASCE (2006), model assumptions, NREL (2017)
Electrical components	Varies by location and system size	Conductors, conduit and fittings, transition boxes, switchgear, panel boards, etc.	Model assumptions, NREL (2017), RSMMeans (2016)
EPC overhead (% of equipment costs)	13%	Costs and fees associated with EPC overhead, inventory, shipping, and handling	NREL (2017)
Sales tax	Varies by location	Sales tax on equipment costs; national benchmark applies an average (by state) weighted by 2016 installed capacities	DSIRE (2017), RSMMeans (2016)
Direct installation labor	Electrician: \$19.37–\$38.22 per hour Laborer: \$12.64–\$25.09 per hour Varies by location and inverter option	Modeled labor rate assumes non-union labor and depends on state; national benchmark uses weighted average of state rates	BLS (2017), NREL (2017)
Burden rates (% of direct labor)	Total nationwide average: 31.8%	Workers compensation (state-weighted average), federal and state unemployment insurance, FICA, builders risk, public liability	RSMMeans (2016)
PII	\$0.11–\$0.16/Wdc	For construction permits fee, interconnection, testing, and commissioning	NREL (2017)
Developer overhead	Assume 10-MW system development and installation per year for a typical developer	Includes fixed overhead expenses such as payroll, facilities, travel, insurance, administrative, business development, finance, and other corporate functions; assumes 10 MW/year of system sales	Model assumptions, NREL (2017)
Contingency	4%	Estimated as markup on EPC price; value represents actual cost overruns above estimated price	NREL (2017)
Profit	7%	Applies a fixed percentage margin to all costs including hardware, installation labor, EPC overhead, developer overhead, etc.	NREL (2017)

4.2 Commercial Model Output

Figure 20 presents the U.S. national benchmark from our commercial model. As in the residential model, the national benchmark represents an average weighted by 2016 state-installed capacities. We model different system sizes because of the wide scope of the “commercial” sector, which comprises a diverse customer base occupying a variety of building sizes. Economies of scale—driven by hardware, labor, and related markups—are evident here. As system sizes increase, the per-watt cost to build them decreases. This holds even as we assume that a typical developer has 10 MW of system development and installation per year, and therefore has overhead on this 10 MW total capacity that does not vary for different system sizes. When a developer installs more capacity annually, the developer’s overhead per watt in each system declines (shown in Figure 18 in our Q1 2015 benchmark report, Chung et al. 2015).

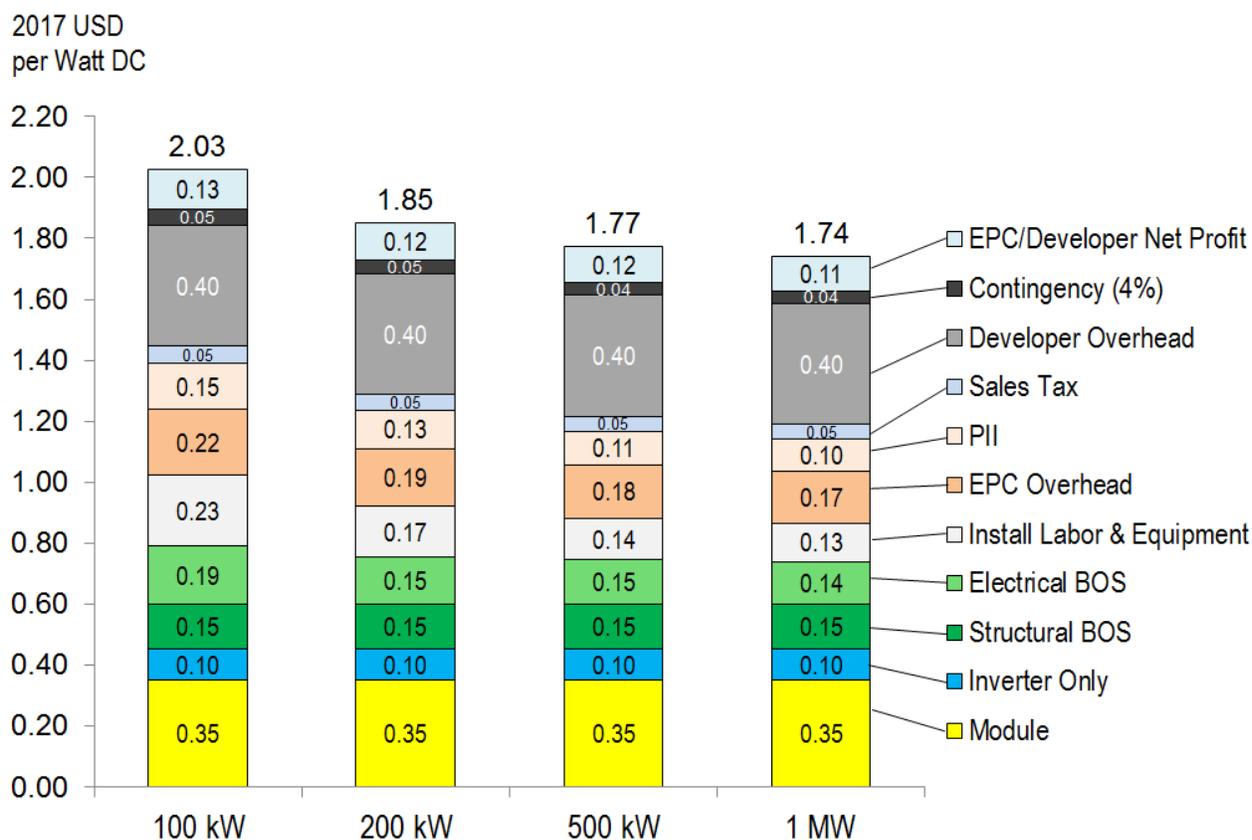


Figure 20. Q1 2017 U.S. benchmark: commercial system cost (2017 USD/Wdc)

The PII cost was higher in Q1 2017 than in Q1 2016, because the low-hanging fruit—such as ideal commercial building rooftops—have already been picked by Q1 2017. Thus, the associated PII time and fees were higher in Q1 2017 for commercial projects with more PII obstacles. Also, the higher net profit in Q1 2017—7%, compared with 2% in Q1 2016—indicates that the rapid module price reduction in 2016 enabled EPC firms and developers to retain a higher profit and still maintain a competitive project cost (NREL 2017).

Figure 21 presents the benchmark from our commercial model by location in the top U.S. solar markets (by 2016 installations). The main cost drivers for different regions in the commercial PV market are the same as in the residential model (labor rates, sales tax, and cost of doing business index), but also include costs associated with wind or snow loading.

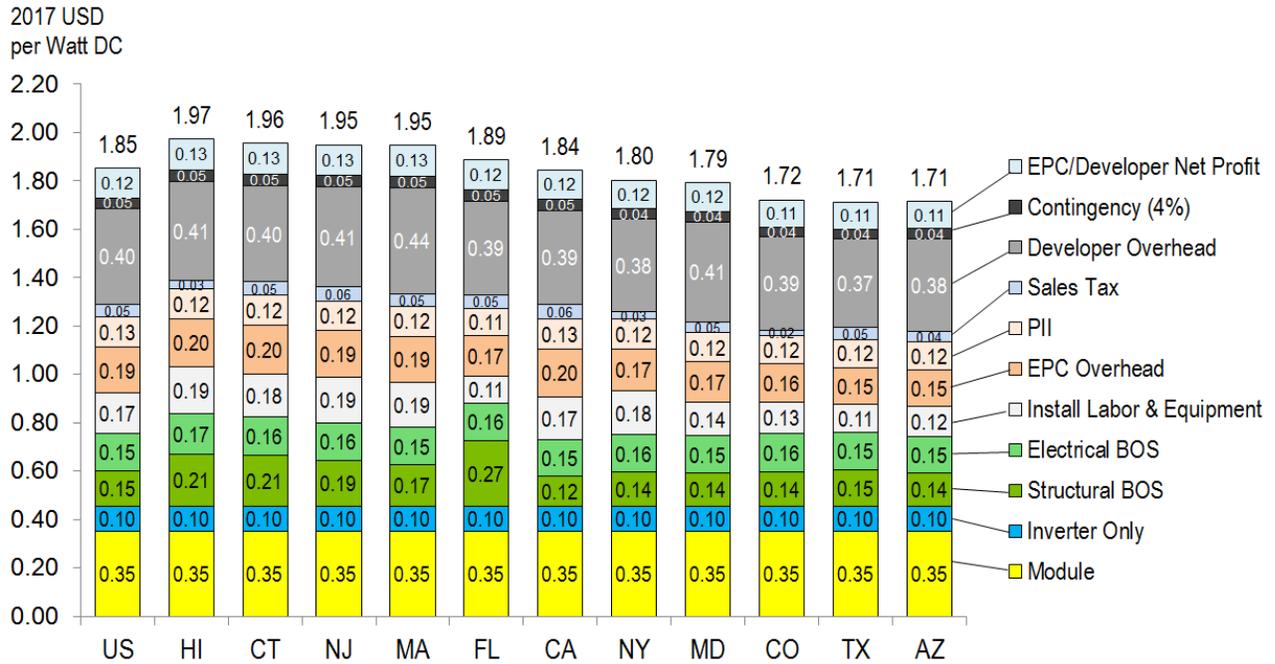


Figure 21. Q1 2017 benchmark by location: 200-kW commercial system cost (2017 USD/Wdc)

4.3 Commercial PV Price Benchmark Historical Trends

Figure 22 summarizes the reduction in commercial PV system cost benchmarks between 2010 and 2017.²⁰

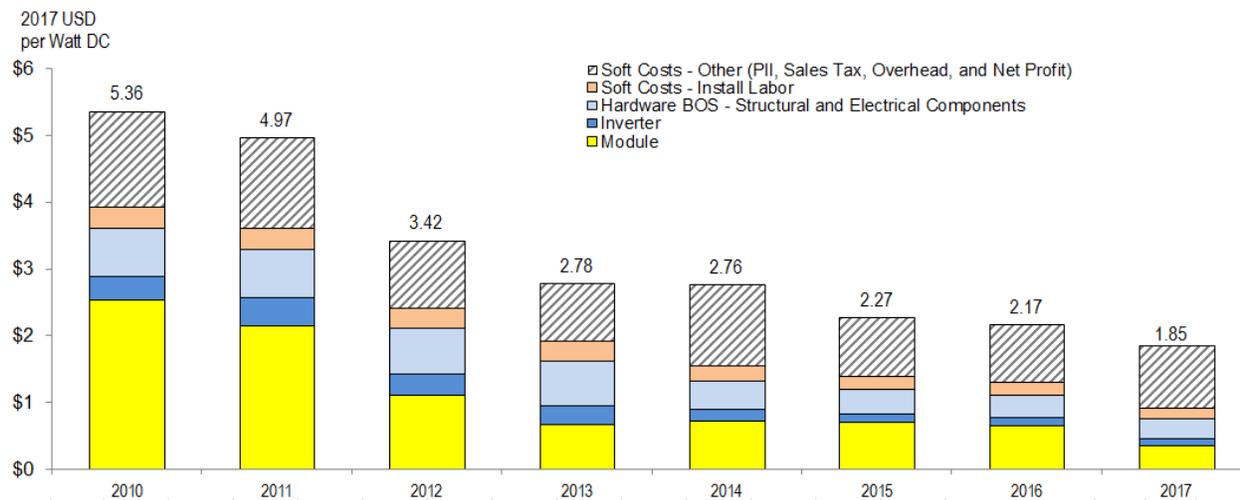


Figure 22. NREL commercial PV system cost benchmark summary (inflation adjusted), Q4 2009–Q1 2017

As demonstrated in Figure 22, from 2010 to 2017 there was a 65% reduction in the commercial PV system cost benchmark. Approximately 82% of that reduction can be attributed to total hardware costs (module, inverter, and hardware BOS), as module prices dropped 86% over that time period. An additional 4% can be attributed to labor, which dropped 47% over that time period, with the final 14% attributable to other soft costs, including PII, sales tax, overhead, and net profit.

Looking at this past year, from 2016 to 2017 there was a 15% reduction in the commercial PV system cost benchmark. The majority of that reduction can be attributed to the 46% reduction in module factory gate price, moderated by an increase in PII and installer profit.

4.4 Commercial PV Levelized Cost of Energy Historical Trends

While LCOE is not a perfect metric to measure the competitiveness of PV within the energy marketplace, it incorporates many other PV metrics important to the energy costs beyond upfront installation costs. These benchmarks are summarized over time in Table 9, from 2010 to 2017 (^aSunShot Vision Study 2010, ^bOn the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; ^cOn the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); ^dTerms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), ^eU.S. Solar Photovoltaic System Cost Benchmark: Q1 2016).²¹

²⁰ Each year’s PV system cost benchmark corresponds to the NREL benchmark calculated in Q4 of the previous year or Q1 of the current year (e.g. 2010 = Q4 2009; 2017 = Q1 2017).

²¹ In instances in which LCOE assumptions were not found from the selected literature in a given year, straight-line changes were assumed between any two values.

Table 9. Commercial PV LCOE Assumptions, 2010–2017

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Installed cost	\$5.36	\$4.97	\$3.42	\$2.78	\$2.76	\$2.27	\$2.17	\$1.85
Annual degradation (%)	1.00% ^a	0.95%	0.90%	0.85%	0.80%	0.75% ^b	0.75%	0.75%
Inverter replacement price (\$/W)	\$0.24 ^a	\$0.22	\$0.19	\$0.17	\$0.15	\$0.12 ^b	\$0.11 ^e	\$0.10
O&M expenses (\$/kw-yr)	\$26 ^a	\$24	\$22	\$20	\$18	\$15 ^b	\$15	\$15
Pre-inverter derate (%)	90.5% ^a	90.50%	90.50%	90.50%	90.50%	90.5% ^b	90.5%	90.5%
Inverter efficiency (%)	95.0% ^a	95.60%	96.20%	96.80%	97.40%	98.0% ^b	98.0%	98.0%
Inverter loading ratio	1.10 ^a	1.11	1.12	1.13	1.13	1.14	1.15 ^e	1.15
Equity discount rate^e (real)	9.0% ^c	8.6%	8.3%	7.9%	7.6%	7.3%	6.9% ^d	6.9%
Inflation rate	2.5% ^a	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate^f	5.5% ^c	5.4%	5.3%	5.2%	5.0%	4.9%	4.8% ^d	4.8%
Debt fraction	34.2% ^c	35.2%	36.1%	37.1%	38.1%	39.0%	40.0% ^d	40.0%

Other important assumptions: commercial PV system LCOE assume a 1) system lifetime of 30 years^b, 2) federal tax rate of 35%^b, 3) state tax rate of 7%^b, 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)^b, 7) a six month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system^b, 8) a system size of 200 kW^a, 9) an inverter lifetime of 15 years^a, 10) a module tilt angle of 10 degrees, and an azimuth of 180 degrees, 11) debt with a term of 18 years^b, and 12) \$1.1MM of upfront financial transaction costs for a \$100MM TPO transaction of a pool of commercial projects^d.

^e The financial assumptions in Table 7 assume a \$100MM TPO transaction of a pool of commercial projects.

^f The historical financial structure for a residential TPO system, assumed in 2010 from Feldman and Bolinger 2016 does not assume a debt raise; however, the financial structure in 2016 from Feldman, Lowder, and Schwabe does assume back-leveraged debt. To make these assumptions uniform, the “debt interest rate” and “debt fraction” are taken from the utility-scale historical financial structure in Feldman and Bolinger 2016 that uses back-leveraged debt.

As demonstrated in Table 9, in addition to a 65% reduction in installed cost from 2010 to 2017, inverter replacement costs reduced 58%, O&M costs reduced 41%, annual degradation rates reduced 25%, the equity discount rate reduced 23%, the debt interest rate reduced 13%, and the debt fraction increased 17%.

Using these assumptions we calculated the LCOE, with and without the 30% federal investment tax credit (ITC), in Phoenix, AZ, Kansas City, MO, and New York, NY, corresponding to higher, medium, and lower resource areas in the United States and the locations used to calculate LCOE in the SunShot Vision Study. The calculated values are summarized in Figure 23.²²

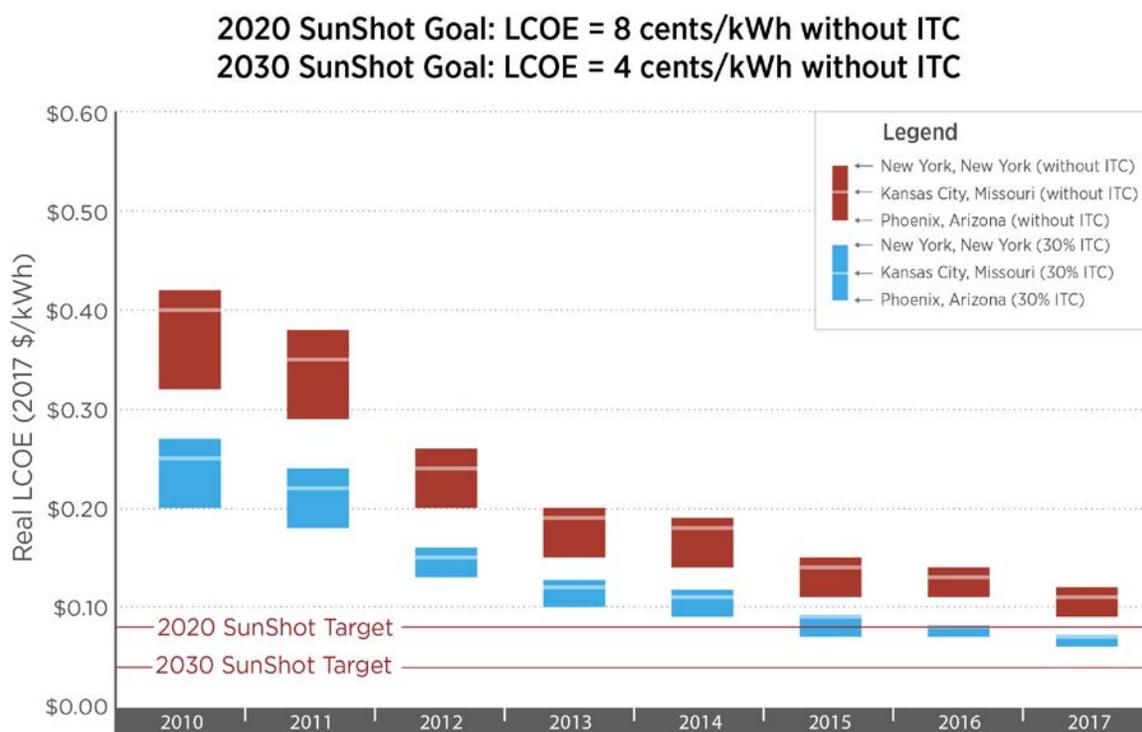


Figure 23. Levelized cost of energy for commercial PV systems, by region and with and without ITC, 2010 –2017

As demonstrated in Figure 23, from 2010 to 2017 there was a 71% - 72% reduction in the commercial PV system electricity cost benchmark (a 12% - 13% reduction was achieved from 2016 to 2017), bringing the unsubsidized LCOE between \$0.09/kWh to \$0.12/kWh (\$0.06/kWh to \$0.08/kWh when including the federal ITC). This reduction is 89% toward achieving SunShot’s 2020 commercial PV LCOE goal.²³

²² Because this analysis uses a more robust set of current and historical assumptions LCOE values may differ from previously reported benchmarked values.

²³ The SunShot 2020 target is adjusted from 2010 USD using the CPI. A Summary of these values can be found in Appendix A and B. For LCOE Kansas City, MO, without ITC cases are \$0.40/kWh in 2010 and \$0.11/kWh in 2017 in 2017 USD from Appendix A and B. Thus, calculation is: $(0.40 - 0.11)/(0.40 - 0.08) = 89\%$.

5 Utility-Scale PV Model

This section describes our utility-scale model’s structure, inputs, and assumptions (Section 5.1) and output (Section 5.2).

5.1 Utility-Scale Model Structure, Inputs, and Assumptions

We model a 100-MW, 1,000-Vdc utility-scale system using 72-cell, multicrystalline 17.5%-efficient modules from a Tier 1 supplier and three-phase central inverters. We model both fixed-tilt and one-axis tracking on ground-mounted racking systems using driven-pile foundations. In addition, we separate our cost estimate into EPC and project-development functions. Although some firms engage in both activities in an integrated manner, we believe the distinction can help separate and highlight the specific cost trends and drivers associated with each function.

Figure 24 presents a schematic of our utility-scale system cost model, and Table 10 details its assumptions and inputs.

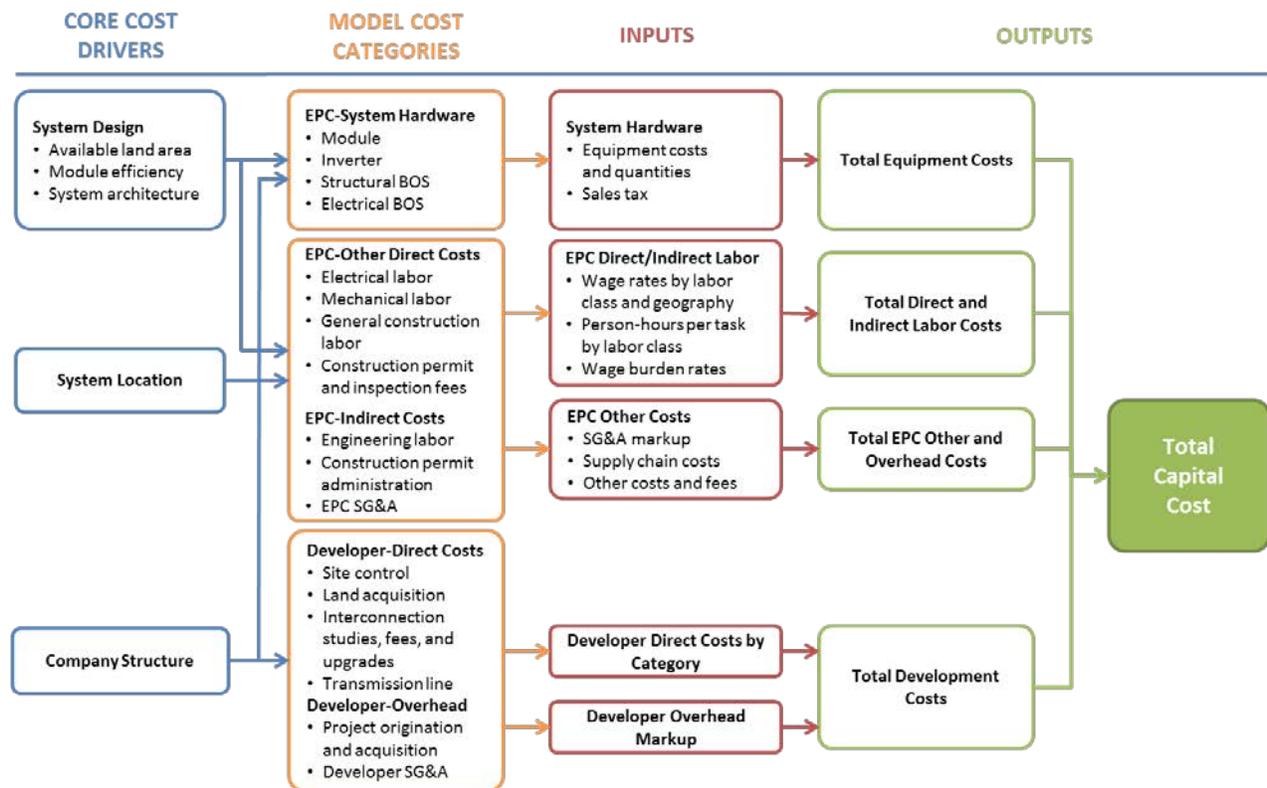


Figure 24. Utility-scale PV: model structure

Table 10. Utility-Scale PV: Modeling Inputs and Assumptions

Category	Modeled Value	Description	Sources
System size	>2 MW	A large utility-scale system capacity	Model assumption
Module efficiency	17.5%	Average module efficiency	NREL (2017)
Module price	\$0.35/Wdc	Ex-factory gate (first buyer) price, Tier 1 modules	Bloomberg (2017), NREL (2017)
Inverter price	\$0.06/Wdc (fixed-tilt)	Ex-factory gate prices (first buyer) price, Tier 1 inverters	Bloomberg (2017), NREL (2017), Bolinger and Seel (2017)
	\$0.06/Wdc (one-axis tracker)	DC-to-AC ratio = 1.3 for both fixed-tilt and one-axis tracker	
Structural components (racking)	\$0.10–\$0.21/Wdc for a 100-MW system; varies by location and system size	Fixed-tilt racking or one-axis tracking system	ASCE (2006), model assumptions, NREL (2017)
Electrical components	Varies by location and system size	Conductors, conduit and fittings, transition boxes, switchgear, panel boards, onsite transmission, etc.	Model assumptions, NREL (2017), RSMMeans (2016)
EPC overhead (% of equipment costs)	8.67%–13% for equipment and material (except for transmission line costs); 23%–69% for labor costs; varies by system size, labor activity, and location	Costs associated with EPC SG&A, warehousing, shipping, and logistics	NREL (2017)
Sales tax	Varies by location	National benchmark applies an average (by state) weighted by 2016 installed capacities	DSIRE (2017), RSMMeans (2016)
Direct installation labor	Electrician: \$19.37–\$38.22 per hour Laborer: \$12.64–\$25.09 per hour Varies by location and inverter option	Modeled labor rate assumes non-union and union labor and depends on state; national benchmark uses weighted average of state rates	BLS (2017), NREL (2017)
Burden rates (% of direct labor)	Total nationwide average: 31.8%	Workers compensation (state-weighted average), federal and state unemployment insurance, FICA, builders risk, public liability	RSMMeans (2016)

Category	Modeled Value	Description	Sources
PII	\$0.03–\$0.09/Wdc Varies by system size and location	For construction permits fee, interconnection, testing, and commissioning	NREL (2017)
Transmission line (gen-tie line)	\$0.00–\$0.02/Wdc Varies by system size	System size < 10 MW, use 0 miles for gen-tie line System size > 200 MW, use 5 miles for gen-tie line System size = 10–200 MW, use linear interpolation	Model assumptions, NREL (2017)
Developer overhead	3%–12% Varies by system size (100 MW uses 3%; 5 MW uses 12%)	Includes overhead expenses such as payroll, facilities, travel, legal fees, administrative, business development, finance, and other corporate functions	Model assumptions, NREL (2017)
Contingency	3%	Estimated as markup on EPC cost	NREL (2017)
Profit	5%–8% Varies by system size (100 MW uses 5%; 5 MW uses 8%)	Applies a percentage margin to all costs including hardware, installation labor, EPC overhead, developer overhead, etc.	NREL (2017)

Figure 25 shows the percentage of U.S. utility-scale PV systems using tracking systems for 2007–2016. Although the data include one-axis and dual-axis tracking systems in the same “tracking” category, there are many more one-axis trackers than dual-axis trackers (Bolinger and Seel 2017). Cumulative tracking system installation reached 64% in 2016.

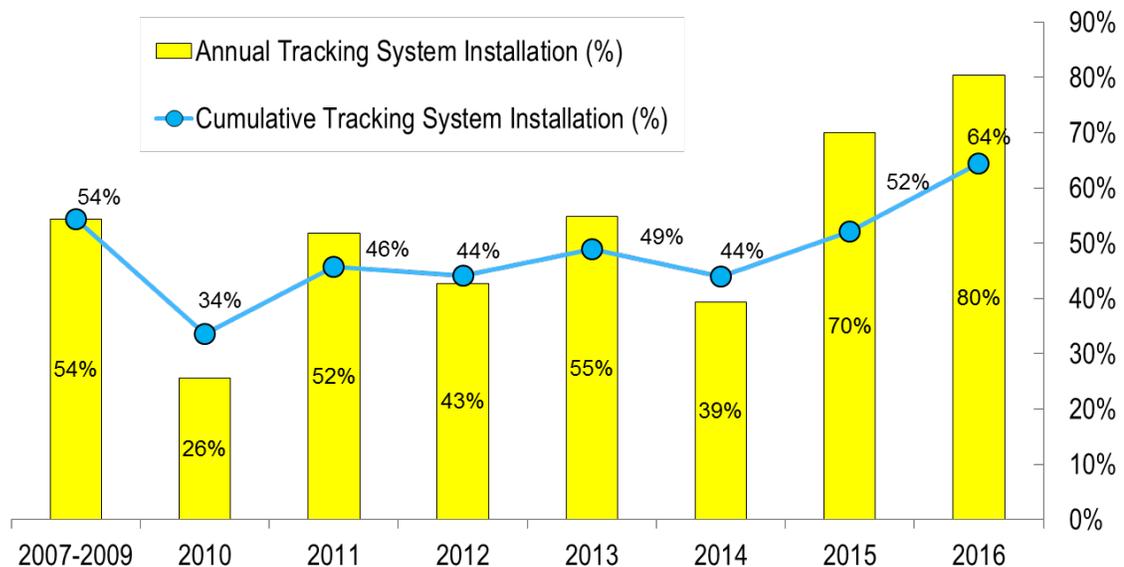


Figure 25. Percentage of U.S. utility-scale PV systems using tracking systems, 2007–2016 (Bolinger and Seel 2017)

Although EPC contractors and developers tend to employ low-cost, non-union labor (based on data from BLS 2017) for PV system construction when possible, union labor is sometimes mandated. Construction trade unions may negotiate with the local jurisdiction and EPC contractor/developer during the public review period of the permitting process. Figure 26 shows 2016 utility-scale PV capacity installed (GTM Research and SEIA 2017) and the proportion of unionized labor in each state (BLS 2017). The unionized labor number represents the percentage of employed workers in each state’s entire construction industry who are union members. In our utility-scale model, both non-union and union labor rates are considered (Figure 27).

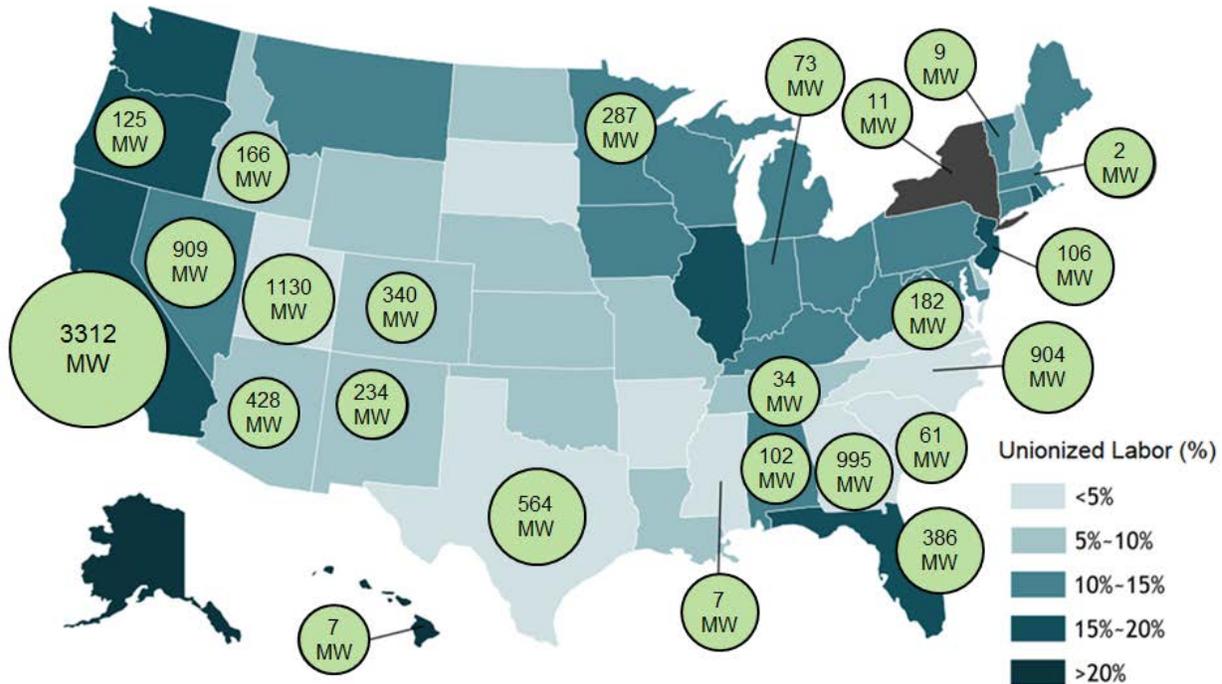


Figure 26. Utility-scale PV: 2016 capacity installed and percentage of unionized labor by state (BLS 2017; GTM Research and SEIA 2017)

5.2 Utility-Scale Model Output

Figure 27 presents the regional EPC benchmark from our utility-scale model, and Figure 28 presents the U.S. national benchmark (EPC + developer) for fixed-tilt and one-axis tracker systems, using non-union labor. In Figure 28, note the following:

1. The national benchmark applies an average weighted by 2016 installed capacities.
2. Non-union labor is used.
3. Economies of scale—driven by BOS, labor, related markups, and development cost—are demonstrated.

As in the commercial PV sector, the 7% net profit in Q1 2017 is higher than the 2% in Q1 2016, because the rapid module price reduction in 2016 enabled EPC firms and developers to retain a higher profit and still keep a competitive project cost bid.

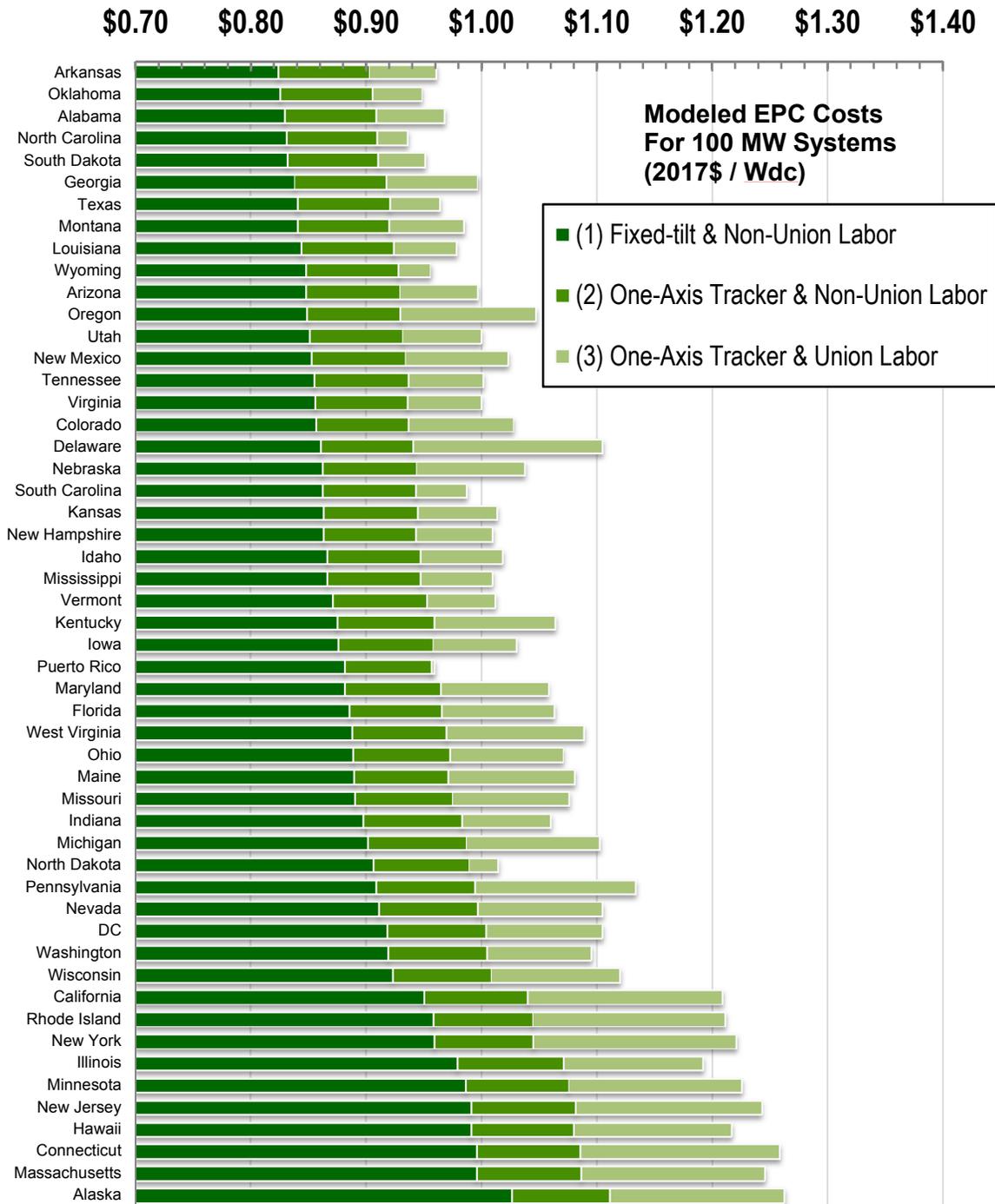


Figure 27. Q1 2017 benchmark by location: 100-MW utility-scale PV systems, EPC only (2017 USD/Wdc)²⁴

²⁴ The fixed-tilt, non-union cost is always lowest, followed by the one-axis tracker, non-union cost and the one-axis tracker, union cost. Thus the bars are additive: the fixed-tilt, non-union cost is represented by the dark green bar alone; the one-axis tracker, non-union cost is the sum of the dark green and medium green bars; and the one-axis tracker, union cost is the sum of all three bars.

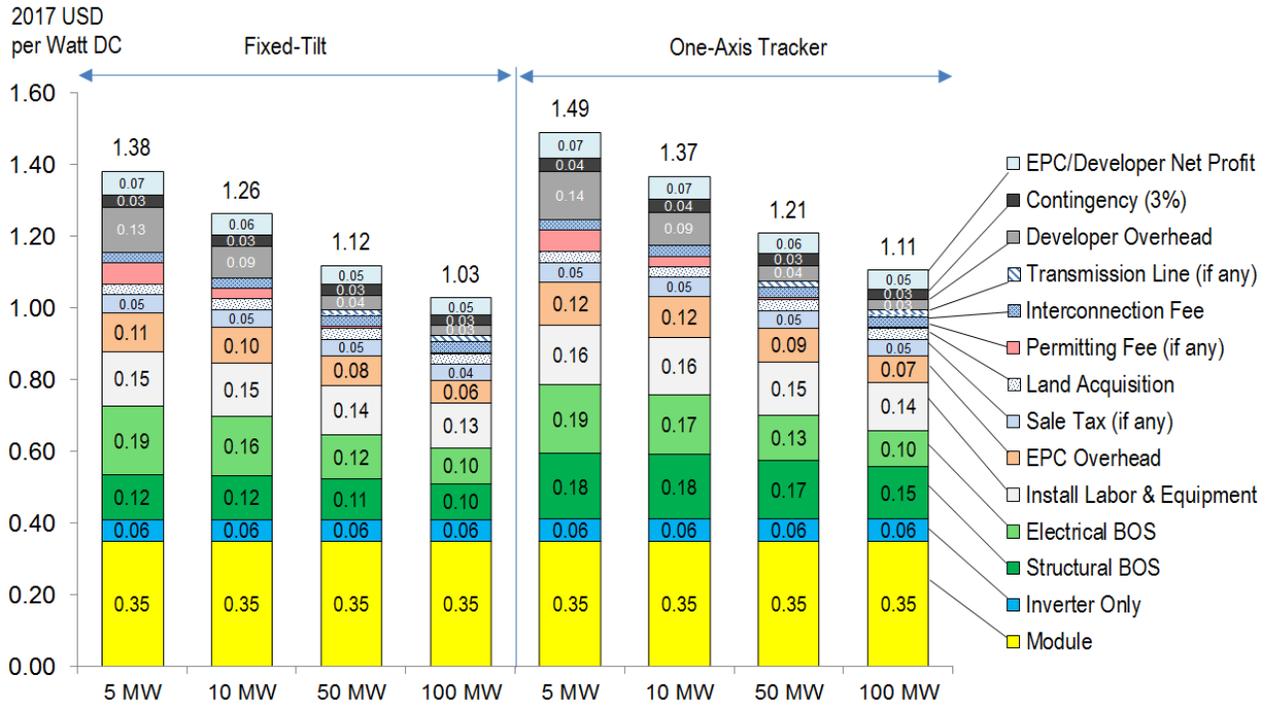


Figure 28. Q1 2017 U.S. benchmark: utility-scale PV total cost (EPC + developer), 2017 USD/Wdc²⁵

²⁵ Although four different system sizes are shown in this figure, the actual national average system size in 2015 was 29 MW for fixed-tilt systems and 37 MW for one-axis tracker systems. Our model estimates \$1.17/W for 29-MW fixed-tilt systems and \$1.25/W for 37-MW one-axis tracker systems.

5.3 Utility-Scale PV Price Benchmark Historical Trends

Figure 29 summarizes the reduction in utility-scale PV system cost benchmarks between 2010 and 2017.²⁶

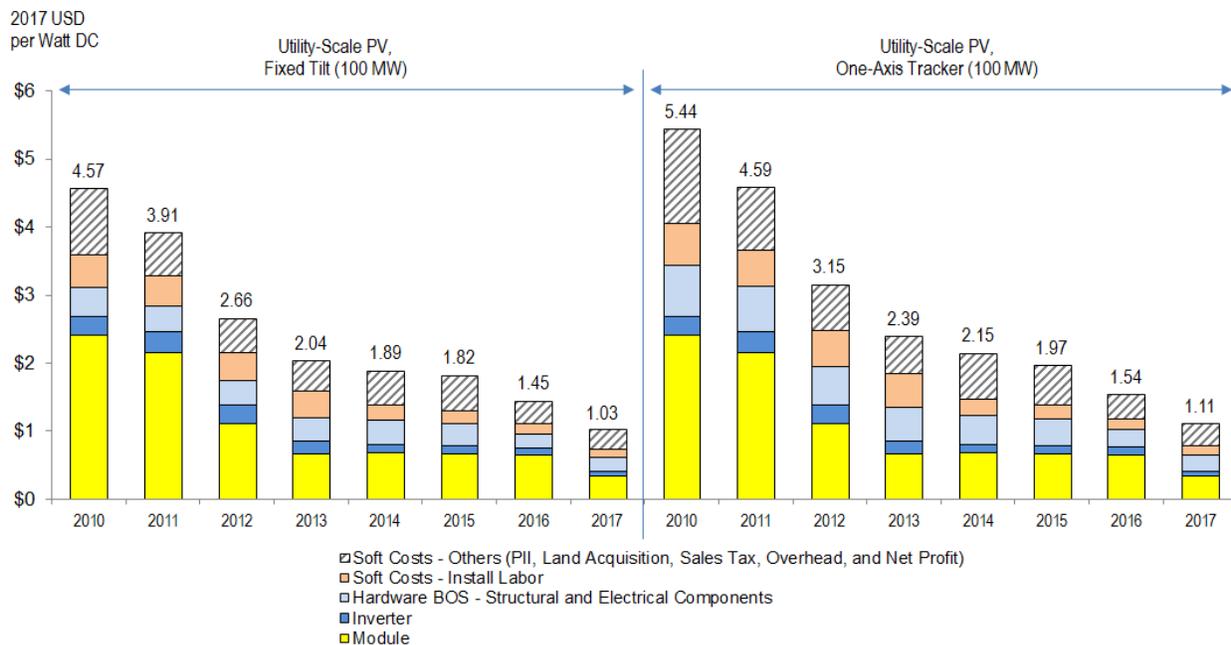


Figure 29. NREL utility-scale PV system cost benchmark summary (inflation adjusted), 2010–2017

As demonstrated in Figure 29, from 2010 to 2017 there was a 77% reduction in the utility-scale (fixed-tilt) PV system cost benchmark, and an 80% reduction in the utility-scale (one-axis) PV system cost benchmark. Approximately 71% and 64% of that reduction can be attributed to total hardware costs (for fixed-tilt and one-axis systems respectively), as module prices dropped 86% over that time period. An additional 10% / 11% can be attributed to labor, which dropped 74% / 78% over that time period, with the final 19% / 25% attributable to other soft costs, including PII, sales tax, overhead, and net profit (for fixed-tilt and one-axis systems respectively).

Looking at this past year, from 2016 to 2017 there was a 29% reduction in the utility-scale (fixed-tilt) PV system cost benchmark, and an 28% reduction in the utility-scale (one-axis) PV system cost benchmark. The majority of that reduction can be attributed to the 46% reduction in module factory gate price, and a 45% / 41% reduction in inverter factory gate price.²⁷

²⁶ Each year’s PV system cost benchmark corresponds to the NREL benchmark calculated in Q4 of the previous year or Q1 of the current year (e.g. 2010 = Q4 2009; 2017 = Q1 2017).

²⁷ One-axis and fixed-tilt PV systems have different reductions in inverter factory gate price due to differing ILRs in 2016.

5.4 Utility-Scale PV Levelized Cost of Energy Historical Trends

While LCOE is not a perfect metric to measure the competitiveness of PV within the energy marketplace, it incorporates many other PV metrics important to the energy costs beyond upfront installation costs. These benchmarks are summarized over time in Table 11 (next page), from Q4 2009 to Q1 2017 (^aSunShot Vision Study 2010, ^bOn the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs; ^cOn the Path to SunShot: Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016); ^dTerms, Trends, and Insights PV Project Finance in the United States (Feldman, Lowder and Schwabe 2016), ^eU.S. Solar Photovoltaic System Cost Benchmark: Q1 2016).²⁸

As demonstrated in Table 11, in addition to a 80% reduction in installed cost of utility-scale (one-axis) systems from 2010 to 2017, inverter replacement costs reduced 68%, O&M costs reduced 17%, annual degradation rates reduced 25%, the equity discount rate reduced 14%, the debt interest rate reduced 18%, and the debt fraction increased 17%.

Using these assumptions we calculated the LCOE, with and without the 30% federal investment tax credit (ITC), in Phoenix, AZ, Kansas City, MO, and New York, NY, corresponding to higher, medium, and lower resource areas in the United States and the locations used to calculate LCOE in the SunShot Vision Study. The calculated values are summarized in Figure 30.²⁹

²⁸ In instances in which LCOE assumptions were not found from the selected literature in a given year, straight-line changes were assumed between any two values.

²⁹ Because this analysis uses a more robust set of current and historical assumptions LCOE values may differ from previously reported benchmarked values.

Table 11. One-Axis Tracker and Fixed-Tilt Utility-Scale PV LCOE Assumptions, 2010–2017

2017 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
One-Axis Tracker								
Installed cost	\$5.44	\$4.59	\$3.15	\$2.39	\$2.15	\$1.97	\$1.54	\$1.11
Annual degradation (%)	1.00% ^a	0.95%	0.90%	0.85%	0.80%	0.75% ^b	0.75%	0.75%
Inverter replacement price (\$/W)	\$0.19 ^a	\$0.17	\$0.15	\$0.14	\$0.12	\$0.10 ^b	\$0.08 ^e	\$0.06
O&M expenses (\$/kw-yr)	\$22.2 ^a	\$21.5	\$20.7	\$20.0	\$19.2	\$18.5 ^b	\$18.5	\$18.5
Pre-inverter derate (%)	90.5% ^a	90.50%	90.50%	90.50%	90.50%	90.5% ^b	90.5%	90.5%
Inverter efficiency (%)	96.0% ^a	96.40%	96.80%	97.20%	97.60%	98.0% ^b	98.0%	98.0%
Inverter loading ratio	1.10 ^a	1.12	1.13	1.15	1.17	1.18	1.20 ^e	1.30
Equity discount rate (real)	7.4% ^c	7.2%	7.0%	6.9%	6.7%	6.5%	6.3% ^d	6.3%
Inflation rate	2.5% ^a	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5% ^c	5.3%	5.2%	5.0%	4.8%	4.7%	4.5% ^d	4.5%
Debt fraction	34.2% ^c	35.2%	36.1%	37.1%	38.1%	39.0%	40.0% ^d	40.0%
Fixed-Tilt								
Installed cost	\$4.57	\$3.91	\$2.66	\$2.04	\$1.89	\$1.82	\$1.45	\$1.03
Annual degradation (%)	1.00% ^a	0.95%	0.90%	0.85%	0.80%	0.75% ^b	0.75%	0.75%
Inverter replacement price (\$/W)	\$0.19 ^a	\$0.17	\$0.15	\$0.14	\$0.12	\$0.10 ^b	\$0.08 ^e	\$0.06
O&M expenses (\$/kw-yr)	\$22.2 ^a	\$20.9	\$19.5	\$18.1	\$16.8	\$15.4 ^b	\$15.4	\$15.4
Pre-inverter derate (%)	90.5% ^a	90.50%	90.50%	90.50%	90.50%	90.5% ^b	90.5%	90.5%
Inverter efficiency (%)	96.0% ^a	96.40%	96.80%	97.20%	97.60%	98.0% ^b	98.0%	98.0%
Inverter loading ratio	1.10 ^a	1.15	1.2	1.25	1.3	1.35	1.40 ^e	1.3
Equity discount rate (real)	7.4% ^c	7.2%	7.0%	6.9%	6.7%	6.5%	6.3% ^d	6.3%
Inflation rate	2.5% ^a	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5% ^c	5.3%	5.2%	5.0%	4.8%	4.7%	4.5% ^d	4.5%
Debt fraction	34.2% ^c	35.2%	36.1%	37.1%	38.1%	39.0%	40.0% ^d	40.0%

Other important assumptions: utility-scale PV system LCOE assume a 1) system lifetime of 30 years^a, 2) federal tax rate of 35%^b, 3) state tax rate of 7%^b, 4) MACRS depreciation schedule, 5) no state or local subsidies, 6) a working capital and debt service reserve account for six months of operating costs and debt payments (earning an interest of 1.75%)^b, 7) a six month construction loan, with an interest rate of 4% and a fee of 1% of the cost of the system^b, 8) a system size of 100 MW^b, 9) an inverter lifetime of 15 years^a, 10) debt with a term of 18 years^b, and 11) \$1.1MM of upfront financial transaction costs^d.

2020 SunShot Goal: LCOE = 6 cents/kWh without ITC
 2030 SunShot Goal: LCOE = 3 cents/kWh without ITC

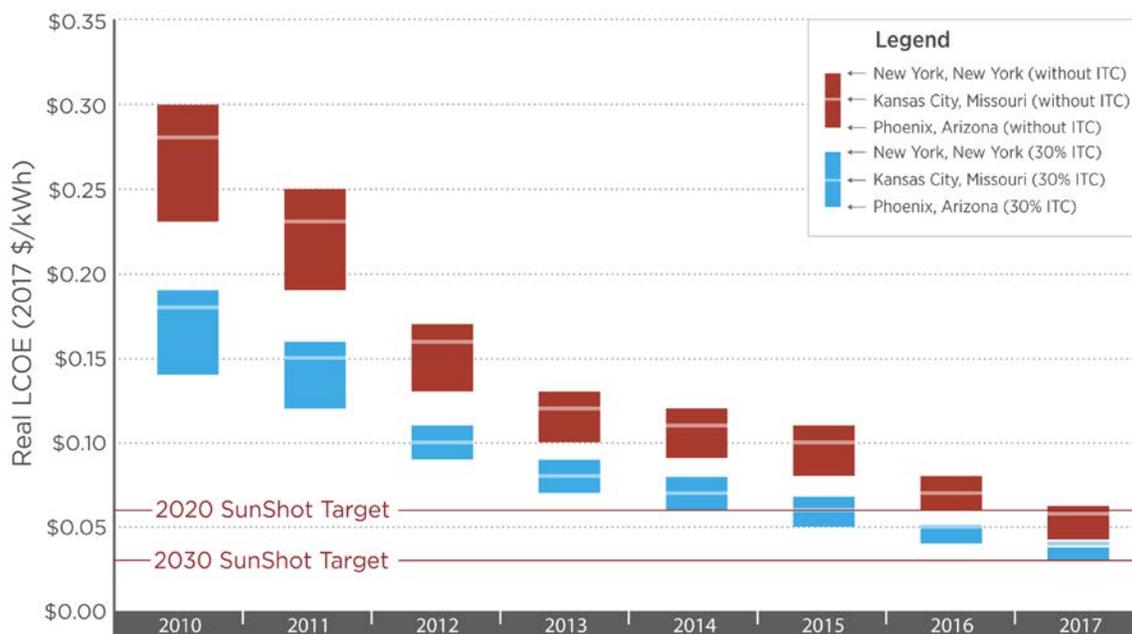


Figure 30. Levelized cost of energy for utility-scale PV systems, by region and with and without ITC, 2010–2017

We use the fixed-tilt systems for LCOE benchmarks from 2010 to 2015 and then switch to one-axis tracking systems from 2016 to 2017 to reflect the market share change in Figure 31. All detailed LCOE values can be found in Appendix A and B.

As demonstrated in Figure 30, from 2010 to 2017 there was a 78%–79% reduction in the utility-scale PV system electricity cost benchmark (a 20%–23% reduction was achieved from 2016 to 2017), bringing the unsubsidized LCOE between \$0.04/kWh to \$0.06/kWh (\$0.03/kWh to \$0.04/kWh when including the federal ITC). This reduction signifies the achievement of SunShot’s 2020 utility-scale PV goal.³⁰

³⁰The 2020 utility-scale goal is not adjusted for inflation as wholesale prices have been relatively flat, and in some cases gone down, from 2010-2017. A Summary of these values can be found in Appendix A and B.

6 Model Applications

This section includes three additional applications of our cost modeling: system cost reduction from economies of scale (Section 6.1), module efficiency impacts (Section 6.2), and regional LCOE (Section 6.3). The granularity of our bottom-up models enables us to determine the changes in particular cost drivers over time. Accordingly, the models can be used to predict future system cost-reduction opportunities based on particular market trends and technologies.

6.1 System Cost Reduction from Economies of Scale

Figure 31 demonstrates the cost savings from increased system size. Scaling up the system size from 10 MW to 100 MW reduces related costs in several ways: per-watt BOS costs because of bulk purchasing, labor costs that benefit from learning-related improvements for larger systems, and EPC overhead and developer costs that are spread over more installed capacity. Note that non-union labor is used in this figure.

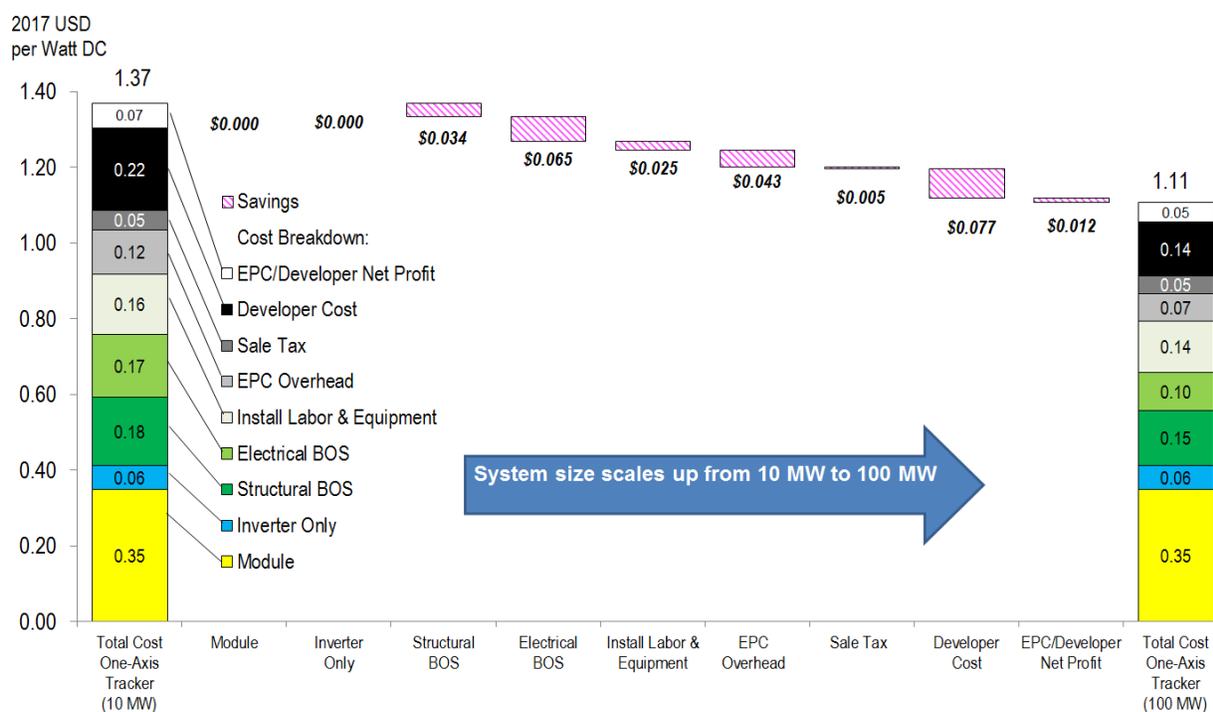


Figure 32. Model application: U.S. utility-scale one-axis tracking PV system cost reduction from economies of scale (2017 USD/Wdc)

6.2 Module Efficiency Impacts

Our system cost models can also assess the economic benefits of high module efficiency. Because higher module efficiency reduces the number of modules required to reach a certain system size, the related racking or mounting hardware, foundation, BOS, EPC/developer overhead, and labor hours are reduced accordingly. Figure 32 presents the relationship between module efficiency and installed cost (with module prices held equal for any given efficiency) and demonstrates the cost-reduction potential due to high module efficiency. Note that a fixed-tilt system is used in the utility-scale curve and a string inverter is used in the residential curve.

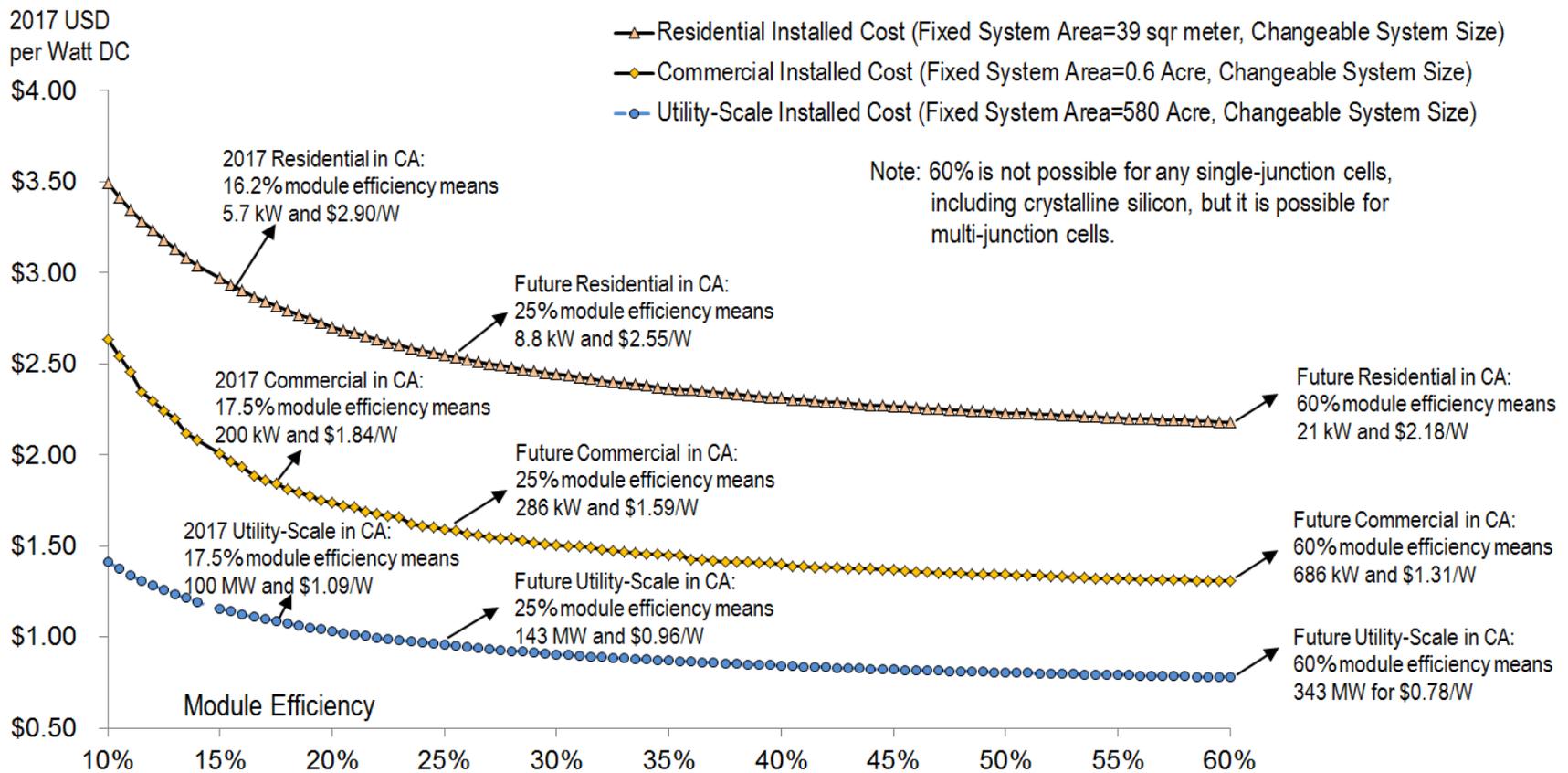


Figure 33. Modeled impacts of module efficiency on total system costs, 2017

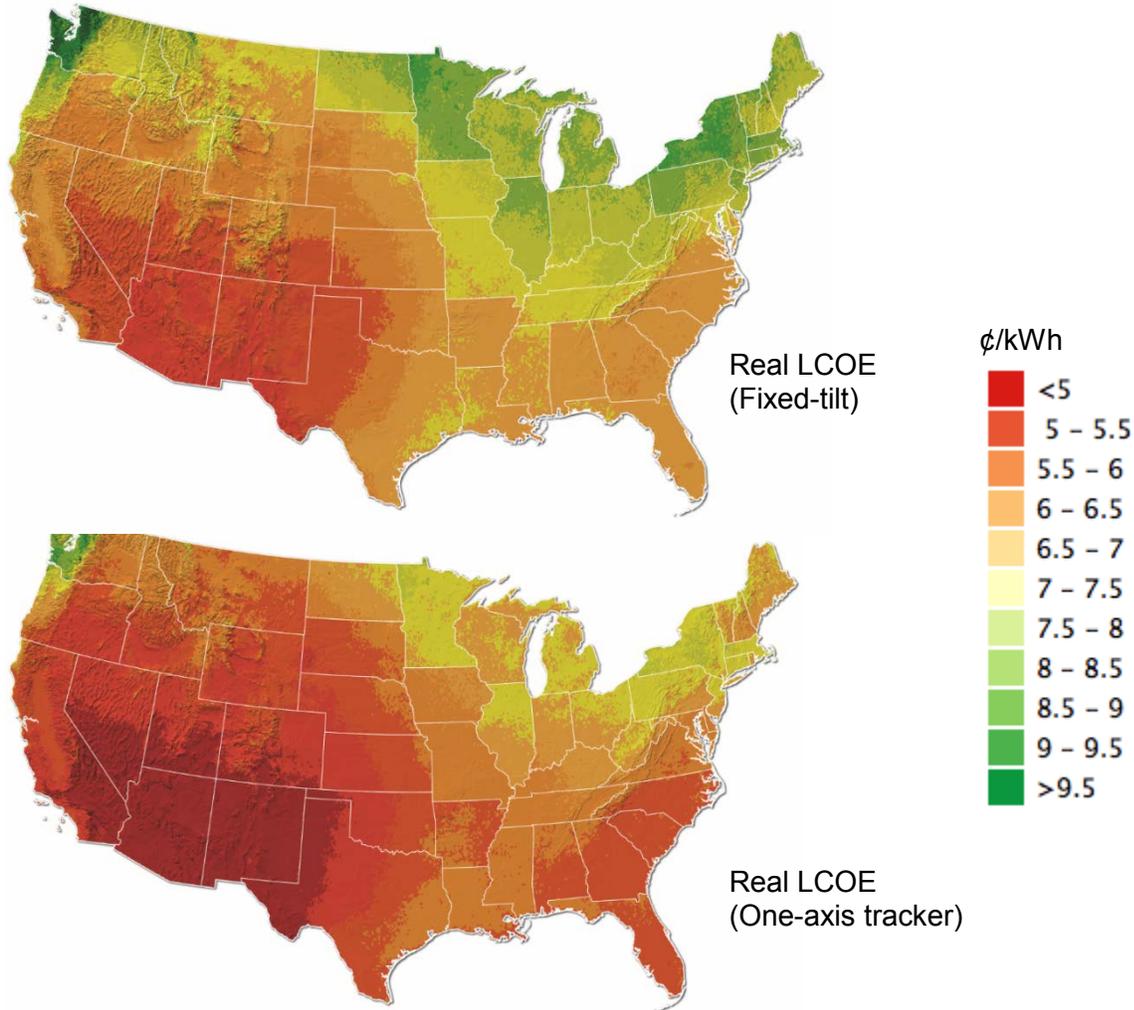
6.3 Regional LCOE

To estimate regional LCOEs across the United States, we combine modeled regional installed cost with localized solar irradiance and weather data, a PV performance model, and a pro forma financial analysis that models the revenue, operating expenses, taxes, incentives, debt structures, and cash flows for a representative PV system. We use NREL's System Advisor Model (SAM), a performance and financial model,³¹ to estimate location-specific hourly energy output over the PV system's lifetime and subsequently calculate the resulting real LCOEs (considering inflation) for each location. Figure 33 presents real LCOEs for a 100-MW utility-scale PV system with fixed tilt or one-axis tracking based on regional labor and material costs, wind speeds, snow loading, solar irradiance, weather data, and sales tax.³² We assume the following:

- ITC = 0%, Real discount rate = 6.3%, IRR target = 6.46%, Inflation = Price escalator = 2.5%, Analysis period = 30-Yr, Degradation rate = 0.75% per year. System size = 100 MW utility-scale PV, Project debt = 40%, Debt interest rate = 4.5%.
- Fixed-tilt: DC-to-AC ratio = 1.3 and Fixed O&M cost = \$15/kW per year. One-axis tracker: DC-to-AC ratio = 1.3 and Fixed O&M cost = \$18.5/kW per year.

³¹ See <https://sam.nrel.gov/>.

³² The assumptions in this LCOE exercise are the same from those in Section 5.



2017 USD		Fixed-Tilt			One-Axis Tracker			One-Axis Tracker vs. Fixed-Tilt		
State	Location	Total Installed Costs (\$/W)	Nominal LCOE (cent per kWh)	Real LCOE (cent per kWh)	Total Installed Costs (\$/W)	Nominal LCOE (cent per kWh)	Real LCOE (cent per kWh)	Installed Costs Premium (%)	Nominal LCOE Change (%)	Real LCOE Change (%)
CA	Bakersfield	1.09	7.26	5.68	1.18	6.44	5.04	8.26%	-11.29%	-11.27%
CA	Imperial	1.09	6.64	5.19	1.18	5.76	4.50	8.26%	-13.25%	-13.29%
AZ	Prescott	0.98	6.20	4.85	1.06	5.47	4.27	8.16%	-11.77%	-11.96%
AZ	Tucson	0.98	6.01	4.70	1.06	5.29	4.14	8.16%	-11.98%	-11.91%
NV	Las Vegas	1.05	6.33	4.95	1.13	5.54	4.33	7.62%	-12.48%	-12.53%
NM	Albuquerque	0.99	6.05	4.73	1.06	5.39	4.21	7.07%	-10.91%	-10.99%
CO	Alamosa	0.99	6.05	4.73	1.07	5.33	4.16	8.08%	-11.90%	-12.05%
NC	Jacksonville	0.96	7.25	5.67	1.03	6.56	5.13	7.29%	-9.52%	-9.52%
TX	San Antonio	0.97	7.11	5.56	1.04	6.55	5.12	7.22%	-7.88%	-7.91%
NJ	Newark	1.13	9.15	7.16	1.22	8.59	6.71	7.96%	-6.12%	-6.28%
FL	Orlando	1.02	8.47	6.63	1.09	7.51	5.87	6.86%	-11.33%	-11.46%
HI	Kona	1.14	8.08	6.32	1.22	7.41	5.79	7.02%	-8.29%	-8.39%

Figure 34. Modeled real LCOE (¢/kWh), ITC = 0%, for a 100-MWdc utility-scale PV system with fixed-tilt and one-axis tracking in 2017³³

³³ The U.S. Department of Energy's SunShot Initiative uses Kansas City's insolation as the national average insolation to calculate LCOE (Woodhouse et al. 2016).

7 Conclusions

Based on our bottom-up modeling, the Q1 2017 PV cost benchmarks are \$2.80/Wdc (or \$3.22/Wac) for residential systems, \$1.85/Wdc (or \$2.13/Wac) for commercial systems, \$1.03/Wdc (or \$1.34/Wac) for fixed-tilt utility-scale systems, and \$1.11/Wdc (or \$1.44/Wac) for one-axis-tracking utility-scale systems. Overall, modeled PV installed costs continued to decline in Q1 2017 for all three sectors.

Figure 34 puts our Q1 2017 benchmark results in context with the results of previous NREL benchmarking analyses. When comparing the results across this period, note the following:

1. Values are inflation adjusted using the U.S. Bureau of Labor Statistics' Consumer Price Index. Thus, historical values from our models are adjusted and presented as real USD instead of as nominal USD.
2. Cost categories are aggregated for comparison purposes. "Soft Costs – Others" represents PII, land acquisition, sales tax, and EPC/developer overhead and profit.³⁴
3. The "Utility-Scale PV, One-Axis Tracker (100 MW)" consists of our previous bottom-up results (2010 and 2013–2016) and interpolation estimates for 2009 and 2011–2012.
4. The comparison of Q1 2016 and Q1 2017 is presented in Table 12.

The inflation-adjusted system cost differences between Q1 2016 and Q1 2017 are \$0.18/Wdc (residential), \$0.32/Wdc (commercial), and \$0.42/Wdc (fixed-tilt utility-scale). Table 12 shows the benchmarked values for all three sectors and drivers of cost decrease and increase.

As Figure 34 shows, hardware costs—and module prices in particular—declined substantially in Q1 2017 owing to an imbalance in global module supply and demand. This has increased the importance of non-hardware, or "soft," costs.³⁵ Figure 35 shows the growing contribution from soft costs.³⁶ Soft costs and hardware costs also interact with each other. For instance, module efficiency improvements have reduced the number of modules required to construct a system of a given size, thus reducing hardware costs. This trend has also reduced soft costs from direct labor and related installation overhead.

Also, our bottom-up system cost models enable us to investigate regional variations, system configurations (such as MLPE vs. non-MLPE, fixed-tilt vs. one-axis tracker, and small vs. large system size). And, business structures (such as installer vs. integrator, and EPC vs. developer) are considered. Different scenarios result in different costs, so consistent comparisons can only be made when cost scenarios are aligned.

³⁴ System cost categories in this report differ from previously published material, beyond inflation adjustments, to delineate profit from overhead for installers and integrators. Also, profit is added to the Q1 2015 commercial benchmark price; thus it is \$0.06/W higher than in the 2015 publication (\$0.05/W profit, \$0.01/W inflation).

³⁵ Soft cost = total cost - hardware (module, inverter, structural, and electrical BOS) cost.

³⁶ An increasing soft cost proportion in Figure 35 indicates soft costs declined more slowly than did hardware costs; it does not indicate soft costs increased on an absolute basis.

Finally, the reduction in installed cost, along with improvements in operation, system design, and technology have resulted in significant reduction in the cost of electricity, as shown in Figure 36. U.S. residential and commercial PV systems are 86% and 89% toward achieving SunShot’s 2020 electricity price targets, and U.S. utility-scale PV systems have achieved their 2020 SunShot target three years early.

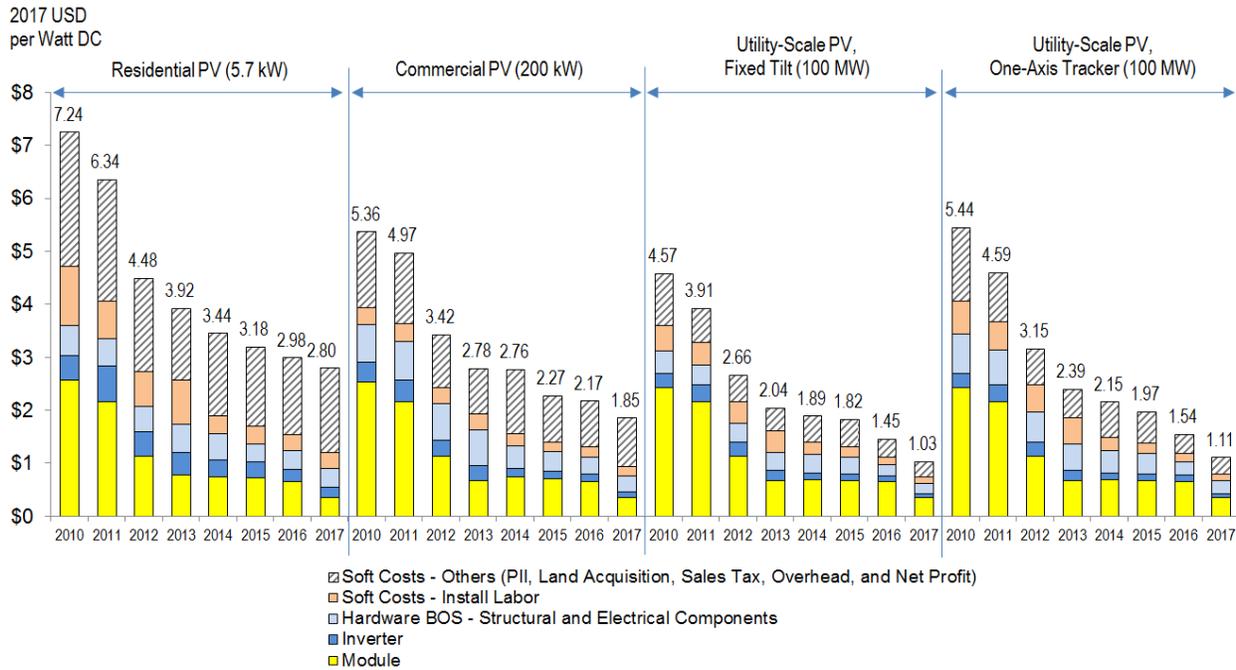


Figure 35. NREL PV system cost benchmark summary (inflation adjusted), 2010–2017

Table 12. Comparison of Q1 2016 and Q1 2017 PV System Cost Benchmarks

Sector	Residential PV	Commercial PV	Utility-Scale PV, Fixed-Tilt
Q1 2016 Benchmarks in 2016 USD/Wdc	\$2.93	\$2.13	\$1.42
Q1 2016 Benchmarks in 2017 USD/Wdc	\$2.98	\$2.17	\$1.45
Q1 2017 Benchmarks in 2017 USD/Wdc	\$2.80	\$1.85	\$1.03
Drivers of Cost Decrease	<ul style="list-style-type: none"> • Lower module price • Lower inverter price • Higher module efficiency • Lower electrical BOS commodity price • Higher small installer market share • Lower sales & marketing costs • Lower overhead (general & administrative) 	<ul style="list-style-type: none"> • Lower module price • Lower inverter price • Higher module efficiency • Smaller developer team 	<ul style="list-style-type: none"> • Lower module price • Lower inverter price • Higher module efficiency
Drivers of Cost Increase	<ul style="list-style-type: none"> • Higher labor wages • Higher advanced inverter adoption • More BOS components for rapid shutdown • Higher supply-chain costs 	<ul style="list-style-type: none"> • Higher labor wages • Higher PII costs • Higher net profit 	<ul style="list-style-type: none"> • Higher labor wages • Higher net profit

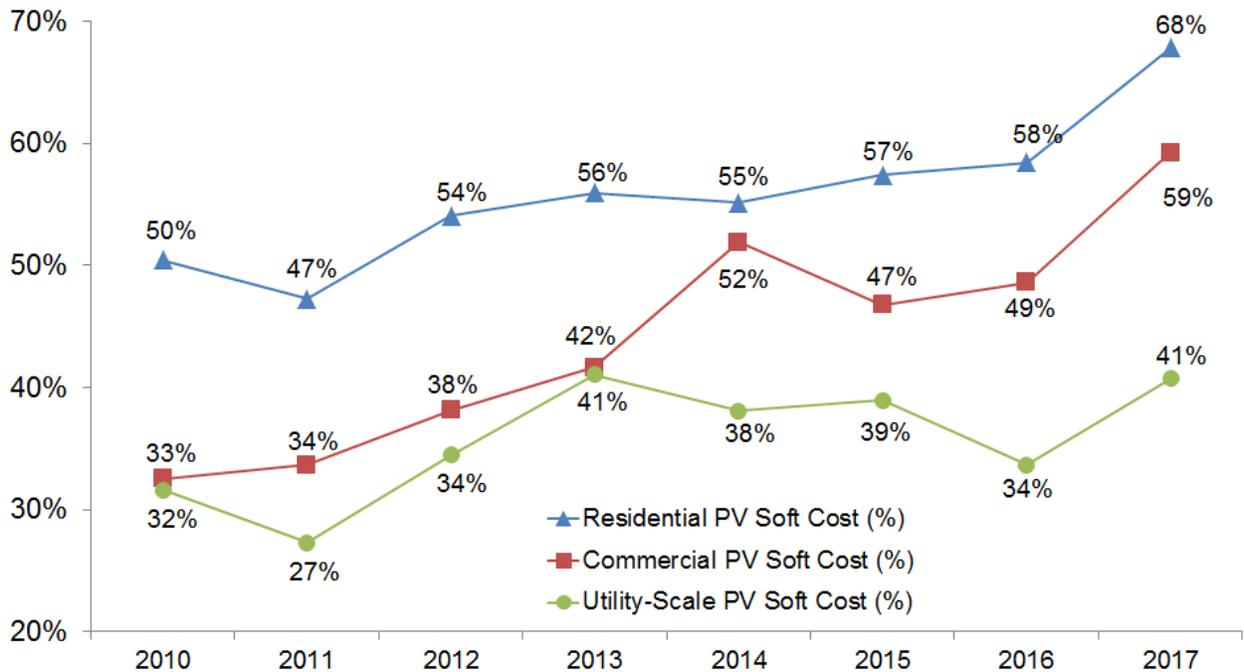


Figure 36. Modeled trend of soft cost as a proportion of total cost by sector, 2010–2017

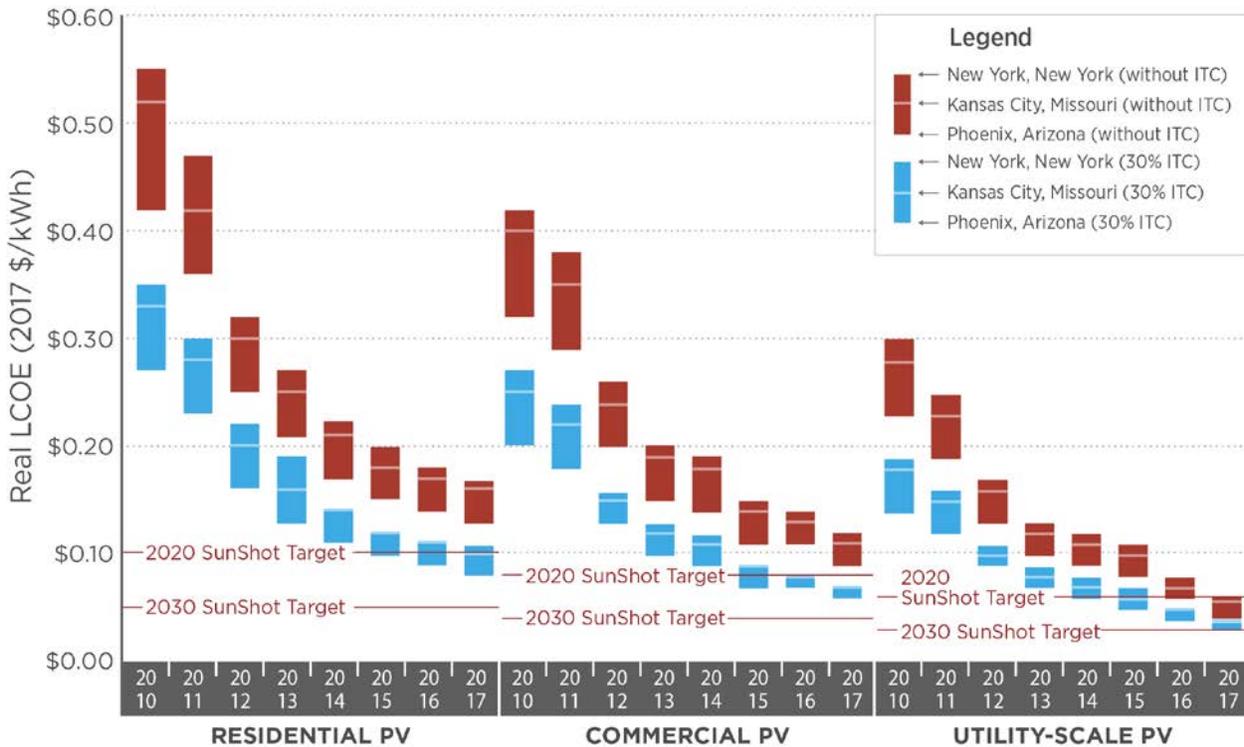


Figure 37. NREL PV LCOE benchmark summary (inflation adjusted), 2010–2017

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Appendix A. Historical PV System Benchmarks in 2010 USD

Table 13. NREL Residential PV Benchmark Summary (Inflation Adjusted), 2010–2017

2010 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Module	\$2.26	\$1.89	\$0.98	\$0.68	\$0.65	\$0.63	\$0.57	\$0.31
Inverter	\$0.41	\$0.60	\$0.40	\$0.38	\$0.28	\$0.26	\$0.19	\$0.17
Hardware BOS - Structural and Electrical Components	\$0.49	\$0.45	\$0.42	\$0.46	\$0.42	\$0.30	\$0.33	\$0.31
Soft Costs - Install Labor	\$0.99	\$0.62	\$0.59	\$0.73	\$0.29	\$0.30	\$0.26	\$0.27
Soft Costs - Others (PII, Sales Tax, Overhead, and Net Profit)	\$2.22	\$2.01	\$1.54	\$1.20	\$1.37	\$1.31	\$1.26	\$1.40
Total	\$6.36	\$5.58	\$3.94	\$3.44	\$3.02	\$2.80	\$2.61	\$2.45
Total Inverter Replacement Price (\$/W)	\$0.37	\$0.32	\$0.28	\$0.23	\$0.18	\$0.14	\$0.13	\$0.12
O&M Expenses (\$/kW-yr)	\$33	\$30	\$27	\$24	\$21	\$18	\$18	\$18
LCOE Phoenix, AZ, no ITC	\$0.38	\$0.32	\$0.22	\$0.19	\$0.15	\$0.13	\$0.12	\$0.12
LCOE Kansas City, MO, no ITC	\$0.46	\$0.39	\$0.27	\$0.23	\$0.19	\$0.16	\$0.15	\$0.14
LCOE New York, NY, no ITC	\$0.49	\$0.42	\$0.29	\$0.24	\$0.20	\$0.17	\$0.16	\$0.15
LCOE Phoenix, AZ, ITC	\$0.24	\$0.20	\$0.14	\$0.12	\$0.10	\$0.09	\$0.08	\$0.07
LCOE Kansas City, MO, ITC	\$0.30	\$0.25	\$0.18	\$0.15	\$0.12	\$0.10	\$0.09	\$0.09
LCOE New York, NY, ITC	\$0.32	\$0.27	\$0.19	\$0.16	\$0.13	\$0.11	\$0.10	\$0.10

Table 13. NREL Commercial PV Benchmark Summary (Inflation Adjusted), 2010–2017

2010 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Module	\$2.23	\$1.89	\$0.98	\$0.59	\$0.64	\$0.62	\$0.57	\$0.31
Inverter	\$0.32	\$0.37	\$0.27	\$0.24	\$0.15	\$0.12	\$0.12	\$0.09
Hardware BOS - Structural and Electrical Components	\$0.63	\$0.64	\$0.60	\$0.59	\$0.38	\$0.33	\$0.29	\$0.26
Soft Costs - Install Labor	\$0.28	\$0.28	\$0.27	\$0.26	\$0.19	\$0.17	\$0.17	\$0.15
Soft Costs - Others (PII, Sales Tax, Overhead, and Net Profit)	\$1.25	\$1.18	\$0.88	\$0.75	\$1.06	\$0.76	\$0.76	\$0.81
Total	\$4.71	\$4.36	\$3.00	\$2.44	\$2.42	\$1.99	\$1.90	\$1.62
Total Inverter Replacement Price (\$/W)	\$0.22	\$0.19	\$0.17	\$0.15	\$0.13	\$0.11	\$0.10	\$0.09
O&M Expenses (\$/kW-yr)	\$24	\$22	\$20	\$18	\$16	\$14	\$14	\$14
LCOE Phoenix, AZ, no ITC	\$0.29	\$0.26	\$0.17	\$0.14	\$0.13	\$0.10	\$0.09	\$0.08
LCOE Kansas City, MO, no ITC	\$0.36	\$0.32	\$0.22	\$0.17	\$0.16	\$0.12	\$0.12	\$0.10
LCOE New York, NY, no ITC	\$0.38	\$0.34	\$0.23	\$0.18	\$0.17	\$0.13	\$0.12	\$0.11
LCOE Phoenix, AZ, ITC	\$0.18	\$0.16	\$0.11	\$0.09	\$0.08	\$0.06	\$0.06	\$0.05
LCOE Kansas City, MO, ITC	\$0.23	\$0.20	\$0.14	\$0.11	\$0.10	\$0.08	\$0.07	\$0.07
LCOE New York, NY, ITC	\$0.24	\$0.21	\$0.15	\$0.12	\$0.11	\$0.08	\$0.08	\$0.07

Table 14. NREL Utility-Scale PV Benchmark Summary (Inflation Adjusted), 2010–2017

2010 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017
Module	\$2.12	\$1.89	\$0.98	\$0.59	\$0.60	\$0.59	\$0.57	\$0.31
Inverter	\$0.24	\$0.28	\$0.24	\$0.16	\$0.11	\$0.10	\$0.10	\$0.05
Hardware BOS - Structural and Electrical Components	\$0.66	\$0.58	\$0.50	\$0.43	\$0.37	\$0.34	\$0.22	\$0.22
Soft Costs - Install Labor	\$0.54	\$0.48	\$0.45	\$0.44	\$0.21	\$0.18	\$0.14	\$0.12
Soft Costs - Others (PII, Land Acquisition, Sales Tax, Overhead, and Net Profit)	\$1.22	\$0.81	\$0.59	\$0.48	\$0.59	\$0.52	\$0.31	\$0.27
Total	\$4.78	\$4.03	\$2.77	\$2.10	\$1.88	\$1.73	\$1.35	\$0.97
Total Inverter Replacement Price (\$/W)	\$0.17	\$0.15	\$0.14	\$0.12	\$0.11	\$0.09	\$0.07	\$0.05
O&M Expenses (\$/kW-yr)	\$20	\$19	\$19	\$18	\$17	\$17	\$17	\$17
LCOE Phoenix, AZ, no ITC	\$0.19	\$0.16	\$0.11	\$0.08	\$0.07	\$0.06	\$0.05	\$0.04
LCOE Kansas City, MO, no ITC	\$0.24	\$0.20	\$0.14	\$0.10	\$0.09	\$0.08	\$0.06	\$0.05
LCOE New York, NY, no ITC	\$0.26	\$0.22	\$0.15	\$0.12	\$0.10	\$0.09	\$0.07	\$0.06
LCOE Phoenix, AZ, ITC	\$0.12	\$0.10	\$0.07	\$0.05	\$0.05	\$0.04	\$0.03	\$0.03
LCOE Kansas City, MO, ITC	\$0.15	\$0.12	\$0.09	\$0.07	\$0.06	\$0.05	\$0.04	\$0.03
LCOE New York, NY, ITC	\$0.17	\$0.14	\$0.10	\$0.08	\$0.07	\$0.06	\$0.05	\$0.04

Appendix B. PV System LCOE Benchmarks in 2017 and 2010 USD

Table 16. NREL LCOE Summary (2017 cents/kWh)

Reporting Year	2010	2011	2012	2013	2014	2015	2016	2017	2020 ³⁷ Goal	2030 Goal
Benchmark Date	Q4 2009	Q4 2010	Q4 2011	Q4 2012	Q4 2013	Q1 2015	Q1 2016	Q1 2017		
Residential										
Phoenix, AZ, no ITC	42.1	35.7	24.9	20.7	17.3	15.0	13.6	12.9		
Kansas City, MO, no ITC	51.8	43.6	30.4	25.3	21.1	18.3	16.7	15.7	10.0	5.0
New York, NY, no ITC	55.2	46.5	32.4	26.9	22.4	19.5	17.7	16.7		
Phoenix, AZ, ITC	26.9	22.8	16.1	13.4	11.1	9.5	8.7	8.2		
Kansas City, MO, ITC	33.1	27.9	19.7	16.3	13.5	11.6	10.6	10.0		
New York, NY, ITC	35.3	29.7	21.0	17.4	14.4	12.3	11.3	10.7		
Commercial										
Phoenix, AZ, no ITC	32.3	28.6	19.5	15.4	14.4	11.2	10.5	9.2		
Kansas City, MO, no ITC	40.0	35.3	24.1	19.0	17.8	13.9	13.0	11.3	7.8	4.0
New York, NY, no ITC	42.4	37.5	25.6	20.2	18.9	14.8	13.8	12.0		
Phoenix, AZ, ITC	20.4	18.0	12.5	9.9	9.2	7.1	6.7	5.9		
Kansas City, MO, ITC	25.2	22.2	15.4	12.3	11.4	8.9	8.3	7.3		
New York, NY, ITC	26.8	23.6	16.4	13.0	12.0	9.4	8.8	7.7		
Utility-scale (one-axis tracking)										
Phoenix, AZ, no ITC	21.2	17.5	12.1	9.2	8.1	7.2	5.7	4.4		
Kansas City, MO, no ITC	26.8	22.1	15.3	11.7	10.2	9.1	7.2	5.6	6.0	3.0
New York, NY, no ITC	29.5	24.3	16.8	12.9	11.3	10.0	7.9	6.1		
Phoenix, AZ, ITC	13.4	11.0	7.8	6.0	5.3	4.7	3.8	3.0		
Kansas City, MO, ITC	16.9	13.9	9.8	7.6	6.7	5.9	4.8	3.8		
New York, NY, ITC	18.6	15.4	10.8	8.4	7.4	6.5	5.3	4.2		

³⁷ 2020 Residential and commercial SunShot goals are adjusted for inflation using the Consumer Price Index; the 2020 utility-scale goal was left unchanged as wholesale prices have been relatively flat, and in some cases gone down, from 2010-2017.

Utility-scale (fixed-tilt)										
Phoenix, AZ, no ITC	22.6	18.9	13.0	10.1	9.0	8.4	6.8	5.0		
Kansas City, MO, no ITC	27.7	23.1	15.9	12.3	11.0	10.2	8.3	6.1		
New York, NY, no ITC	29.6	24.7	17.0	13.2	11.8	10.9	8.8	6.6		
Phoenix, AZ, ITC	14.4	12.0	8.5	6.6	5.9	5.4	4.5	3.4		
Kansas City, MO, ITC	17.6	14.7	10.4	8.1	7.3	6.7	5.4	4.2		
New York, NY, ITC	18.9	15.8	11.1	8.7	7.8	7.1	5.8	4.4		
Residential										
Phoenix, AZ, no ITC	37.8	32.0	22.3	18.5	15.5	13.4	12.2	11.5		
Kansas City, MO, no ITC	46.4	39.1	27.3	22.7	18.9	16.4	14.9	14.1	9.0	5.0
New York, NY, no ITC	49.5	41.6	29.0	24.1	20.1	17.4	15.9	15.0		
Phoenix, AZ, ITC	24.1	20.4	14.5	12.0	9.9	8.5	7.8	7.4		
Kansas City, MO, ITC	29.7	25.0	17.7	14.6	12.1	10.4	9.5	9.0		
New York, NY, ITC	31.6	26.6	18.8	15.6	12.9	11.1	10.1	9.6		
Commercial										
Phoenix, AZ, no ITC	29.0	25.6	17.5	13.8	12.9	10.1	9.4	8.2		
Kansas City, MO, no ITC	35.8	31.7	21.6	17.0	16.0	12.5	11.7	10.1	7.0	4.0
New York, NY, no ITC	38.0	33.6	22.9	18.1	16.9	13.3	12.4	10.7		
Phoenix, AZ, ITC	18.3	16.1	11.2	8.9	8.2	6.4	6.0	5.3		
Kansas City, MO, ITC	22.6	19.9	13.8	11.0	10.2	8.0	7.4	6.5		
New York, NY, ITC	24.0	21.1	14.7	11.6	10.8	8.4	7.9	6.9		
Utility-scale (one-axis tracking)³⁸										
Phoenix, AZ, no ITC	19.0	15.6	10.8	8.3	7.2	6.4	5.1	3.9		
Kansas City, MO, no ITC	24.0	19.8	13.7	10.5	9.2	8.1	6.4	5.0	6.0	3.0
New York, NY, no ITC	26.4	21.8	15.1	11.5	10.1	9.0	7.1	5.5		
Phoenix, AZ, ITC	12.0	9.9	7.0	5.4	4.7	4.2	3.4	2.7		
Kansas City, MO, ITC	15.1	12.5	8.8	6.8	6.0	5.3	4.3	3.4		

³⁸LCOE benchmarks are highlighted in bold. As noted previously, we use the fixed-tilt systems for LCOE benchmarks from 2010-2015 and then switch to one-axis tracking systems from 2016 to 2017

New York, NY, ITC	16.7	13.8	9.7	7.6	6.6	5.9	4.7	3.7
Utility-scale (fixed-tilt)								
Phoenix, AZ, no ITC	20.3	16.9	11.6	9.0	8.1	7.5	6.1	4.5
Kansas City, MO, no ITC	24.8	20.7	14.3	11.1	9.9	9.2	7.4	5.5
New York, NY, no ITC	26.5	22.1	15.3	11.8	10.6	9.8	7.9	5.9
Phoenix, AZ, ITC	12.9	10.8	7.6	6.0	5.3	4.9	4.0	3.0
Kansas City, MO, ITC	15.8	13.2	9.3	7.3	6.5	6.0	4.9	3.7
New York, NY, ITC	16.9	14.1	9.9	7.8	7.0	6.4	5.2	4.0

Exhibit F



Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant

Clyde Loutan, Peter Klauer, Sirajul Chowdhury,
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California Independent System Operator

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List of Acronyms

ACE	Area control error
AGC	Automatic generation control
APC	Active power control
BAAL	Balancing Authority ACE Limit
BA	Balancing authority
CAISO	California Independent System Operator
FERC	Federal Energy Regulatory Commission
FFR	Fast frequency response
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
PFR	Primary frequency response
POI	Point of interconnection
PPC	Power plant controller
PV	Photovoltaic
ROCOF	Rate of change of frequency
RPS	Renewable portfolio standard
SCADA	Supervisory Control and Data Acquisition

Executive Summary

The California Independent System Operator (CAISO), First Solar, and the National Renewable Energy Laboratory (NREL) conducted a demonstration project on a large utility-scale photovoltaic (PV) power plant in California to test its ability to provide essential ancillary services to the electric grid. With increasing shares of solar- and wind-generated energy on the electric grid, traditional generation resources equipped with automatic governor control (AGC) and automatic voltage regulation controls—specifically, fossil thermal—are being displaced. The deployment of utility-scale, grid-friendly PV power plants that incorporate advanced capabilities to support grid stability and reliability is essential for the large-scale integration of PV generation into the electric power grid, among other technical requirements.

A typical PV power plant consists of multiple power electronic inverters and can contribute to grid stability and reliability through sophisticated “grid-friendly” controls. In this way, PV power plants can be used to mitigate the impact of variability on the grid, a role typically reserved for conventional generators. In August 2016, testing was completed on First Solar’s 300-MW PV power plant, and a large amount of test data was produced and analyzed that demonstrates the ability of PV power plants to use grid-friendly controls to provide essential reliability services. These data showed how the development of advanced power controls can enable PV to become a provider of a wide range of grid services, including spinning reserves, load following, voltage support, ramping, frequency response, variability smoothing, and frequency regulation to power quality. Specifically, the tests conducted included various forms of active power control such as AGC and frequency regulation; droop response; and reactive power, voltage, and power factor controls.

This project demonstrated that advanced power electronics and solar generation can be controlled to contribute to system-wide reliability. It was shown that the First Solar plant can provide essential reliability services related to different forms of active and reactive power controls, including plant participation in AGC, primary frequency control, ramp rate control, and voltage regulation. For AGC participation in particular, by comparing the PV plant testing results to the typical performance of individual conventional technologies, we showed that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The plant’s ability to provide volt-ampere reactive control during periods of extremely low power generation was demonstrated as well.

The project team developed a pioneering demonstration concept and test plan to show how various types of active and reactive power controls can leverage PV generation’s value from being a simple variable energy resource to a resource that provides a wide range of ancillary services. With this project’s approach to a holistic demonstration on an actual, large, utility-scale, operational PV power plant and dissemination of the obtained results, the team sought to close some gaps in perspectives that exist among various stakeholders in California and nationwide by providing real test data.

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1 Introduction

Solar photovoltaic (PV) generation is growing rapidly. At the end of 2015, the United States had 25 GW of installed solar PV capacity, with an additional 1.8 GW of concentrating solar power [1], [2]. As PV continues to grow, questions are arising about the ability of PV to contribute to maintaining grid reliability. In this study, we demonstrated various grid-friendly controls on First Solar's 300-MW PV plant located in the California Independent System Operator's (CAISO's) footprint. Our analysis shows that advanced power electronics and solar generation can be controlled to contribute to system-wide reliability. More specifically, we show that the First Solar plant can provide essential reliability services related to different forms of active and reactive power controls, including plant participation in automatic generation control (AGC), primary frequency control, ramp rate control, and voltage regulation. For AGC participation in particular, by comparing the PV plant testing results to the typical performance of conventional individual technologies, we showed that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The plant's ability to provide volt-ampere reactive (VAR) control during periods of extremely low power generation was demonstrated as well.

The project team—consisting of experts from CAISO, First Solar, and the National Renewable Energy Laboratory (NREL)—developed a demonstration concept and test plan to show how various types of active and reactive power controls can leverage PV generation's value from being a simple variable energy resource to a resource that provides a wide range of ancillary services. With this project's approach to a holistic demonstration on an actual, large, utility-scale, operational PV power plant and dissemination of the obtained results, the team sought to close some gaps in perspectives that exist among various stakeholders in California and nationwide by providing real test data. If PV-generated power can offer a supportive product that benefits the power system and is economic for PV power plant owners and customers, this functionality should be recognized and encouraged. This project showed, through real-world testing, that PV power plants can contribute to maintaining grid reliability.

Pioneering work done by NREL, First Solar, and AES in 2015 in West Texas and Puerto Rico provided a detailed understanding of the advanced capabilities offered by modern PV power plants [3]. The current CAISO-First Solar-NREL project is aimed at breaking new barriers to the provision of ancillary services by PV generation in terms of both plant capacity (300 MW) and system-level impacts. Taken as a whole, these three studies show that PV power plants can be used to manage a variety of grid challenges on island systems, isolated interconnections, and within market environments in large synchronous systems.

Renewable energy in the United States accounted for 13.44% of domestically produced electricity in 2015 [3]. California is a leading state for integrating renewable resources and for renewable portfolio standards (RPSs), with approximately 29% of its electricity provided from RPS-eligible renewable sources (including small hydropower) [4]. In addition, California is leading the way in climate change policies that are intended to reduce emissions from all sectors, including electricity, by 40% from 1990 levels by 2030 and by 80% from 1990 levels by 2050. If California is to achieve these goals while enhancing grid reliability, all resources, including renewables, must be leveraged to provide essential reliability services.

Rapid penetrations of variable renewable generation into an electric grid are changing the ways power system operators manage their systems. Higher levels of variable generation are creating real-time reliability and operational changes. For example, the California Independent System Operator (CAISO) is trying to adapt to rapid increases in its solar PV generation during sunrise and rapid losses in solar production during sunset.

CAISO currently has more than 9,000 MW of transmission-connected solar resources within its operational footprint. To meet its RPS goal of 33% by 2020, CAISO is expecting an additional 4,000–5,000 MW of solar. Beyond 2020, to meet a 50% RPS goal, CAISO is expecting an additional 15,000 MW of renewable resources, and a significant portion of this is anticipated to be transmission-connected solar PV because of the expected reduction in the price of solar panels (Figure 1). Thus, the capability of solar PV resources to provide essential reliability services is necessary to achieve a low-carbon grid.

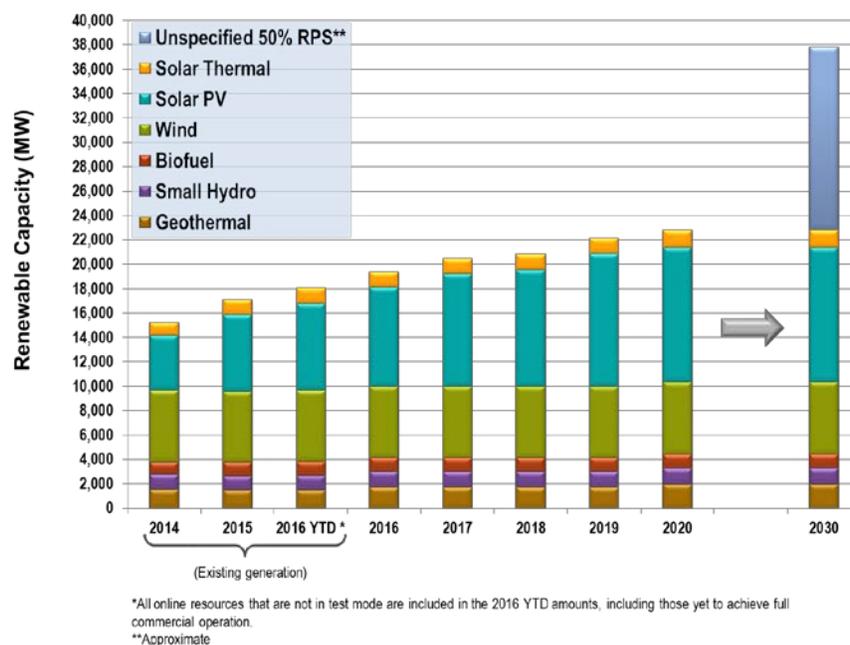


Figure 1. CAISO’s expected renewable capacity build-out to meet its 50% RPS goal.
Illustration from CAISO

In addition, CAISO has experienced a significant increase in rooftop solar PV installations (Figure 2). Currently, more than 5,000 MW of rooftop solar PV is installed within CAISO’s footprint, and it is expected to exceed 9,000 MW by 2020. Rooftop solar PV does not count toward RPS, but it does have an impact on grid operations, especially during sunrise and sunset.

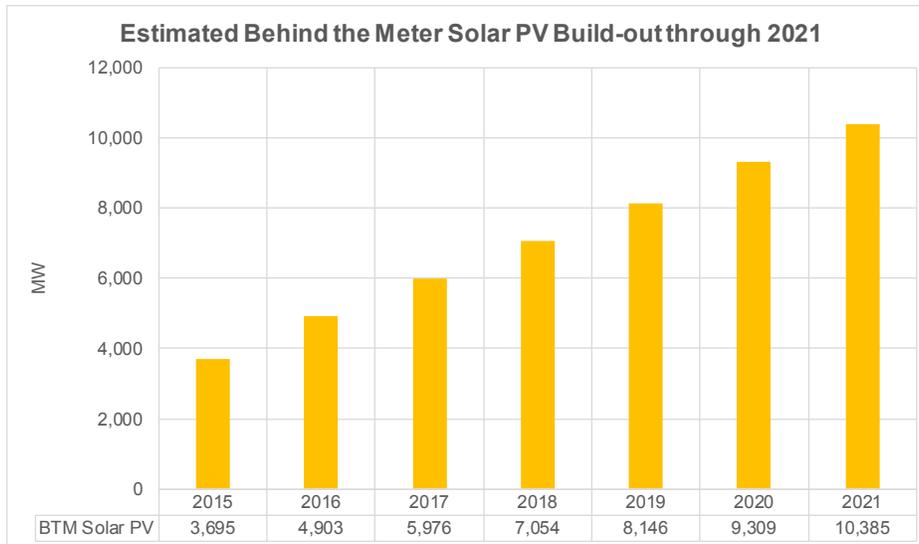


Figure 2. CAISO’s expected build-out of rooftop solar PV. Illustration from CAISO

High levels of solar generation during midday hours are already contributing to oversupply, especially on light load days when renewable production is high. Therefore, it is during these conditions that opportunity is created if renewable resources could provide essential reliability services that have traditionally been provided by conventional resources. Sharp changes in the real-time ramping needs are also happening during afternoon-to-evening hours. This is especially evident during the spring and fall months, when loads are relatively light and hourly penetrations of renewable generation are high. In its “duck chart” (Figure 3), CAISO shows these integration changes and opportunities for a typical spring day as a significant drop in its midday net load is met by an increased share of PV in the system. These changes and opportunities to leverage the capability of these new resources are growing at a faster rate than previously expected; and during certain days in the spring of 2016, CAISO’s minimum net load was already less than the predicted 2020 level.

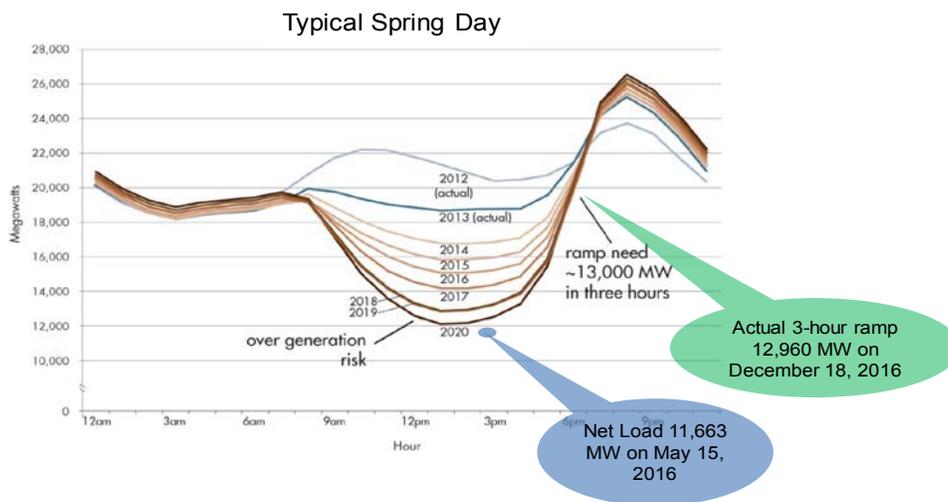


Figure 3. CAISO duck chart. Illustration from CAISO

Because of low net loads, the risk of oversupply increases, so significant curtailment of renewables took place during certain days in the spring of 2016. An example of this type of curtailment period is shown in Figure 4. During certain daytime hours on April 24, 2016, more than 2 GW of renewable generation were curtailed to maintain reliable operation of the system. With increased curtailment, more opportunity is created if the industry can tap into the controllability of renewable resources and thus reduce reliance on conventional resources to provide such services.

Advanced inverter functions and how projects are designed and operated can help address grid stability problems during such periods. A typical modern utility-scale PV power plant is a complex system of large PV arrays and multiple power electronic inverters, and it can contribute to mitigating the impacts on grid stability and reliability through sophisticated automatic “grid-friendly” controls. Many of the PV control capabilities that were demonstrated in this project have already generally been proven to be technically feasible, and a few areas throughout the world have already started to request or require PV power plants to provide some of them; however, in the United States, utility-scale PV plants are rarely recognized as having these capabilities, and typically they are not used by utilities or system operators to provide electric grid services.

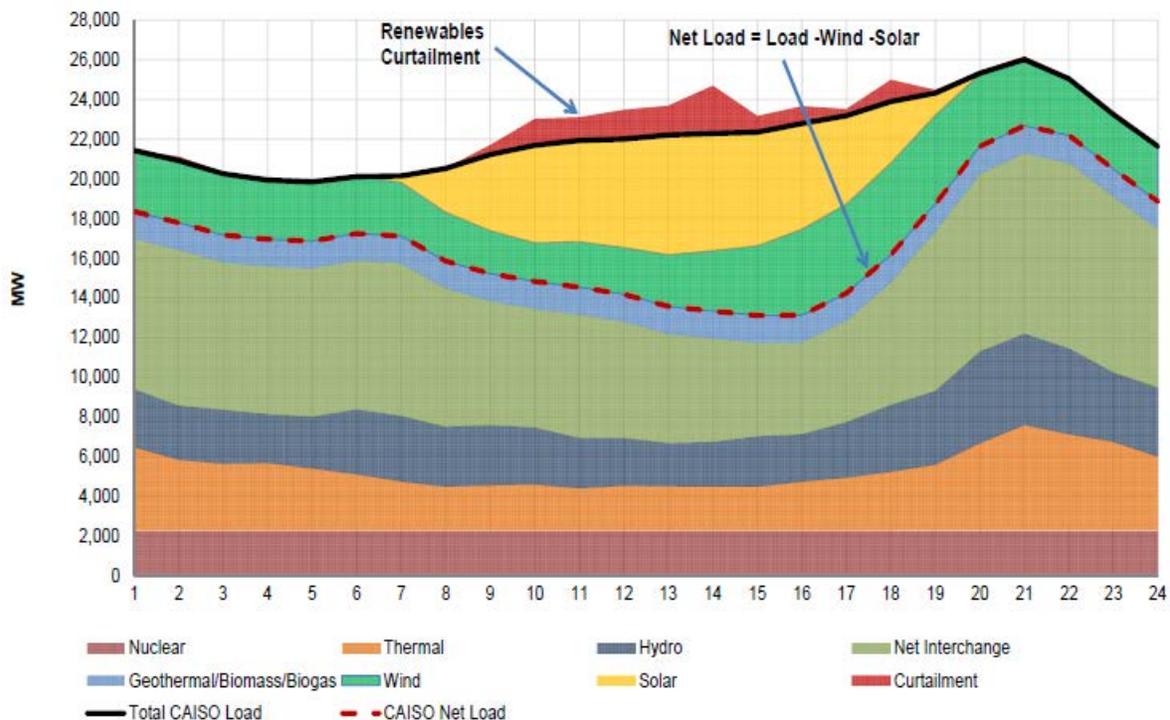


Figure 4. CAISO's generation breakdown for April 24, 2016. Illustration from CAISO

CAISO is continually adapting its operational practices and market mechanisms to make the integration of shares of fast-growing variable renewable generation both reliable and economic. This new reality leads to growing needs by CAISO and other independent system operators to:

- Better coordinate between day-ahead and real-time markets
- Increase flexibility in the form of fast ramping capacity

- Better utilize ancillary service capabilities by variable renewable generation
- Deepen regional coordination
- Implement new market mechanisms incentivizing the participation of renewables in ancillary service markets
- Develop new market products to take advantage of faster and higher-precision ancillary service providers
- Add energy storage capacity
- Align time-of-use rates with system demand.

Currently, regulation-up and regulation-down are two of the four ancillary service products that CAISO procures through co-optimization with energy in the day-ahead and real-time markets. The other two products are spinning and nonspinning reserves. Most ancillary service capacity is procured in the day-ahead market. CAISO procures incremental ancillary services in the real-time market processes to replace unavailable ancillary services or to meet additional ancillary service requirements. A detailed description of the ancillary service market design, which was first implemented in 2009, is provided in CAISO’s 2016 market report [5], [6].

From February 20, 2016, through June 9, 2016, CAISO increased the requirements to a minimum of 600 MW for regulation-up and regulation-down in both the day-ahead and real-time markets. Average prices for these two ancillary services increased immediately following the change in requirements in February and reverted to lower levels again in June 2016 (Figure 5). Regulation procurement costs continued to average more than \$400,000 per day when the requirements were high and fell to \$80,000 per day when the requirements were lowered, beginning on June 10, 2016.

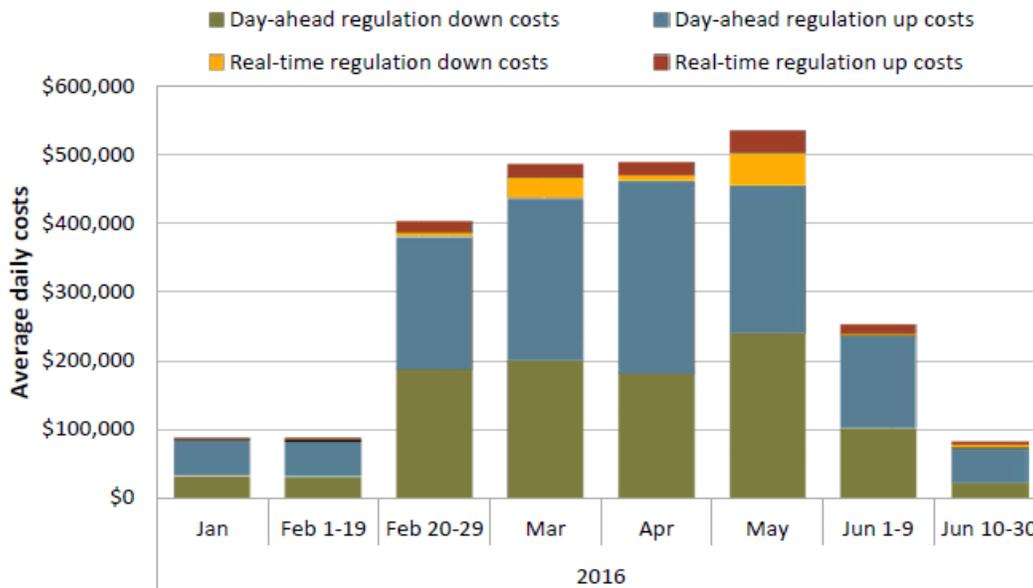


Figure 5. CAISO’s average daily regulation procurement costs from January–June 2016.
Illustration from CAISO

In 2012, CAISO implemented standards for importing regulation service [7]. These standards implemented CAISO's tariff provisions relating to the imports of regulation services, either bid or self-provided, by scheduling coordinators with system resources located outside CAISO's balancing authority area. In addition to imported regulation services, regulation provided by PV power plants within CAISO's footprint can become an additional stability tool at CAISO's disposal.

As power system continues to evolve, the Federal Energy Regulatory Commission (FERC) noted that there is a growing need for a refined understanding of the services necessary to maintain a reliable and efficient system. In orders 755 and 784, FERC required improving the mechanisms by which frequency regulation service is procured and enabling compensation by fast-response resources such as energy storage. CAISO is working on a new market design in which aggregated distributed resources (rooftop PV, behind-the-meter batteries, electric vehicles, fast demand response) can bid in its market. In addition, FERC recently issued a notice of proposed rulemaking to enable aggregation of distributed storage and distributed generation [8].

The Electric Reliability Council of Texas and the New York Independent System Operator are also working on similar ancillary service markets for utility-scale and distributed generation [9].

In 2012, the North American Electric Reliability Corporation's (NERC) Integration of Variable Generation Task Force made several recommendations for requirements for variable generators (including solar) to provide their share of grid support, including active power control (APC) capabilities [7, 10]. These recommendations address grid requirements such as voltage control and regulation, voltage and frequency fault ride-through, reactive and real power control, and frequency response criteria in the context of the technical characteristics and physical capabilities of variable generation equipment.

- APC capabilities include:
 - Ramp-rate-limiting controls
 - Active power response to bulk power system contingencies
 - Inertial response
 - Primary frequency response (PFR)
 - Secondary frequency response, or participation in AGC
 - Ability to follow security-constrained economic dispatch (SCED) set points that are sent every 5 minutes through its real-time economic dispatch market software.
- Performance during and after disturbances
 - Fault ride-through
 - Short-circuit current contribution.
- Voltage, reactive, and power factor control and regulation (both dynamic and steady state).

In 2015, the NERC task force on Essential Reliability Services published a report exploring important directional measures to help the energy sector understand and prepare for the increased deployment of variable renewable generation [11], [12]. According to this report, to maintain an adequate level of reliability through this transition, generation resources need to provide sufficient voltage control, frequency support, and ramping capability—essential components of a reliable bulk power system.

The California state legislature passed Senate Bill 350 in the fall of 2015, which requires all utilities in the state to produce 50% of their electricity sales from renewable sources with the objective of reducing carbon emissions. To reach that 50% RPS goal, California operators will need to find additional ways to balance generation and load to manage the variability of increased renewable generation and maintain grid reliability. In this context, the curtailment of renewables can be viewed as a resource, not only a problem. Because wind and solar generation can be ramped up and down, curtailment can become a helpful resource to relieve oversupply and provide frequency regulation and ramping services. In combination with the 1.3-GW California energy storage mandate, ancillary services provided by renewables can enhance system flexibility and reliability and reduce needs in spinning reserves by conventional power plants. Thus, unleashing these capabilities from renewable resources helps achieve the broader objective of a resilient, reliable, low-carbon grid.

Currently, only a few grid operators in the United States are using curtailed renewables as a resource. For example, the Public Service Company of Colorado (PSCO) has means to control its wind generation to provide both up and down regulation reserves (the PSCO has had periods of 60% wind power generation in its system). The PSCO is able to use wind reserves as an ancillary service for frequency regulation by integrating the wind power plants in their footprint to provide AGC. Similar services can be provided by curtailed PV power plants in California; however, regulatory, market, and operational issues need to be resolved for this to become possible [13], [14].

Prior to testing, the team developed a plan that was coordinated with technical experts from First Solar. The test plan is shown in the appendix of this report). The following sections describe the tests and results conducted by the team:

1. CAISO-NREL-First Solar custom-developed test scenarios (conducted on August 24, 2016)
 - A. Regulation-up and regulation-down, or AGC tests during sunrise, middle of the day, and sunset
 - B. Frequency response tests with 3% and 5% droop settings for overfrequency and underfrequency conditions
 - C. Curtailment and APC tests to verify plant performance to decrease or increase its output while maintaining specific ramp rates
 - D. Voltage and reactive power control tests
 - E. Voltage control at near zero active power levels (nighttime control).

2. More standardized First Solar's power plant controller (PPC) system commissioning tests (conducted on August 23, 2016)
 - A. Automatic manual control of inverters (individual, blocks of inverters, whole plant)
 - B. Active power curtailment control, generation failure and restoration control, frequency control validation
 - C. Automatic voltage regulation at high and low power generation
 - D. Power factor control
 - E. Voltage limit control
 - F. VAR control.

2 PV Power Plant Description

First Solar constructed a 300-MW AC PV power plant in CAISO’s footprint. An aerial photo of the plant using First Solar’s advanced thin-film cadmium-telluride PV modules is shown in Figure 6. The plant is tied to 230-kV transmission lines via two 170-MVA transformers (34.5/230 kV). The 34.5-KV side of each transformer is connected to the plant’s MV collector system with four blocks each rated 40 MVA. Individual PV inverter units, each rated 4 MVA, operate at 480 VAC and are connected to a 34.5-kV collector system via pad-mounted transformers. Switched capacitor banks are connected to both 34.5-kV buses to meet the power factor requirements of FERC’s Large Generator Interconnection Agreement (LGIA) power factor requirements. Two phasor measurement units (PMUs) were set to collect data at the 230-kV sides of both plant transformers.



Figure 6. Aerial photo of First Solar’s 300-MW PV power plant. *Photo from First Solar*

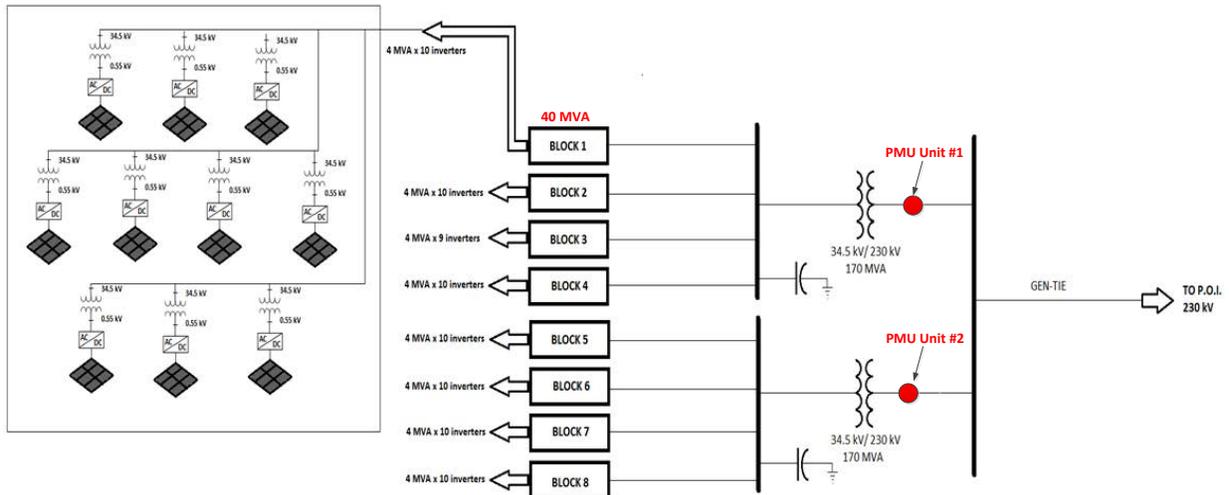


Figure 7. Electrical diagram of First Solar’s 300-MW PV plant. *Illustration from First Solar*

A key component of this tested grid-friendly solar PV power plant is a PPC developed by First Solar. It is designed to regulate real and reactive power output from the PV power plant so that it behaves as a single large generator. Although the plant comprises individual inverters, with each inverter performing its own energy production based on local solar array conditions, the plant controller's function is to coordinate the power output to provide typical large power plant features, such as APC and voltage regulation through reactive power regulation [16].

First Solar's PPC is capable of providing the following plant-level control functions:

- Dynamic voltage and/or power factor regulation and closed-loop VAR control of the solar power plant at the point of interconnection (POI)
- Real power output curtailment of the solar power plant when required so that it does not exceed an operator-specified limit
- Ramp-rate controls to ensure that the plant output does not ramp up or down faster than a specified ramp-rate limit, to the extent possible
- Frequency control (governor-type response) to lower plant output in case of an overfrequency situation or increase plant output (if possible) in case of an underfrequency situation
- Start-up and shutdown control.

The PPC implements plant-level logic and closed-loop control schemes with real-time commands to the inverters to achieve fast and reliable regulation. It relies on the ability of the inverters to provide a rapid response to commands from the PPC. Typically, there is one controller per plant controlling the output at a single high-voltage bus (referred to as the POI). The commands to the PPC can be provided through the Supervisory Control and Data Acquisition (SCADA) human-machine interface or even through other interface equipment, such as a substation remote terminal unit.

Figure 8 illustrates a general block diagram overview of First Solar's control system and its interfaces to other devices in the plant. The PPC monitors system-level measurements and determines the desired operating conditions of various plant devices to meet the specified targets. It manages capacitor banks and/or reactor banks, if present. It has the critical responsibility of managing all the inverters in the plant, continuously monitoring the conditions of the inverters and commanding them to ensure that they are producing the real and reactive power necessary to meet the desired voltage schedule at the POI [16].

A conceptual diagram of the plant's control system architecture is shown in Figure 9. The plant operator can set an active power curtailment command to the controller. In this case, the controller calculates and distributes active power curtailment to individual inverters. In general, some types of inverters can be throttled back only to a certain specified level of active power and not any lower without causing the DC voltage to rise beyond its operating range. Therefore, the PPC dynamically stops and starts inverters as needed to manage the specified active power output limit. It also uses the active power management function to ensure that the plant output does not exceed the desired ramp rates, to the extent possible. It cannot, however, always accommodate rapid reductions in irradiance caused by cloud cover.

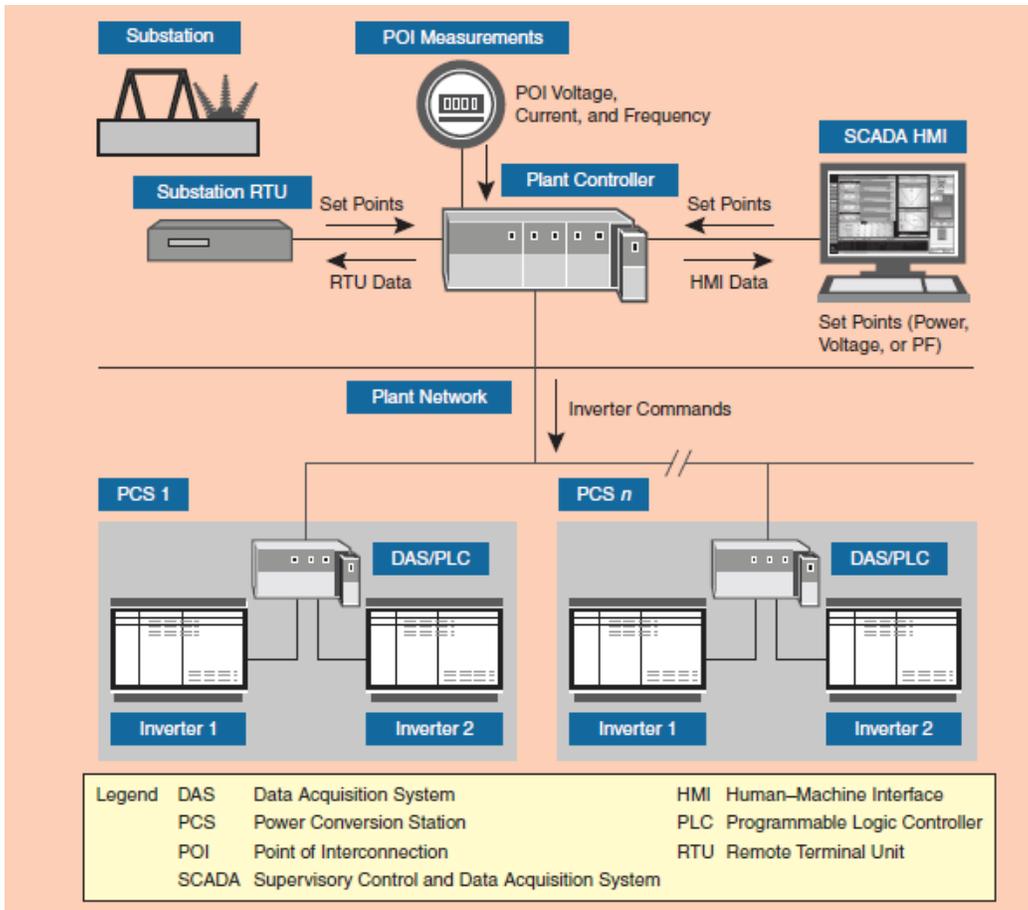


Figure 8. General diagram of First Solar's PV power plant controls and interfaces.
Illustration from First Solar

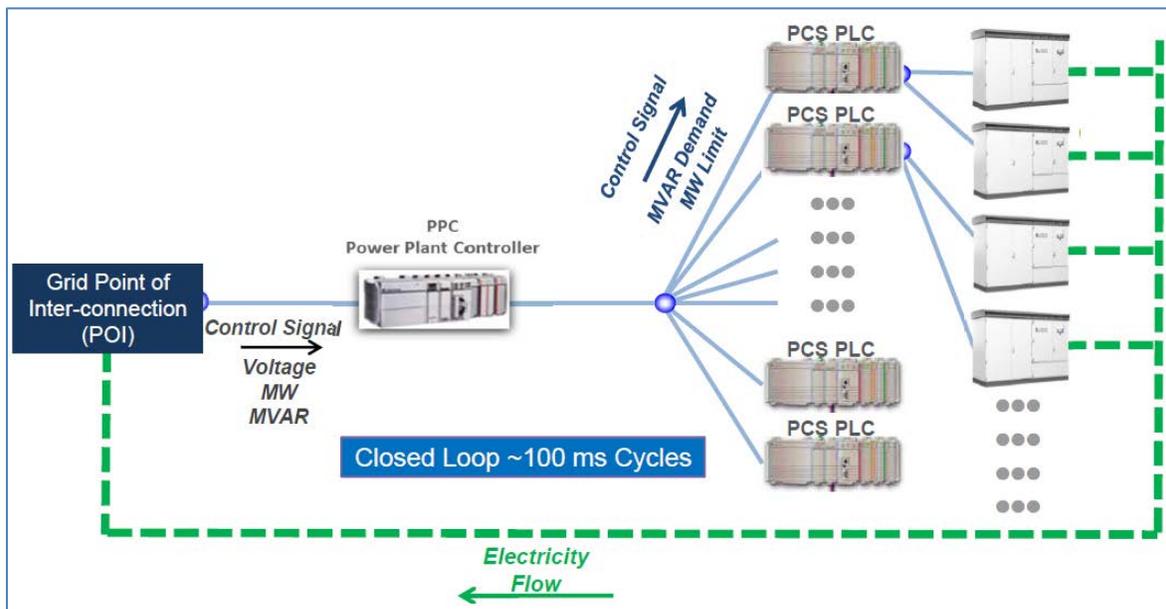


Figure 9. Diagram of First Solar's PV power plant control system architecture.
Illustration from First Solar

The testing of the 300-MW plant within CAISO's footprint was conducted remotely by the First Solar team from their operations center located in First Solar's corporate offices, in Tempe, Arizona (Figure 10). As a NERC-registered generator operator, the First Solar staff was capable of remotely supervising the ongoing testing activities at the 300-MW PV plant in California, tracking the plant's performance and making changes to test set point and plant control parameters from the center in Arizona.



Figure 10. First Solar's operations center in Tempe, Arizona. Photo from First Solar

3 AGC Participation Tests for First Solar’s 300-MW PV Power Plant

3.1 Description and Rationale for AGC Tests

The purpose of the AGC tests is to enable the power plant to follow the active power set points sent by CAISO’s AGC system. The set point signal is received by the remote terminal unit in the plant substation and then scaled and routed to the PPC in the same time frame. When in AGC mode, the PPC initially set the plant to operate at a power level that was 30 MW lower than the estimated available peak power to have headroom for following the up-regulation AGC signal (see hypothetical example in Figure 11). The lower boundary of AGC operation can be set at any level below available peak power, including full curtailment if necessary.

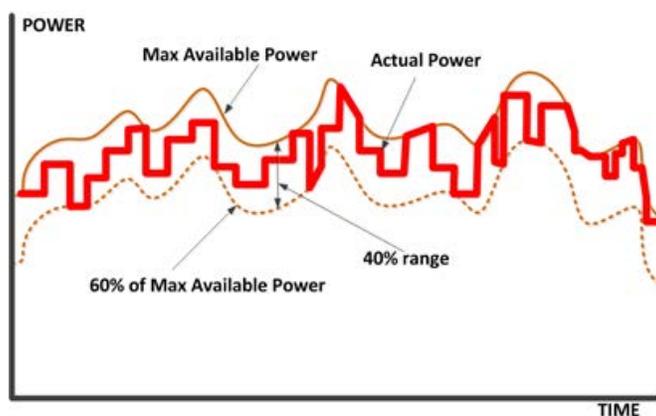


Figure 11. Concept of AGC following by a PV power plant (e.g., with 40% headroom).
Illustration from NREL

CAISO’s AGC is normally set to send a direct MW set point signal to all participating units every 4 seconds. All ramp-rate settings in the PV power plant’s PPC were set at very high level of 600 MW/min (10 MW/sec) during the AGC tests. AGC control logic for a balancing authority with interconnections (such as CAISO) is based on determining the:

- Area’s total desired generation
- Base points for each AGC participating unit
- Regulation obligation for each AGC participating unit.

Area control error (ACE) is an important factor used in AGC control. For a balancing authority area, ACE is determined as:

$$ACE = -\Delta P_{tie} - 10B(f_a - f_s) + I_{ME} + I_T \quad (1)$$

where ΔP_{tie} is the net tie-line interchange error, B is the frequency bias (MW/0.1Hz); f_a and f_s are the actual measured and scheduled frequencies (typically 60 Hz, but they can also be 59.8 Hz or 60.2 Hz during time error corrections), respectively; and I_{ME} and I_T are the meter error correction and time error correction factors, respectively (MW). The ACE value is then used by the AGC control logic to determine the total desired generation that will drive it to zero. The desired generation for each participating generating unit is split into two components: the base

point and regulation. The base point for each generating unit is set at its economic dispatch point, and the system's total regulation is calculated as the difference between the total desired generation and the sum of the base points for all AGC participating units. The total regulation for the whole system is allocated among all participating regulating units. The 300-MW plant under test is considered as one plant-level generating unit, and individual inverter outputs are not considered by CAISO's operations. Various unit-specific parameters are used in its regulation allocation, such as ramp rates and operating limits. Figure 12 shows a general diagram of CAISO's AGC distributing set point signals to individual generating units. The raw ACE signal is filtered first, and it is then processed by a proportional-integral (PI) filter that has proportional and integral control gains. The filtered ACE is then passed to the AGC calculation and distribution module that generates the ramp-limited AGC set points for the individual participating units based on their participation factor, dispatch status, available headroom, unit physical characteristics, etc., as shown in Figure 12.

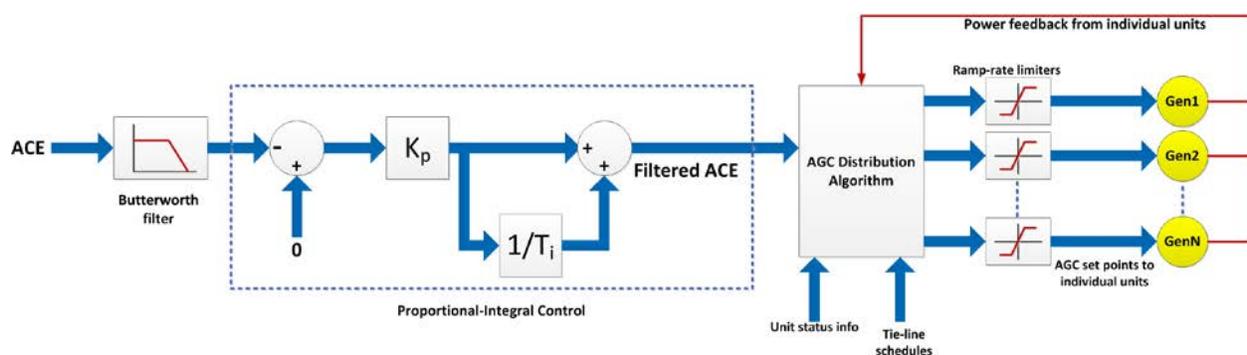


Figure 12. Simplified diagram of CAISO's AGC system. Illustration from NREL

AGC operates in conjunction with supervisory control and data acquisition (SCADA) systems [17]. SCADA gathers information on system frequency, generator outputs, and actual interchange between the system and adjacent systems. Using system frequency and net actual interchange, plus knowledge of net scheduled interchange, an AGC system determines the system's energy balancing needs with its interconnection in near real time. CAISO's SCADA system polls sequentially for electric system data with a periodicity of 4 seconds. The degree of success of AGC in complying with balancing and frequency control is manifested in a balancing authority's control performance compliance statistics and metrics as defined by NERC's control performance standards (CPS). In particular, CPS1 is a measure of a balancing authority's long-term frequency performance with the control objective to bound excursions of an average 1-minute frequency error during 12 months in the interconnection. CPS1 allows for evaluating how well a balancing authority's ACE performs in conjunction with the frequency error of the whole interconnection. CPS2 is a measure of the balancing authority's ACE during all 10-minute periods in a month with the control objective to limit ACE variations and bound unscheduled power flows among balancing authority areas.

NREC's Standards Committee approved the replacement of CPS2 with the Balancing Authority ACE Limit (BAAL) in June 2005. BAAL is unique for each balancing authority and provides dynamic limits for its ACE value limits as a function of its interconnection frequency. The objective of BAAL is to maintain the interconnection frequency within predefined limits. A field trial of BAAL began in the Eastern Interconnection in July 2005 and in the Western

Interconnection in March 2010. Enforcement of BAAL began on July 1, 2016 [18]. Both CPS1 and BAAL scores are important metrics for understanding the impacts of variable renewable generation on system frequency performance. NERC’s reliability standards require that a balancing authority balances its resources and demand in real time so that the clock-minute average of its ACE does not exceed its BAAL for more than 30 consecutive clock-minutes.

PV generation participation in CAISO’s AGC is expected to maintain CPS above the minimum NERC requirements and BAAL within predefined operating limits and avoid degradation in reliability. AGC participation by faster and higher-precision responsive generation is potentially more valuable because these types of generation allow for applying controls at the exact moment in time and exact amount needed by the system. Faster AGC control is desirable because it facilitates more reliable compliance with NERC’s operating standards at relatively less regulation capacity procurements [19]. Currently, CAISO practices and markets do not differentiate between faster and slower providers, with the exception of some minimum ramping capabilities. The data produced by AGC testing of the 300-MW PV plant in California are intended to provide real field-measured results to confirm the above-described benefits and facilitate the transition to improved ancillary service markets that value and incentivize superb performance by inverter-coupled renewable generation.

3.2 AGC Test Results

The AGC tests were conducted on August 24, 2016, at three different solar resource intensity time frames: (1) sunrise, (2) middle of the day (noon–2 p.m.), and (3) sunset (for 20 minutes at each condition). Historic 4-second AGC signals that CAISO previously sent to another regulation-certified resource of similar capacity were provided to the plant controller.

The 300-MW PV plant under test was not connected to CAISO’s AGC system because the plant’s owner did not request this control option at the time of construction; instead, historical CAISO ACE data were provided to the PPC for AGC performance testing. Each test was conducted using actual 4-second AGC signals that CAISO had previously sent to a regulation-certified resource of similar size. The historical AGC signal provided by CAISO had a regulation range of 30 MW, or 10% of rated plant power (Figure 13). This signal is represented as ΔP_{AGC} in the equation below:

$$P_{command} = (P_{available} - 30MW) + \Delta P_{AGC} \quad (2)$$

where $P_{available}$ is the maximum available instantaneous power that the plant can produce for a given solar irradiation conditions, and $P_{command}$ is the actual commanded MW set point sent to the PPC.

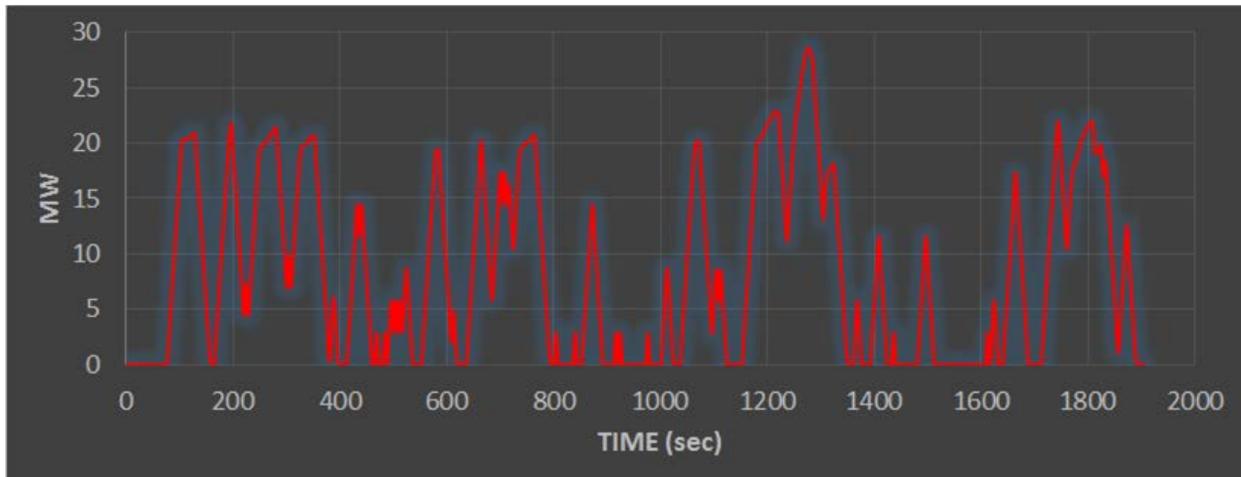


Figure 13. Historic CAISO AGC signal used in testing. Illustration from NREL

In this way, the plant’s response to the AGC-like set point signal can be tested within a 30-MW range. CAISO’s regulation system has a significant total ramping capability for shorter periods of time. Longer ramps may cause regulation problems after faster units exhaust their regulation range. CAISO’s real-time economic dispatch software would try to return units that are not awarded service to their preferred point of operation (POP), so sufficient up-regulation and down-regulation capabilities can be maintained. Because the plant under test was not participating in CAISO’s real AGC scheme, the adopted method of AGC mimicking provides a sufficient approximation of real conditions because both the up-regulation and down-regulation characteristics of the plant can be tested.

For this PV plant to be able to maintain the desired regulation range (30 MW in this case), the plant PPC must be able to estimate the available aggregate peak power that all the plant’s inverters can produce at any point in time. The available power is normally estimated by an algorithm that considers solar irradiation, PV module I-V characteristics and temperatures, inverter efficiencies, etc. The plant under test did not have this estimation function because the plant owner did not request it during construction; instead, the project team implemented a less sophisticated approach to evaluate the available maximum power. For this purpose, a single 4-MVA inverter was taken from the APC scheme by the First Solar team, and it was set to operate at the power level determined by its maximum power point tracking (MPPT) algorithm. The measured AC power of this inverter was used as an indicator of available power for the other 79 inverters (80 inverters total). The available maximum power was then calculated as:

$$P_{available} = 79 \times P_i^{MPPT} \quad (3)$$

where P_i^{MPPT} is the measured AC power of the single inverter that was designated to operate at its MPPT point. Therefore, Eq. 2 can be rewritten as:

$$P_{command} = (79 \times P_i^{MPPT} - 30MW) + \Delta P_{AGC} \quad (4)$$

So the aggregate power command sent to the PPC for the remaining 79 inverters was calculated using Eq. 4. This method has inherent uncertainties because it assumes uniform solar irradiation conditions across the whole 300-MW plant. Fortunately, cloud conditions were favorable for this

method to be acceptable because there was a clear sky above the plant during most of the day on August 24. Of course, under moving cloud conditions the accuracy of this method would drop significantly due to the large geographical footprint of the 300-MW PV plant. The importance of accurate peak power estimation for any type of up-regulation was also emphasized in Ref. 11, and it is a crucial factor for AGC performance accuracy by PV plants.

The measured 1-second time series for the August 24, 2016, AGC tests are shown in Figures 14–18. In particular, Figure 14 shows the results of the morning AGC test. The test started when the plant was commanded to curtail its production to a lower level (orange trace), which was 30 MW below its available peak power (green trace), according to Eq. 4. The AGC signal was then fed to the PPC (red trace), so the plant output (yellow trace) was changing accordingly, demonstrating good AGC performance by following the set point during this period of smooth power production. A similar test was conducted during the peak production hour, as shown in Figure 15. A magnified view of the same test is shown in Figure 16 allowing a closer look to the plant AGC performance. The plant’s response to each new AGC set point is almost immediate; however, there were periods when the plant was not able to reach the set point with this high level of precision. This mismatch can be explained by the internal active ramp rate limit in individual inverters. The absolute control error for the same test is small, as shown in Figure 16, and it is confined within the range of ± 5 MW (or $\pm 1.67\%$ of the plant’s rated power capacity).

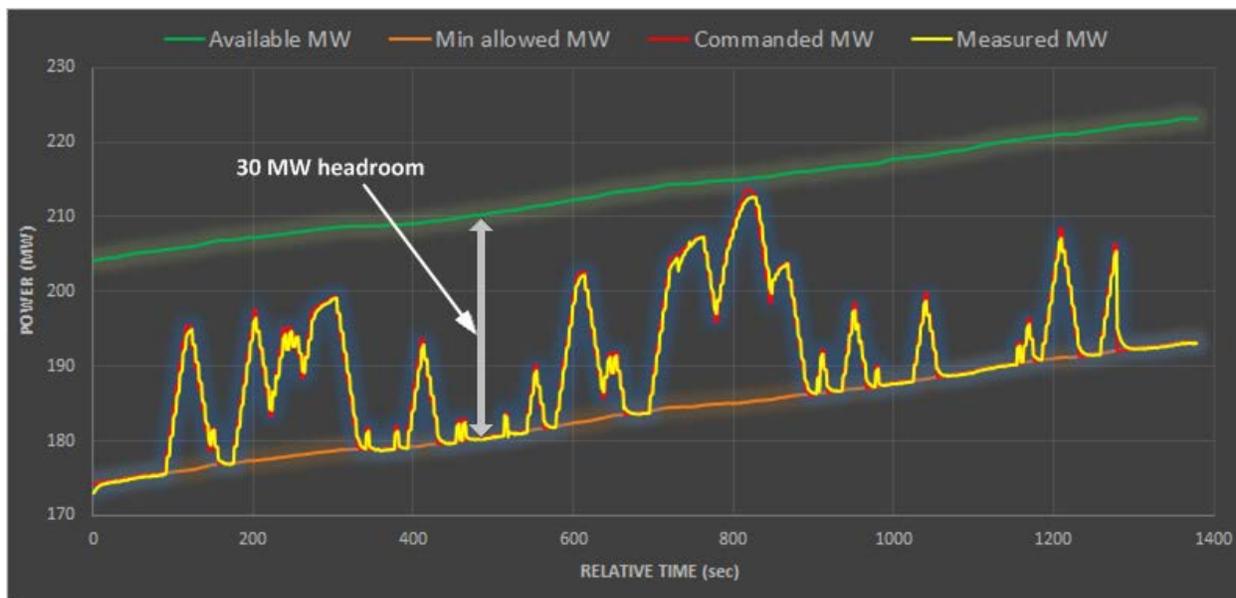


Figure 14. Morning AGC test (9:47 a.m.–10:10 a.m.). Illustration from NREL

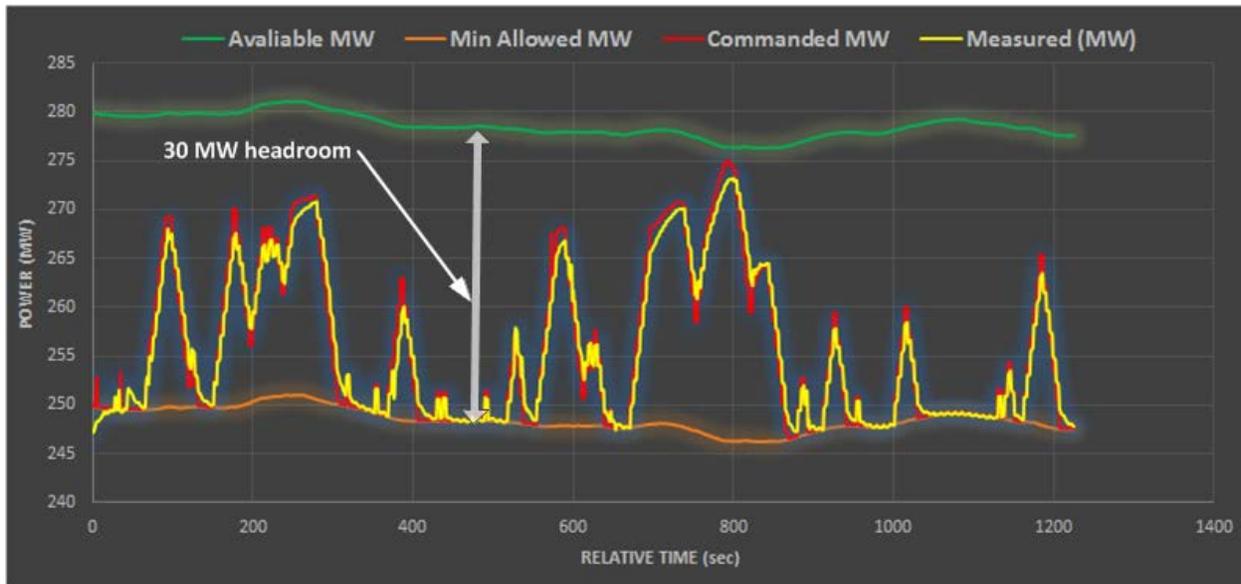


Figure 15. Midday AGC test (12:40 p.m.–1 p.m.). *Illustration from NREL*

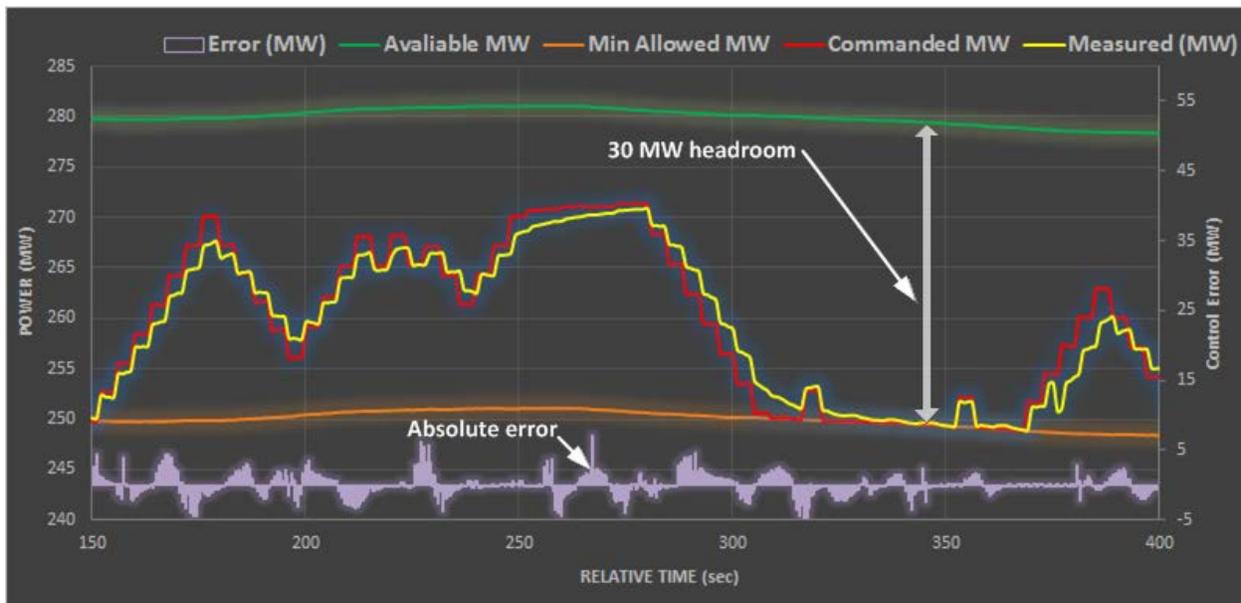


Figure 16. Midday AGC test (12:40 p.m.–1 p.m.) magnification. *Illustration from NREL*

Results of the AGC test conducted during the afternoon are shown in Figure 17. The plant demonstrated similar AGC performance as in the previous cases; however, a cloud front was moving over the plant on the afternoon of August 24, which introduced variability in the plant’s output. During these periods, the available peak power from the plant was reduced significantly, causing the AGC set point to decrease as well, according to Eq. 4; however, even during these periods, the plant demonstrated good AGC performance by closely following the commanded set point, as shown in Figure 18 for one such event.

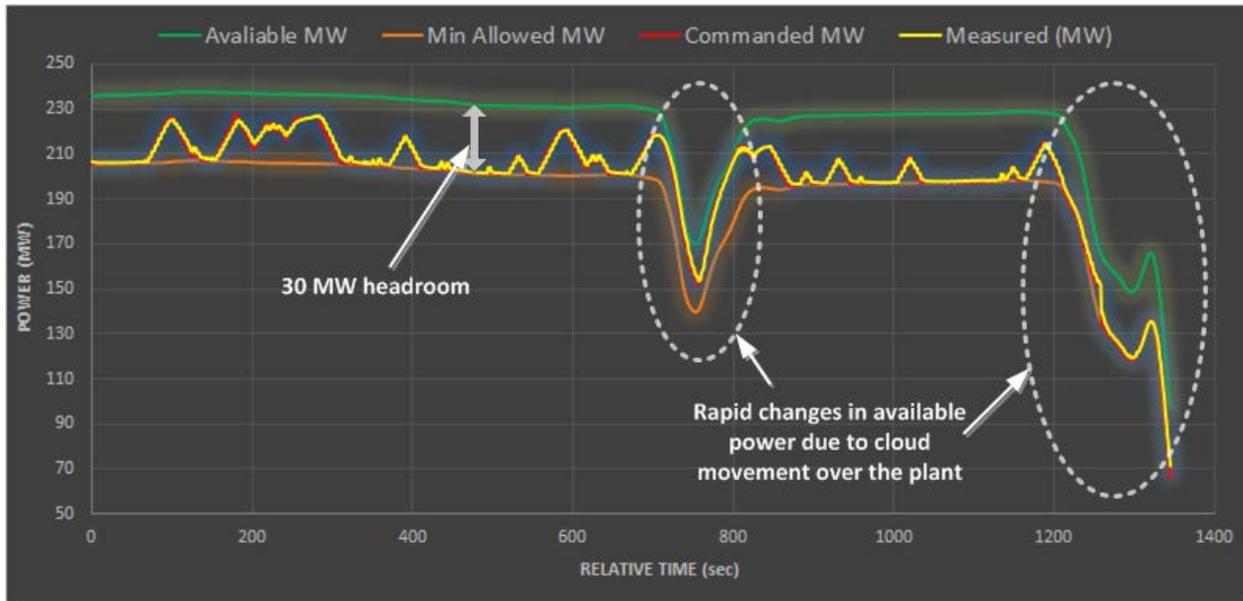


Figure 17. Afternoon AGC test (2:54 p.m.–3:16 p.m.). Illustration from NREL

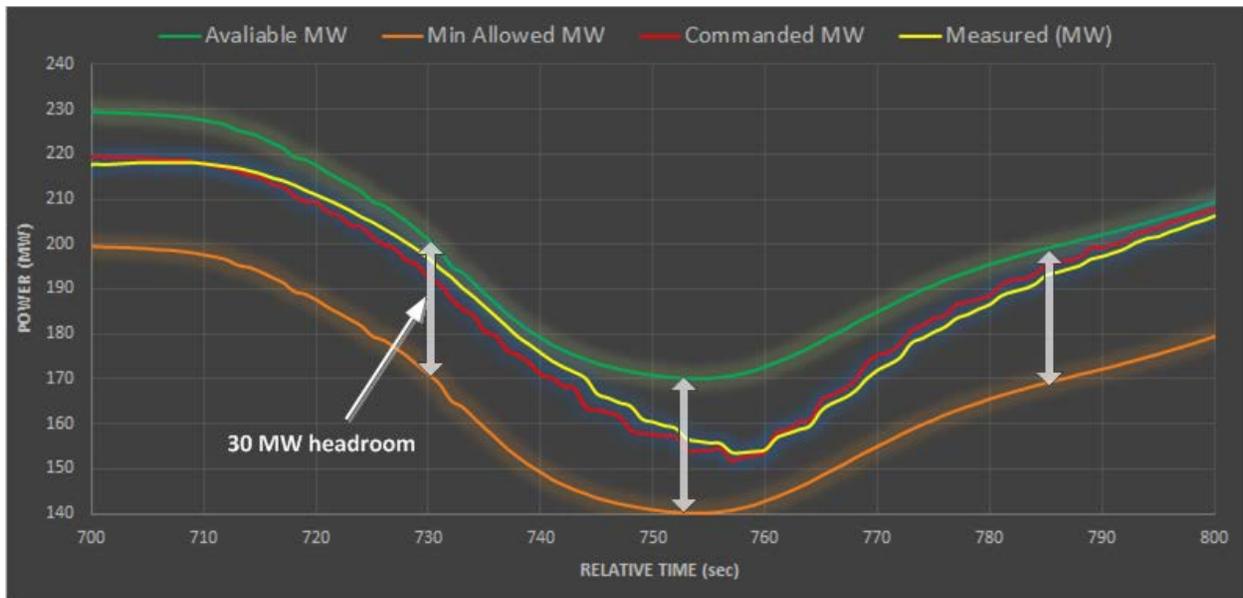


Figure 18. Afternoon AGC test (2:54 p.m.–3:16 p.m.) magnification. Illustration from NREL

The performance results for all three AGC tests are consolidated in an X-Y plot (Figure 19) that shows the linear correlation between the commanded and measured plant power for the morning, midday, and afternoon testing periods (red, blue, and green dots, respectively). The slope and offset of the linear regression for each test indicate low scatter and good linearity. In addition, the R-squared values of the correlation coefficients for each time period also show a high degree of correlation between the set point and measured plant power.

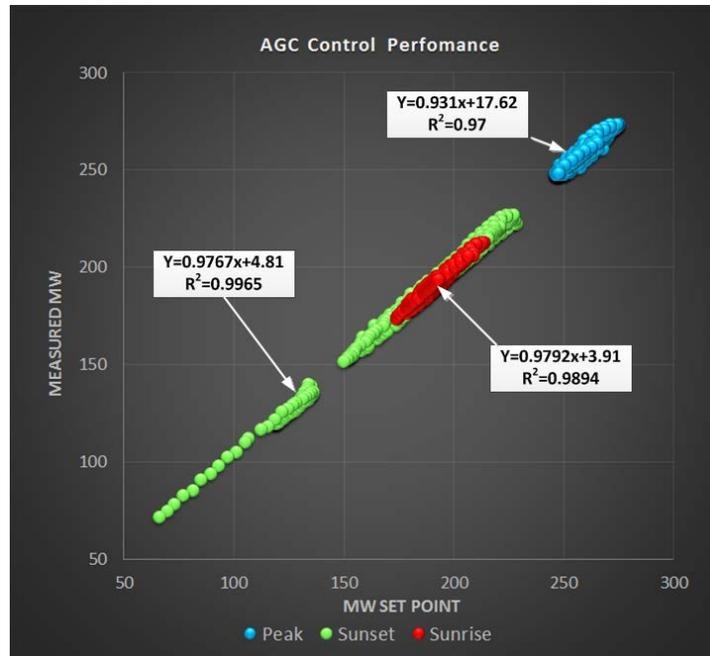


Figure 19. AGC performance for three time periods. *Illustration from NREL*

The relative AGC control error as a percentage of installed plant capacity for all three AGC tests is shown in Figure 20 for a 20-minute time interval for comparison. Table 1 lists the mean, min/max, and standard deviation values of the AGC control error. The mean value of the AGC control error during the whole period of testing for all three data sets is very low (-0.013% of the plant's rated capacity), with standard deviation of error equal to 0.439%.



Figure 20. AGC control error for all three tests. *Illustration from NREL*

Table 1. AGC Control Error Statistics

	Sunrise	Peak	Sunset	Total for the Period of Testing
Mean error (% of rated power)	0.02	0.0	-0.06	-0.01
Min error (% of rated power)	-1.16	-1.85	-2.1	-2.1
Max error (% of rated power)	1.25	2.35	2.12	2.35
Standard deviation (% of rated power)	0.31	0.47	0.51	0.44

The frequency distribution of the AGC control errors for all three periods of observation are shown in Figure 21 in logarithmic scale as a visual representation of the difference between the number of error magnitude occurrences for each test. These distribution shapes are not exactly symmetric, but they are still concentrated around the center with visible tails. Only a few AGC control errors with large magnitudes occurred during the periods of observation. Of course, longer testing (many days or weeks) under different cloud conditions will be required to collect sufficient statistics on AGC control accuracy. Yet even such a short testing opportunity allows some preliminary conclusions on the accuracy of AGC control by a large utility-scale power plant. These results also suggest that relatively small and short-term energy storage can help reduce the AGC error to essentially 0% by taking care of small control inaccuracies due to cloud impact and uncertainties of peak power calculation methods.

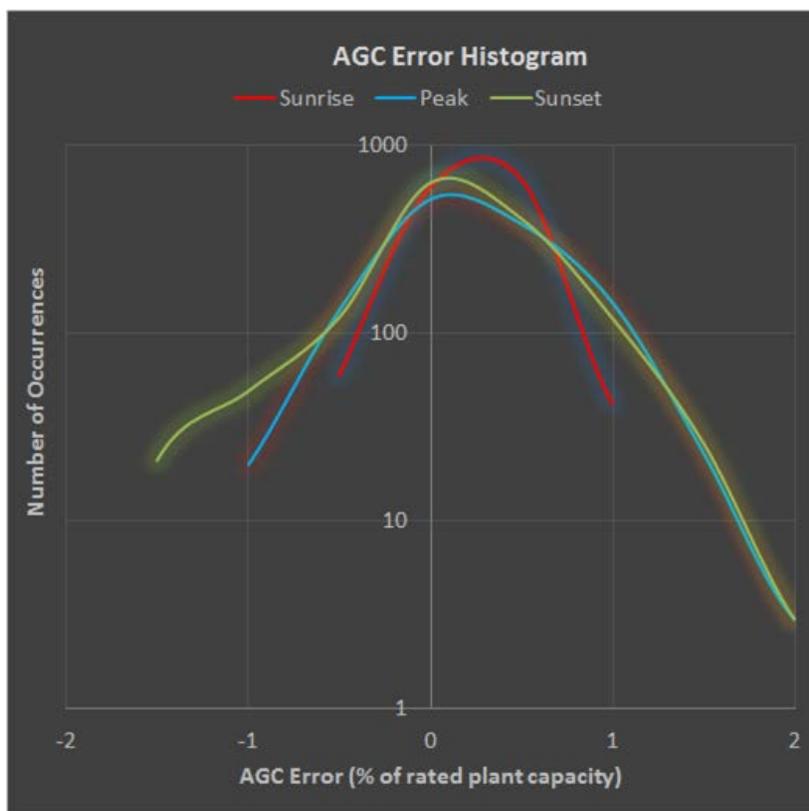


Figure 21. Distribution of AGC control error. Illustration from NREL

Normally, CAISO measures the accuracy of a resource’s response to energy management system (EMS) signals during 15-minute intervals by calculating the ratio between the sum of the total 4-second set point deviations and the sum of the AGC set points. The future CAISO resource instructed mileage percentage is also being calculated during 15-minute intervals. The plant’s monitored delayed response time and the accuracy of the plant’s response to the regulation set point changes were used to calculate its regulation accuracy values, which are shown in Table 2 for all three testing periods. Table 3 lists the typical regulation-up accuracies for CAISO’s conventional generation for comparison. By comparing the PV plant testing results from Table 2 to the values for individual technologies in Table 3, a conclusion can be made that regulation accuracy by the PV plant is 24–30 points better than fast gas turbine technologies. The data from these tests will be used by CAISO in the future ancillary service market design to determine the resource-specific expected mileage to award regulation-up and regulation-down capacity.

Table 2. Measured Regulation Accuracy by 300-MW PV Plant

Time Frame	Measured Accuracy of Solar PV Plant
Sunrise	93.7%
Middle of the day	87.1%
Sunset	87.4%

Table 3. Typical Regulation-Up Accuracy of CAISO Conventional Generation

	Combined Cycle	Gas Turbine	Hydro	Limited Energy Battery Resource	Pump Storage Turbine	Steam Turbine
Regulation-Up Accuracy	46.88%	63.08%	46.67%	61.35%	45.31%	40%

4 Frequency Droop Control Tests

4.1 Rationale and Description of Frequency Droop Tests

The ability of a power system to maintain its electrical frequency within a safe range is crucial for stability and reliability. Frequency response is a measure of an interconnection’s ability to stabilize the frequency immediately following the sudden loss of generation or load. An interconnected power system must have adequate resources to respond to a variety of contingency events to ensure rapid restoration of the balance between generation and load. On January 16, 2014, FERC approved Reliability Standard BAL-003-1 (“Frequency Response and Frequency Bias Setting”), submitted by NERC. By approving this standard, NERC created a new obligation for balancing authorities, including CAISO, to demonstrate that they have sufficient frequency response to respond to disturbances resulting in the decline of system frequency. The purpose of this initiative is to ensure that CAISO provides sufficient primary frequency response to support system reliability while complying with the new NERC requirement [16]. NERC determines the Western Interconnection’s frequency response obligation (IFRO) based on the largest potential generation loss of two Palo Verde generating units (2,626 MW). NERC created this standard to ensure that balancing authorities have sufficient frequency response capability on hand. Like all balancing authorities, CAISO must plan on having an adequate amount of frequency response capability available to respond to actual frequency events. CAISO’s estimated frequency response obligation is 258 MW/0.1 Hz. Based on historical events during 2015–2016, CAISO recognized that its median frequency response rate might fall short of its frequency response obligation (FRO) by as much as 100 MW/0.1Hz [16]. From this perspective, the participation of curtailed PV power plants in CAISO’s frequency response could help address this potential deficiency. The objective of the frequency response test conducted under this project was to demonstrate that the plant can provide a response in accordance with 5% and 3% droop settings through its governor-like control system.

The definition of implemented droop control for PV is the same as that for conventional generators:

$$\frac{1}{Droop} = \frac{\Delta P/P_{rated}}{\Delta f/60Hz} \quad (5)$$

The plant’s rated active power (300 MW) is used in Eq. 5 for the droop setting calculations. For the purposes of the droop test, the plant was set to operate at a curtailed power level that was 10% lower than the available estimated peak power. The PPC was programmed to change the plant’s power output in accordance with a symmetric droop characteristic, shown in Figure 22 at both the 5% and 3% droop values. The upper limit of the droop curve was the available plant power, and the lower limit was at a level that was 20% below the then-available peak power. The implemented droop curve also had a ± 36 -mHz frequency deadband.

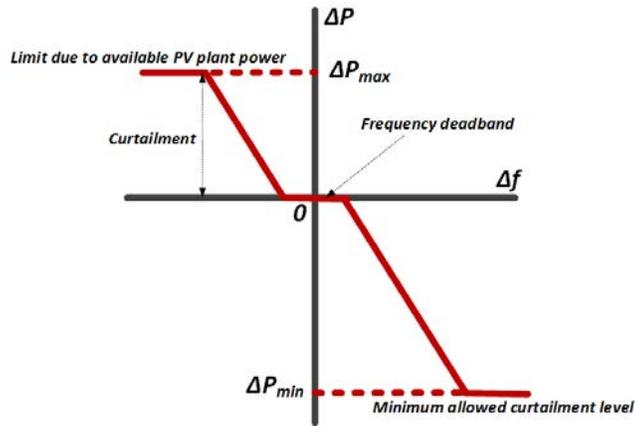


Figure 22. Frequency droop characteristic. *Illustration from NREL*

The frequency droop capability of the plant was tested using the actual underfrequency and overfrequency events in the Western Interconnection measured by NREL in Colorado (Figure 23 and Figure 24, respectively).

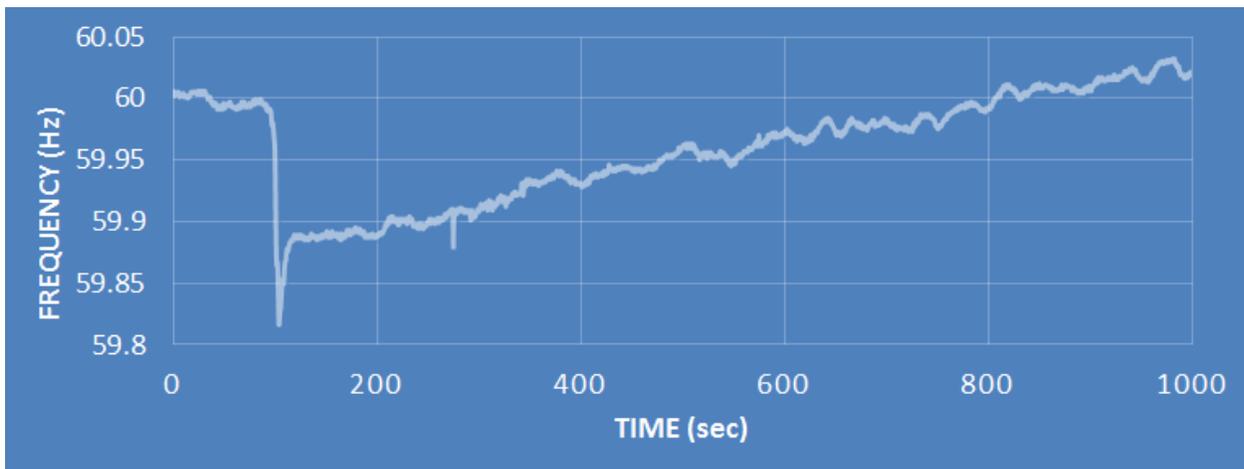


Figure 23. Underfrequency event. *Illustration from NREL*

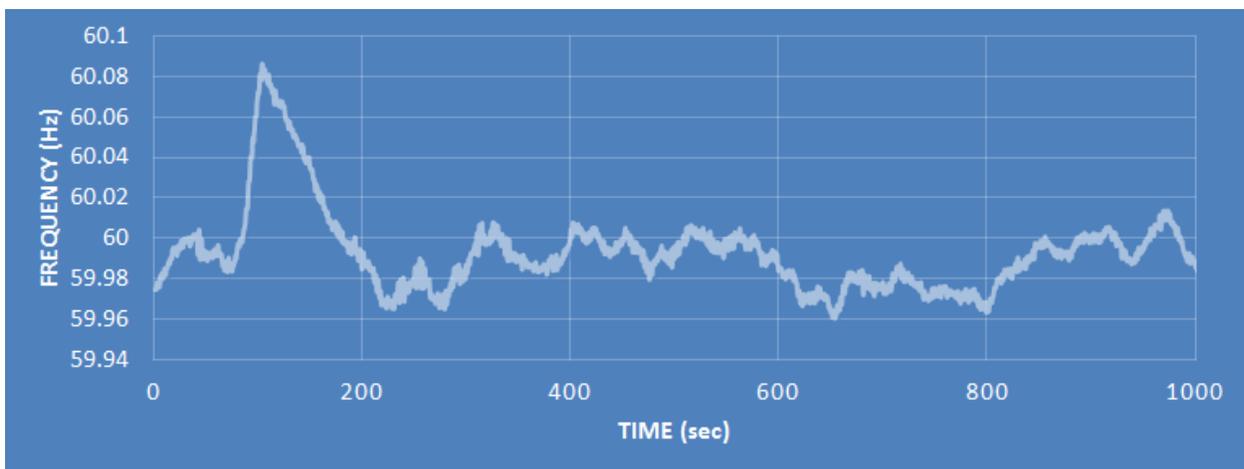


Figure 24. Overfrequency event. *Illustration from NREL*

The frequency event time series shown in Figure 23 and Figure 24 were provided to the PPC, so the plant can demonstrate a frequency response as if it were exposed to a real frequency event measured at the plant’s POI. This is the common method for testing the frequency response of inverter-coupled generation because waiting for a real frequency event to occur in the power system may be time consuming because large contingency events do not happen very often (two to three times per month for the Western Interconnection). The active power ramp-rate limit in the PPC was set at 600 MW/min (10 MW/sec) during the droop control tests.

4.2 Droop Test Results

The 5% and 3% frequency droop tests on the 300-MW PV power plant were conducted on August 24, 2016. For this purpose, the First Solar team remotely set the PPC into droop control mode in accordance with the control method shown in Figure 22, with 5% and 3% droop values and 10% power curtailment. The minimum allowed power level for down-regulation was set to 20% below the available peak power for all droop tests (to minimize plant revenue losses).

4.2.1 Droop Tests during Underfrequency Event

The results of one 3% droop test during the morning on August 24, 2016, are shown in Figure 25. The plant’s active power response in MW to the underfrequency event was measured by the phasor measurement units at the plant’s POI. The calculated active power time series show that the plant increased its power output during the initial grid frequency decline, and then gradually returned to its original pretest level as frequency returned to its normal pre-fault level. The droop response of the plant can be observed on the X-Y plot shown in Figure 26, wherein a linear dependence between frequency and measured power can be observed once the frequency deviation exceeded the deadband.

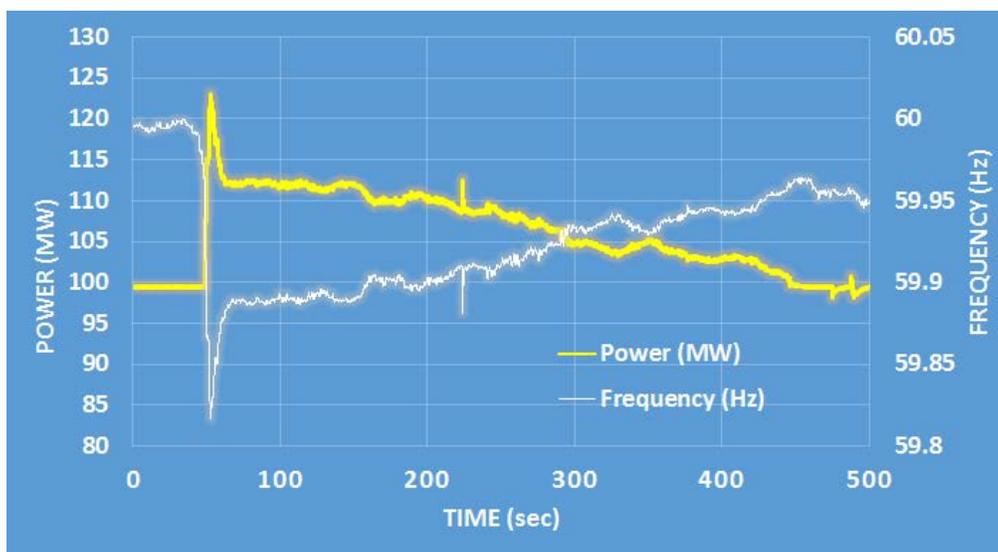


Figure 25. Example of the plant’s response to an underfrequency event (3% droop test during sunrise). *Illustration from NREL*

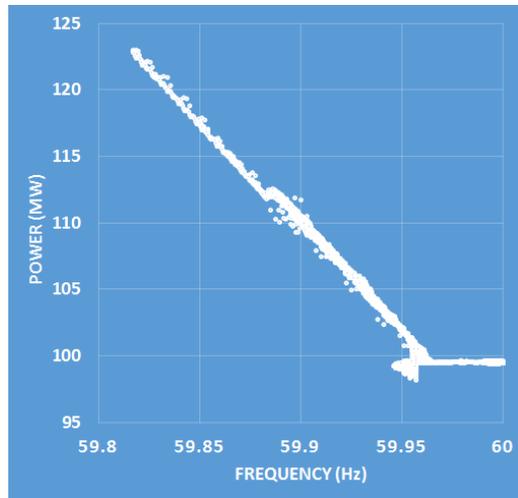


Figure 26. Measured droop characteristic for an underfrequency event (3% droop test during sunrise)

Similarly, 3% and 5% droop tests were conducted during midday (peak solar production period) and during the afternoon. Example test results for these periods are shown in Figure 27 (a and b) and Figure 28. Some nonlinearity in the plant’s response was observed during these tests when the frequency deviation exceeded 120 mHz from its prefault level, causing some mismatch between the expected and actual droop response. Such nonlinearity was not observed during the morning droop tests when the solar resource was increasing steadily during the test under clear-sky conditions. One reason for this mismatch could be the decreasing solar resource and increased resource variability due to cloud conditions during the afternoon. It is expected that further fine-tuning the PPC control parameters can help mitigating such nonlinearity, and the First Solar team will address this issue in the future.

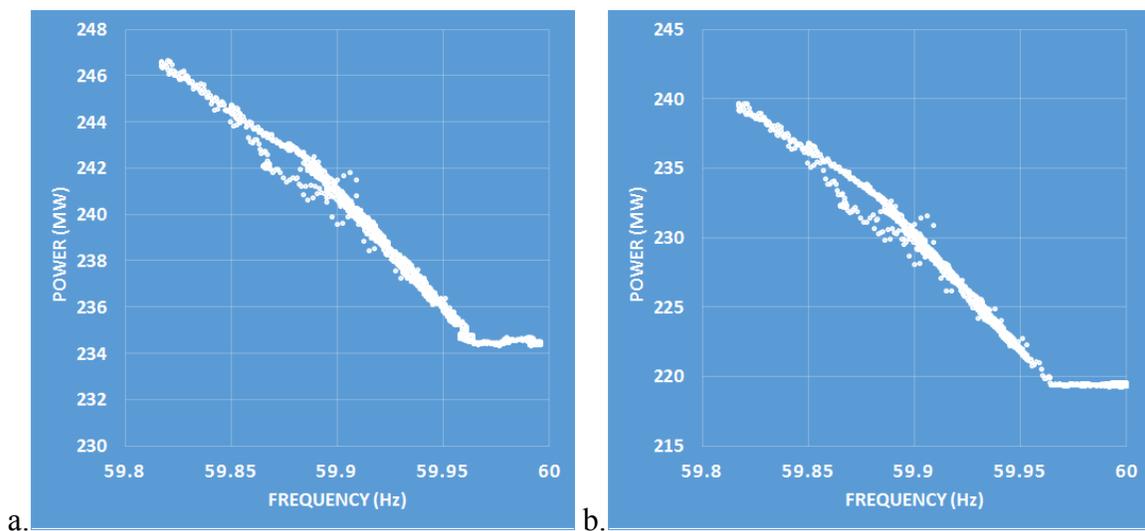


Figure 27. Measured droop characteristics for an underfrequency event: (a) 5% droop test and (b) 3% droop test during midday. Illustration from NREL

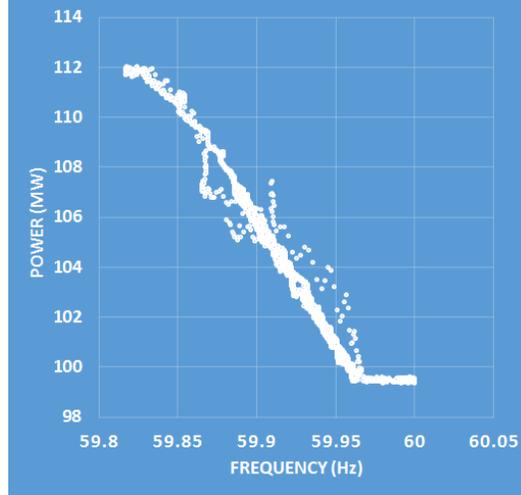


Figure 28. Measured droop characteristics for an underfrequency event (5% droop test during sunset). Illustration from NREL

Results of the individual droop tests are shown in greater detail in figures 29–33. The first plot in each figure shows the data points scattered around the calculated target droop characteristic (figures 29[a]–33[a]). In these X-Y plots, the X-axis represents the frequency deviation, Δf (or change in frequency), from its pre-fault value, calculated as:

$$\Delta f = f_{grid} - 60\text{Hz} \quad (6)$$

where f_{grid} is the value of grid frequency from the event time series.

The Y-axis represents the plant's active power response, $\Delta P_{measured}$ (or change in the plant's active power output), calculated as:

$$\Delta P_{measured} = P_{actual} - P_{max.estimated} \quad (7)$$

where P_{actual} is the measured plant's active power at the POI, and $P_{max.estimated}$ is the estimated peak power for a given level of solar resource.

The calculated plant response, $\Delta P_{calculated}$ (or target response), for a given droop value can be calculated as (frequency deadband is not included in this equation, but it is added in the control logic):

$$\Delta P_{calculated} = \frac{\Delta f}{60\text{Hz}} \cdot \frac{1}{Droop} \cdot P_{nom} \quad (8)$$

where $P_{nom} = 300 \text{ MW}$ is the plant's nameplate capacity.

The droop control error is then calculated as a difference between the calculated target and actual plant response for any given droop setting:

$$Error = \Delta P_{calculated} - \Delta P_{measured} \quad (9)$$

The frequency distribution of the control error data for each droop test along with the error statistics data are shown in figures 29(b)–33(b). The detailed comparison of these test results concluded that the PV plant demonstrated a satisfactory droop performance during the underfrequency events for the morning, midday, and afternoon time frames. Some nonlinearities in the response can be further improved by fine-tuning the controller parameters. The observed scatter around the target response is due to the short-term solar resource variability, and it can be mitigated if such a response is generated by a number of PV plants within a larger geographical footprint.

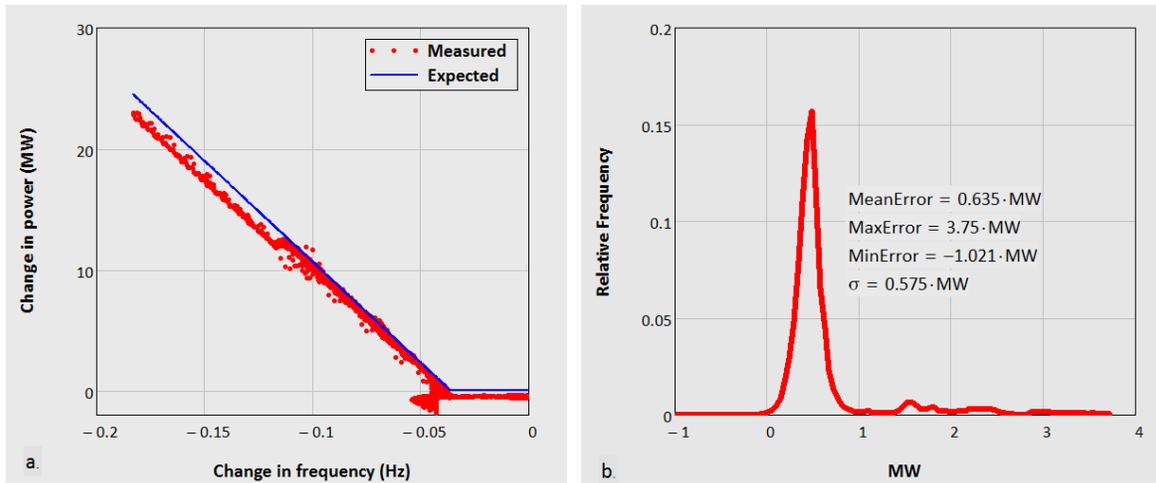


Figure 29. (a) Results and (b) control error during the sunrise 3% droop test for an underfrequency event. Illustration from NREL

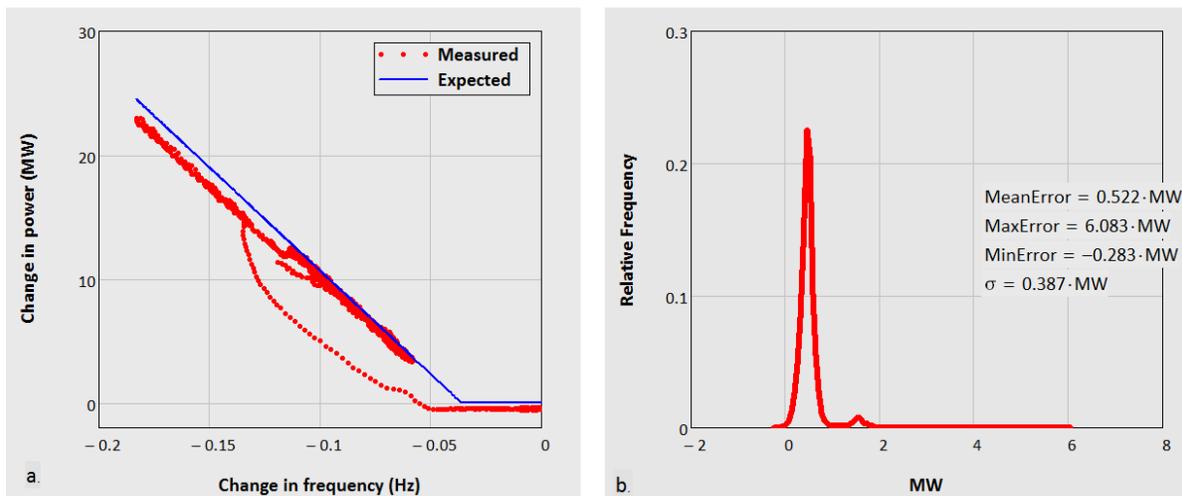


Figure 30. (a) Results and (b) control error during a second sunrise 3% droop test for an underfrequency event. Illustration from NREL

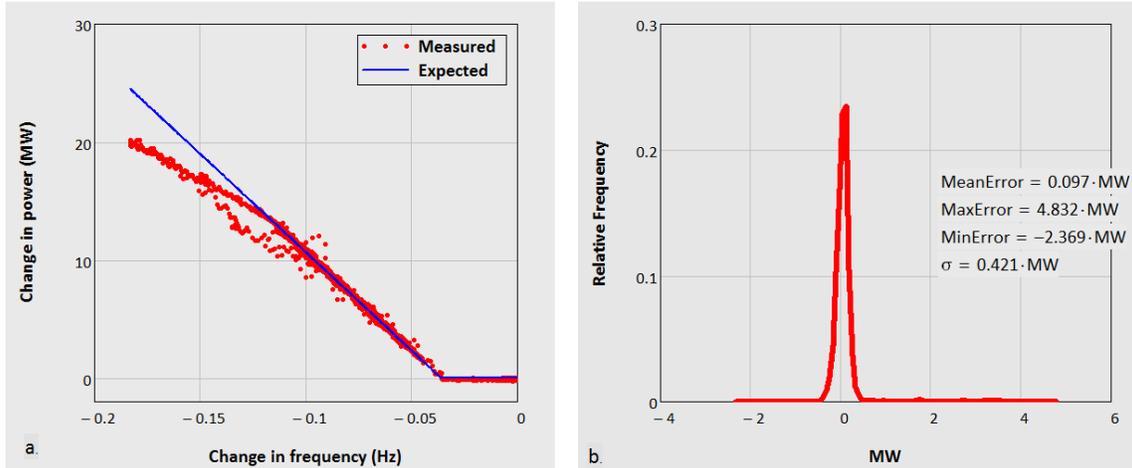


Figure 31. (a) Results and (b) control error during the midday 3% droop test for an underfrequency event. *Illustration from NREL*

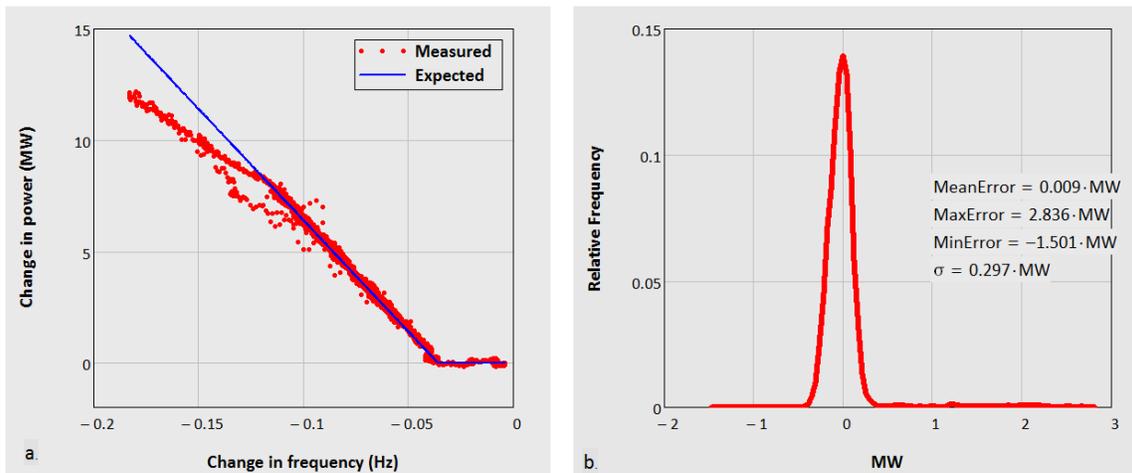


Figure 32. (a) Results and (b) control error during the midday 5% droop test for an underfrequency event. *Illustration from NREL*

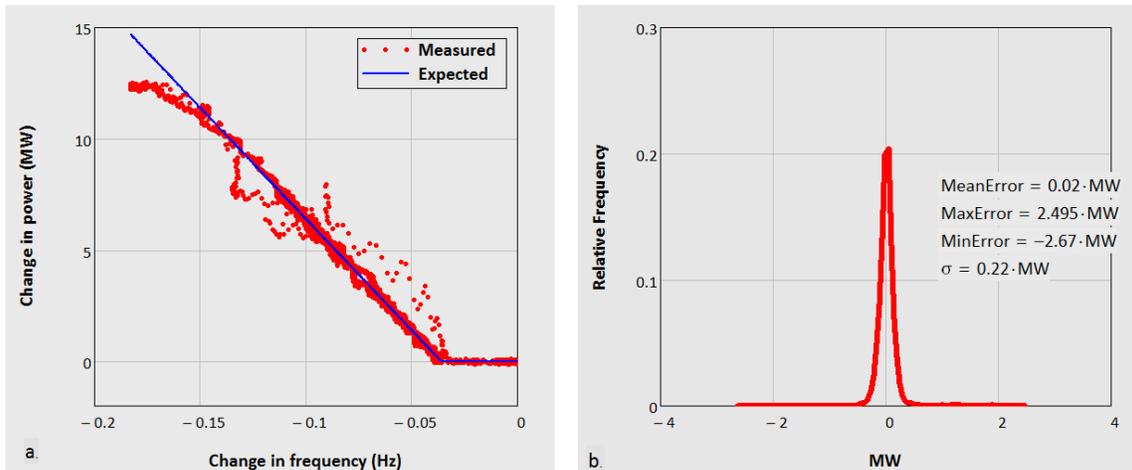


Figure 33. (a) Results and (b) control error during the sunset 5% droop test for an underfrequency event. *Illustration from NREL*

Table 4 and Table 5 show the control error statistics for the underfrequency droop tests in absolute MW units and percentage of plant capacity, respectively. Despite observed nonlinearities and scatter, the mean control error is very small, ranging from 0%–0.21% of the plant’s rated capacity. The standard deviation control error is also small (0.07%–0.19% of rated capacity). The largest measured positive and negative error values are 2.03% and -0.89% of the plant’s rated capacity. Figure 34 shows the consolidated data for many up-regulation tests for comparison.

Table 4. Droop Control Error Statistics (Absolute Values in MW)

Test Type	Mean Error (MW)	Max + Error (MW)	Max – Error (MW)	Standard Deviation (MW)
3% droop, sunrise	0.63	3.75	-1.02	0.57
3% droop, sunrise	0.52	6.08	-0.28	0.39
3% droop, midday	0.1	4.83	-2.37	0.42
5% droop, midday	0.0	2.84	-1.5	0.3
5% droop, sunset	0.02	2.5	-2.67	0.22

Table 5. Droop Control Error Statistics (Percentage of Plant Rated Capacity)

Test Type	Mean Error (%)	Max + Error (%)	Max – Error (%)	Standard Deviation (%)
3% droop, sunrise	0.21	1.25	-0.34	0.19
3% droop, sunrise	0.17	2.03	-0.09	0.13
3% droop, midday	0.03	1.61	-0.79	0.14
5% droop, midday	0.00	0.95	-0.5	0.1
5% droop, sunset	0.01	0.83	-0.89	0.07

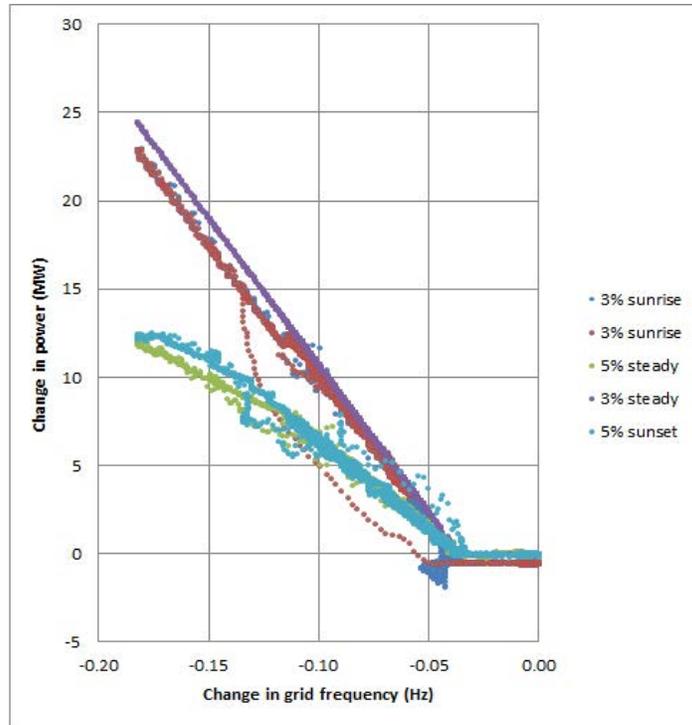


Figure 34. Consolidated underfrequency droop test results. *Illustration from NREL*

4.2.2 Frequency Droop Tests during Overfrequency Event

Frequency droop tests for the overfrequency events were also conducted on August 24, 2016. The results of one 5% droop test on the morning on August 24, 2016, are shown in Figure 35. The plant's response to the overfrequency event was measured at the plant's POI. The calculated active power time series shows that the plant decreased its power output during the initial grid frequency increase, then gradually returned to its original pretest level as frequency returned to its normal pre-fault level. The droop response of the plant from several tests can be observed in the X-Y plots shown in Figure 36 (a and b) and Figure 37, wherein a linear dependence between frequency and measured power can be observed once the frequency deviation exceeded the deadband. The plant demonstrated consistent and accurate down-regulation performance during all overfrequency droop tests.

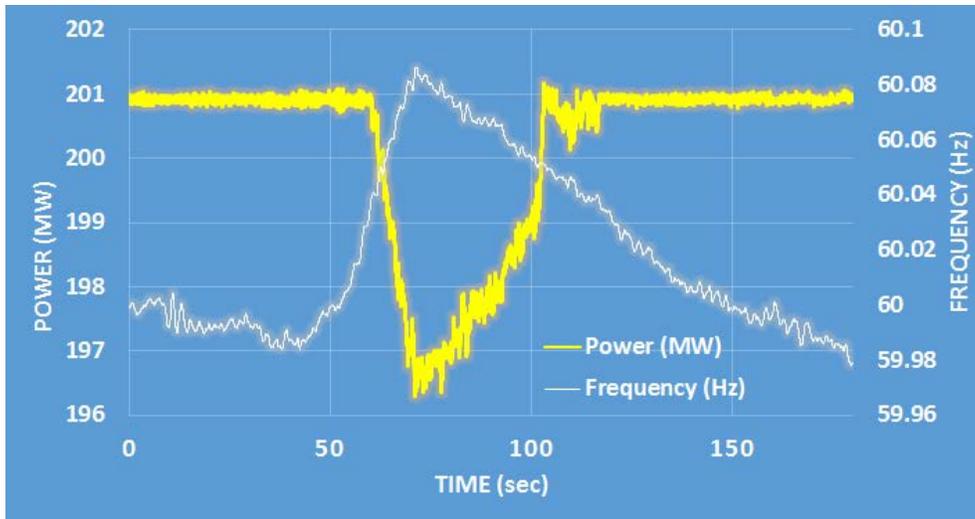


Figure 35. Example of the plant's response to an overfrequency event (5% droop test during sunrise). *Illustration from NREL*

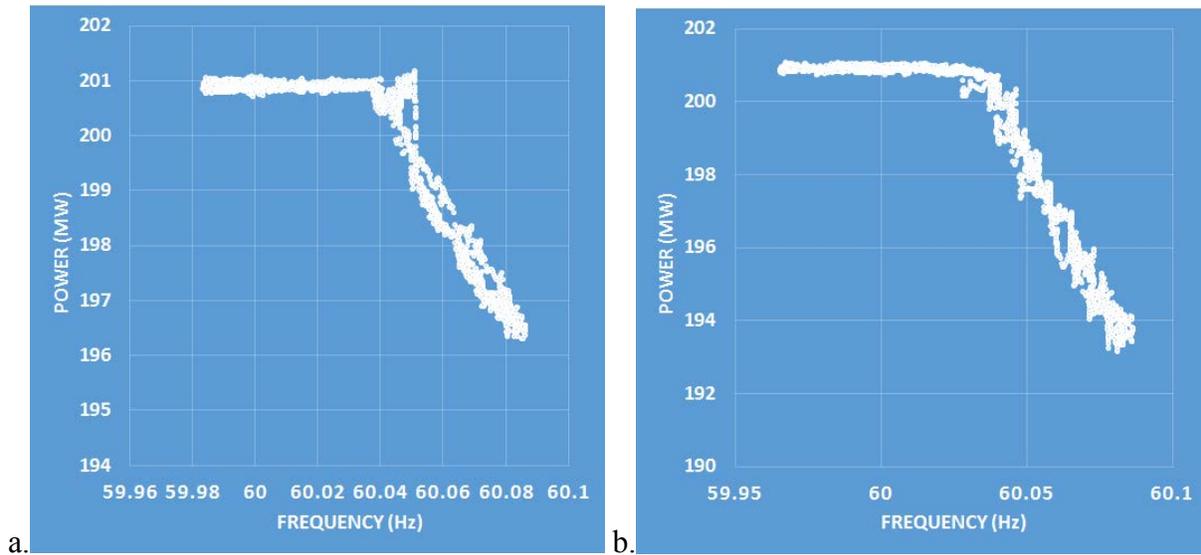


Figure 36. Measured droop characteristics for an overfrequency event: (a) 5% droop test and (b) 3% droop test during midday. *Illustration from NREL*

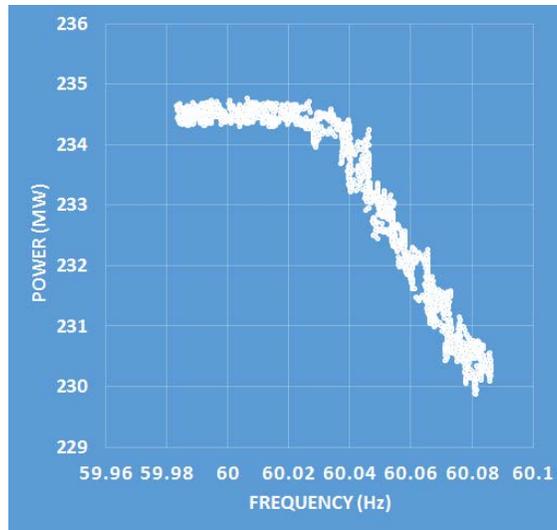


Figure 37. Measured droop characteristics for an overfrequency event (5% droop test during sunset). *Illustration from NREL*

A PV plant must operate in curtailed mode to provide enough reserve for PFR response during underfrequency conditions. During normal operating conditions with near-nominal system frequency, the control is set to provide a specified margin by generating less power than is available from the plant. The reserve available (i.e., headroom) is the available power curtailed, which is shown as the reserve between the operational point and P_0 in Figure 38. If required by reliability consideration, a nonsymmetric droop curve is possible with solar PV power, depending on system needs, as shown in Figure 38. More aggressive droops (e.g., 1% or 2%) can be implemented for overfrequency regulation because PV plants are able to provide very fast curtailment. This type of nonsymmetric droop response will likely be demonstrated in future stages of this testing project.

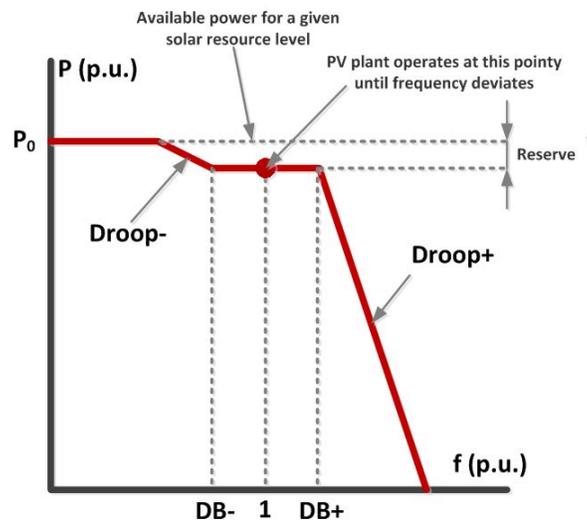


Figure 38. Concept of nonsymmetric droop characteristic for PV plants. *Illustration from NREL*

5 Reactive Power and Voltage Control Tests

5.1 Rationale and Description of Reactive Power Tests

Voltage on the North American bulk system is normally regulated by generator operators, which are typically provided with voltage schedules by transmission operators [17]. The growing level of penetration of variable wind and solar generation has led to the need for them to contribute to power system voltage and reactive regulation because in the past the bulk system voltage regulation was provided almost exclusively by synchronous generators. According to FERC's LGIA [18], the generally accepted power factor requirement of a large generator is ± 0.95 . In conventional power plants with synchronous generators, the reactive power range is normally defined as dynamic, so synchronous generators need to continuously adjust their reactive power production or absorption within a power factor range of ± 0.95 . For PV power plants, the reactive power requirements are not well defined. FERC Order 661-A [19] is applicable to wind generators but sometimes applied to PV plants as well. It also requires a power factor range of ± 0.95 measured at the POI and requires that the plant provide sufficient dynamic voltage support to ensure safety and reliability (the requirement for dynamic voltage support is normally determined during interconnection studies). Utility-scale wind power plants are designed to meet the ± 0.95 power factor requirements; however, the common practice in the PV industry is to configure PV inverters to operate at unity power factor. It is expected that similar interconnection requirements for power factor range and low-voltage ride-through will be formulated for PV in the near future. To meet this requirement, PV inverters need to have MVA ratings large enough to handle full active and reactive current.

In its recent Order 827, FERC issued a final rule requiring all newly interconnecting nonsynchronous generators, including wind generators, to design their facilities to be capable of providing reactive power [20]. The generating facilities need to be capable of maintaining a composite power delivery at continuous rated power output at the high side of the generation substation at ± 0.95 power factors.

Conventional synchronous generators of power plants have reactive power capability that is typically described as a "D curve," as shown in Figure 39. The reactive power capability of conventional power plants is limited by many factors, including their maximum and minimum load capability, thermal limitations due to rotor and stator current-carrying capacities, and stability limits. The ability to provide reactive power at zero loads is usually not possible with many large plant designs. Only some generators are designed to operate as synchronous condensers with zero active loads. The reactive power capability of a PV inverter is determined by its current limit only. With proper MW and MVA rating, the PV inverter should be able to operate at full current with reactive power capability, similar to the one shown in Figure 39. In general, for the same MVA rating, a PV power plant is expected to have much superior reactive power capability than a conventional synchronous generator-based plant, as indicated notionally in Figure 39. In principle, PV inverters can provide reactive power support at zero power, similar to a STATCOM (see definition in [21]); however, this functionality is not standard because PV inverters are disconnected from the grid at night.

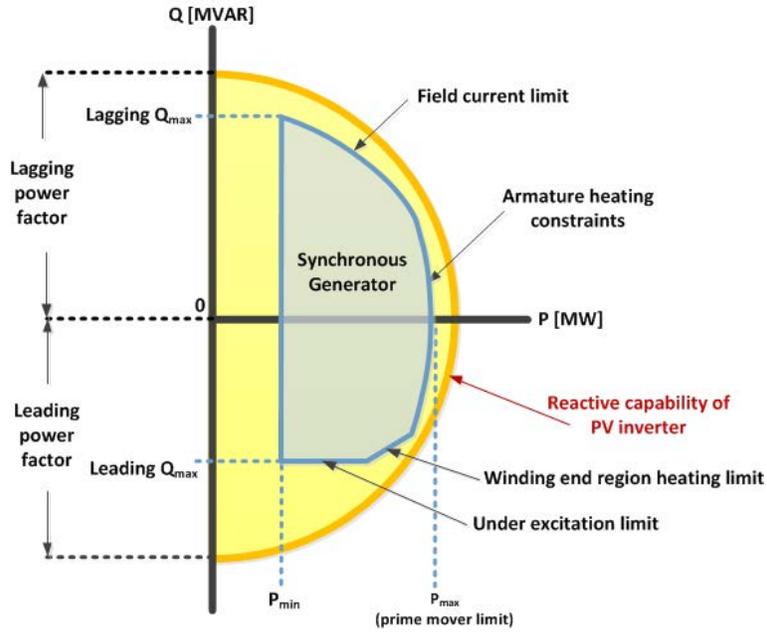


Figure 39. Comparison of reactive power capability for a synchronous generator and PV inverter of the same MVA and MW ratings. *Illustration from NREL*

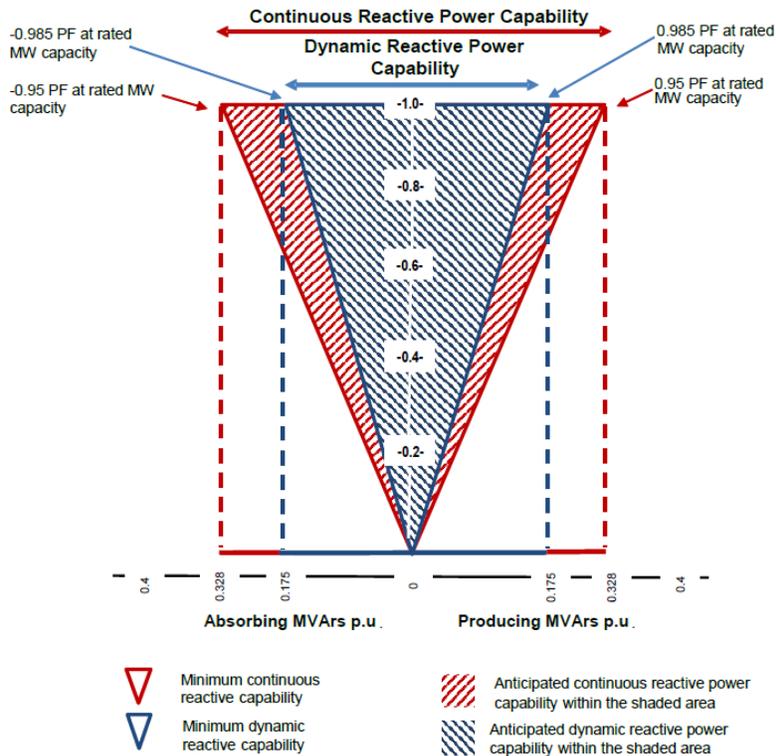


Figure 40. Proposed reactive power capability for asynchronous resources. *Illustration from CAISO*

In its proposed reactive power capability characteristic for asynchronous generation (Figure 40), CAISO defined the requirements for dynamic and continuous reactive power performance by such resources [21]. The red vertical lines shown in Figure 40 represent the expected reactive capability of the asynchronous generating plant at the high side of the generator step-up bank. At all levels of real power output, the plant is expected to produce or absorb reactive power equivalent to approximately 33% of the plant's actual real power output. For example, at the plant's maximum 300-MW real power capability, the expected dynamic reactive capability should be 100 MVARs lagging or 100 MVARs leading. Also, at 50% real power output, the expected reactive capability should be 50 MVARs lagging or 50 MVARs leading, and at zero MW output, the expected reactive output should be zero. Figure 41 shows the expected reactive capability of the 300-MW PV plant under test if it must comply with the proposed CAISO requirement for asynchronous generating facilities at the POI. The PV plant is supposed to absorb or produce 100 MVAR of reactive power when operating at full MW capacity at a power factor of -0.95 or +0.95, respectively.

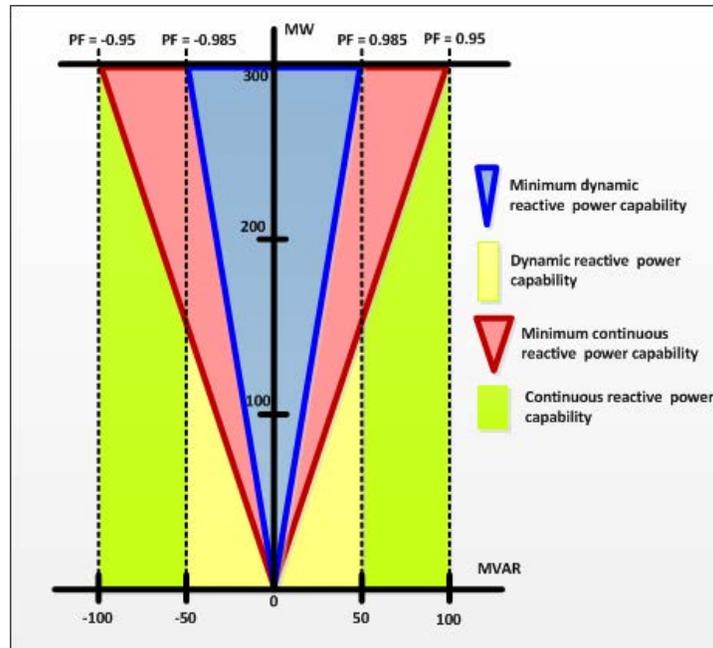


Figure 41. CAISO's proposed reactive capability applied to the 300-MW PV plant under testing.
Illustration from NREL

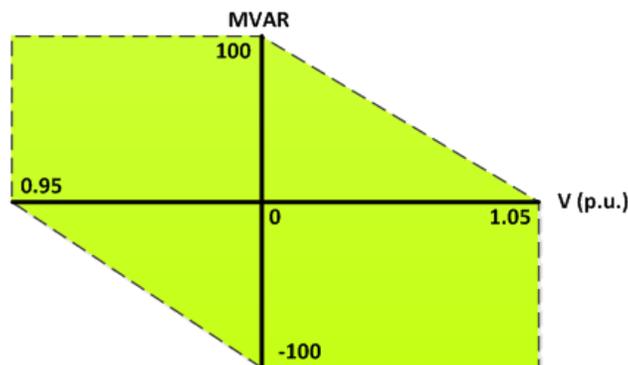


Figure 42. The plant's reactive power capability at different voltage levels at full MW output.
Illustration from NREL

The voltage at the POI may change because of grid conditions, but the plant must maintain its reactive power capability. For this purpose, CAISO's proposed reactive power requirement specifies a voltage operating window for the asynchronous generating facility to provide reactive power at 0.95 lagging power factor when voltage levels are between 0.95–1 p.u. at the POI. Likewise, it should be able to absorb reactive power at 0.95 leading power factor when voltage levels are between 1–1.05 p.u. The proposed capability at different voltage levels applied to the 300-MW PV plant at its full production level is shown in Figure 42.

CAISO proposed adopting a uniform requirement of asynchronous inverter-coupled resources to provide reactive power capability and voltage regulation, as shown in Figure 40 [21]. According to CAISO's draft proposal on reactive power and financial compensation, the asynchronous generating facility shall have dynamic and continuous reactive capability for power factor ranges of ± 0.985 and ± 0.95 , respectively. Through its initiative, CAISO has explored mechanisms to compensate resources for the capability and provision of reactive power. In some regions transmission providers make payments for reactive power capability, but not all. These regions conclude that requiring the capability for this operation is a good utility practice and a necessary condition for conducting normal business [21], [22].

The primary objective of the reactive power test was to demonstrate the capability of the PV plant to operate in the voltage regulation mode within the power factor range of 0.95 leading/lagging. The plant controller maintained the specified voltage set point at the high side of the generator step-up bank by regulating the reactive power produced by the inverters.

The tests were conducted at three different real power output levels: (1) maximum production during the middle of the day, (2) during sunset when the plant is at approximately 50% of its maximum capability, and (3) during sunset when the plant is close to zero production. Measurements were conducted to verify the plant's capability to absorb and produce reactive power in accordance with Figure 40, within a range of ± 100 MVAR during various levels of real power output.

- The plant was first tested at its maximum real power output for a given irradiance level. At maximum real power output, the plant must demonstrate that it can produce approximately 33% of real output as dynamic reactive. Similarly, at maximum real power output, the plant must demonstrate that it can absorb approximately 33% of its real power output as reactive output.
- During sunset, as solar production drops off to approximately 50% of the resource's maximum capability, the plant must demonstrate that it can produce and absorb approximately 33% of its real power output as dynamic reactive output.
- During sunset, as the plant production approaches zero MW, the plant must demonstrate that it can produce and absorb approximately 33% of its real power output as dynamic reactive output.

5.2 Results of Reactive Capability Power Tests

The plant's reactive power capability was tested at two different power levels on August 23, 2016, and August 24, 2016. First, the plant's reactive power capability was measured during a number of tests when the plant was producing high levels of active power (250 MW and more).

Then the reactive power capability was measured at extremely low levels of MW production (less than 5 MW). The results of both tests are consolidated in a graph showing MVAR compared to MW, Figure 43, wherein the blue dots represent the data points measured by the plant's PMUs. The measurements are compared to the proposed CAISO reactive power requirement for asynchronous generation (yellow triangle), demonstrating that the plant meets the expected reactive power capability. In addition, the plant is capable of producing and absorbing reactive power at close to zero power production. Another, more articulate view of the same test results is shown in a three-dimensional view in Figure 44, which combines measured MW, MVAR, and POI voltage, allowing for the positioning of measured data points with respect to the proposed CAISO requirements.

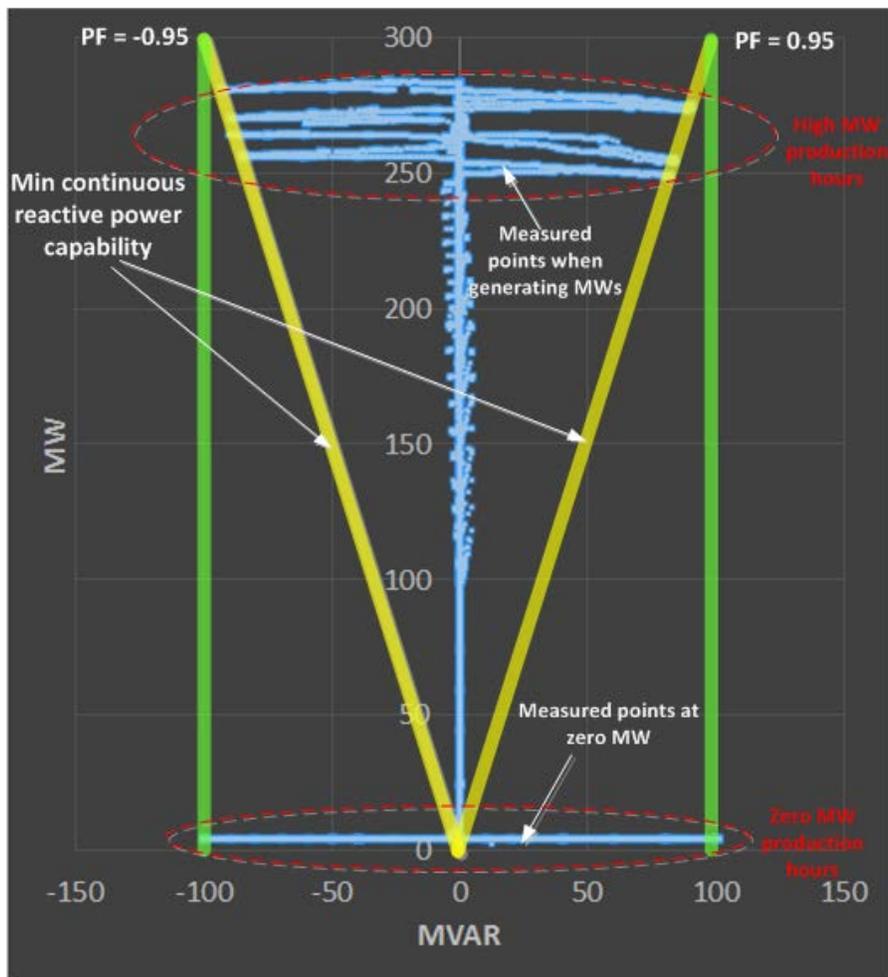


Figure 43. Measured reactive power capability at the POI. *Illustration from NREL*

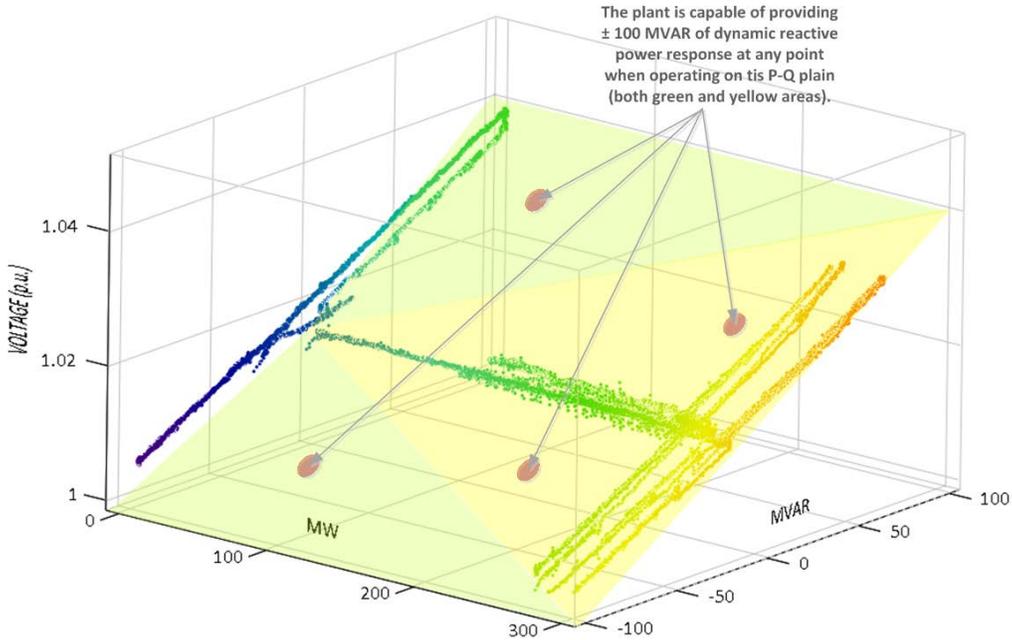


Figure 44. Measured reactive power capability and voltages at the POI. Illustration from NREL

The voltage limit control test was conducted to verify the ability of the plant's control system capability to maintain a power factor target at the same time as maintaining voltage at the POI between the low and high limits (0.95 p.u. and 1.05 p.u., respectively), as shown in Figure 45. First, the plant was operating at nearly maximum active power generation in close to unity power factor control mode. An artificial POI voltage signal was provided to the plant controller to override the real measurement. While in power factor control mode, the control automatically switched to voltage limit mode to maintain the voltage within safe operating limits. Upon completion of the POI voltage increase or decrease with the power factor near the unity value, the control system switched back to power factor control mode.

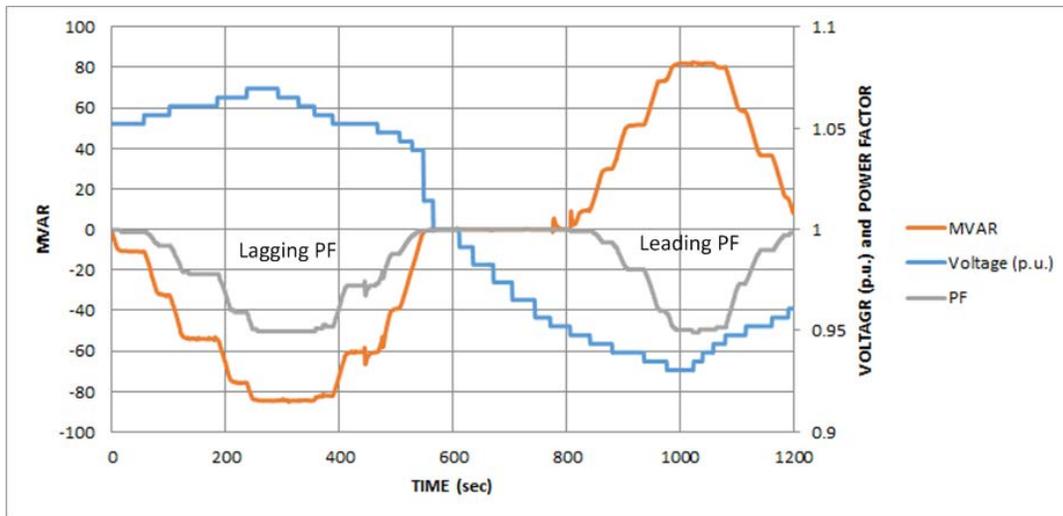


Figure 45. Results of the voltage limit control test. Illustration from NREL

The same test is shown in Figure 46, wherein the measured reactive power is compared to the reactive power capability window from Figure 42. As shown in Figure 46, the plant is fully capable of operating within CAISO's proposed window at PF= ± 0.95 .

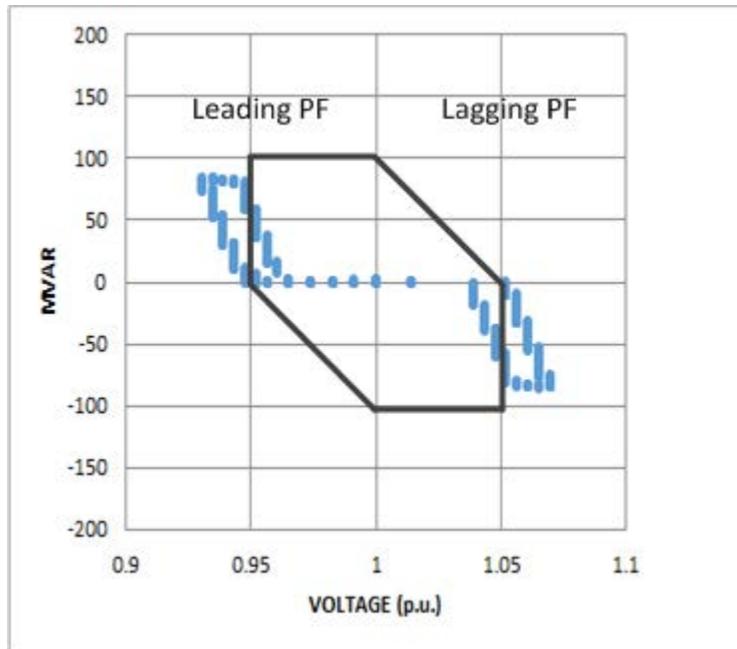


Figure 46. Voltage limit control test and reactive power capability. Illustration from NREL

In addition, the plant was tested to demonstrate the control operation in power factor control mode and characterize control system response to changes in power factor set point. Reactive power ramp rates and power factor limits for this test were specified at ± 100 MVAR/min and ± 0.95 , respectively. The results of the leading and lagging power factor control tests are shown in Figure 47. For both tests, the system was operating at nearly full power output. It reached its power factor targets with specified ramp rates in the PPC without any oscillation and stability issues.



Figure 47. Lagging and leading power factor control tests. *Illustration from First Solar*

Results of the reactive power set point control test are shown in Figure 48. This test was conducted during a period of high power generation, and it was intended to demonstrate the ability of the plant to maintain capacitive or inductive VARs at the POI. As shown in Figure 48, the plant was fully capable of following the reactive power set points with prescribed PPC reactive power ramp rates.

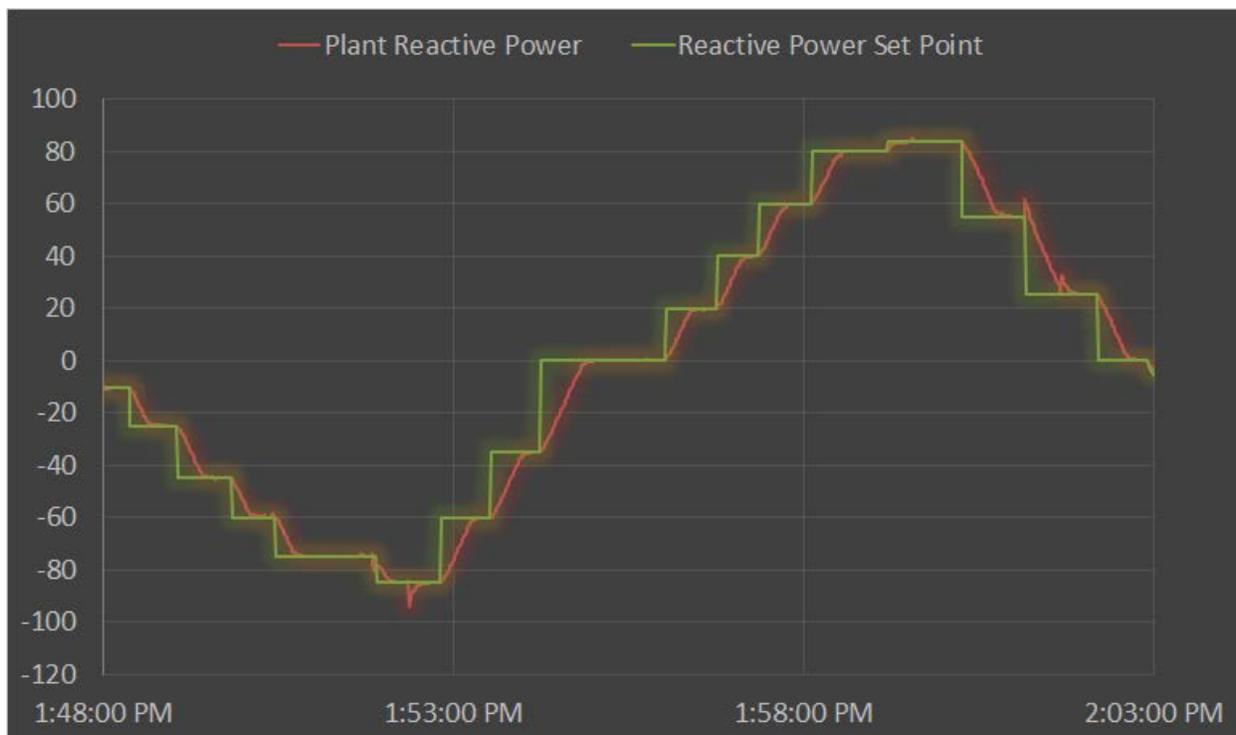


Figure 48. Reactive power control test. *Illustration from First Solar*

5.3 Low-Generation Reactive Power Production Test

One way to increase the optimal utilization of PV power plants is to use their capability to provide VAR support to the grid during times when the solar resource is not available. For this purpose, the capability of the grid-tied inverters of the 300-MW PV plant to provide reactive power support during a period of no active power generation was demonstrated. Due to the limited time window available for this testing, it was not possible to test this capability during dark hours of the day; instead, the team decided to demonstrate the VAR support capability of the plant at nearly zero active power generation. The plant's active output was curtailed to nearly zero MW on August 24, 2017. Then the command was sent to the plant controller to ramp the reactive power to produce or absorb 100 MVAR. The results of these tests along with the measured POI voltage are shown in Figure 49. The plant was fully capable of producing or absorbing the commanded MVAR levels during the whole testing time. Note that the conditions of this test are only partially realistic because special control schemes are needed for grid-tied inverters to operate as STATCOM when a PV array is fully de-energized, and a certain amount of active power needs to be drawn from the grid to compensate for inverter losses. A more realistic test for nighttime VAR mode is planned for the near future.

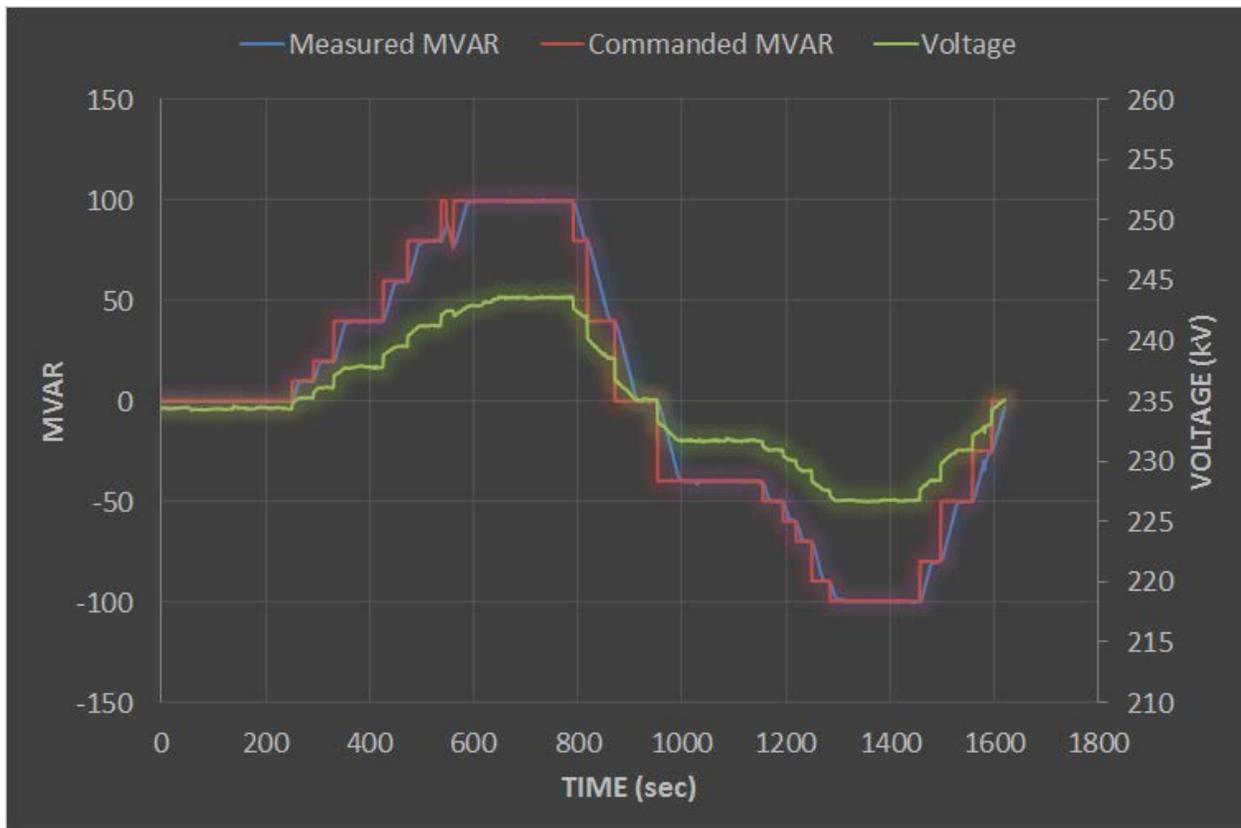


Figure 49. Reactive power production test at no active power ($P \approx 0$ MW). *Illustration from NREL*

6 Additional Tests

The time series of the plant's measured active and reactive power and POI voltage for the whole period of testing on August 23, 2016, is shown in Figure 50. This summary combines results of several commissioning tests conducted between 10 a.m. and 3 p.m. on August 23, 2016. The tests conducted in the morning were related to various forms of APC, and the tests conducted in the afternoon involved various forms of reactive power, voltage, and power factor controls.

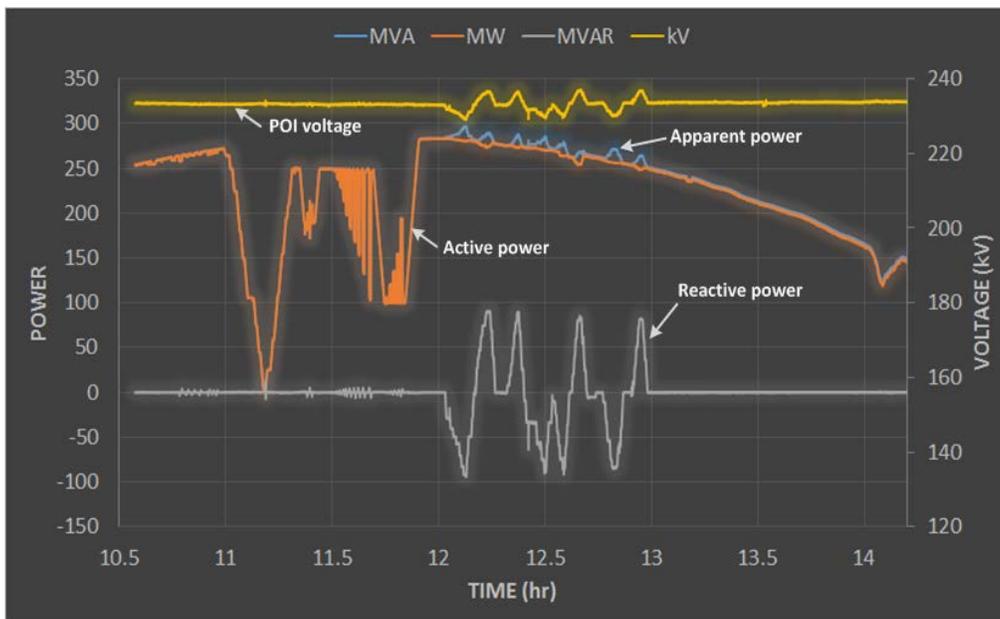


Figure 50. Plant output during the August 23, 2016, tests. *Illustration from NREL*

The curtailment control test was conducted to demonstrate the plant's ability to limit its active power production and then restore it to any desired level. The results of the test are shown in Figure 51. The plant was accurately following the active power set point from a nearly full production level to the zero level with a preset ramp rate of 30 MW/min. The plant's active power was then commanded to increase in accordance with the increasing set points. Note that the reactive power of the plant remained unchanged at a level of nearly zero MVAR for the whole range of active power. This is an indicator of the PV inverters' capability to independently control active and reactive power.

The curtailment control test also demonstrates that PV generation can provide additional ancillary services in the form of spinning and nonspinning reserves. According to CAISO's definitions, spinning reserve is a standby capacity from generation units already connected or synchronized to the grid and that can deliver their energy in 10 minutes when dispatched. With a demonstrated 30-MW/min ramp rate capability, the PV plant under test is capable of deploying 300 MW of spinning reserve in only 10 minutes for some hypothetical case of full curtailment. Nonspinning reserve is capacity that can be synchronized to the grid and ramped to a specified load within 10 minutes. Similarly, the PV plant can provide nonspinning reserve as well. In fact, in a PV plant, unlike any conventional generation, there is no differentiation between spinning and nonspinning reserve capacity due to the nature of PV generation.

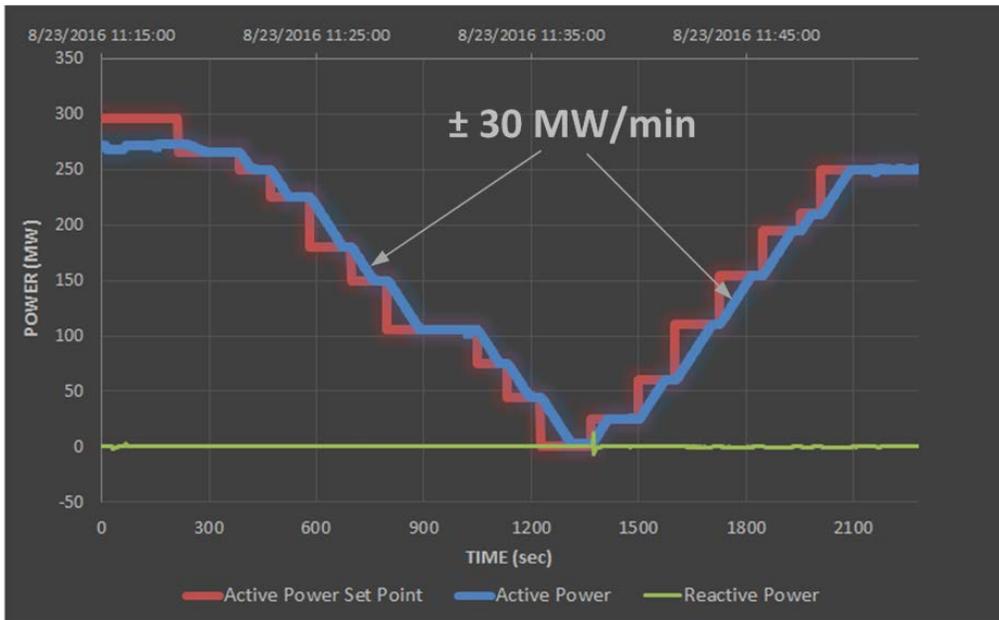


Figure 51. Results of the active power curtailment test. *Illustration from NREL*

Another type of APC test, called frequency validation, was conducted to demonstrate the control system response to frequency disturbances. Unlike the frequency droop tests described in Section 4 of this report, the frequency validation tests were conducted with artificially commanded step changes in POI frequency. Figure 52 shows the plant's response to the commanded frequency values. The plant's response corresponds to a 5% frequency droop setting with an excellent match between the measured and calculated target power levels. (All active power ramp rates in the PPC were bypassed when the plant is in frequency regulation mode.)

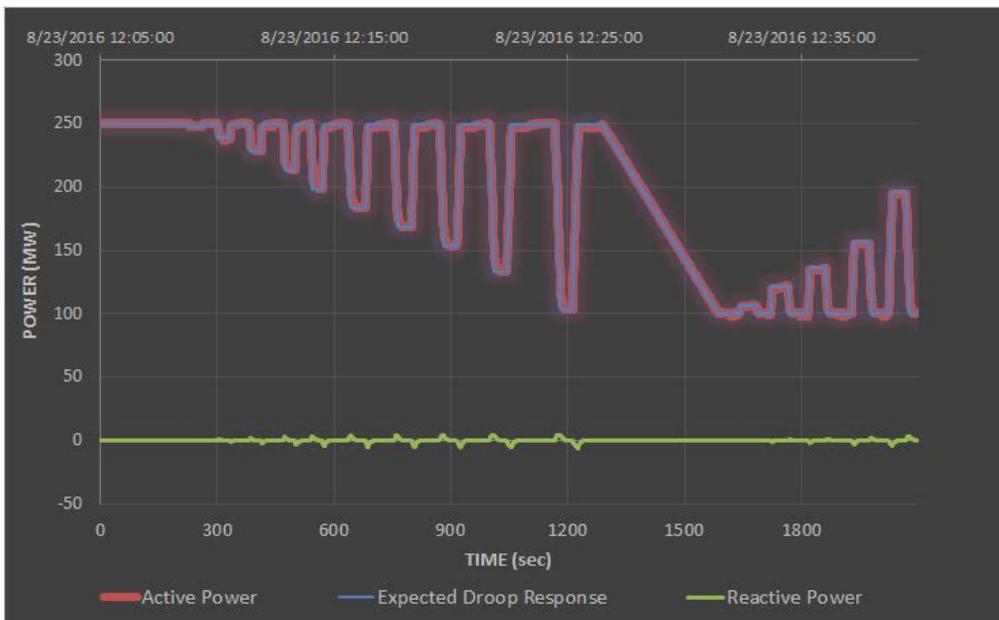


Figure 52. Results of the frequency validation test. *Illustration from NREL*

7 Conclusions and Future Plans

This project demonstrated how solar PV generating plants can provide a wide range of essential reliability services. Tests showed fast and accurate PV plant response to AGC, frequency, voltage, power factor, and reactive power signals under a variety of solar conditions.

7.1 Test Summary

The focus of this project was on demonstrating the controls of a 300-MW utility-scale PV power plant within CAISO's footprint to provide various types of active and reactive power controls for ancillary services.

Active power control capabilities for inverter-connected plants such as PV power plants have been acknowledged and available for a number of years; however, many of these capabilities have not been proven in a real, commercially operational setting by interfacing with the plant's operator on the ground as well as the system operator (either utility off-taker or transmission system operator).

This project is a result of collaboration among NREL, CAISO, and First Solar; NREL's participation was funded through DOE's Solar Energy Technologies Office. The project team gained valuable real experience for all industry players regarding (1) a PV power plant's implementations of these capabilities, (2) the system operators' interface and communications acceptance of measured plant parameters and use of the parameters, (3) the iterative loop for the system operators to send back appropriate set points, (4) the logic of the PV PPCs to respond to the set points, and (5) the PV power plant's return of up-to-date information (such as available peak plant power) to complete the iterative loop.

The AGC tests demonstrated the plant's ability to follow CAISO's AGC dispatch signals during three different solar resource intensity time frames: (1) sunrise, (2) middle of the day (noon–2 p.m.), and (3) sunset. For this purpose, the plant was curtailed by 30 MW from its available peak power to have maneuverability to follow CAISO's AGC signal. During these tests, fast and accurate AGC performance was demonstrated at different solar resource conditions.

For the frequency response tests, the plant was also operated in curtailed mode to have enough headroom to increase its output in response to a frequency decline outside of a defined deadband. Headroom is achieved by sending a curtailment command to the PPC after initially computing its estimation of maximum capability using real-time solar irradiance data from the network of pyranometers, real-time measurements of panel and inverter data, and other static characteristics of the system's components. Assuming that the plant will be reimbursed for the energy loss due to curtailment for these ancillary services, it is likely that the maximum power estimation will need to be refined and validated. The plant demonstrated fast and accurate frequency response performance for different droop settings (3% and 5%) under various solar resource conditions for both underfrequency and overfrequency events.

The plant also demonstrated the ability to operate in three modes related to reactive power control: voltage regulation, power factor regulation, and reactive power control. The plant can operate in only one of the three modes at a time, with a seamless transition from one mode to another. The plant controller was able to maintain the specified voltage set points at the POI by

regulating the reactive power produced or absorbed by the PV inverters. Also, the plant's ability to produce or absorb reactive power at nearly zero MW production (STATCOM mode) was demonstrated as well.

7.2 Detailed Conclusions

General conclusions include the following:

- Advancements in smart inverter technology combined with advanced plant controls allow solar PV resources to provide regulation, voltage support, and frequency response during various operation modes.
- Solar PV resources with these advanced grid-friendly capabilities have unique operating characteristics that can enhance system reliability, like conventional generators, by providing:
 - Essential reliability services during periods of oversupply
 - Voltage support when the plant's output is near zero
 - Fast frequency response (inertia response time frame)
 - Frequency response for low as well as high frequency events.
- Accurate estimation of available peak power is important for the precision of AGC control.
- It makes sense to include specifications for such available peak power estimations into future interconnection requirements and resource performance verification procedures.
- System-level modeling exercises will be needed to determine the exact parameters of each control feature to maximize the reliability benefits to CAISO or any other system operator that will be utilizing such controls in its operations.
- All hardware components enabling PV power plants to provide a full suite of grid-friendly controls are already in existence in many utility-scale PV plants. Fully enabling these is mainly a matter of activating these controls and/or implementing communications upgrades. Issues to be addressed in the process include communications protocol compatibility and proper scaling for set point signals. Although these are not significant barriers, dialogue and interaction among the plant operators and the system operators is an important component of implementing APC capabilities. Modifying programming logic may be necessary at multiple places in the chain of communications.
- Fine-tuning the PPC to achieve rapid and precise responses might be a necessary step in many PV plants. It may be easier with newer equipment because of the faster response times of newer inverters and controller systems.
- Many utility-scale PV power plants are already capable of receiving curtailment signals from grid operators; each plant is different, but it is expected that the transition to AGC operation mode will be relatively simple with modifications made only to the PPC and interface software (Figure 53).
- Fast response by PV inverters coupled with plant-level controls make it possible to develop other advanced controls, such as STATCOM functionality, power oscillation

damping controls, subsynchronous controls oscillations damping and mitigation, active filter operation mode by PV inverters, etc.

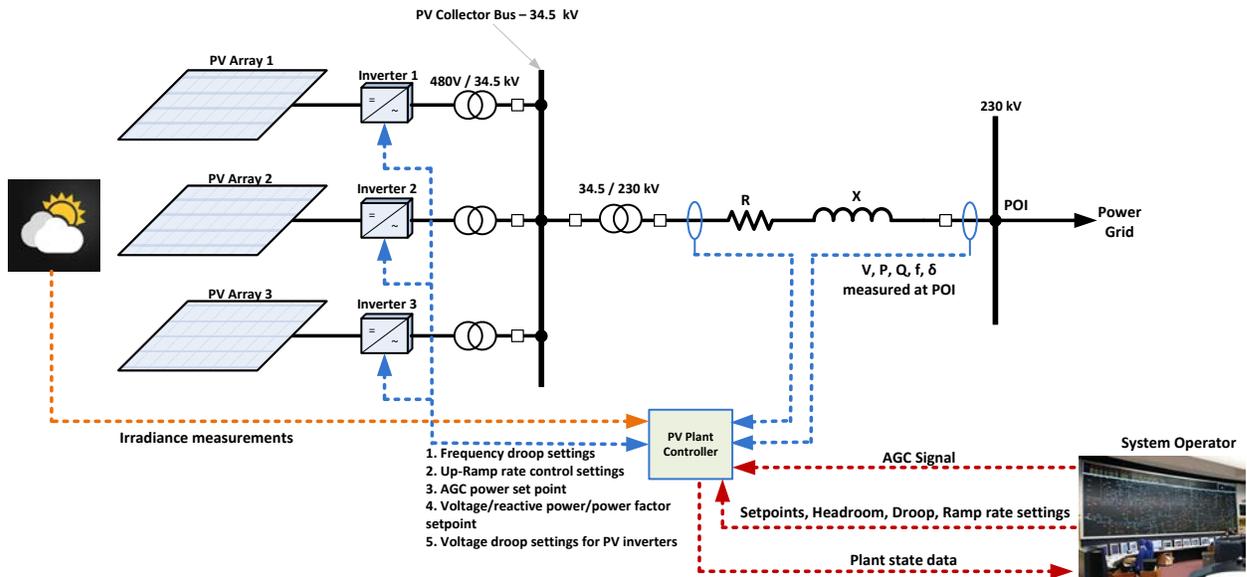


Figure 53. A grid-friendly PV power plant. Illustration from NREL

The project team conducted tests that demonstrated how various types of active and reactive power controls can leverage PV generation’s value from being a simple variable energy resource to a resource providing a wide range of ancillary services. With this project’s approach to a holistic demonstration on an actual large utility-scale operational PV power plant and dissemination of the obtained results, the team sought to close some gaps in perspectives that exist among various stakeholders in California and nationwide by providing real test data. If PV-generated power can offer a supportive product that benefits the power system and is economic for PV power plant owners and customers, this functionality should be recognized and encouraged.

7.3 Future Plans

Future plans by the project team include:

- Identifying potential barriers to providing essential reliability services to make these services operationally feasible
- Exploring economic and/or contractual incentives to maximize production and not hold back production to provide reliability services
- Identifying necessary steps to unlock opportunities to use reliability services from renewable resources by:
 - Assessing and quantifying the fleet’s capability to provide reliability services
 - Evaluating policies such as FERC Notice of Inquiry RM16-6, which recommends requiring all synchronous and asynchronous machines to provide primary frequency response

- Considering how renewable resources already dispatched or curtailed can provide upward regulation and frequency response
- Identifying what tariff changes are necessary to remove barriers and allow variable energy resources to provide reliability services
- Exploring ways to allow inverter-based resources and associated control systems to be used to enhance reliability and response to frequency events
- Exploring further opportunities for inverter-based resources to participate in the various markets for energy and ancillary services.
- Developing further modifications to control algorithms and fine-tune control parameters for improved performance of the demonstrated services
- Demonstrating true PV STATCOM functionality during nighttime hours
- Demonstrating ancillary services by a number of PV plants within CAISO's footprint to understand the impacts of solar resource geographical diversity on the aggregate response by solar generation on various types of ancillary services
- Finally, CAISO and NREL are interested in exploring the possibility of conducting simultaneous demonstration testing of ancillary service controls by solar PV and wind generation to understand the aggregate response by two different renewable energy resources when providing various combinations of ancillary services.

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Appendix: Test Plan

Objective

Perform multiple tests, and document the performance of a 300-MW PV solar facility in a commercially operational setting. The plant currently has a maximum capacity of 299.9 MW and participates in the independent system operator's (ISO's) market. The plant is in the process of completing its final acceptance testing by mid- to late August 2016.

The California Independent System Operator (CAISO) is responsible for ensuring that sufficient ancillary services are available to maintain the reliability of the grid controlled by the ISO. Modern utility-scale PV power plants consist of multiple power electronic inverters and can contribute to grid stability and reliability through sophisticated “grid-friendly” controls. The findings of this testing project will provide valuable information to the ISO concerning the ability of variable energy resources to provide ancillary services, enhance system reliability, and participate in future ancillary service markets in a manner that is similar to that of traditional generators. All tests would be done in a manner to minimize curtailment to the plant below its current commercial P_{\max} . Curtailment details and actual test times would be worked out prior to the tests.

The project team—consisting of experts from CAISO, First Solar, and the National Renewable Energy Laboratory (NREL)—developed the demonstration concept and test plan to show how various types of active and reactive power controls can leverage PV generation's value from being a simple intermittent energy resource to providing a wide range of ancillary services. Through this demonstration and the subsequent dissemination of the results, the team will provide valuable real test data from an actual utility-scale operational PV power plant to all stakeholders in California and nationwide. If PV-generated power can offer a supportive product that benefits the power system and is economic for PV power plant owners and customers, this functionality should be recognized and encouraged.

Regulation-Up and Regulation-Down

This test will demonstrate the plant's ability to follow the ISO's automatic generation control (AGC) dispatch signals. The purpose of AGC is to enable the power plant to follow the active power set point dispatched by the ISO at the end of every 4-second time interval. The ISO will conduct the test at three different solar resource intensity time frames: (1) sunrise, (2) middle of the day (noon–4 p.m.), and (3) sunset. Each test will provide actual 4-second AGC signals that the ISO has previously sent to a regulation-certified resource of similar size. Normally, CAISO measures the accuracy of a resource's response to energy management system signals during 15-minute intervals by calculating the ratio between the sum of the total 4-second set point deviations and the sum of the AGC set points.

- Sunrise

During sunrise, the plant would be instructed to operate within a real power range of *20 MW below its peak power capability*. Approximately 10 minutes of actual 4-second AGC signals would then be fed into the plant's controller, and the plant's response would be monitored.

- Middle of the day

During the middle of the day, the plant would be instructed to operate within a real power range of *20 MW below its peak power capability*. Approximately 20 minutes of actual 4-second AGC signals would then be fed into the plant's controller, and the plant's response would be monitored.

- **Sunset**

During sunset, the plant would be instructed to operate within a real power range of *20 MW below its peak power capability*. About 20 minutes of actual 4-second AGC signals would then be fed into the plant's controller, and the plant's response would be monitored.

Expectation

During the test, the ISO will monitor the delayed response time of the plant (i.e., the time between the resource receiving a control signal indicating a change in set point and the instant the resource's MW output changes). The ISO will also monitor the accuracy of the plant's response to the regulation set-point changes. The data from this test will be used by ISOs in future resource-specific expected mileage for the purposes of awarding regulation-up and regulation-down capacity.

Curtailment

It is expected that the plant would be curtailed by 20 MW for approximately 45 (3 x 15 minutes) minutes.

Voltage Regulation Control

The ISO will test the plant in the voltage regulation mode, whereby the controller maintains a scheduled voltage at the terminal of the generator step-up transformer by regulating the reactive power produced by the inverters. The voltage regulation system is based on the reactive capabilities of the inverters using a closed-loop control system similar to automatic voltage regulators in conventional generators.

The reactive power capability would be tested to show the Federal Energy Regulatory Commission's (FERC's) proposed reactive capability (Order 827), which requires that all newly interconnecting nonsynchronous generators design their generating facilities to meet the reactive power requirements at all levels of real power output. (*Refer to the vertical red lines in Figure A-1.*)

Objective

The primary objective of this test is to demonstrate the capability of the plant to operate in voltage regulation mode within a power factor range of 0.95 leading/lagging. The plant controller maintains the specified voltage set point at the high side of the generator step-up bank by regulating the reactive power produced by the inverters.

Test Procedure

The ISO would test the plant at *three* different real power output levels: (1) maximum production during the middle of the day, (2) during sunset when the plant is at approximately 50% of its maximum capability, and (3) during sunset when the plant is close to zero production. The ISO

will test the plant’s reactive power capability to absorb and produce reactive power in accordance with Figure A-1, within a range of ± 100 MVAR during various levels of real power output.

- The plant would first be tested at its maximum real power output for a given irradiance level. At maximum real power output, the plant must demonstrate that it can produce approximately 33% of real output as dynamic reactive. Similarly, at maximum real power output, the plant must demonstrate that it can absorb approximately 33% of its real power output as reactive output.
- During sunset, as the solar production drops off to approximately 50% of the resource’s maximum capability, the plant must demonstrate that it can produce and absorb approximately 33% of its real power output as dynamic reactive output.
- During sunset, as the plant production approaches zero MW, the plant must demonstrate that it can produce and absorb approximately 33% of its real power output as dynamic reactive output.

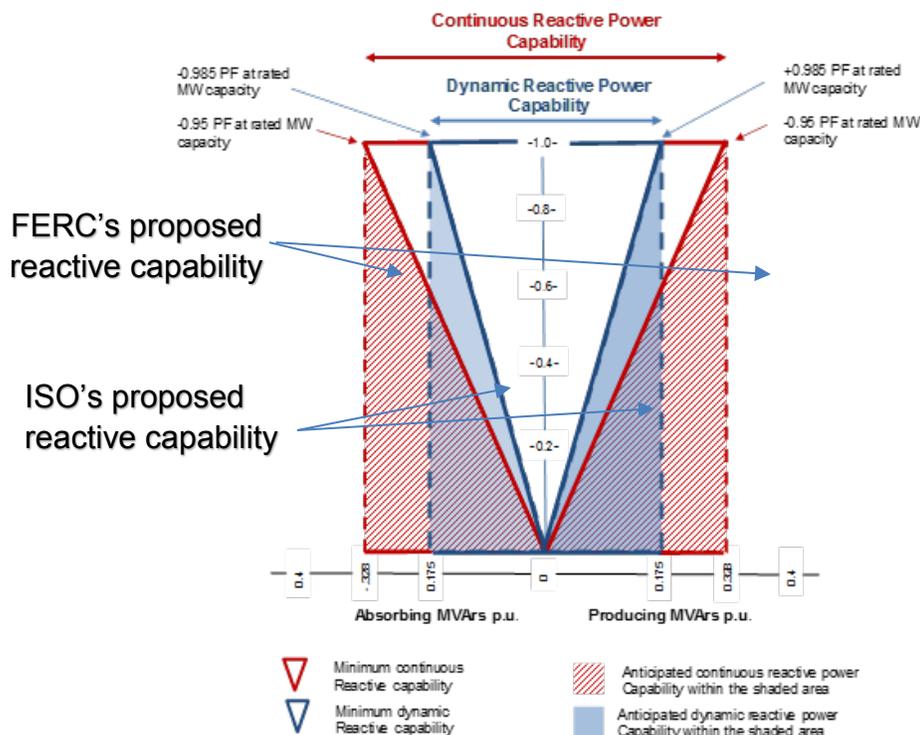


Figure A-1. Reactive power capability at the POI. Illustration from NREL

Note: The red vertical lines shown in Figure A-1 represent the expected reactive capability of the asynchronous generating plant at the high side of the generator step-up bank. At all levels of real power output, the plant is expected to produce or absorb reactive power equivalent to approximately 33% of the plant’s actual real power output. For example, at the plant’s maximum real power capability, the expected reactive capability should be 33 MVARs lagging or 33 MVARs leading. Also, at zero real power output, the expected dynamic reactive capability should be zero MVARs lagging or zero MVARs leading.

Expectation

The plant must demonstrate that its reactive capability follow FERC’s proposed reactive capability, as shown in Figure A-1.

Curtailment

None.

Active Power Control Capabilities

CAISO seeks to test the APC capability to assess the plant's ability to control its output in specific increments by being able to mimic a specified ramp rate. The results of this test would be used to determine the plant's ability to provide ancillary services such as spinning reserve and nonspinning reserve.

Objective

This objective of this test is to demonstrate that the plant can decrease output or increase output while maintaining a specific ramp rate.

Test Procedure

This test is similar to starting up and shutting down the plant in a coordinated and controllable manner. The test would be done at *two different ramp rates*.

- The plant would be instructed to reduce its output to three different set points (*not to exceed 60 MW*) at a predetermined ramp rate, as shown in Figure A-2.
- The plant would then be instructed to ramp back up to full production following predefined set points at the predetermined ramp rate, as shown in Figure A-2.
- Repeat the above test using a different ramp rate.

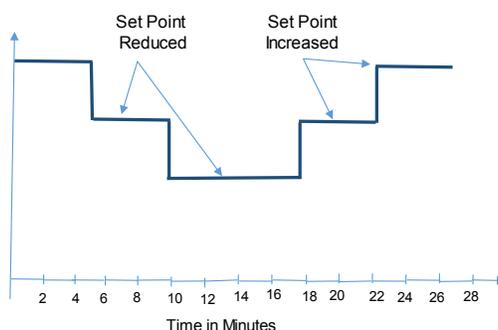


Figure A-2. Increase/decrease output at a specified ramp rate. *Illustration from CAISO*

Expectation

The plant must demonstrate its capability to move from its current set point to a desired set point at a specified ramp rate.

Curtailment

It is expected that the plant would be curtailed up to 60 MW for a period of 60 minutes.

Frequency Response

The frequency response capability would entail two separate tests: (1) a droop test and (2) a frequency response test.

The definition of implemented frequency droop control for PV plant is the same as that for conventional generators:

$$Droop = \frac{\Delta P / P_{rated}}{\Delta f / 60Hz}$$

The plant's rated power (299.9 MW) is used in the above equation from the droop setting calculation. The plant should adjust its power output in accordance with the droop curve with a symmetric deadband, as shown in Figure A-3. The upper limit of the droop curve is the available plant power based on the current level of solar irradiance and panel temperatures.

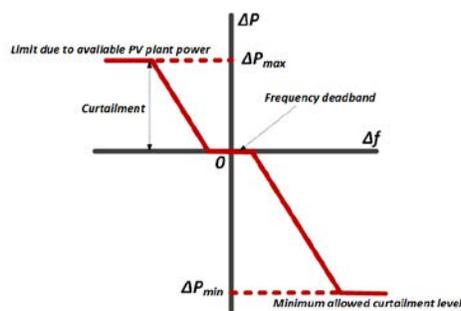


Figure A-3. Frequency droop explained. Illustration from NREL

Frequency Droop Test (Capability to Provide Spinning Reserve)

Objective

The objective of this test is to demonstrate that the plant can provide a response in accordance with the 5% and 3% droop settings through its governor-like control system. The plant would be instructed to operate *below its maximum capability during both tests*.

Test Procedure

For the first test, the plant would be instructed to operate at *20 MW below its maximum capability*. This test would be done using a 5% droop and a deadband of ± 0.036 Hz.

- The ISO would test the frequency droop capability of the plant by using an actual underfrequency event that occurred in the Western Interconnection during the past year. The underfrequency event data set (*approximately 10 minutes of data*) would be fed into the plant's controller, and the plant response would then be monitored.
- The frequency droop capability would be demonstrated using one actual high-frequency time series data set provided by NREL. Examples of underfrequency and overfrequency event time series measured by NREL are shown in Figure A-4 and Figure A-5, respectively.

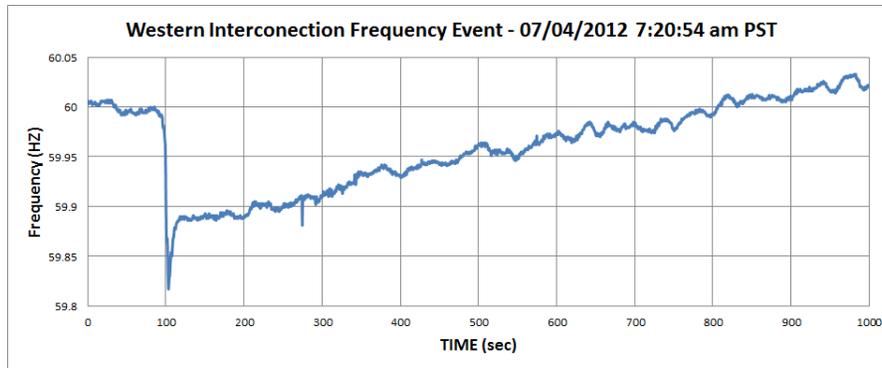


Figure A-4. Example of an underfrequency event. Illustration from NREL

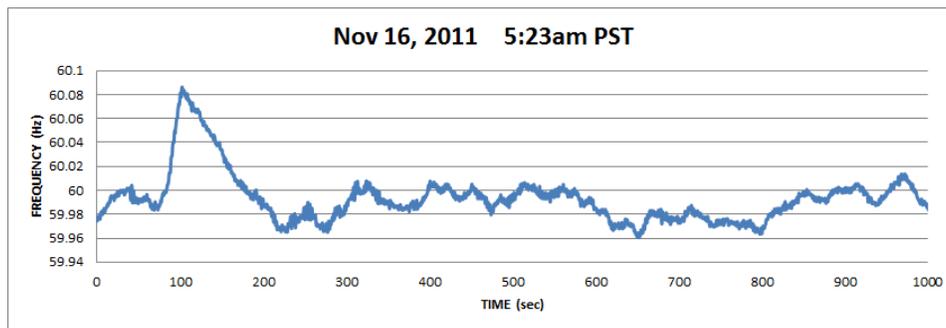


Figure A-5. Example of an overfrequency event. Illustration from NREL

- The frequency event time series data will be used by the power plant controller to trigger the droop response by the plant.
- The above test would be repeated with the plant at 20 MW below its maximum capability. This test would be done using a 3% droop and a deadband of ± 0.036 Hz.

Expectation

Through the action of the governor-like control system, the plant must respond automatically within 1 second in proportion to the frequency deviations outside the deadband.

Curtailment

It is expected that the plant would be curtailed by 30 MW for approximately 60 minutes.

Capability to Provide Frequency Response

Objective

The objective of this test is to demonstrate that the plant can provide frequency response consistent with the North American Electric Reliability Corporation's BAL-003-1.

Test Procedure

- The plant would be instructed to operate 20 MW below its maximum capability before applying a step change of rapid frequency decline. An actual frequency event (approximately 10 minutes) would be fed into the plant's controller, and the plant's response would be monitored. This test may require tuning a delay in response to ensure

that the frequency response occurs within 20–52 seconds following the step change in frequency.

- The plant *does not have headroom* and can only reduce output in response to large frequency deviations below the scheduled frequency. The test would entail feeding the plant controller with a frequency more than 0.036 Hz above scheduled frequency.
- Repeat the above test with the plant operating *40 MW* below its capability for a given irradiance level.

Expectation

Through the action of the governor-like control system, the plant must respond automatically in proportion to frequency deviations.

Curtailement

It is expected that the plant would be curtailed by 20 MW for 60 minutes and by 40 MW for 60 minutes.

Exhibit G



SunShot 2030 for Photovoltaics (PV): Envisioning a Low-cost PV Future

Wesley Cole, Bethany Frew, Pieter Gagnon, James Richards, Yinong Sun, Jarett Zuboy, Michael Woodhouse, and Robert Margolis
National Renewable Energy Laboratory

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List of Acronyms and Abbreviations

CEM	capacity expansion model
CPP	Clean Power Plan
CSP	concentrating solar power
dGen	distributed generation model
DOE	Department of Energy
DPV	distributed photovoltaics
EERE	Office of Energy Efficiency & Renewable Energy
EIA	Energy Information Administration
ELCC	effective load carrying capability
GW	gigawatt
LCOE	levelized cost of energy
LDC	load duration curve
LOLP	loss of load probability
LSC	low storage costs
NG	natural gas
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NLDC	net load duration curve
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OGS	oil-gas-steam
PV	photovoltaics
RE	renewable energy
ReEDS	Regional Energy Deployment System model
UPV	utility photovoltaics
VG	variable generation
yr	year
WACC	weighted average cost of capital

Executive Summary

After launching the SunShot Initiative, the U.S. Department of Energy (DOE) published the *SunShot Vision Study* (DOE 2012), which envisions a future in which solar’s levelized cost of energy (LCOE) in 2020 declines to 6 cents per kilowatt-hour (¢/kWh) for utility-scale systems, 7 ¢/kWh for commercial systems, and 9 ¢/kWh for residential systems. In the context of dramatic solar cost reductions and electricity-sector changes that have occurred since 2010, DOE recently set new LCOE goals for PV to achieve by 2030 in order to enable significantly greater PV adoption: 3 ¢/kWh for utility-scale, 4 ¢/kWh for commercial, and 5 ¢/kWh for residential systems (Figure 1).

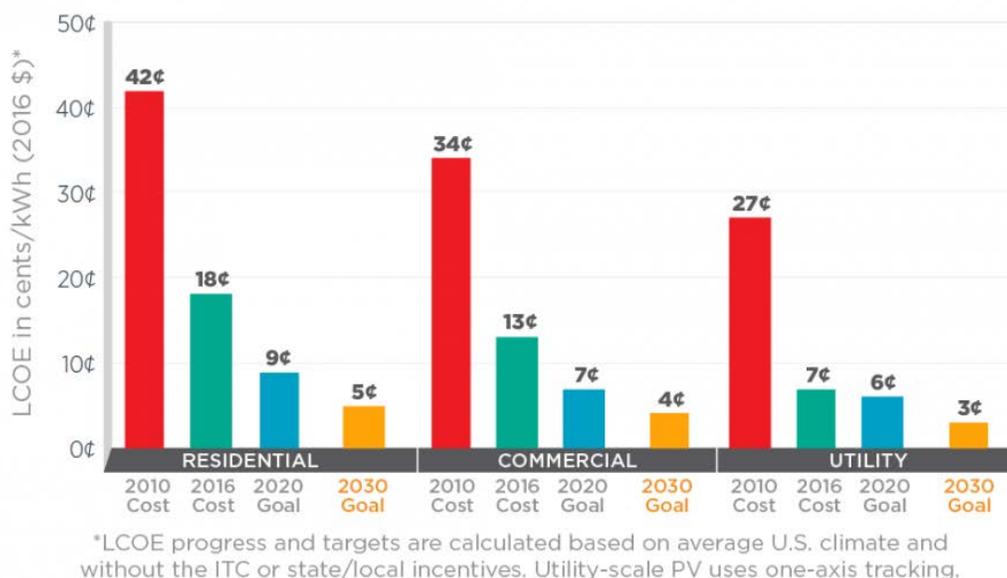


Figure 1. Historical and current PV costs and SunShot 2020 and 2030 goals (DOE 2016b)

This report analyzes the potential impacts of achieving the SunShot 2030 cost targets for the contiguous United States.¹ In addition, it analyzes the impact of SunShot-level PV costs combined with low-cost energy storage. Specifically, we analyze two SunShot scenarios in comparison with a baseline scenario. Both SunShot scenarios assume that DOE’s 2030 LCOE goals are achieved for utility-scale, commercial, and residential PV systems. The two SunShot scenarios differ in that one assumes mid-case storage cost reductions (~\$260/kWh by 2030), whereas the other assumes low storage costs (LSC) are achieved (~\$130/kWh by 2030). The baseline scenario uses the mid-case PV cost values from NREL’s 2016 Annual Technology Baseline (ATB),² and it assumes the mid-case storage cost reductions.

¹ The post-2030 PV costs continue to decline such that 2050 PV costs are 33% lower than the 2030 targets. See Appendix D for details on pathways that can achieve these low costs.

² The ATB contains current and future cost and performance projections for the U.S. electricity sector technologies (NREL 2016). The mid-case projections from the ATB are used in these scenarios for all non-PV technologies unless otherwise stated. These mid-case projections include anticipated cost declines for all technologies. Additional details are available in Appendix A.

With these assumptions, we project evolution of the contiguous U.S. electricity system using NREL’s Regional Energy Deployment System (ReEDS) and Distributed Generation (dGen) models. These models have been specifically designed to represent variable renewable electricity (e.g., time and locational value of renewable energy, curtailment, and declining capacity value) in the U.S. power system. Figure 2 shows the modeled results for PV capacity. Projected PV deployment under the SunShot and SunShot LSC scenarios rapidly outpaces deployment under the baseline ATB Mid scenario, leading to a future grid system that is significantly different from today’s system. The SunShot scenario sees annual PV deployment peak in 2030 at just under 55 gigawatts (GW)/year, with post-2030 annual deployment ranging from 20 GW/year to 40 GW/year. The SunShot LSC scenario continues to see growth throughout the model period with average annual PV deployment levels from 2040 to 2050 reaching approximately 65 GW/year.³ The projected PV growth is dominated by utility-scale systems, but the actual mix of utility and distributed systems will ultimately vary depending on how policies, system costs, and rate structures evolve. Figure 3 compares the generation mixes among the SunShot, SunShot LSC, and ATB Mid scenarios.

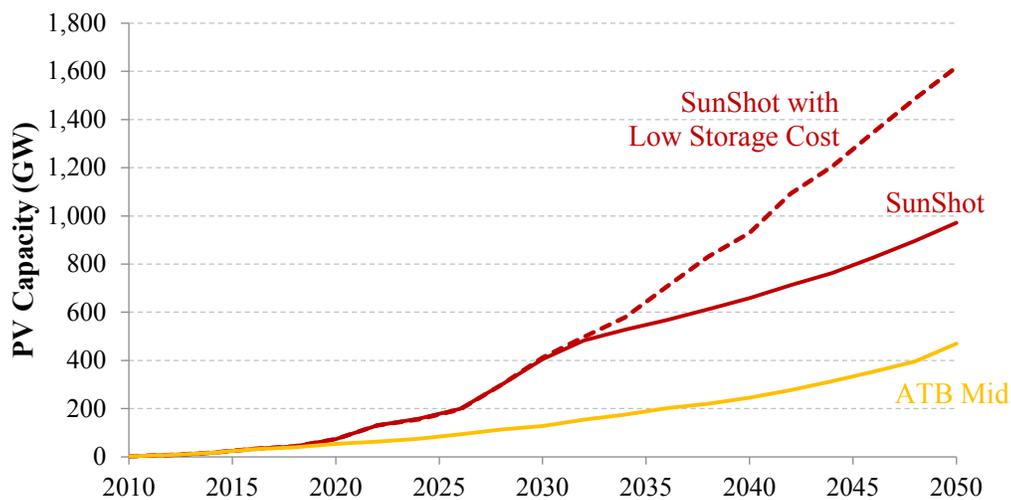


Figure 2. Cumulative PV deployment projections for the SunShot, SunShot LSC, and ATB Mid scenarios for the contiguous United States

³ These annual deployment values reflect new builds only and do not include any repowered or rebuilt capacity.

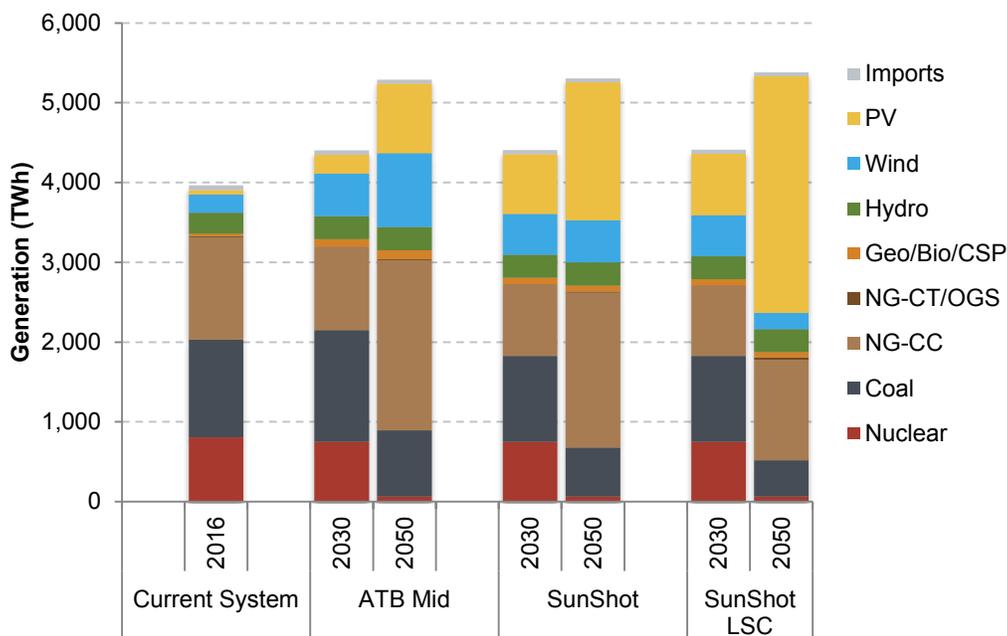


Figure 3. Generation mix in 2016, 2030, and 2050 by technology for the ATB Mid, SunShot, and SunShot LSC scenarios for the contiguous United States

NG-CC is natural gas combined cycle. NG-CT is natural gas combustion turbine. OGS is oil-gas-steam. And, Geo/Bio/CSP is geothermal, biopower, and concentrating solar power technologies. Imports are net electricity imports from Canada and Mexico.

Projected impacts of achieving the SunShot and SunShot LSC scenarios include the following:

- PV deployment increases twofold to threefold.* Achieving the SunShot PV cost targets could result in 405 GW of PV capacity in 2030, which would provide 17% of contiguous U.S. electricity generation. In 2050, deployment could rise to 971 GW, which would provide 33% of generation. With the addition of low-cost storage (i.e., by achieving the SunShot LSC scenario), 1,618 GW of PV capacity could be deployed by 2050, which would provide 55% of generation. In comparison, the ATB Mid scenario deploys only 127 GW of PV in 2030 (5% of generation) and 470 GW in 2050 (17% of generation).
- Electricity prices and electric-system costs decline.* In 2030, retail electricity prices are projected to be approximately 2% lower in the SunShot and SunShot LSC scenarios than they are in the ATB Mid scenario. By 2050 SunShot electricity prices are projected to be 1.8% lower, while SunShot LSC prices are projected to be 12% lower. This translates into a residential consumer bill savings of \$2/month per household (SunShot) and \$13/month per household (SunShot LSC). Total system costs are also projected to decline relative to the ATB Mid scenario: the SunShot scenario is projected to save (in net present value) \$194 billion through 2050 (5.1% lower than ATB Mid), while the SunShot LSC scenario is projected to save (in net present value) \$338 billion through 2050 (9.0% lower than ATB Mid).
- Water withdrawals and consumption are reduced.* Because PV uses far less water than the conventional generators it displaces, the SunShot scenario is projected to reduce cumulative water withdrawals in the power sector by 11% and consumption by 13%

through 2050 compared with the ATB Mid scenario. Adding low-cost storage could produce even greater benefits, potentially reducing water withdrawals by 13% and consumption by 19% through 2050.

- *Emissions of carbon dioxide (CO₂) continue to decline.* Under the SunShot scenario, CO₂ emissions are projected to be 22% lower in 2030 and 18% lower in 2050 compared with the ATB Mid scenario. With the addition of low-cost storage, CO₂ emissions are projected to be 22% lower in 2030 and 42% lower in 2050 compared with the ATB Mid scenario.
- *Relatively little additional transmission is required.* In general, the greater the amount of PV deployed, the more transmission is needed to transmit electricity from PV plants to demand centers. However, this is in part mitigated by the abundance of PV energy close to load centers. In the ATB Mid scenario, transmission capacity is projected to increase by 2.5% in 2030 and 8.3% in 2050 relative to 2016, while the SunShot scenario transmission capacity is projected to increase by 3.0% in 2030 and 9.6% by 2050. The SunShot LSC scenario requires a slightly greater level of transmission build-out, with transmission capacity projected to increase by 3.1% in 2030 and 11.9% in 2050. These levels of transmission build-out are the same or lower than historical transmission build-out rates.
- *Energy storage capacity increases dramatically when low-cost storage is available.* The projected storage capacity installed in 2050 in the SunShot LSC scenario reaches 323 GW, which is roughly 6 times greater than in the SunShot scenario and 11 times greater than in the ATB Mid scenario. This dramatic increase in projected storage deployment indicates the synergistic value of low-cost flexibility in a low-cost PV future.
- *Curtailed rates rise without low-cost storage, and storage losses rise with low-cost storage.* In general, more PV leads to more curtailment, although low-cost storage mitigates this effect. In 2030, the curtailment rates are 2.8% in the SunShot scenario and 2.1% in the SunShot LSC scenario. In 2050, the spread is similar: 3.7% in the SunShot scenario and 2.9% in the SunShot LSC scenario. These results compare with curtailment rates of 1.2% in 2030 and 0.7% in 2050 under the ATB Mid scenario. However, storage systems incur losses during their charge and discharge cycles. In the SunShot LSC scenario, losses due to storage are nearly the same as the losses from curtailment.

We analyze the sensitivity of the SunShot and SunShot LSC scenarios to various market assumptions, including lower and higher electricity demand growth, lower and higher natural gas prices, accelerated and extended conventional generator lifetimes, and lower and higher non-PV renewable energy technology costs. We also consider scenarios where we include cost penalties for rapid growth in PV deployment in order to represent potential supply chain constraints. These analyses provide a range of plausible projections for PV deployment when the SunShot 2030 LCOE goals are achieved (Figure 4).⁴ In these sensitivity scenarios PV deployment in 2030 ranges from 307 GW (13% of electricity supplied by PV) to 435 GW (18%), and deployment in 2050 ranges from 850 GW (28%) to 1,923 GW (64%). The availability of low-cost storage has

⁴ Here and throughout the report we use LCOE as a summary indicator, but the ReEDS and dGen models do not use LCOE for model decision-making.

the largest impact on projected SunShot deployment, followed by natural gas prices and electricity demand.

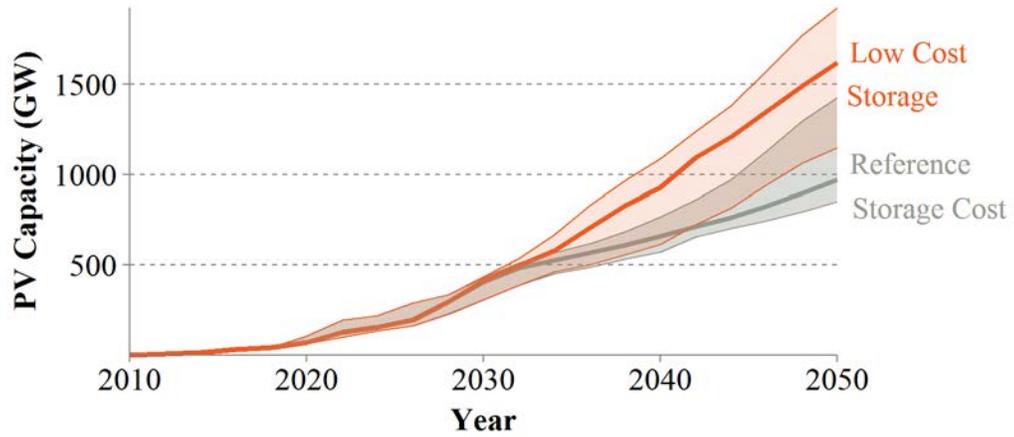


Figure 4. Cumulative PV capacity ranges for SunShot (gray) and SunShot LSC (orange) sensitivity scenarios for the contiguous United States

Bold lines show the SunShot and SunShot LSC core scenario projections.

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1 Introduction

The U.S. Department of Energy (DOE) launched the SunShot Initiative in January 2011 with the goal of making solar electricity cost competitive with conventionally generated electricity by 2020. At the time, this meant reducing photovoltaic (PV) and concentrating solar power (CSP) prices by approximately 75%—relative to 2010 costs—across the residential, commercial, and utility-scale sectors. For utility-scale solar, this target translated into an average levelized-cost of energy (LCOE) target of \$0.06/kWh by 2020.⁵ To examine the implications of achieving this goal, DOE’s Solar Energy Technologies Office published the *SunShot Vision Study* in 2012, which projected that achieving the SunShot 2020 targets could lead to solar penetration levels of 14% by 2030 and 27% by 2050 (DOE 2012). These projected penetration levels were realized through a combination of PV and CSP and would lead to a variety of benefits (DOE 2016a; Wisner, Millstein, et al. 2016).

As Figure 5 shows, today’s typical utility-scale PV (UPV) prices are already approaching the original SunShot 2020 target (Bolinger and Seel 2016; Fu et al. 2016; Wesoff 2017), and distributed PV (DPV) costs have declined substantially (Barbose and Darghouth 2016). Current deployment levels of PV (Figure 6) exceed those projected in the *SunShot Vision Study*. This rapid progress has presented an opportunity to envision even more ambitious PV goals.

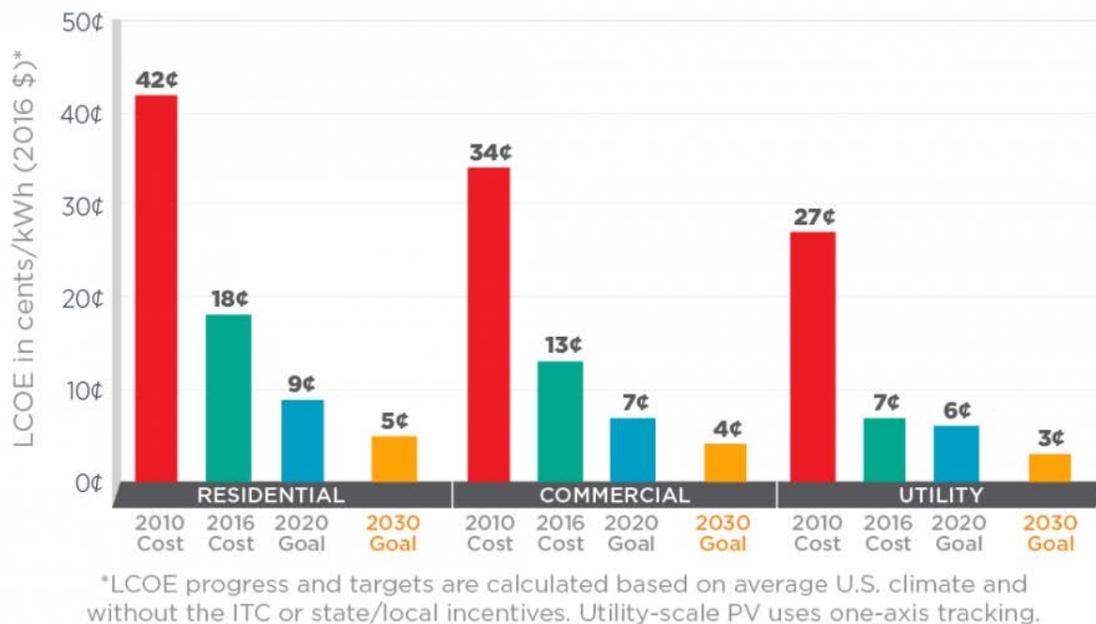


Figure 5. Historical and current PV costs and SunShot 2020 and 2030 goals (DOE 2016b)

⁵ The LCOE is the total cost of installing and operating a generator, expressed in dollars per kilowatt-hour of electricity generated by the system over its life. It accounts for installation costs, financing costs, taxes, O&M costs, salvage value, incentives, revenue requirements (for utility financing options), and quantity of electricity generated over the system’s lifetime. The LCOEs reported in this work do not include the investment tax credit, so an LCOE goal of \$0.06/kWh is before the investment tax credit is applied.

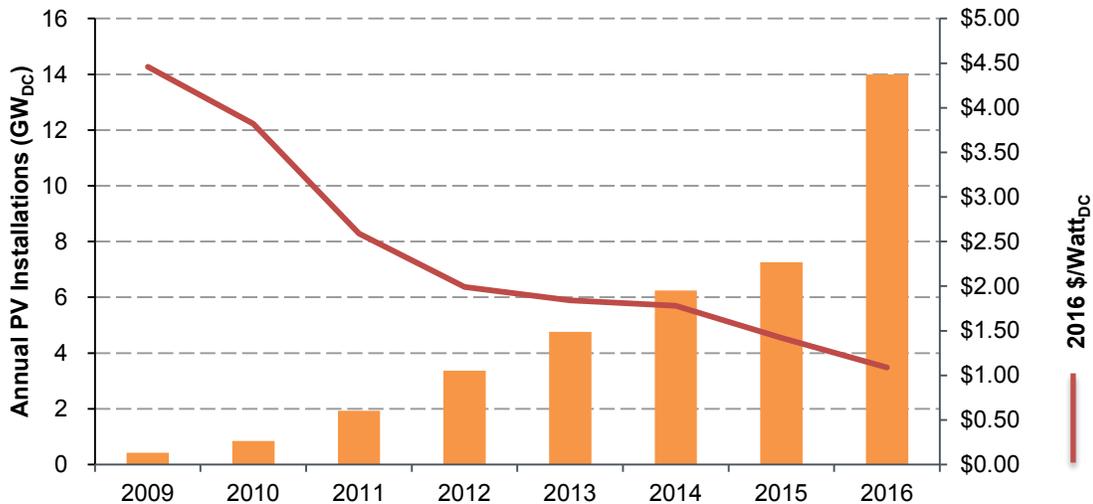


Figure 6. Total PV deployment and UPV system price in the United States, 2009–2016

Sources: Fu et al. (2016) and GTM/SEIA (2016)

At the same time, changes in the broader U.S. electricity sector suggest a need for updated PV deployment projections. Abundant low-cost natural gas made available by the shale gas revolution has driven down projected natural gas prices since the original *SunShot Vision Study* was published (Cole, Mai, et al. 2016). Electricity demand growth projections have slowed owing to the lingering effects of the recession as well as investments in energy efficiency. Projected wind energy costs have declined (Wiser, Jenni, et al. 2016; NREL 2016). Finally, policy changes have included updated renewable portfolio standards and extended schedules for the federal production and investment tax credits.

Within this new context, DOE recently set LCOE goals for PV to achieve by 2030: \$0.03/kWh for utility-scale, \$0.04/kWh for commercial, and \$0.05/kWh for residential systems.⁶ These SunShot 2030 goals are shown in Figure 5.

Achieving such very-low-cost PV could dramatically shift how electricity is produced and used. Considering only LCOEs, PV would outcompete many other generating technologies and undergo very rapid deployment. However, without changes to generation, transmission, and distribution systems—and to how electricity is sold to the end consumer—the value of PV will decline substantially as PV penetration increases (Mills and Wiser 2013; Denholm et al. 2016). This decline in PV value could ultimately limit the penetration of PV by reducing the economics of PV systems. The extent of that decline, however, depends on the relative costs of PV versus other generator types and on the cost of flexibility options, such as demand response and storage, which can be used to integrate PV more cost-effectively.

Previous analysis has demonstrated that grid flexibility options that have been deployed, or are in the process of being deployed, can help maintain the energy and capacity value of PV above what it costs to build, thereby increasing PV deployment. However, existing grid-flexibility options have potential limitations, and the current high cost of implementing certain

⁶ Updated CSP targets were not announced with the SunShot 2030 targets for PV.

technologies, such as energy storage, could limit how much PV can be deployed (Denholm and Margolis 2016; Denholm, Clark, and O’Connell 2016).

Reducing the costs of PV and grid-flexibility options simultaneously could spur a breakthrough, as low-cost PV makes combining PV with grid-flexibility options more affordable, and low-cost flexibility enables greater PV deployment. For this reason, DOE is incorporating grid-flexibility cost considerations with its PV cost goals. One important grid-flexibility option is energy storage, which can store PV-generated energy during the day and then discharge it when there is little or no PV resource; this capability becomes more valuable as PV deployment increases and the peak net load⁷ period moves from the afternoon into the evening.

In this report we project the PV deployment and associated impacts due to achieving the SunShot 2030 targets, using updated inputs and assumptions for the U.S. electricity sector. Other technologies also hold potential for large cost reductions, and these could affect grid evolution significantly (Donohoo-Vallett et al. 2017). However, because PV is the focus of this report, we include only limited analysis of varying other renewable energy costs.

We also analyze the impacts of low-cost energy storage in conjunction with low-cost PV. However, storage is only one of numerous grid-flexibility options, which also include strategies such as demand response, increased conventional generator flexibility, and expanded electricity transmission (Denholm et al. 2016). In that sense, the energy storage analysis reported here could represent other flexibility options that provide similar services at similar costs.

The remainder of this report is organized as follows. Section 2 analyzes two SunShot scenarios (one with and one without low-cost storage) in comparison with a baseline scenario, providing results in terms of projected deployment of PV and other generating technologies. Section 2 also shows the sensitivity of the SunShot scenarios to various market assumptions. Section 3 presents the impacts of the SunShot scenarios on projected renewable energy curtailment and system operation, storage capacity, transmission requirements, electricity prices and system costs, carbon dioxide (CO₂) emissions, and water withdrawal and consumption. It also compares these impacts with the impacts of six other scenarios that vary based on PV and storage costs. Finally, Section 4 offers conclusions and suggestions for future research. A set of appendices provide additional detail about the underlying assumptions, modeling tools, analysis, and results.

⁷ Net load is load minus variable renewable energy generation.

2 SunShot PV Projections

We analyze two SunShot scenarios in comparison to a baseline scenario. Both SunShot scenarios assume that DOE’s 2030 LCOE goals are achieved for utility-scale, commercial, and residential PV systems and that costs continue to decline after 2030.⁸ One SunShot scenario assumes mid-case storage cost declines, and the other assumes low storage costs (LSC), with both storage cost decline trajectories coming from Cole, Marcy, et al. (2016).⁹ The baseline scenario assumes the NREL Annual Technology Baseline (ATB) mid-case PV costs are achieved, and it assumes the mid-case storage cost declines. These scenarios represent current regulations such as renewable portfolio standards and the investment and production tax credits, but they do not include the Clean Power Plan. Non-solar generator cost and performance assumptions are taken from the 2016 ATB (NREL 2016) and fuel cost and demand projections are taken from the Annual Energy Outlook 2016 Reference Scenario (EIA 2016). For distributed PV, retail rates and net metering policies are based on current rates and policies as of spring 2017, and retail rate structures are assumed unchanged over time (e.g., we do not introduce time-of-use rates for residential customers who are currently on flat rates). Details on specific scenario inputs are provided in Appendix A, and the modeling structure and assumptions are included in Appendix B. Table 1 and Table 2 summarize the SunShot and baseline scenario PV and storage cost inputs.

Table 1. PV Cost Inputs for SunShot and Baseline Scenarios.

See Appendix A for more details on these assumptions.

Market Sector	Benchmark 2016 (¢/kWh) ^a	2030 PV LCOE (¢/kWh) ^a		2050 PV LCOE (¢/kWh) ^a	
		ATB Mid	SunShot	ATB Mid	SunShot
Utility-scale	7	5.7	3	4.7	2
Commercial rooftop	13	9.1	4	7	2.7
Residential rooftop	18	10.2	5	8.3	3.3

^a The LCOE in the table is calculated using an “average” capacity factor, which is represented by the capacity factor that would be seen in Kansas City, Missouri.

¢/kWh = cents per kilowatt-hour

⁸ Appendix D includes details on pathways that can lead to these low-cost PV targets.

⁹ Although ReEDS also includes pumped-hydro and compressed air energy storage, the mid and low storage cost projections refer just to battery storage. Pumped-hydro and compressed air energy storage do not have assumed cost declines. These battery cost projections assume a 15-year battery life at ~1 cycle per day and a 90% round-trip efficiency.

Table 2. Storage Cost Inputs used in the SunShot and Baseline Scenarios

See Appendix A for more details on these assumptions.

		2030 Energy Storage Cost (\$/kWh)		2050 Energy Storage Cost (\$/kWh)	
Market Sector	Benchmark 2016 (\$/kWh)	Reference	LSC	Reference	LSC
Utility-scale, eight hours	479	264	131	220	97
Commercial, three hours	1,034	663	450	537	300
Residential, three hours	1,854	1,189	807	962	539

With these assumptions, we project evolution of the contiguous U.S. electricity system using two models developed by the National Renewable Energy Laboratory. Our primary tool is the Regional Energy Deployment System (ReEDS) capacity expansion model, which relies on system-wide least-cost optimization to estimate the type and location of future generation and transmission capacity (Eurek et al. 2016). ReEDS accounts for the locational and temporal variations in variable renewable technologies, including impacts on curtailment, need for new transmission, declining capacity value, and the need to hold operating reserves to account for uncertainty in short-term renewable energy forecasts. Because ReEDS does not explicitly model distributed generation, we also use the Distributed Generation (dGen) consumer-adoption model,¹⁰ which projects adoption of U.S. rooftop PV and battery storage in the industrial, commercial, and residential sectors. This joint modeling captures the dynamic balances between growth in electricity consumption, plant retirements, competing generation options, policies, and the projected deployment and operation of behind-the-meter technologies—all of which affect the demand for new PV and storage resources. These models have been used extensively for U.S. electricity-sector analysis, especially with respect to renewable energy technologies.¹¹ Appendix B provides details about both models, including caveats and limitations.

As shown in Figure 7, projected PV deployment under the SunShot and SunShot LSC scenarios rapidly outpaces deployment under the baseline ATB Mid scenario. In 2030, both SunShot scenarios result in just over 400 gigawatts (GW) deployed, which is more than three times as much as in the ATB Mid scenario. By 2050, the SunShot scenario has deployed more than twice as much PV (971 GW) as the ATB Mid scenario (470 GW),¹² and the SunShot LSC scenario has

¹⁰ The dGen model is a rewrite of the original PVDS model (Denholm, Margolis, and Drury 2009) used in the original *SunShot Vision Study*.

¹¹ For related publications, see www.nrel.gov/analysis/reeds/related_pubs.html (ReEDS) and www.nrel.gov/analysis/dgen/related_pubs.html (dGen).

¹² The original *SunShot Vision Study* (DOE 2012) reported a 2050 PV penetration level of 27% when achieving a \$0.06/kWh utility-scale PV cost target using a combination of 8% CSP and 19% PV. The lower natural gas price and wind cost projections in particular make both CSP and PV less competitive in the scenarios presented here relative to the original scenarios employed in the *SunShot Vision Study*. Thus, this report's SunShot scenario,

deployed more than three times as much (1,618 GW). Table 3 shows the results in terms of generation and percentage of contiguous U.S. electricity supplied by PV. These PV penetration levels in 2030, while substantially higher than current levels, are in line with what integration studies have evaluated to date (Ahlstrom et al. 2015; Brinkman et al. 2016). However, 2050 penetration levels are beyond what most integration studies have considered.¹³ Although system changes would need to be implemented to accommodate this higher level of PV energy, the long evaluation period does provide some opportunity to continue to increase system flexibility through increased cooperation, transmission expansion, demand response, storage, and other enabling technologies and institutional solutions.

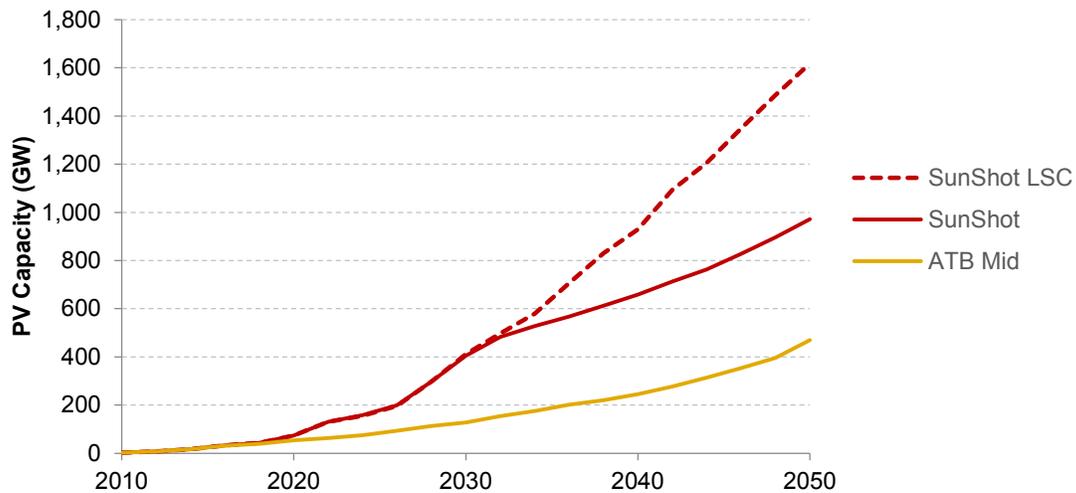


Figure 7. Cumulative PV deployment projections for SunShot, SunShot LSC, and ATB Mid scenarios

All capacity numbers presented in this section are in AC. We used an inverter loading ratio of 1.1 in the ReEDS and dGen models, so the PV capacity numbers in AC can be converted to DC by multiplying by 1.1.

which achieves the \$0.03/kWh utility-scale PV target in 2030, now reaches roughly the same overall level of PV penetration, but the PV mix achieving that penetration level is almost entirely PV (see Table 3).

¹³ Some studies have looked at higher levels of renewable penetration (Mai et al. 2012; Jacobson et al. 2015; Brinkman et al. 2016), but most have not (Ahlstrom et al. 2015).

Table 3. Cumulative PV Projections for SunShot, SunShot LSC, and ATB Mid Scenarios

Year	Scenario	Installed Capacity (GW)	Electricity Generation (TWh) ^a	PV Penetration (% of Electricity Supplied)
2030	SunShot	405	749	17.0%
	SunShot LSC	412	770	17.5%
	ATB Mid	127	235	5.3%
2050	SunShot	971	1,729	32.6%
	SunShot LSC	1,618	2,968	55.2%
	ATB Mid	470	872	16.5%

^a TWh = terawatt-hour

Figure 8 shows results in terms of annual PV deployment. In both the SunShot and SunShot LSC scenarios, the impact of the investment tax credit (ITC) can be seen in the early 2020s, which leads to rapid near-term deployment followed by a short period of lower deployment rates as the ITC is stepped down. The SunShot scenario deployment peaks in 2030 at just under 55 GW/year, with post-2030 annual deployment ranging from 20 to 40 GW/year. Annual PV deployment in the SunShot LSC scenario generally continues to grow through 2050, with average annual deployment from 2040 to 2050 reaching about 65 GW/year. The rapid increase in deployment that begins in the late 2020s occurs because that is when the LCOE of PV begins to drop below the marginal cost of most *existing* generators, meaning that it is cheaper to build a new PV system than to operate an existing plant. That high level of deployment then falls in the SunShot scenario as PV curtailment increases and PV capacity value declines, but is largely maintained in the SunShot LSC scenario because storage is able to mitigate the declining value of PV. In contrast to the SunShot scenarios, the ATB Mid scenario does not reach 20 GW/year of PV deployment until the late 2040s.

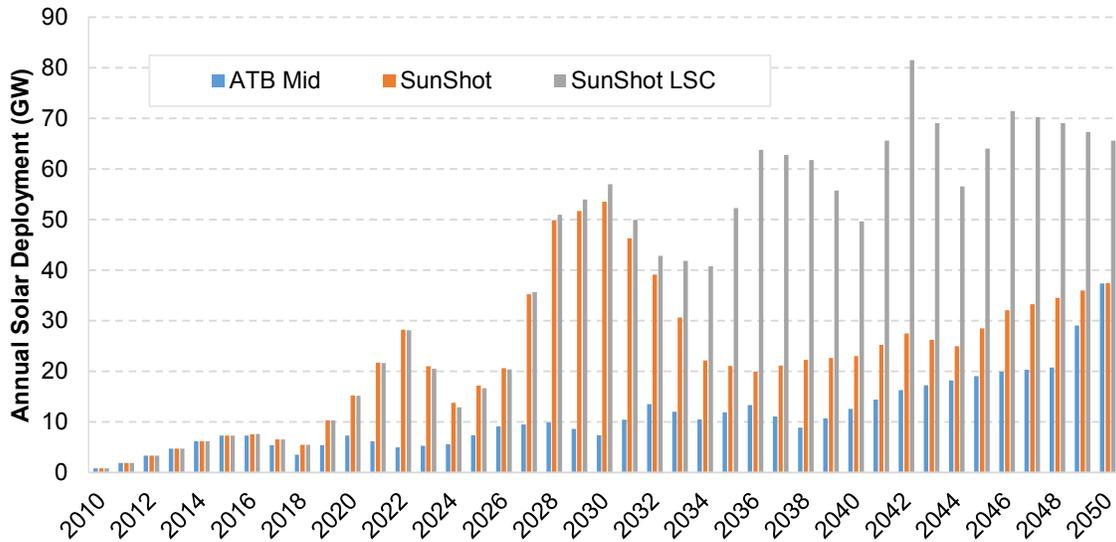


Figure 8. Annual PV deployments for the SunShot and SunShot LSC scenarios (for new builds only, repowered units not included)

ReEDS has limited foresight, so it does not do any smoothing of deployment in order to avoid ramp ups or down in deployment (e.g., ReEDS does not reduce deployment in year X so that deployment does not decrease significantly in year X+2).

State-level deployment is shown in Figure 9 (cumulative capacity in 2050) and Figure 10 (fraction of state generation supplied by PV in 2050). State-level PV penetration exhibits substantial variation, ranging from 3% to 62% in the SunShot scenario and from 13% to 81% in the SunShot LSC scenario.¹⁴ The PV capacity is not simply deployed in the best resource locations. Rather, the capacity is optimally sited based on regional capital cost difference, regional natural gas price differences, transmission needs and constraints, need for new capacity (due to load growth and retirements), and local policy differences (e.g., the presence or absence of renewable portfolio standards). In addition, value is added by smoothing out resource variability via the spreading of PV across a wider geographic area.¹⁵ Because of these considerations, ReEDS interprets some states as especially favorable for PV deployment. For example, Virginia’s high deployment results from a relatively high PV resource, lower regional capital costs than surrounding states, high levels of power plant retirements, the state’s ability to export into higher-cost regions, and a relatively poor wind resource.

¹⁴ The high PV penetration values can be achieved by states exporting their electricity to neighboring regions.

¹⁵ Because of the greater geographic dispersion, clouds and other localized weather effects have a lesser impact on overall system performance.

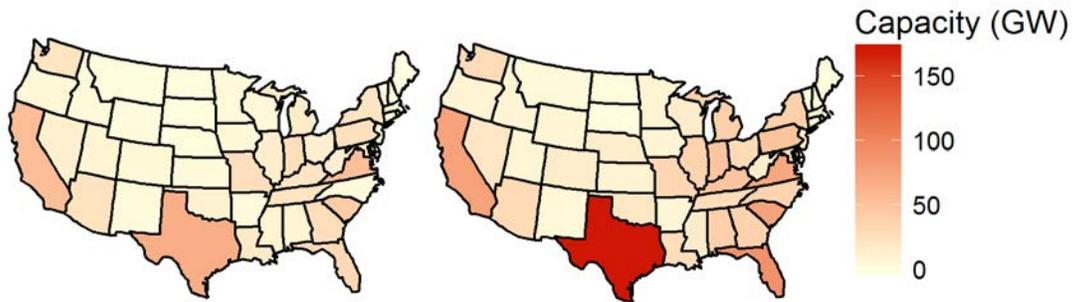


Figure 9. Cumulative PV capacity by state in 2050, SunShot scenario (left) and SunShot LSC scenario (right)

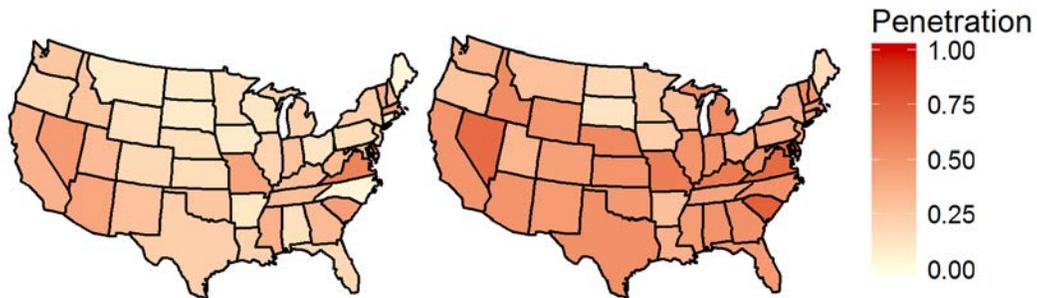


Figure 10. PV penetration (fraction of state generation supplied by PV) by state in 2050, SunShot scenario (left) and SunShot LSC scenario (right)

In the SunShot scenarios, total projected U.S. electricity-system capacity essentially doubles between today and 2050. The impact of SunShot deployment on this grid mix is shown in Figure 11 (capacity) and Figure 12 (generation), and the impact of SunShot LSC deployment is shown in Figure 13 (capacity) and Figure 14 (generation). On a capacity basis, PV grows more than any other generation type in both scenarios. Although the growth in PV generation is also dramatic, it is less pronounced than the capacity growth, owing to PV's relatively low capacity factor. By 2050, system-wide PV capacity factors average about 20%, because significant amounts of PV are deployed in lower-resource locations, and because PV curtailment increases.¹⁶

¹⁶ Current PV capacity factors are around 26% (Bolinger and Seel 2016).

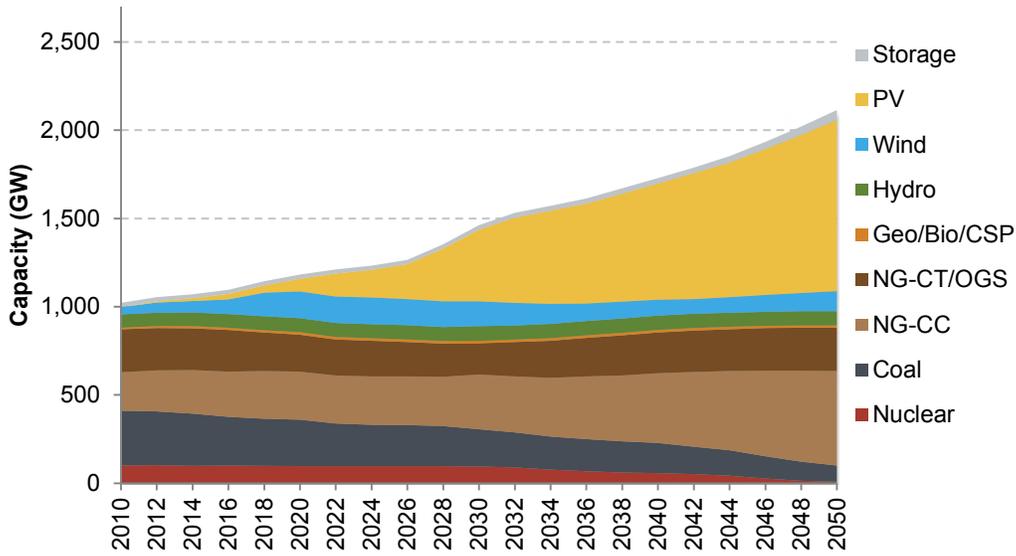


Figure 11. Nationwide cumulative capacity by technology and year for SunShot scenario

NG-CC is natural gas combined cycle. NG-CT is natural gas combustion turbine. OGS is oil-gas-steam. And, and Geo/Bio/CSP is geothermal, biopower, and concentrating solar power technologies. Imports are net electricity imports from Canada and Mexico.

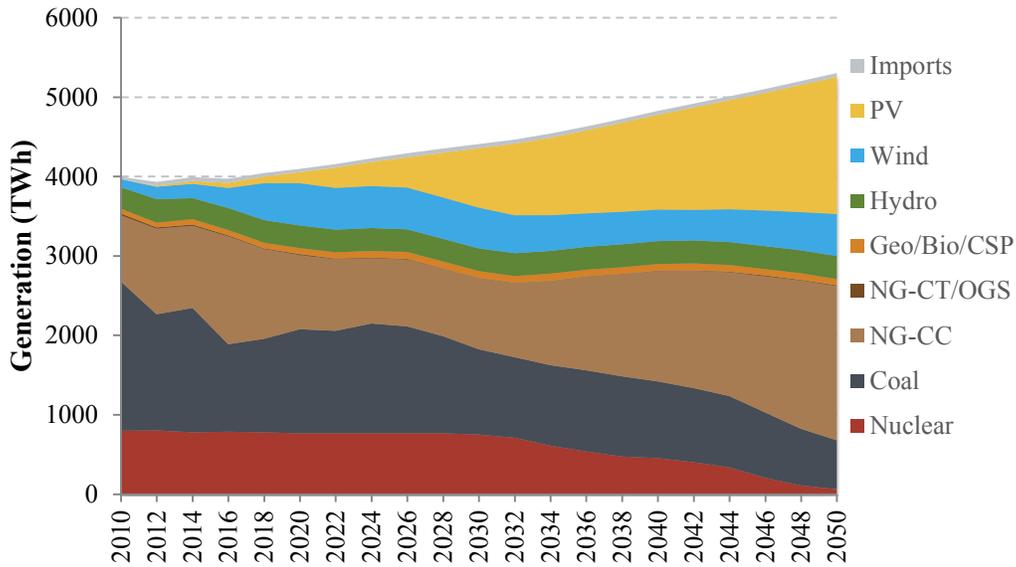


Figure 12. Nationwide annual generation by technology and year for SunShot scenario

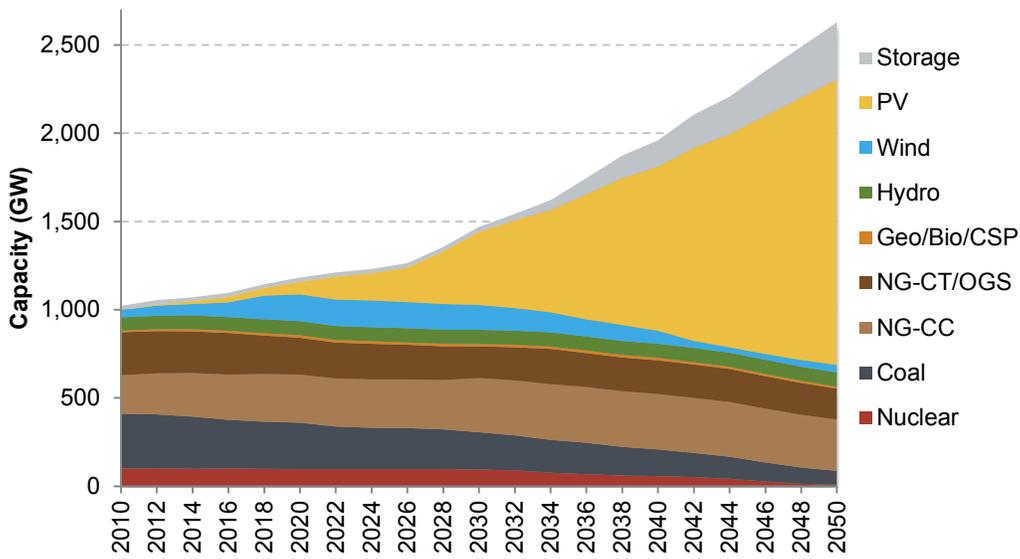


Figure 13. Nationwide cumulative capacity by technology and year for SunShot LSC scenario

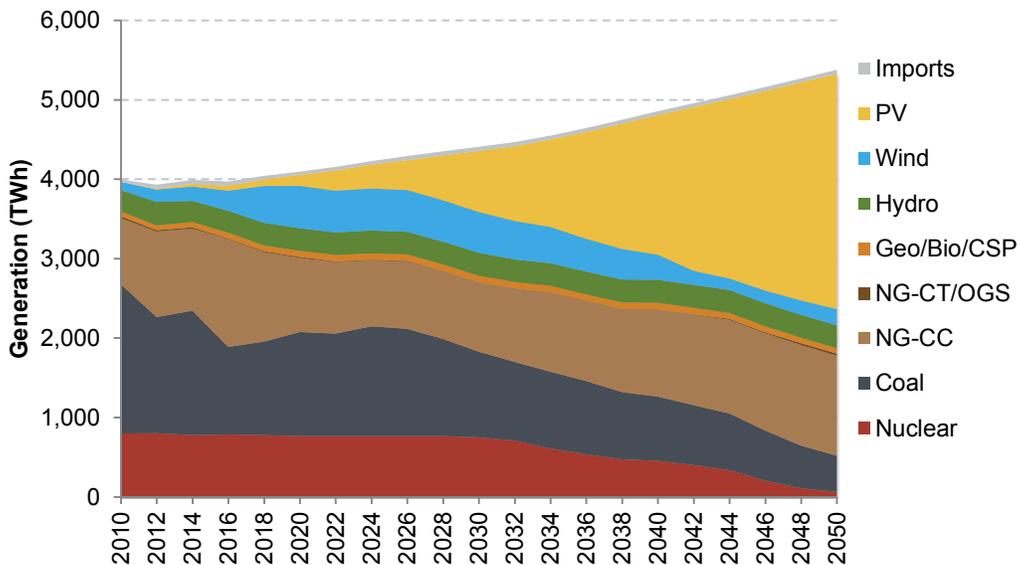


Figure 14. Nationwide annual generation by technology and year for SunShot LSC scenario

Figure 15 and Figure 16 compare the capacity and generation mixes among the SunShot, SunShot LSC, and ATB Mid scenarios. Although all the SunShot scenarios have significantly more PV capacity than the ATB Mid scenario, only the SunShot LSC scenario in 2050 has considerably less conventional capacity than its ATB Mid counterpart, with the reductions primarily coming from natural gas units. The impacts of PV deployment on the use of natural gas plants are more pronounced in the generation mixes (Figure 16). In particular, the low-cost energy storage in the SunShot LSC scenario replaces natural gas combustion turbines—because batteries function as peaking and fast-ramping units—and storage provides already-stored PV energy when PV power is unavailable, which displaces combined-cycle natural gas generation.

Also seen in these figures is the impact of strong PV growth on wind and coal deployment. Wind capacity and generation are squeezed by the competition from low-cost PV. Coal capacity is not influenced as much as natural gas and wind, but the generation share of coal is. By the 2030s, existing coal units typically have a lower marginal cost than new or existing natural gas units, so additional energy provided by PV more often offsets natural gas generation instead of coal generation. Also, because nuclear capacity begins to retire in the 2030s (owing to the assumed 60-year lifetime for nuclear plants), coal units can fill in that baseload capacity while still ramping down during the day to accommodate more low-cost PV energy (see Section 3.2 for additional discussion of system operation).

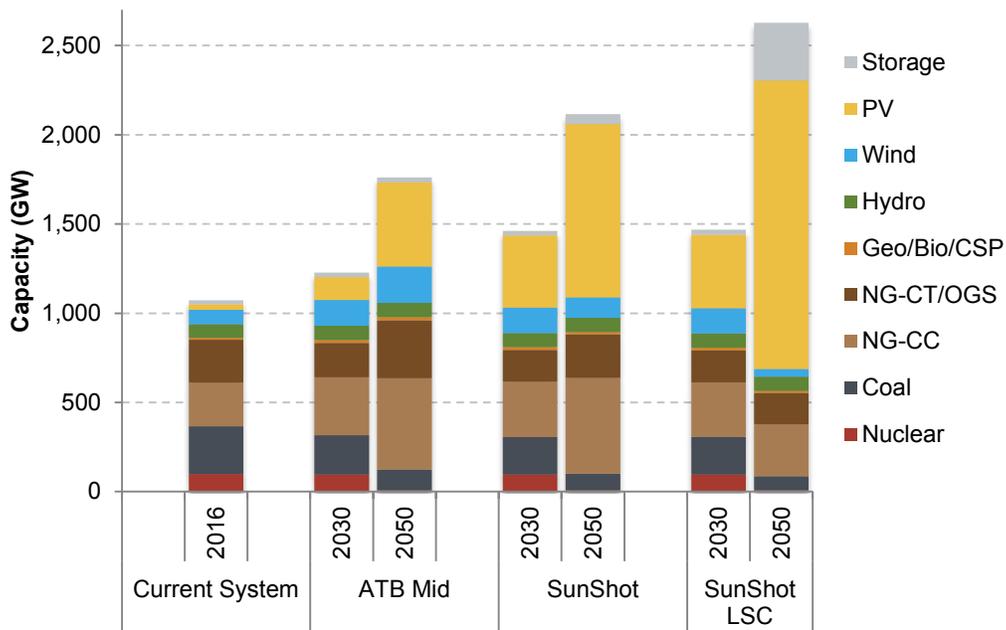


Figure 15. Nationwide cumulative capacity in 2016, 2030, and 2050 by technology for the ATB Mid, SunShot, and SunShot LSC scenarios

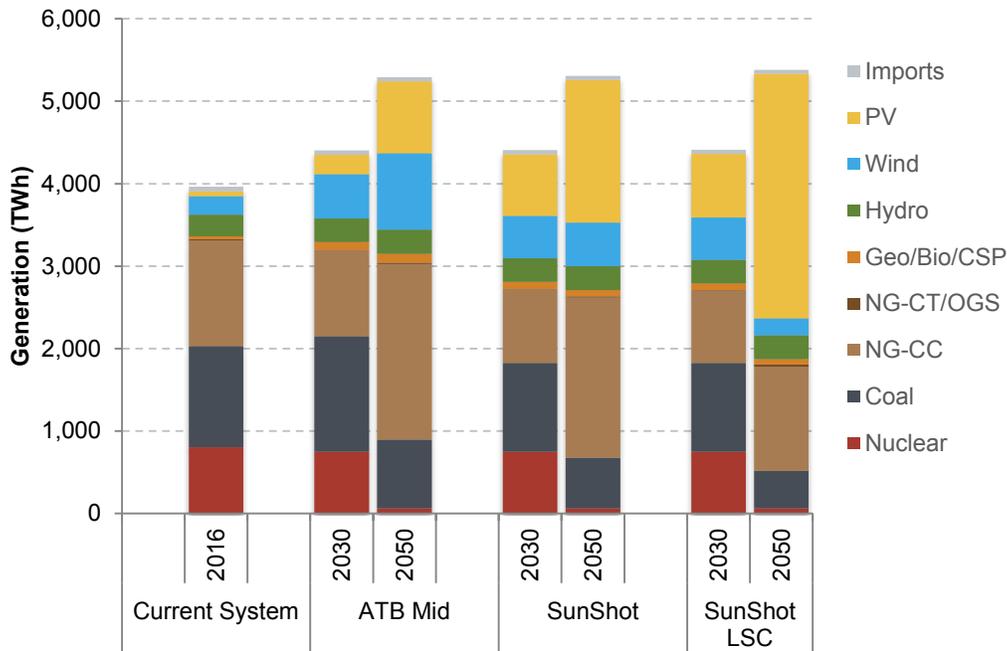


Figure 16. Nationwide generation in 2016, 2030, and 2050 by technology for the ATB Mid, SunShot, and SunShot LSC scenarios

2.1 Sensitivity of SunShot Deployment Projections to Market Assumptions

We analyze the sensitivity of the SunShot and SunShot LSC scenarios to various market assumptions, including lower and higher electricity demand growth, lower and higher natural gas prices, accelerated and extended conventional generator lifetimes, and lower and higher non-PV renewable energy technology costs. The scenario definitions are taken from the suite of 2016 Standard Scenarios (Cole, Mai, et al. 2016). We also include a scenario that includes growth penalties on utility-scale PV. See Appendix A for details on how the sensitivity scenario inputs are defined.

These analyses provide a range of plausible projections for the SunShot and SunShot LSC scenarios. As shown in Figure 18 and Table 4, 2030 PV deployment ranges from 307 GW (13% of electricity demand met by PV) to 435 GW (18%),¹⁷ and 2050 deployment ranges from 850 GW (28%) to 1,923 GW (64%). A more complete set of result for the sensitivity scenarios are presented in Appendix C. Text Box 1 presents a special sensitivity case in which both PV and wind achieve their new goals.

¹⁷ Nearly all of the PV capacity is from PV, because no new CSP is built by the model except in the ATB Mid and High NG Price scenarios.

Text Box 1. Wind Atmosphere to Electrons (A2e) Initiative Sensitivity

This analysis focuses on the impacts of PV technology advancements under a range of future market conditions, including a range of non-wind renewable energy (RE) technology costs. However, this range does not encompass all possibilities and it excludes DOE's recently announced Atmosphere to Electrons (A2e) initiative (Dykes et al. 2017; Mai et al. forthcoming), where wind technology cost reductions exceed those in the lowest cost projections modeled in our market sensitivity scenarios (i.e., Low RE Cost scenario). In this text box, we show RE capacity and generation results assuming successes in both PV and wind technologies by using SunShot 2030 and A2e projections, respectively. These results are compared to the SunShot scenario. Both scenarios use the SunShot assumptions for all settings except for the wind costs.

The dotted lines in Figure 17 show annual generation and capacity results from the SunShot + A2e scenario in which RE generation grows consistently over time and is projected to serve a large majority of total generation needs by 2050. In 2050, wind and solar generation together comprise 90% of all RE generation. Installed capacity results follow similar trends with total RE capacity exceeding 1,300 GW by 2050, including over 500 GW from wind and over 700 GW from PV technologies.

The solid lines in the figure show results for the SunShot scenario which has more-modest wind technology advancements. As would be expected, wind penetration and deployment are lower in this scenario and PV growth is greater than in the SunShot + A2e scenario. However, we find that aggregate RE generation and capacity are higher when both wind and PV achieve their greatest technology advancements, demonstrating that successful technology innovations in both would yield even greater system benefits than success in any single individual technology.

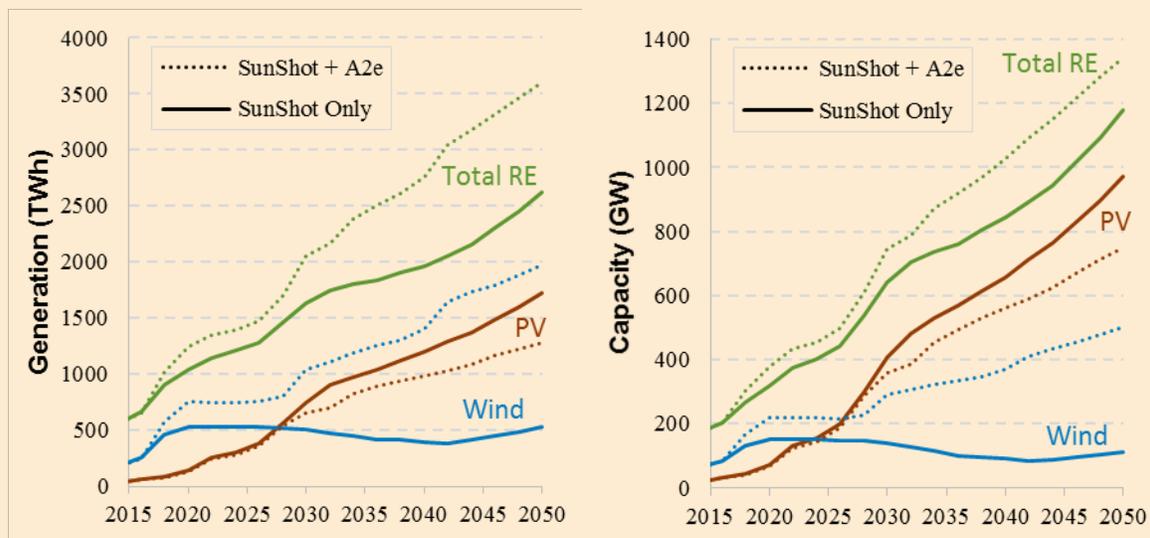


Figure 17. Wind, PV, and total RE generation (left) and capacity (right) in select RE technology sensitivities

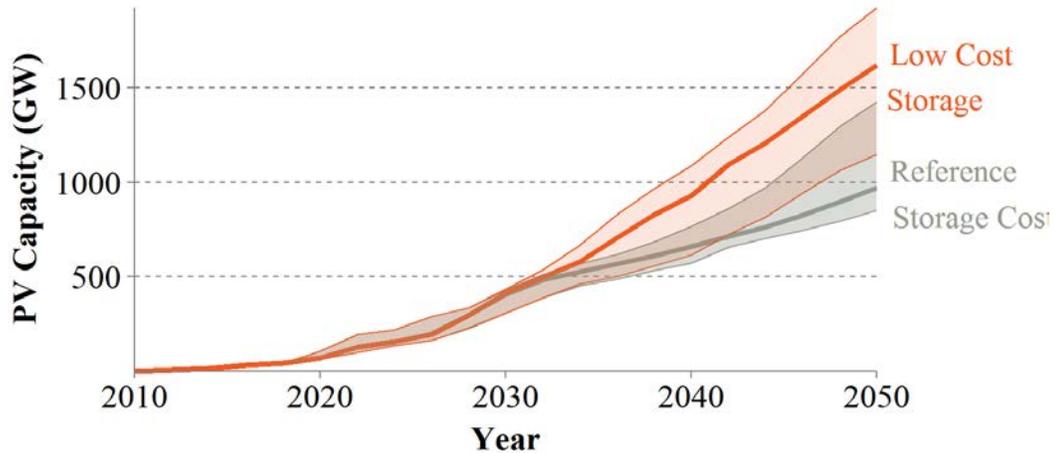


Figure 18. Nationwide cumulative PV capacity ranges for SunShot (gray) and SunShot LSC (orange) sensitivity scenarios

Bold lines show the SunShot and SunShot LSC core scenario projections.

Table 4. PV Deployment in 2030 and 2050 across Sensitivity Scenarios

Scenario Set	PV Capacity (GW)		PV Penetration (% of Electricity Supplied)	
	2030	2050	2030	2050
SunShot—reference storage cost	307–431	850–1,426	13%–18%	28%–46%
SunShot LSC —low storage cost	307–435	1,148–1,923	13%–18%	41%–64%

The sensitivity scenarios also quantify which factors produce the largest impact on projected PV deployment. Clearly, from Figure 18 and Table 4, the availability of low-cost storage has the largest impact on projected deployment. Assuming low-cost storage instead of reference-cost storage increases 2050 PV capacity by an average of more than 50% across the sensitivity scenarios. Among the other factors considered, natural gas prices and electricity demand have the next-largest impacts on PV capacity (see Figure 19). Natural gas is projected to be a cost-effective technology well into the future (Cole, Mai, et al. 2016), but deviations in expected natural gas prices can yield much greater or lesser deployment of natural gas technologies. Increasing or decreasing demand directly impacts the need for new capacity, including PV capacity. In addition, extending the lifetime of the nuclear fleet by 20 years (low retirements) decreases PV deployment substantially by reducing the need for new capacity and—because nuclear generation is highly inflexible—making it more challenging to integrate larger quantities of variable renewable energy.

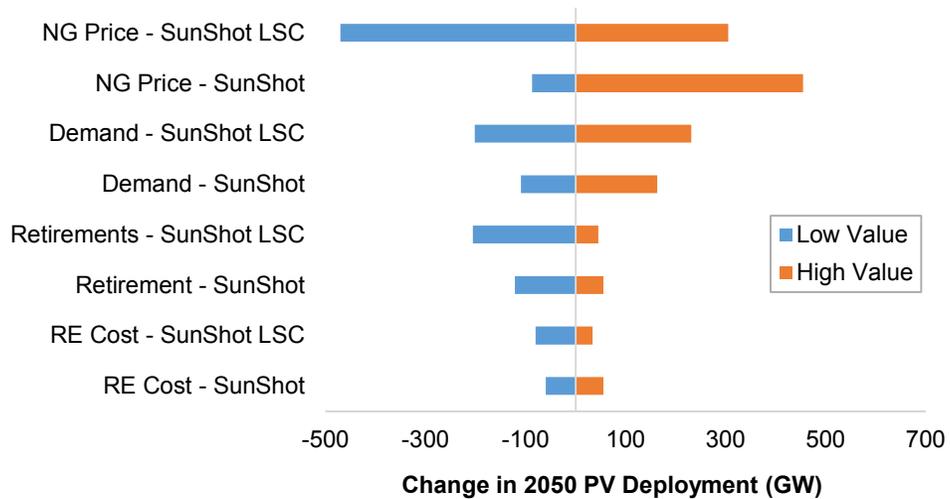


Figure 19. Impact of the specified sensitivity on 2050 PV deployment relative to the SunShot and SunShot LSC reference scenarios

Details of the sensitivities are provided in Appendix A, but a summary of the magnitudes is provided here. The natural gas price scenarios represent changes in 2050 natural gas prices of -40% and +70%. The demand scenarios have changes of -33% and +40% in the average growth rate. The high retirements shorten coal plant lifetimes by 10 years and the low retirements increase nuclear lifetimes by 20 years. And, the RE costs scenarios change costs by -34% to +58%, depending on the technology.

3 Impacts of SunShot Compared with other PV Cost Scenarios

This section compares the impacts of the SunShot and SunShot LSC scenarios—which assume PV LCOEs of 3 ¢/kWh (utility-scale), 4 ¢/kWh (commercial), and 5 ¢/kWh (residential) in 2030—with the impacts of scenarios that underachieve or overachieve with respect to those SunShot LCOE goals. The overachieving scenarios assume the PV LCOEs reach 33% below the SunShot LCOE in 2030 (i.e., utility PV reaches 2 ¢/kWh in 2030), with one scenario that uses reference storage costs and another that uses low storage costs (LSC). These scenarios are named 33% Below and 33% Below LSC.¹⁸ A similar pair of scenarios—named 33% Above and 33% Above LSC—assumes PV LCOEs are 33% higher than the SunShot targets in 2030 (i.e., utility PV reaches 4 ¢/kWh in 2030). We also include additional ATB mid-case scenarios, one with LSC and another (which we only use for comparing CO₂ emissions projections) that includes the U.S. Environmental Protection Agency’s Clean Power Plan (CPP). Impacts considered include PV capacity and generation (Section 3.1), renewable energy curtailment and system operation (3.2), storage capacity (3.3), transmission requirements (3.4), electricity prices and system costs (3.5), CO₂ emissions (3.6), and water withdrawal and consumption (3.7).

We chose to represent the impacts listed above using cost sensitivities because of the large uncertainty related to projections that extend decades into the future (see Section 2.1). The higher and lower cost scenarios lead to higher and lower amounts of PV deployment, so in showing the impact across these cost sensitivity scenarios we can at least approximately capture the impact of over or underestimating the amount of PV that might be deployed in the types of low-cost PV futures envisioned in this work.

3.1 Capacity and Generation

Figure 20 shows the PV capacity projections for each scenario. Total PV deployment is a function of PV costs and storage costs. The lower storage costs let the growth that occurs prior to 2035 continue into the 2040s rather than slow down. In the most optimistic cost scenario, the PV penetration reaches 62% by 2050 (Table 5).

¹⁸ Appendix D includes details for how these cost pathways might be achieved.

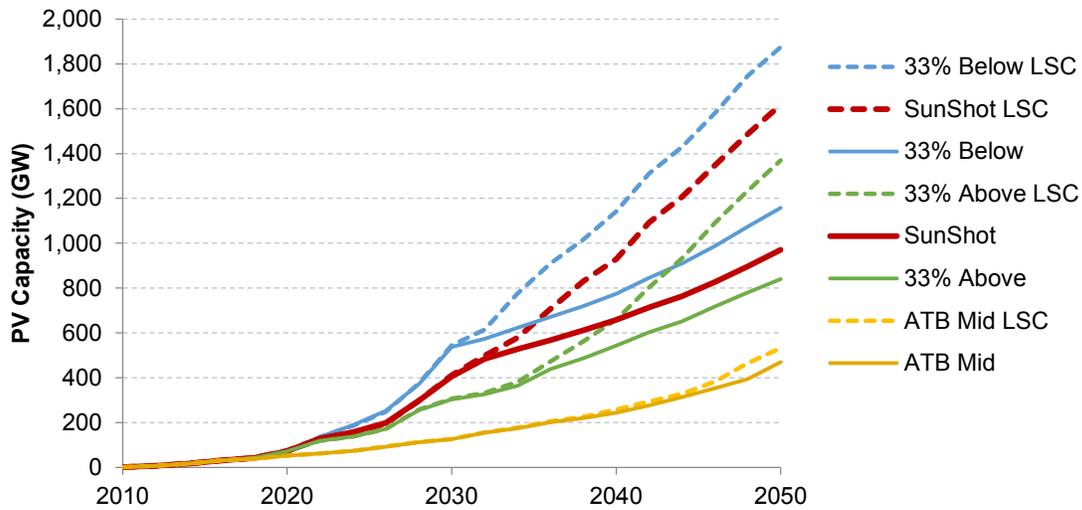


Figure 20. Nationwide cumulative PV capacity by year for PV cost scenarios with and without low storage costs

Table 5. Cumulative PV Projections for PV Cost Scenarios with and without LSC

Scenario	PV Capacity (GW)		PV Penetration (% of Electricity Supplied)	
	2030	2050	2030	2050
33% Below	537	1,158	22.5%	38.0%
SunShot	405	971	17.0%	32.6%
33% Above	303	840	13.0%	28.8%
ATB Mid	127	470	5.3%	16.5%
33% Below LSC	545	1,875	23.0%	61.8%
SunShot LSC	412	1,618	17.5%	55.2%
33% Above LSC	306	1,370	13.2%	48.2%
ATB Mid LSC	127	532	5.3%	19.1%

Figure 21 and Figure 22 show the capacity and generation mixes for each cost scenario in 2030 and 2050. The capacities of the conventional plants (nuclear, gas, and coal-fired plants) do not have large differences among the scenarios without low-cost storage. With low-cost storage, however, conventional capacities decrease as PV costs decrease. Figure 22 demonstrates that additional PV generation has the largest impact on coal in 2030 and on wind in 2050. With LSC, PV primarily offsets coal generation in 2030 and natural gas generation in 2050, though wind is also largely impacted in 2050.

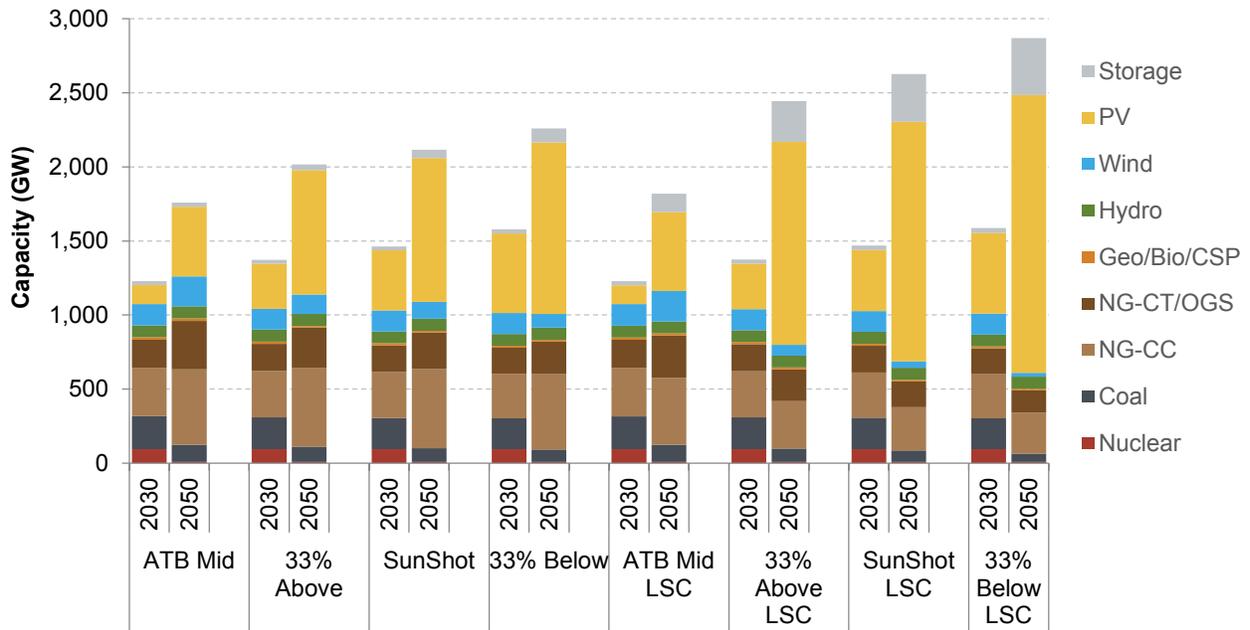


Figure 21. Nationwide cumulative capacity in 2030 and 2050 by technology for PV cost scenarios with and without low storage costs

NG-CC is natural gas combined cycle. NG-CT is natural gas combustion turbine. OGS is oil-gas-steam. And, Geo/Bio is geothermal and biopower technologies.

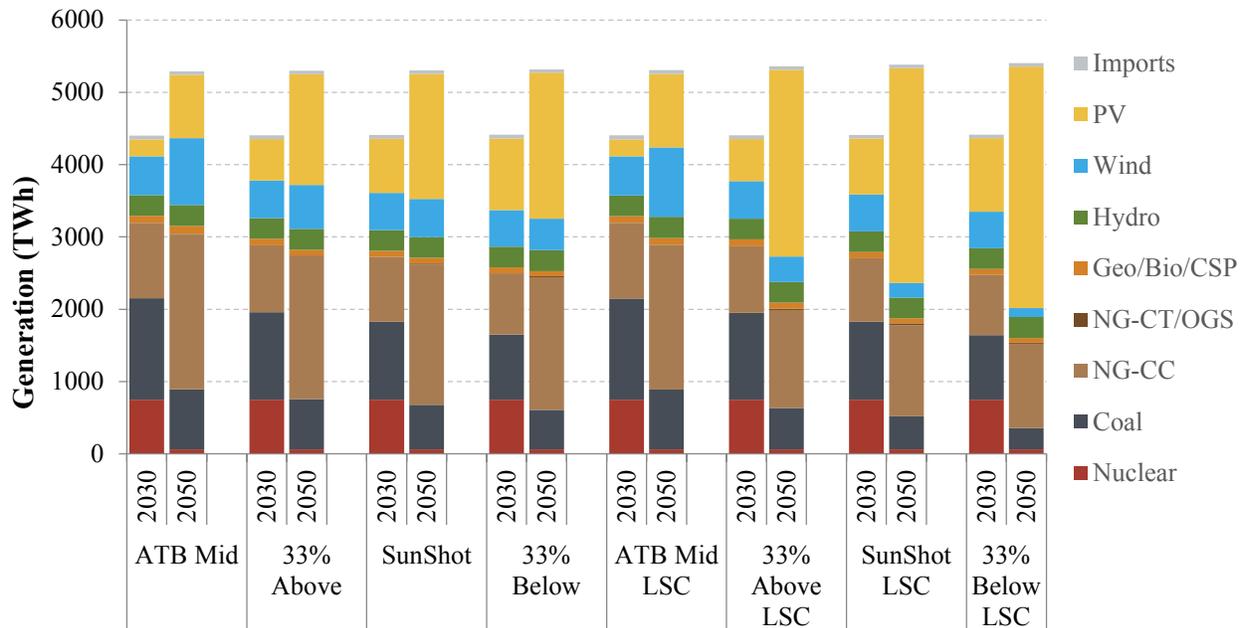


Figure 22. Nationwide generation in 2030 and 2050 by technology for PV cost scenarios with and without low storage costs

Figure 23 shows projected DPV capacity across the PV cost scenarios with reference storage costs.¹⁹ DPV adoption is a somewhat less sensitive to PV costs than is utility PV deployment (Figure 20). For example, utility PV capacity under the SunShot scenario is 115% more than the ATB Mid value in 2050 with reference storage costs, whereas DPV adoption is 88% higher. This is largely driven by the difference in revenue streams between DPV and UPV. Because DPV obtains revenue by offsetting retail tariffs, it is an attractive investment for many potential customers in all scenarios, and adoption is largely driven by the rate at which DPV spreads through the public. Lower PV costs can unlock new DPV markets and accelerate adoption but not to the same degree observed in the utility-scale sector. In addition, because DPV deployment is a function of consumers’ willingness to adopt, other factors—such as financing and the availability of alternative business models like third-party ownership—can impact the rate of adoption.²⁰

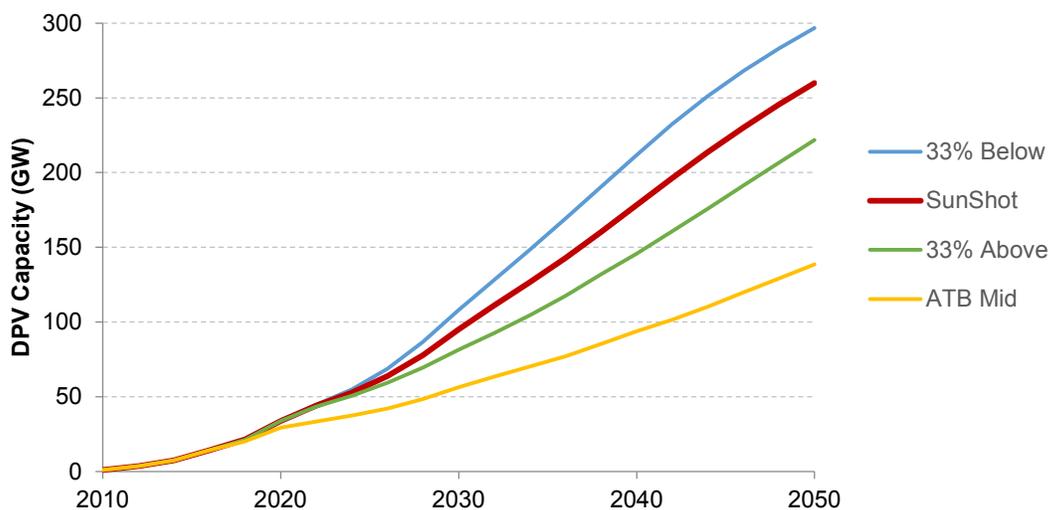


Figure 23. Nationwide cumulative DPV capacity by year for PV cost scenarios without low storage costs

3.2 Renewable Energy Curtailment and System Operation

The impact of PV and storage cost assumptions on curtailment rate is summarized in Figure 24.²¹ The curtailment rate is defined as curtailment divided by variable renewable energy generation. As expected, the curtailment rate is higher in the lower-cost PV scenarios. As PV becomes more competitive, the system is able to “throw away” more energy cost-effectively via curtailment. Figure 24 also demonstrates one of the primary value streams of low-cost storage; it reduces

¹⁹ These scenarios do not include any assumptions about the evolution of retail tariffs as the penetration of PV increases. The DPV adoption projections included here assume that the rate structures that existed in 2016 across the United States continue through 2050.

²⁰ It is expected that low-cost storage will influence DPV adoption through three primary factors: increased financial performance of co-deployed PV-plus-storage systems, reduced total cost of electricity, and changed retail tariff structures. Because dGen’s is currently unable to model the changes in retail tariff structures, the influence of low-cost storage on DPV adoption is omitted from this analysis.

²¹ The hump in curtailment in the early 2020s does not persist because of increased deployment of new transmission capacity (see Figure 28).

curtailment, which in turn allows more PV to be deployed cost-effectively. In 2050, curtailment ranges from 2.5% to 5.4% in the non-ATB-Mid scenarios without low storage costs and from 1.2% to 5.1% in the scenarios with low storage costs. Marginal curtailment rates are much higher. For example, in the SunShot scenario in 2050, the average marginal curtailment rate for a UPV system is 31%, with some regions seeing annual marginal curtailment rates of up to 53%.²² In addition to curtailment, storage systems incur losses, such that in the low-cost storage scenarios, losses due to storage more than double the losses from curtailment. If storage losses are counted as curtailment, the 2050 curtailment rates would be 3.2%–8.6% in the SunShot scenarios and 2.0%–8.4% in the SunShot LSC scenarios.

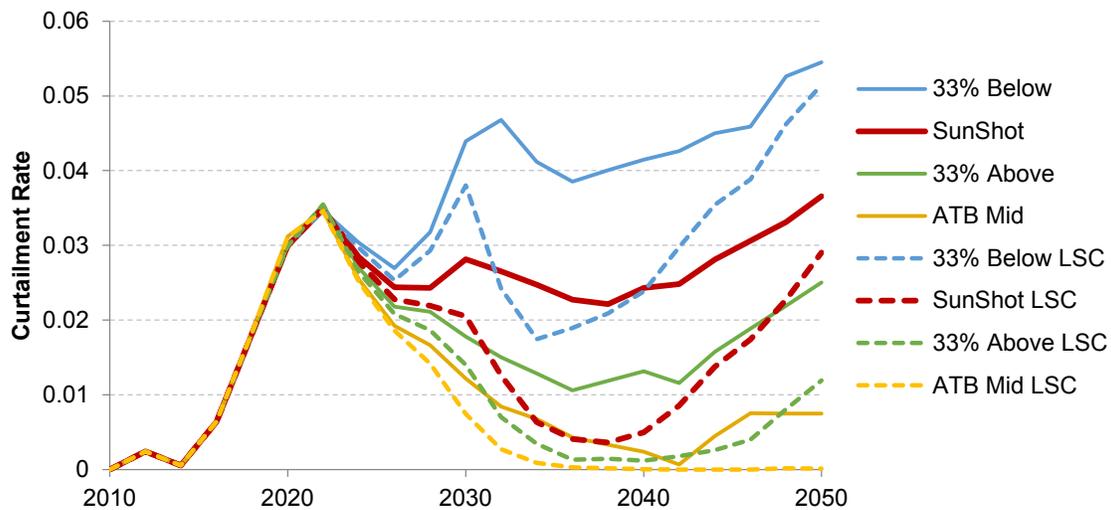


Figure 24. Total annual curtailment rate for PV cost scenarios with and without low storage costs²³

One of the reasons that curtailment rates remain fairly low even at these very high PV penetrations is that by 2050 many of the less-flexible generators (i.e., coal and nuclear) have retired (see Figure 21). With fewer must-run generators online, PV can more easily be integrated because non-PV generation can be turned down to very low levels during daytime hours. Sensitivity scenarios that keep must-run generators online longer result in lower PV deployment (see Figure 19 and Appendix C).

Figure 25 shows the operation of the system in 2050 in the SunShot scenario, and Figure 26 shows the operation in the SunShot LSC scenario. PV is the primary energy supplier during daytime hours, with additional limited generation during the evening. Coal generators still

²² Some regions are so saturated with PV that large portions of the output from a new PV plant would be unusable. However, ReEDS can do things to mitigate a high curtailment rate. For example, it can turn down must-run generators or add storage in order to recover that curtailed energy, which creates a lower effective marginal curtailment rate. Most often, however, ReEDS simply chooses to build new PV in regions that have lower marginal curtailment rates and avoid those regions with high curtailment rates.

²³ The reason for the “hump” in curtailment rate in 2022 is that 2022 is the first year that new, unannounced transmission is allowed to be built in ReEDS. It also corresponds with the end of new wind builds that receive the PTC, so wind builds also slow considerably after 2022.

operate in a typical baseload fashion in summer and winter, but they ramp down during spring and fall afternoons to their minimum generation levels to reduce PV curtailment. The natural gas combined-cycle plants are very flexible and are used to match load while minimizing renewable energy curtailment. Storage in these scenarios is used in a manner that is opposite to how it is typically employed today, with charging occurring overnight and discharging occurring in the afternoon. In these high-PV scenarios, storage charges during the day, when there is excess PV energy, and then discharges in the evening and overnight periods. During daytime periods, storage and curtailment are both employed to address PV overgeneration.

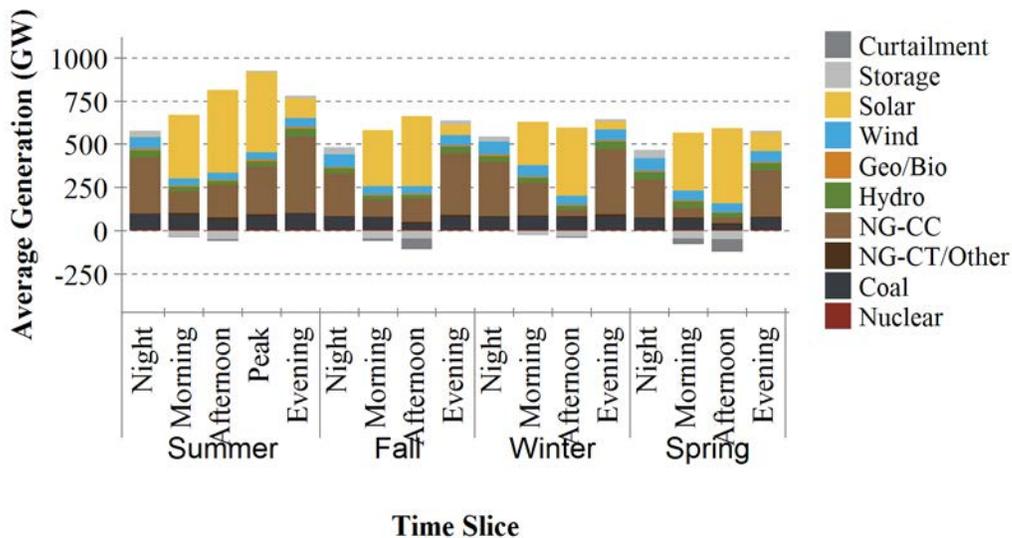


Figure 25. Dispatch stack for four representative days (in 2020) in the SunShot scenario, showing peak generation from non-renewable energy technologies occurring during the evening

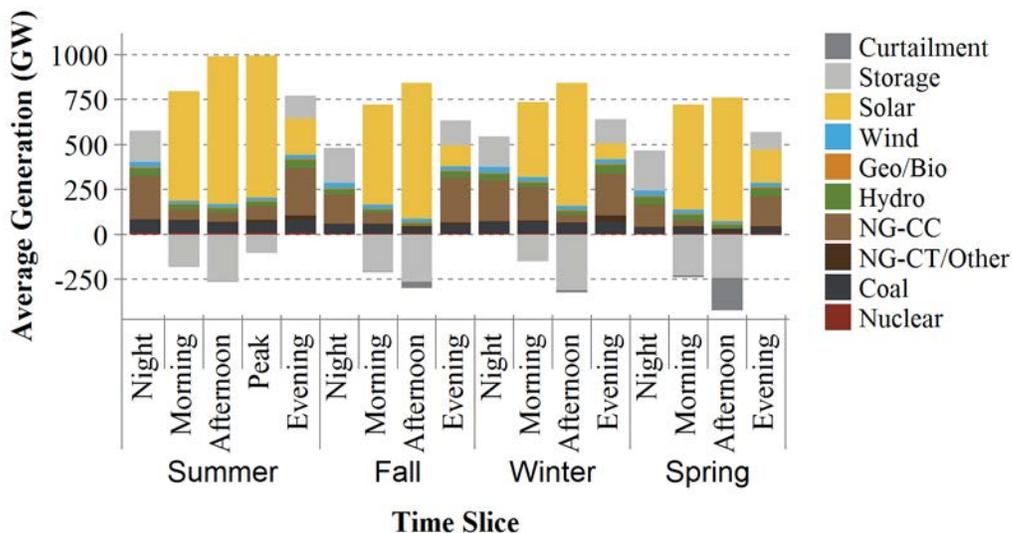


Figure 26. Dispatch stack for four representative days (in 2020) in the SunShot LSC scenario, showing storage charging from PV during the day and discharging during the evening and night

3.3 Storage Capacity

The impact of PV and storage cost assumptions on total utility-scale storage capacity deployed is summarized in Figure 27.²⁴ Not surprisingly, scenarios with lower-cost storage result in greater capacity. Cumulative storage capacity in 2050 is roughly an order of magnitude greater in the low-storage-cost scenarios that it is in their reference-storage-cost counterparts. This trend is amplified in scenarios that achieve greater reductions in PV costs to support correspondingly larger PV deployment. The scenarios with reference storage costs still see a small amount of storage deployed. The storage deployment under the reference-case battery cost assumptions is a mix of battery, compressed air, and pumped-hydro energy storage.

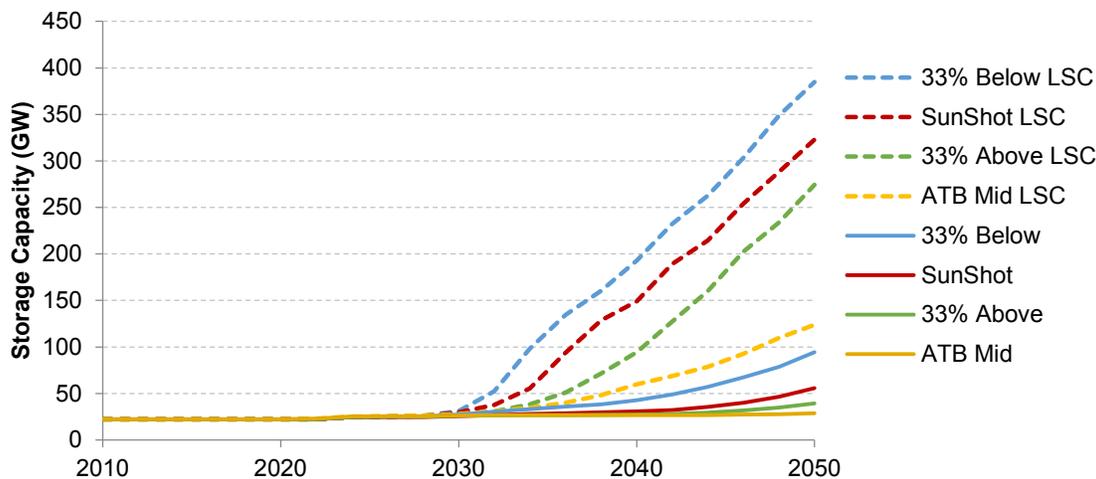


Figure 27. Nationwide cumulative utility-scale storage capacity for PV cost scenarios with and without low storage costs

ReEDS does not build new storage in any scenarios until the latter 2020s. The model cannot capture localized value for storage such as voltage support or specific participation in ancillary service markets, but rather it accounts for the system-wide benefits of storage such as curtailment reduction, contribution toward reserve margin requirements, and contribution toward quick-start and spinning reserve requirements. Thus, the ReEDS projections are more likely to underestimate rather than overestimate the deployment potential for utility-scale storage in the near-term. Also, because of the relatively low penetration of renewables and the relatively small need for new capacity before 2030, ReEDS does not find significant value with storage until the 2030 timeframe.

Adoption of behind-the-meter storage is projected to be much lower than utility-scale storage deployment. For example, behind-the-meter storage deployment is just over 6 GW in 2050 in the SunShot LSC scenario, compared with 323 GW of utility-scale storage. This disparity results from the higher costs of behind-the-meter storage as well as dGen’s assumptions that current tariff structures do not evolve and existing PV systems cannot be retrofitted with storage. Behind-the-meter storage deployment is based solely on revenue from bill reductions under current tariff structures. An evolution of tariff structures, or continued development of alternative

²⁴ The initial storage capacity is the 22 GW of existing pumped-hydro energy storage.

revenue models beyond monthly bill reduction, could drive the adoption of significantly more behind-the-meter storage.

3.4 Transmission Requirements

The impact of PV and storage cost assumptions on transmission capacity additions²⁵ is summarized in Figure 28.²⁶ The lower-cost PV scenarios lead to greater amounts of PV deployment, which results in more transmission builds so PV generation can be transported to demand centers. However, the availability of low-cost storage reduces the need for new transmission builds for the same PV penetration level. When storage is available, PV can often be constructed and used near where the electricity is consumed. Thus, an increase in PV deployment does not necessarily signify a need to build new long-distance transmission capacity. Because PV resources are so abundant in the United States, the option of installing PV closer to load centers becomes increasingly cost effective, especially when low-cost storage is available. The transmission builds projected in these scenarios is in line with or smaller than historical transmission investment rates (DOE 2015a).

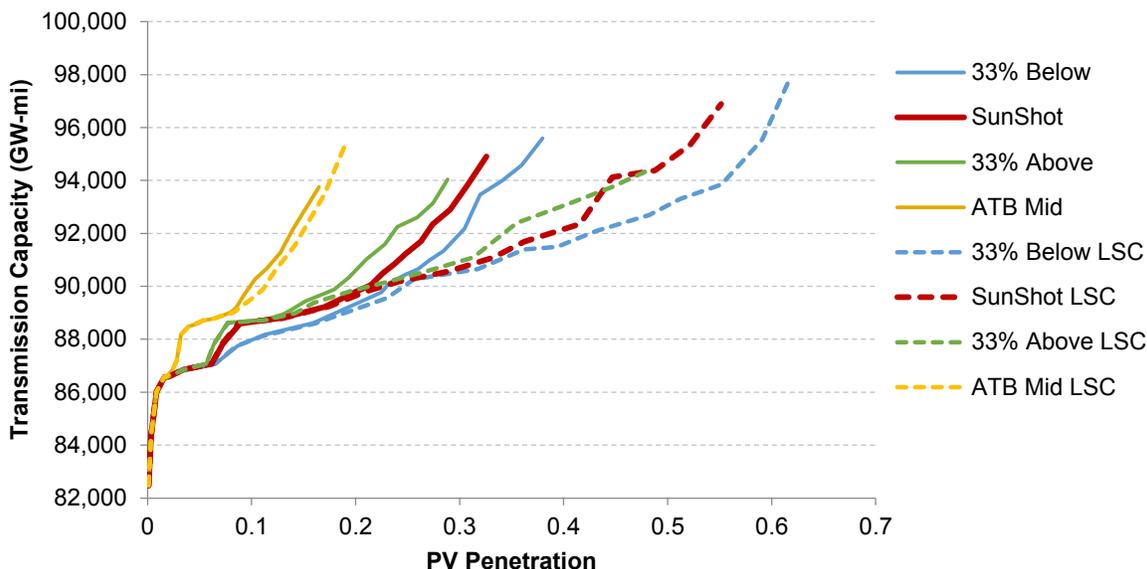


Figure 28. Transmission builds as a function of PV penetration (fraction of generation supplied by PV) for PV cost scenarios with and without low storage costs

²⁵ In this section, transmission capacity refers to high-voltage bulk power system transmission. It does not include the spur lines built to connect remote sites to the high-voltage transmission system or any distribution-level transmission.

²⁶ The rapid increases in transmission capacity at very low PV penetration levels are primarily spurred by near-term wind growth driven by the production tax credit.

3.5 Electricity Prices and System Costs

The impact of PV and storage cost assumptions on modeled cost-of-service electricity prices is shown in Figure 29. In 2030, lower cost PV leads to decreases in electricity prices of 1.4%–2.5% relative to their respective ATB Mid scenarios.²⁷ By 2050, the electricity prices are again slightly lower (1.1%–2.0%) in the 33% Below, SunShot, and 33% Above scenarios than they are in the ATB Mid scenario. Adding low-cost storage, however, leads to substantial reductions in electricity prices. For example, in 2050, the SunShot scenario’s electricity price is 1.8% lower than the ATB Mid scenario’s price, and the SunShot LSC scenario’s price is 9.8% lower than the ATB Mid LSC scenario’s price. This electricity savings translates into a residential consumer bill savings of \$2/month per household (savings for SunShot over ATB Mid) and \$13/month per household (savings for SunShot LSC over ATB Mid).

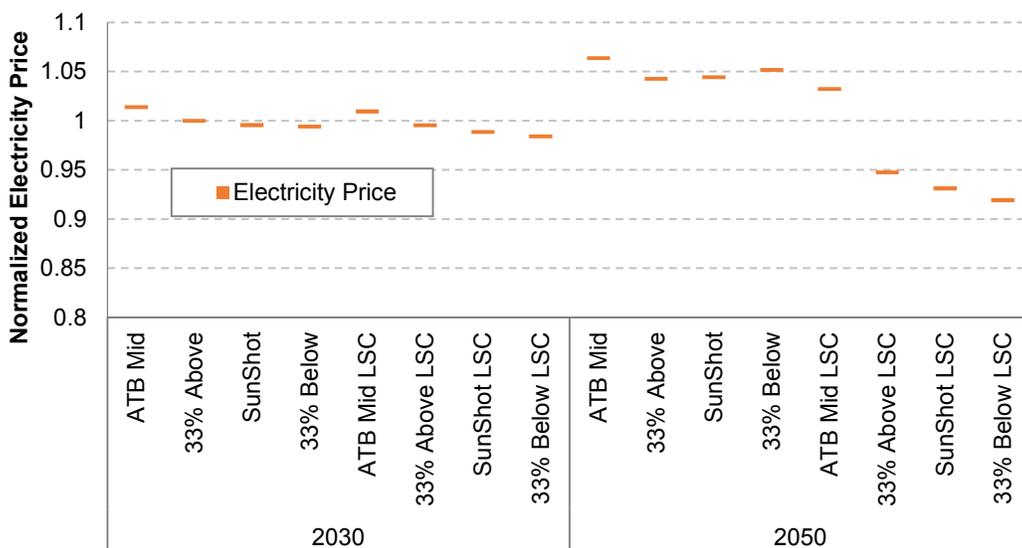


Figure 29. Normalized national average retail electricity prices for PV cost scenarios with and without low storage costs²⁸

The present value of total system costs²⁹ from 2016 to 2050 is shown in Figure 30. The lower PV cost scenarios reduce total system costs primarily by reducing conventional fuel and O&M costs. The low-cost storage scenarios provide further cost reductions by reducing conventional capital costs. Storage increases PV generation (which has no fuel cost and little O&M cost) and reduces the need for peaking units; this dual use of storage creates a cost-efficient system. For example, the SunShot scenario’s system cost is \$194 billion lower than the ATB Mid scenario’s system cost, and the SunShot LSC scenario’s system cost is \$310 billion less than the ATB Mid LSC scenario’s system cost.

²⁷ ReEDS only captures costs associated with the build-out of the bulk power system when calculating an electricity price. It assumes that other costs such as distribution system costs and billing costs remain at historical levels.

²⁸ The electricity prices have been normalized to their 2016 values such that a value of 1.1 means the value is 1.1 times the 2016 value.

²⁹ Total system costs include all utility-scale investments made by the ReEDS model to construct and operate power plants and long-distance transmission. For details, see Eureka et al. (2016).

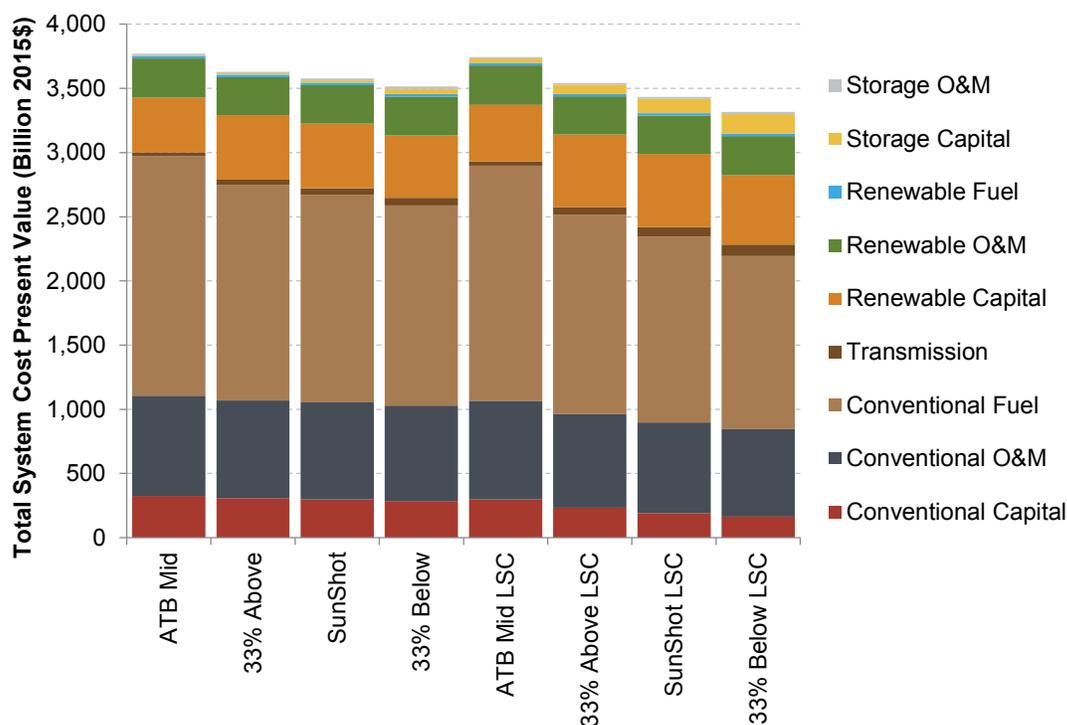


Figure 30. Total present value of system costs from 2016 to 2050 for PV cost scenarios

3.6 CO₂ Emissions

The impact of PV and storage cost assumptions on total nationwide CO₂ emissions is shown in Figure 31 for the PV cost scenarios.³⁰ The three ATB Mid scenarios demonstrate the baseline for current expectations of electric-sector emissions over time. In the ATB Mid cases without the CPP, emissions rise in the 2020s and 2030s as natural gas prices increase slightly, nuclear plants retire, and demand grows, which leads to more dispatch of existing coal generators as well as additional natural gas generation. In the ATB Mid CPP scenario, the CPP in effect imposes a ceiling on electric-sector CO₂ emissions resulting in the flat emissions trajectory that is somewhat higher than the emissions in the SunShot scenario, while the SunShot LSC scenario's emissions are lower than emissions in both of those scenarios and continue to decline in the 2030s. Compared with 2005 levels, 2050 emissions are 44% lower in the SunShot scenario and 60% lower in the SunShot LSC scenario. Emissions in the 33% Below and 33% Below LSC scenarios are lower than emissions in the ATB Mid CPP scenario, with the 33% Below LSC scenario achieving a 68% reduction in 2050 CO₂ emissions relative to 2005 levels.

³⁰ The CPP is only included in the ATB Mid CPP scenario. None of the other scenarios represents implementation of the CPP.

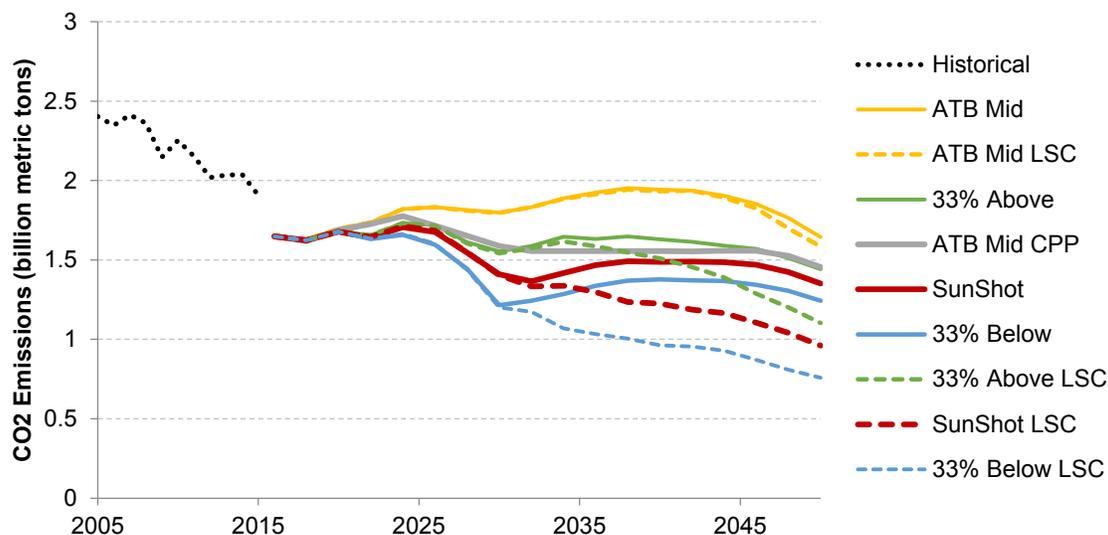


Figure 31. Nationwide electric-sector CO₂ emissions for PV cost scenarios with and without low storage costs

3.7 Water Withdrawal and Consumption

ReEDS models electric-sector water withdrawal (water removed for cooling but then returned at a higher temperature) and consumption (water for cooling that is lost via evaporation). Operation of nearly all natural gas combined-cycle plants, coal plants, and nuclear plants requires some water withdrawal and consumption—whereas PV technologies require little or no water during operation. Because generation from conventional technologies is offset by additional PV deployment in our low-cost PV scenarios, these scenarios use less water than the ATB Mid scenarios (Figure 32). For example, relative to the ATB Mid scenario, the SunShot scenario reduces cumulative water withdrawals by 11% and consumption by 13%. Relative to the ATB Mid LSC scenario, the SunShot LSC scenario reduces cumulative water withdrawals by 13% and consumption by 19%.

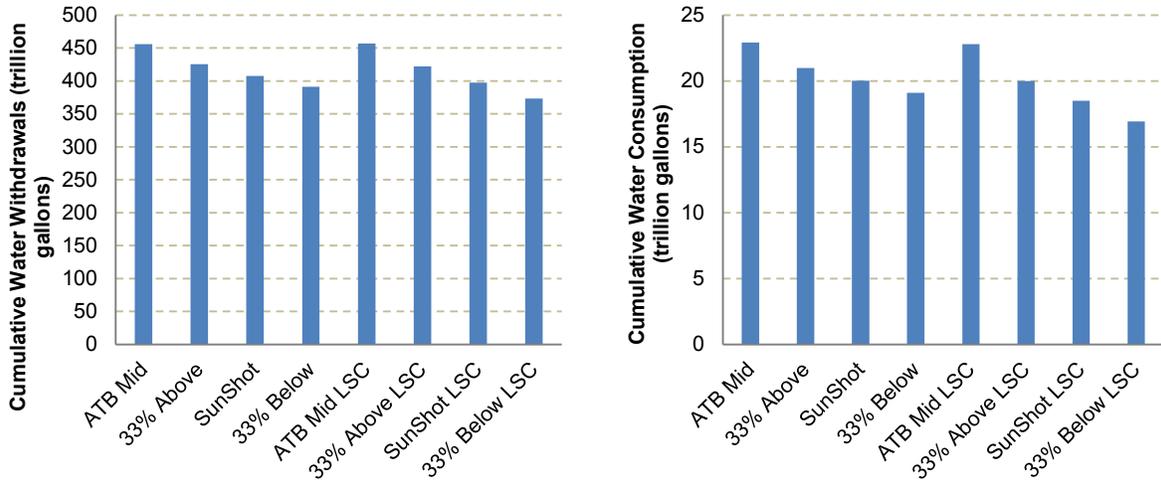


Figure 32. Cumulative electric-sector water withdrawals (left) and consumption (right), 2016–2050

4 Summary and Key Findings

In this report, we project the impacts of achieving the SunShot LCOE targets of \$0.03/kWh for utility-scale PV, \$0.04/kWh for commercial PV, and \$0.05/kWh for residential PV by 2030. We also project the impacts of achieving the SunShot PV cost targets in conjunction with low-cost energy storage—in our SunShot LSC scenario. Here we summarize the impacts of those SunShot scenarios compared with the impacts under the baseline ATB Mid scenario, which represents potential future conditions with more modest PV cost and reductions as well as reference-case storage cost assumptions.

- *PV deployment increases two- to threefold.* Achieving the SunShot PV cost targets could result in 405 GW of PV capacity in 2030, which would provide 17% of contiguous U.S. electricity generation. In 2050, deployment could rise to 971 GW, which would provide 33% of generation. With the addition of low-cost storage (i.e., by achieving the SunShot LSC scenario), 1,618 GW of PV capacity could be deployed by 2050, which would provide 55% of generation. In comparison, the ATB Mid scenario deploys only 127 GW of PV in 2030 (5% of generation) and 470 GW in 2050 (17% of generation).
- *Electricity prices and electric-system costs decline.* In 2030, retail electricity prices are projected to be approximately 2% lower in the SunShot and SunShot LSC scenarios than they are in the ATB Mid scenario. By 2050, SunShot electricity prices are projected to be 1.8% lower, while SunShot LSC prices are projected to be 12% lower. This translates to residential consumer bill savings of \$2/month per household (SunShot) and \$13/month per household (SunShot LSC). Total system costs are also projected to decline relative to the ATB Mid scenario; the SunShot scenario is projected to save (in net present value) \$194 billion through 2050 (5.1% lower than ATB Mid), while the SunShot LSC scenario is projected to save (in net present value) \$338 billion through 2050 (9.0% lower than ATB Mid).
- *Water withdrawals and consumption are reduced.* Because PV uses far less water than the conventional generators it displaces, the SunShot scenario is projected to reduce cumulative water withdrawals by 11% and consumption by 13% through 2050 compared with the ATB Mid scenario. Adding low-cost storage could produce even greater benefits, potentially reducing water withdrawals by 13% and consumption by 19% through 2050.
- *Emissions of CO₂ continue to decline.* Under the SunShot scenario, CO₂ emissions are projected to be 22% lower in 2030 and 18% lower in 2050 than they are with the ATB Mid scenario. With the addition of low-cost storage, CO₂ emissions are projected to be 22% lower in 2030 and 42% lower in 2050 than they are with the ATB Mid scenario.
- *Little additional transmission is required.* In general, the greater the amount of PV deployed, the more transmission is needed to transmit electricity from PV plants to demand centers. However, this is in part mitigated by the abundance of PV energy close to load centers. In the ATB Mid scenario, transmission capacity is projected to increase by 2.5% in 2030 and 8.3% in 2050 relative to 2016, while the SunShot scenario transmission capacity is projected to increase by 3.0% in 2030 and 9.6% in 2050. The SunShot LSC scenario requires a slightly reduced level of transmission build-out, with transmission capacity projected to increase by 3.1% in 2030 and 11.9% in 2050. These

levels of transmission build-out are the same or lower than historical transmission build-out rates.

- *Energy storage capacity increases when low-cost storage is available.* The projected storage capacity installed in 2050 in the SunShot LSC scenario is roughly 6 times greater than in the SunShot scenario and 11 times greater than in the ATB Mid scenario. This dramatic increase in projected storage deployment indicates the high value of low-cost flexibility in a low-cost PV future.
- *Curtailment rates rise without low-cost storage, and storage losses rise with low-cost storage.* In general, more PV leads to more curtailment, although low-cost storage mitigates this effect. In 2030, the curtailment rates are 2.8% in the SunShot scenario and 2.1% in the SunShot LSC scenario. In 2050, the spread is similar: 3.7% in the SunShot scenario and 2.9% in the SunShot LSC scenario. These results compare with curtailment rates of 1.2% in 2030 and 0.7% in 2050 under the ATB Mid scenario. However, storage systems incur losses during their charge and discharge cycles. In the SunShot LSC scenario, losses due to storage are nearly the same as the losses from curtailment.

We analyze the sensitivity of the SunShot and SunShot LSC scenarios to various market assumptions, including lower and higher electricity demand growth, lower and higher natural gas prices, accelerated and extended conventional generator lifetimes, and lower and higher non-PV renewable energy technology costs. We also consider scenarios where we include cost penalties for rapid growth in PV deployment. These analyses provide a range of plausible projections for PV deployment when the SunShot 2030 LCOE goals are achieved. PV deployment in 2030 ranges from 307 GW (13% of electricity supplied by PV) to 435 GW (18%), and deployment in 2050 ranges from 850 GW (28%) to 1,923 GW (64%). The availability of low-cost storage has the largest impact on projected SunShot deployment; it is followed by natural gas prices and electricity demand.

We also compare the impacts of the SunShot and SunShot LSC scenarios with the impacts of six other scenarios that vary PV costs up and down from the SunShot 2030 LCOE goals. Two scenarios—one with reference storage costs and one with low storage costs—assume PV LCOEs are 33% below the SunShot target in 2030 (i.e., utility-scale PV LCOE is 2 ¢/kWh in 2030). A similar pair of scenarios assumes PV LCOEs are 33% above the SunShot target in 2030 (i.e., utility PV LCOE is 4 ¢/kWh in 2030). We also include additional ATB mid-case scenarios: one with low storage costs and another that includes the U.S. Environmental Protection Agency’s Clean Power Plan. Across all these scenarios, PV deployment ranges from 127 GW to 545 GW (5%–23% of demand met by PV) in 2030, and it ranges from 470 GW to 1,875 GW (17%–62%) in 2050. The scenario results are grouped relatively tightly in 2030, but by 2050 the 33% Below SunShot scenario with low-cost storage deploys the most PV, and the ATB Mid scenario deploys the least.

Utility-scale PV accounts for most of the PV deployment in our scenarios. However, the actual mix of utility-scale and distributed PV deployed likely will be influenced significantly by the evolution of policies and rate structures that impact distributed PV systems. We do not analyze this topic in detail, and it merits further exploration.

Overall, continued analysis is needed to better understand and quantify the impacts of a high-PV, and potentially high-storage future in which the electricity generation system operates in a fundamentally different manner than today's system. Specific areas for future work include the following:

- **Impacts on the Distribution Grid.** We do not represent any of the costs or benefits of integrating large amounts of PV with distributions systems. Those costs and benefits are location specific and will depend on how the distribution network and PV systems evolve.
- **Utility Business Models.** As PV penetration increases, the value of energy and capacity during different parts of the day will shift. That shift might put pressure on some existing rate structures and utility business models, including DPV valuation (e.g., net metering). This work does not represent changes to rate structures (e.g., shifting to time-of-use rates) or changes to current net metering policies.
- **Impacts on Electricity Consumption.** As PV penetration increases, the number of hours that have zero or negative marginal costs for electricity are likely to increase. Electricity consumer might change behavior (e.g., charge an electric vehicle during the afternoon rather than overnight) or otherwise create opportunities (e.g., hydrogen electrolyzers, economy-wide electrification) to use this low-cost energy, which could in turn have an impact on load shapes and total electricity demand. Additionally, low-cost energy storage would reduce the cost of electric vehicles, which could in turn increase their adoption and drive up overall electricity consumption.
- **Grid-Integration Challenges.** The PV penetration levels envisioned in this work far exceed current penetration levels. The higher penetration likely would require changes in utility and grid operator practices and techniques (e.g., improved PV forecasting, increased system cooperation, and more frequent dispatch periods).
- **Land-Use Requirements and Impacts.** ReEDS and dGen screen out land areas and rooftops that are unsuitable or are otherwise unavailable for PV deployment (e.g., national parks), but detailed land-use impacts go far beyond this initial screening.
- **Supply Chain Impacts.** Our scenarios see high levels of PV deployment relative to today's levels. PV supply chains would need to be scaled to accommodate that growth, and that scaling is not considered in this work beyond simple growth penalties included in the model.
- **Job Impacts.** The evolution of the electricity sector described in this work would increase job opportunities in PV while impacting job opportunities across the other electricity-generating sectors.
- **The Role of CSP.** This work focuses only on a future in which PV reaches \$0.03/kWh but does not consider additional possible reductions in the cost of CSP beyond the original SunShot 2020 targets. Future work that specifically considers the potential role of CSP is forthcoming.

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Appendix A: Scenario Inputs

This analysis considers the U.S. power sector deployment and generation trends projected through 2050 based on a variety of economic, technology, and policy assumptions across 25 scenarios. The factors varied in these scenarios include PV costs, battery costs, electricity demand growth, natural gas prices, conventional generator retirements, renewable energy technology costs, and the inclusion of the Environmental Protection Agency's Clean Power Plan (EPA 2015). Table 6 summarizes the 25 scenarios, grouped into four scenario sets:

- SunShot scenarios
- SunShot—Low Storage Cost scenarios
- PV price sensitivity scenarios
- Baseline scenarios.

These scenarios are designed provide not just a single projection achieving the SunShot 2030 goal but a range of projections based on a variety of uncertainties around major assumptions that shape the evolution of the power sector. The PV price sensitivity scenarios are included to demonstrate the relative impacts of under or over achieving on the SunShot 2030 goal. The baseline scenarios are included as a benchmark for demonstrating the level of change from current reference-case-like scenarios.

Table 6. Scenarios Used in the Study. Scenarios are generally centered on the SunShot scenario (i.e., the SunShot 2030 goal). Bold values are the reference values. Any blank cells use the reference value from the SunShot scenario. Additional scenario details are provided in Appendix A.

NG = natural gas, RE = renewable energy, and CPP = Clean Power Plan.

Scenario Name	2030 PV Cost ^a	Battery Cost	Electricity	NG Price	Retirements	RE Costs	CPP
SunShot	3¢	Ref	Ref	Ref	Ref	Ref	None
Low Demand			Low				
High Demand			High				
Low NG Price				Low			
High NG Price				High			
Low Retire					Low		
High Retire					High		
Low RE Cost						Low	
High RE Cost						High	
W/ Growth Penalty							
SunShot – Low Storage Cost		Low					
Low Demand – Low Storage Cost		Low	Low				
High Demand – Low Storage Cost		Low	High				
Low NG Price – Low Storage Cost		Low		Low			
High NG Price – Low Storage Cost		Low		High			
Low Retire – Low Storage Cost		Low			Low		
High Retire – Low Storage Cost		Low			High		
Low RE Cost – Low Storage Cost		Low				Low	
High RE Cost – Low Storage Cost		Low				High	
W/ Growth Penalty – Low Storage Cost							
2 Cents	2¢						

Scenario Name	2030 PV Cost ^a	Battery Cost	Electricity	NG Price	Retirements	RE Costs	CPP
SunShot	3¢	Ref	Ref	Ref	Ref	Ref	None
4 Cents	4¢						
2 Cents – Low Storage Cost	2¢	Low					
4 Cents – Low Storage Cost	4¢	Low					
ATB Mid	ATB Mid						
ATB Mid CPP	ATB Mid						National
ATB Mid – Low Storage Cost	ATB Mid	Low					

^a PV cost is shown as an levelized cost of energy in cents/kWh or as the Annual Technology Baseline (ATB) mid-case projection (NREL 2016)

Because ReEDS and dGen use system costs instead of LCOE for their economic calculations, the 2030 target LCOE values were converted to overnight capital costs using the 2016 Annual Technology Baseline (ATB) spreadsheet (NREL 2016). The financing assumptions in ReEDS were left at the default values to ensure consistency across the technologies.³¹ The resulting capital cost trajectories are shown in Figure 33 through Figure 35. The 2015 cost value is taken from the 2016 Annual Technology Baseline, and the 2020 cost value is the original SunShot 2020 target (DOE 2012). Values between the 2015 and 2020 years and between the 2020 and 2030 years are linear interpolations. These trajectories represent the LCOE targets being reached primarily through capital cost reductions; however, these targets could instead be achieved through various combinations of technology cost reduction and/or more favorable financing terms (discussed below). Additional parameters—including fixed operations and maintenance costs, variable operations and maintenance costs, degradation rates, and physical lifetimes—are summarized in Table 7 for utility-scale PV in 2020 and 2030. These values are also ramped linearly between 2020 and 2030 for the SunShot scenarios.

³¹ The financial calculations used were 8% interest rate (nominal), 13% rate of return on equity, 60% debt fraction for UPV, 80% debt fraction for DPV, 40% tax rate, and a five-year depreciation period. These values result in a weighted-average cost of capital (WACC) of 8.1% nominal. More favorable financing costs (e.g., longer system life and lower cost of capital) would result in higher system costs than those shown in Figure 33, but they would result in the same model outputs. See

Table 9 and Table 10 for details.

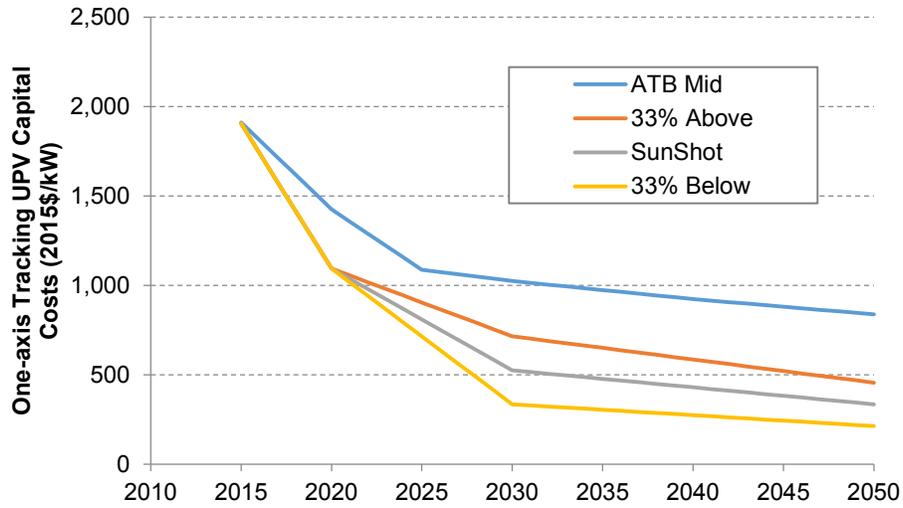


Figure 33. Utility-scale PV capital cost assumptions

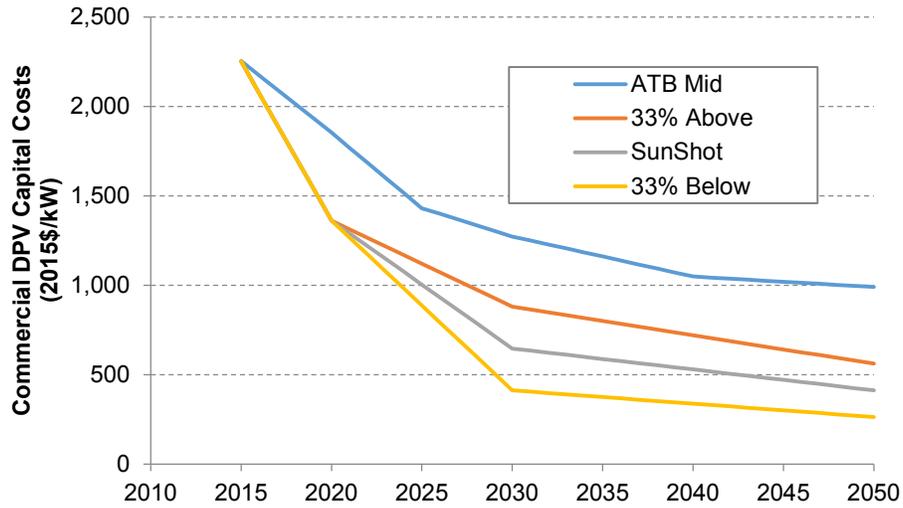


Figure 34. Commercial DPV capital cost assumptions

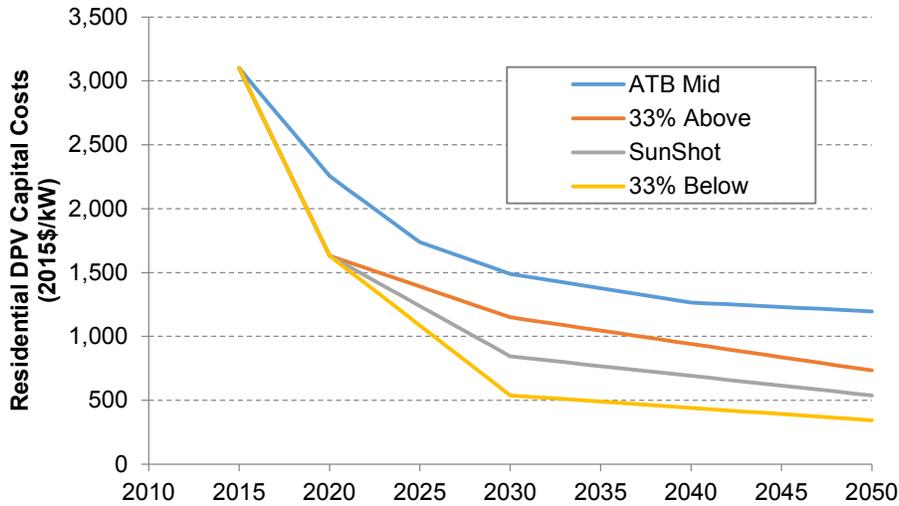


Figure 35. Residential DPV capital cost assumptions

Table 7. Utility-Scale PV Operational Costs (2015\$), Performance, and Lifetime Parameters in 2020, 2030, and 2050

	2020	2030	2050
Fixed O&M (\$/kW-yr)			
ATB Mid	12.1	8.1	8.1
Two, Three, and Four Cents	7.7	4.4	4.4
Variable O&M (\$/MWh)	0	0	0
Degradation Rate			
ATB Mid	0.5%/year	0.5%/year	0.5%/year
Two, Three, and Four Cents	0.5%/year	0.2%/year	0.2%/year
Lifetime	30 years	30 years	30 years

Table 8. DPV Operational Costs (2015\$), Degradation, and Lifetime Parameters in 2020, 2030, and 2050

	2020	2030	2050
Residential Fixed O&M (\$/kW-yr)			
ATB Mid	14.0	10.0	10.0
Two, Three, and Four Cents	10.9	7.0	7.0
Commercial Fixed O&M (\$/kW-yr)			
ATB Mid	11.0	8.0	8.0
Two, Three, and Four Cents	8.2	5.0	5.0
Variable O&M (\$/MWh)	0	0	0
Degradation Rate	0.5%/year	0.5%/year	0.5%/year
Lifetime	25 years	25 years	25 years

Although the scenarios defined here use capital cost reductions as the primary metric to achieve the SunShot LCOE targets, the SunShot targets could be achieved through multiple paths, including declining technology costs and/or more favorable financing assumptions.

Table 9 shows four different sets of capital cost and financing assumptions, which each result in a levelized cost of energy (LCOE) that achieves the \$0.03/kWh (\$30/MWh) utility-scale PV 2030 SunShot goal. For example, in the first row, which reflects the SunShot scenario, the \$0.03/kWh LCOE target is reached primarily through capital cost reductions. Conversely, the second row assumes a higher capital cost but is able to reach the same LCOE goal by instead increasing the economic lifetime of PV plants. A third possible path to the same SunShot goal yields a higher capital cost by using a lower weighted average cost of capital (WACC). Finally, the last row demonstrates the combined effect of multiple favorable financing assumptions; with both a longer economic lifetime and lower WACC, PV capital costs can be much larger than in the previous cases while still achieving the SunShot 2030 goal.

Additional combinations of capital cost and financing assumptions are also possible, but these examples merely demonstrate the wide range of possible paths to the SunShot 2030 goal. These capital cost and financing parameters and associated cumulative LCOE values were calculated using the 2016 ATB spreadsheet (NREL 2016). Table 10 demonstrates a similar effect for residential and commercial PV systems. Discussion of other pathways that can lead to low-cost PV systems is included in Appendix D.

Table 9. Example of Financing Assumptions to Reach the Utility-Scale PV SunShot 2030 Target

	Capital Cost and Financing Assumptions	Levelized Cost of Energy (\$/MWh)
Default scenario	Capital Cost = \$525/kW Economic lifetime ³² = 20 years WACC (Nominal) = 8.1%	\$30/MWh
Longer economic lifetime	Capital Cost = \$746/kW Economic lifetime = 50 years WACC (Nominal) = 8.1%	\$30/MWh
Lower WACC	Capital Cost = \$656/kW Economic lifetime = 20 years WACC (Nominal) = 5.8%	\$30/MWh
Longer economic lifetime and lower WACC	Capital Cost = \$928/kW Economic lifetime = 50 years WACC (Nominal) = 5.8%	\$30/MWh

Table 10. Example of Financing Assumptions to Reach the Residential and Commercial PV SunShot 2030 Target³³

	Financing Assumptions	Capital Cost
SunShot scenario	Economic lifetime = 30 years Discount rate (nominal) = 8.1%	\$646/kW = 4 ¢/kWh \$884/kW = 5 ¢/kWh
Loan-financed	Economic lifetime = 30 years Discount rate (nominal) = 8.1% Loan with 20% down payment Interest rate = discount rate	\$1,032/kW = 4 ¢/kWh \$1,310/kW = 5 ¢/kWh
Loan-financed with lower interest rate	Economic lifetime = 30 years Discount rate (nominal) = 8.1% Loan with 20% down payment Interest rate (nominal) = 5%	\$1,205/kW = 4 ¢/kWh \$1,529/kW = 5 ¢/kWh
All-cash payment	Economic lifetime = 30 years Discount rate (nominal) = 8.1%	\$800/kW = 4 ¢/kWh \$1,015/kW = 5 ¢/kWh

³² Economic lifetime is different than physical lifetime. Economic lifetime only considers the period over which the investment is to be recouped. Physical lifetimes of PV systems is much longer than the 20-year economic lifetime considered under the default financing assumptions.

³³ Because of differences in tax rates and incentives (e.g., depreciation and tax write-offs), the capital costs were calculated assuming a commercially financed system (e.g., third-party ownership for residential homes). Other variations in the financing structure would lead to different capital costs.

The reference and low-cost storage projections are taken as the mid-case and low-case storage cost projection from Cole, Marcy, et al. (2016). The projections for behind-the-meter systems use the same ratio of declines as the utility-scale systems but have different starting costs. The commercial capital costs were estimated as part of an ongoing project (McLaren et al. 2016), while the residential capital costs were adapted from Ardani et al. (2016). The utility-scale projections are shown in Figure 36 for an eight-hour duration battery storage system, and the behind-the-meter projections are shown in Figure 37 and Figure 38 for three-hour duration systems.

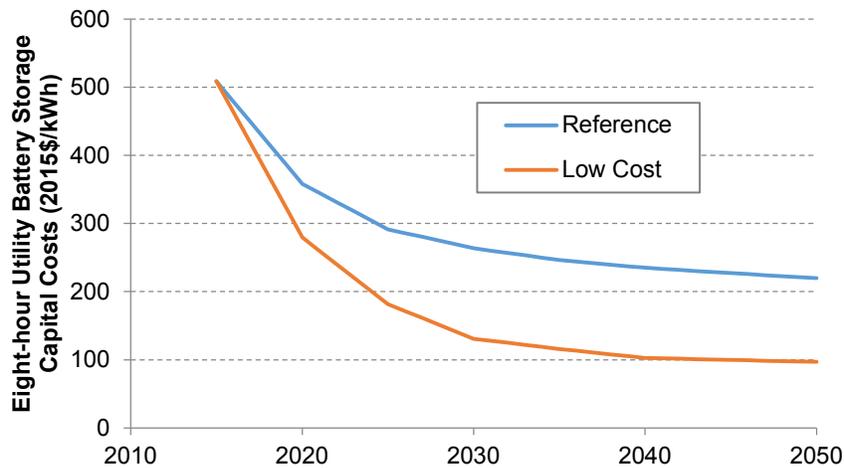


Figure 36. Capital cost projections for utility-scale battery storage systems

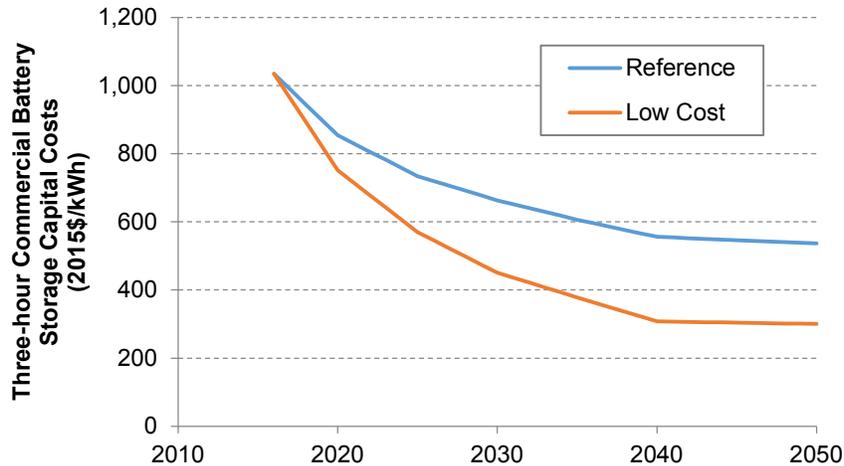


Figure 37. Capital cost projections for commercial behind-the-meter battery storage systems

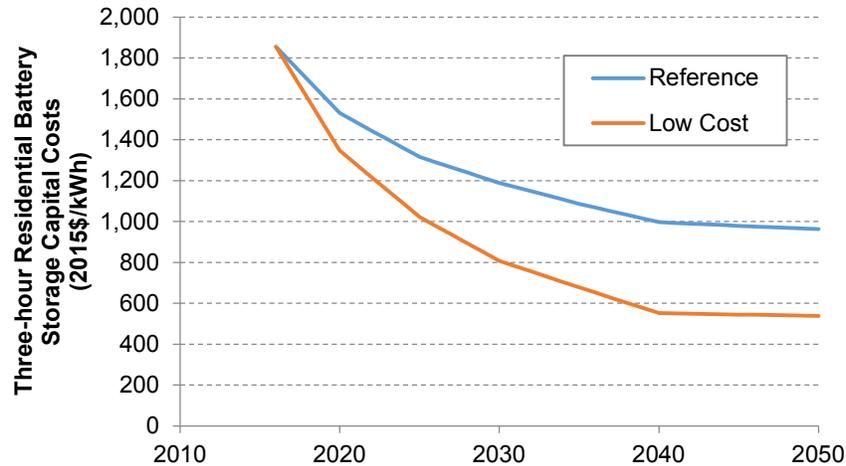


Figure 38. Capital cost projections for residential behind-the-meter battery systems

The battery systems are generic battery storage systems, but the projections by Cole, Marcy, et al. (2016) were generally based on lithium-ion systems. The round-trip efficiency is assumed to be 90% with a 15-year lifetime at ~1 cycle per day. Additional cost details such as operations and maintenance cost projections are in Cole, Marcy, et al. (2016).

All other system costs not mentioned here are taken from the 2016 ATB mid-case projection (NREL 2016) with the exception of concentrating solar power (CSP) costs, which are assumed to achieve the SunShot 2020 target in 2020 and remain constant thereafter (DOE 2012).³⁴

Electricity demand, natural gas prices, renewable energy cost trajectories, and retirement schedules are described below. The Clean Power Plan (CPP) is applied only in one scenario in order to provide a baseline both with and without the CPP present.³⁵ As is seen in the results section, several of the scenarios have emission levels below the modeled limit such that if the CPP were included in the scenarios the modeled results would not change.

Aside from the CPP, all other state and federal regulations and policies are implemented according to current law as of June 1, 2016. Especially relevant to this work are the investment tax credit with its scheduled step-down, net metering policies, and state renewable portfolio standards. For details about the policies represented in the models and the methods used to represent them, see the models' documentation (Eurek et al. 2016; Benjamin Sigrin et al. 2016).

³⁴ Updated CSP targets were not announced with the SunShot 2030 targets for PV.

³⁵ The CPP is implemented in the model as a mass-based policy with new source compliments and unrestricted national allowance trading. Other implementations will result in different outcomes from those included in this work.

Fossil Fuel Prices

The natural gas input price points are based on the trajectories from the AEO 2016 (EIA 2016). The prices are shown in Figure 39 and are from the AEO 2016 Reference scenario, the Low Oil and Gas Resource and Technology scenario, and the High Oil and Gas Resource and Technology scenarios (EIA 2016). Actual natural gas prices in ReEDS are based on the AEO scenarios, but they are not exactly the same; instead, they are price-responsive to ReEDS natural gas demand. Each census region includes a natural gas supply curve that adjusts the natural gas input price based on both regional and national demand (Cole, Medlock III, and Jani 2016).

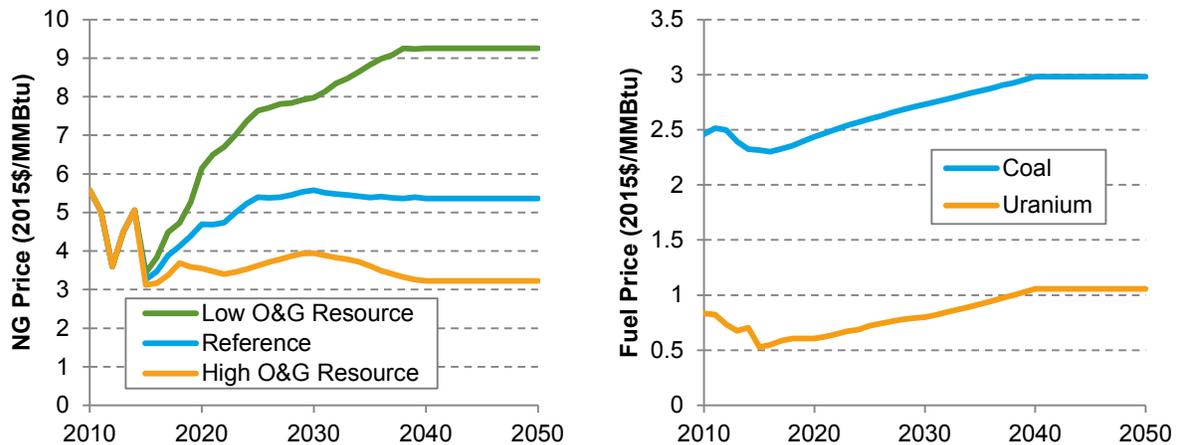


Figure 39. Fuel price trajectories used in the scenarios

The reference coal and uranium price trajectories are from AEO 2016 Reference scenario and are shown in Figure 39. Both coal and uranium prices are assumed to be fully inelastic. Because AEO 2016 fuel prices are only projected through 2040, fuel prices from 2040 to 2050 are held constant at the 2040 values.

Demand Growth

The Mid-case Scenario is based on the AEO 2016 Reference scenario load growth. The high and low load growth scenarios are also from AEO 2016 based on the Low and High Economic Growth scenarios, which use lower/higher rates of population growth, productivity, and lower/higher inflation than the Reference scenario (see Figure 40). For the years after the AEO 2016 horizon (which ends in 2040), we assume an annual growth rate equal to the average growth rate from 2030 to 2040.

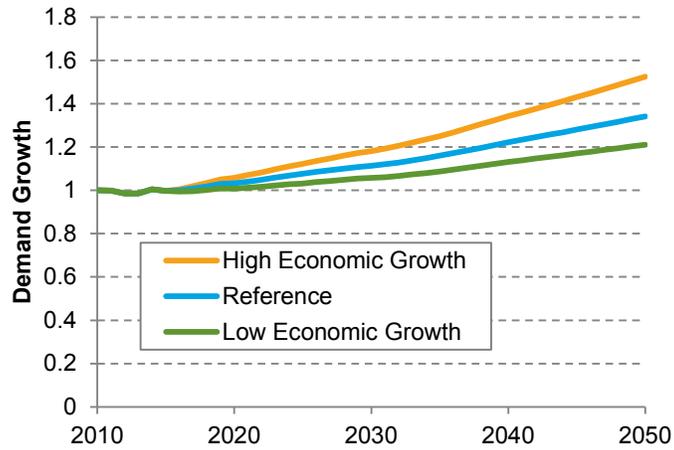


Figure 40. Demand growth trajectories used in the scenarios

Technology Cost and Performance

For non-PV technologies, cost and performance assumptions are taken from the 2016 ATB (NREL 2016). The ATB includes low, mid, and high cost and performance projections through 2050 for the generating technologies used in the ReEDS model. Technology LCOE ranges from the ATB are shown in Figure 41, Figure 42, and Figure 43 for 2015, 2030, and 2050 respectively. The mid-case LCOE projections from the ATB were used for all scenarios in this work except the Low RE Cost and High RE Cost scenarios, which used the ATB low and high projections respectively.

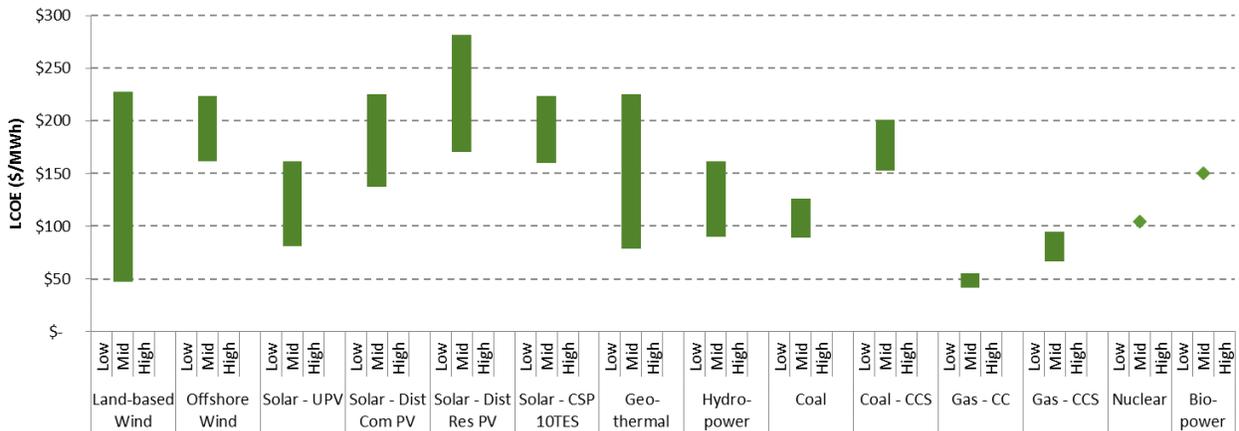


Figure 41. LCOE ranges from the 2016 ATB for 2015

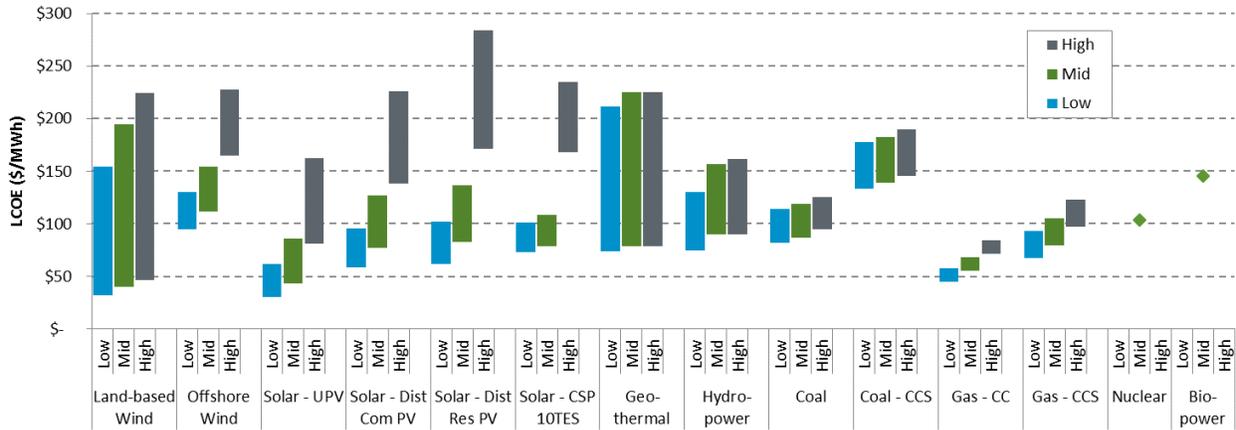


Figure 42. LCOE ranges from the 2016 ATB for 2030

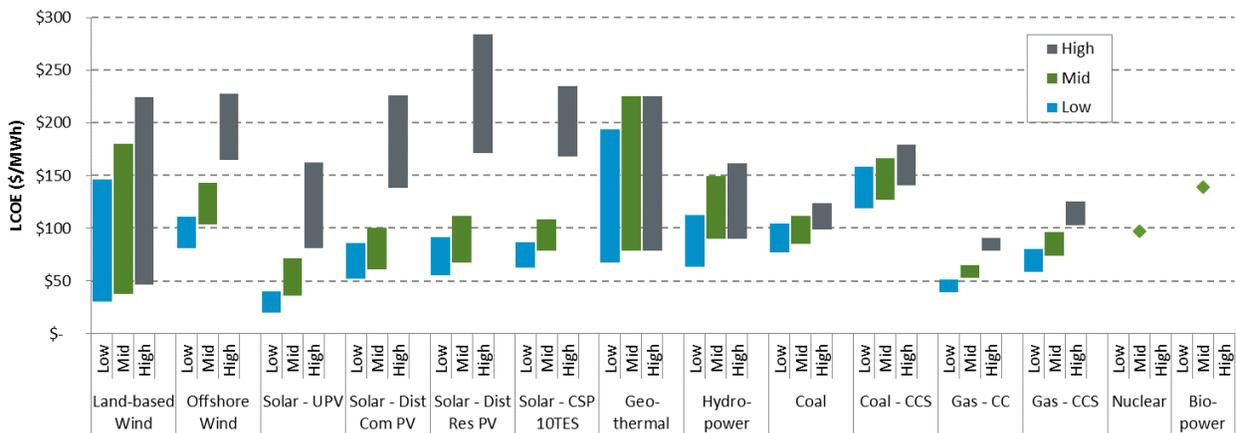


Figure 43. LCOE ranges from the 2016 ATB for 2050

Existing Fleet Retirements

Retirements for conventional power plants are taken from the ABB Velocity Suite database (ABB 2016a), which use age-based retirements unless an official retirement date has been announced. All other generator types use strictly age-based retirement schedules.

The Accelerated Coal Retirements scenario reduces coal plant lifetimes by 10 years. The Extended Nuclear Lifetime scenario assumes all nuclear plants (except those with an announced retirement date) receive a second relicense that gives them an 80-year life.

Utility PV Growth Penalty

The W/ Growth Penalty scenario includes a growth penalty for utility PV systems. It increases utility PV capital costs by 12% when annual deployment is more than 2 GW greater than the previous year and by 41% when annual deployment is more than 4 GW greater than the previous year. For example, if 10 GW of new utility PV capacity were added in 2020, 12 GW could be added in 2021 without penalty. The 2-GW limit was developed based on average annual increases in utility PV deployment from 2010 to 2016. The purpose of the growth penalty is

to represent limitations in rapidly scaling up the deployment. Distributed PV is not impacted by growth penalties.

Retail Rates and Net Metering

Retail rates for the dGen model are taken from the Utility Rate Data Base³⁶ and curated as of spring 2017. Retail rate structures are assumed not to change over time. For example, a residential customer who is currently on a flat retail rate will not be converted to a time-of-use tariff during the analysis period. However, the magnitude of the retail rates is adjusted according to the calculated electricity price from ReEDS. If ReEDS calculates that the electricity prices in a given region are 5% higher in 2030 than in 2016, the rates used in dGen to project PV adoption are increased by 5% in 2030. The electricity prices are passed from ReEDS to dGen at the census region level.³⁷

Net metering policies are represented as of spring 2017. Conditions that lead to the discontinuation of net metering are captured in dGen. For example, if a net metering policy phases out after DPV penetration reaches 3%, dGen will remove net metering once that penetration level is achieved.

³⁶ See en.openei.org/wiki/Utility_Rate_Database.

³⁷ See www.eia.gov/outlooks/aeo/pdf/fl.pdf for a map of the census regions.

Appendix B: Modeling Tools

For this analysis, we use electric sector models developed by the National Renewable Energy Laboratory (NREL). The primary modeling tool is the Regional Energy Deployment System (ReEDS) capacity expansion model of the contiguous United States that relies on system-wide least-cost optimization to estimate the type and location of future generation and transmission capacity. Because ReEDS does not explicitly model distributed generation, we also use the Distributed Generation (dGen) model,³⁸ a consumer adoption model for the U.S. rooftop, distributed PV (DPV) market. dGen projects the future adoption of DPV and battery storage in the industrial, commercial, and residential sectors. This joint modeling approach captures the dynamic balances between growth in electricity consumption, plant retirements, competing generation options, policies, and the projected deployment and operation of behind-the-meter technologies—all of which affect the demand for new PV and storage resources. These modeling tools have been used for a wide variety of power sector analyses, especially those that require additional detailed representation of renewable energy, including the original SunShot Vision Study (DOE 2012), the Wind Vision Study (DOE 2015b), and policy valuations and impacts (Cole et al. 2015; Mai, Cole, et al. 2016; Mai, Wiser, et al. 2016).³⁹

ReEDS

ReEDS is an electricity system capacity expansion model that simulates the construction and operation of generation and transmission capacity across the contiguous United States from present day⁴⁰ to 2050. We provide a brief overview here of the features most relevant to this study, but we refer the reader to the *2016 ReEDS Documentation* (Eurek et al. 2016) and the *2016 Standard Scenarios* report (Cole, Mai, et al. 2016) for detailed descriptions of the model's formulation and inputs. We use the ReEDS model 2016 version from these documents, with some variations, which we discuss at the end of this section.

ReEDS calculates the competing costs of differing energy supply options and selects the regional mix of technologies that meet physical and policy requirements of the electric sector at least cost. Model results are based on total system costs, which account for the type and location of fossil, nuclear, renewable, and storage resource development; the transmission infrastructure expansion requirements of those installations; and the generator dispatch and fuel needed to satisfy regional electricity consumption requirements and maintain grid system adequacy. The ReEDS model also considers technology, resource, and policy considerations such as state renewable portfolio standards (RPS). It also has the option of including the U.S. Environmental Protection Agency's Clean Power Plan (EPA 2015).

The primary outputs from ReEDS include the amount, type, year, and location of generator capacity; annual generation from each technology; storage capacity expansion; and transmission capacity expansion needed to satisfy regional electricity consumption requirements and maintain

³⁸ The dGen model is a rewrite of the original PVDS model (Denholm, Margolis, and Drury 2009) used in the original *SunShot Vision Study*.

³⁹ More complete lists of publications using the ReEDS and dGen models can be found at www.nrel.gov/analysis/reeds/related_pubs.html and www.nrel.gov/analysis/dgen/related_pubs.html respectively

⁴⁰ ReEDS includes all existing and under-construction projects as of April 2016 in the ABB Velocity Suite database (ABB 2016).

grid system adequacy. The generation and storage technologies modeled in ReEDS include coal-fired (pulverized coal with and without scrubbers, biomass cofiring, integrated gasification combined cycle with and without carbon capture and storage), natural-gas-fired (combined cycle and combustion turbines), oil and gas steam, nuclear, wind (land-based and offshore), biopower, geothermal, hydropower, UPV, concentrating solar power with and without thermal energy storage, pumped-hydropower storage, compressed-air energy storage (CAES), and utility-scale batteries.

ReEDS represents the electric sector with high spatial resolution to enable comparative electricity sector cost evaluation based on local costs, regional pricing, and the relative value of geographically and temporally constrained renewable power sources. The model divides the contiguous United States into 134 “balancing area” regions, wherein electricity supply and consumption are balanced and planning reserves are enforced. ReEDS also characterizes the quality, variability, uncertainty, and geographic resource constraints of renewable resources across these 134 regions; some technologies are further characterized into more resolved sub-regions. These regions are also aggregated into 18 regional transmission organization (RTOs) that very roughly represent regional cooperation areas. See Figure 44 for a map of these 134 balancing area and 18 RTO modeling regions. In addition, long-distance transmission is represented as single-path connections between most adjacent or near-adjacent modeling balancing area regions, and ReEDS models both existing transmission lines as well as new transmission capacity on these inter-region lines. ReEDS also models the intra-region “spur line” transmission costs required to interconnect renewable capacity from their resource region to the transmission grid or load centers.

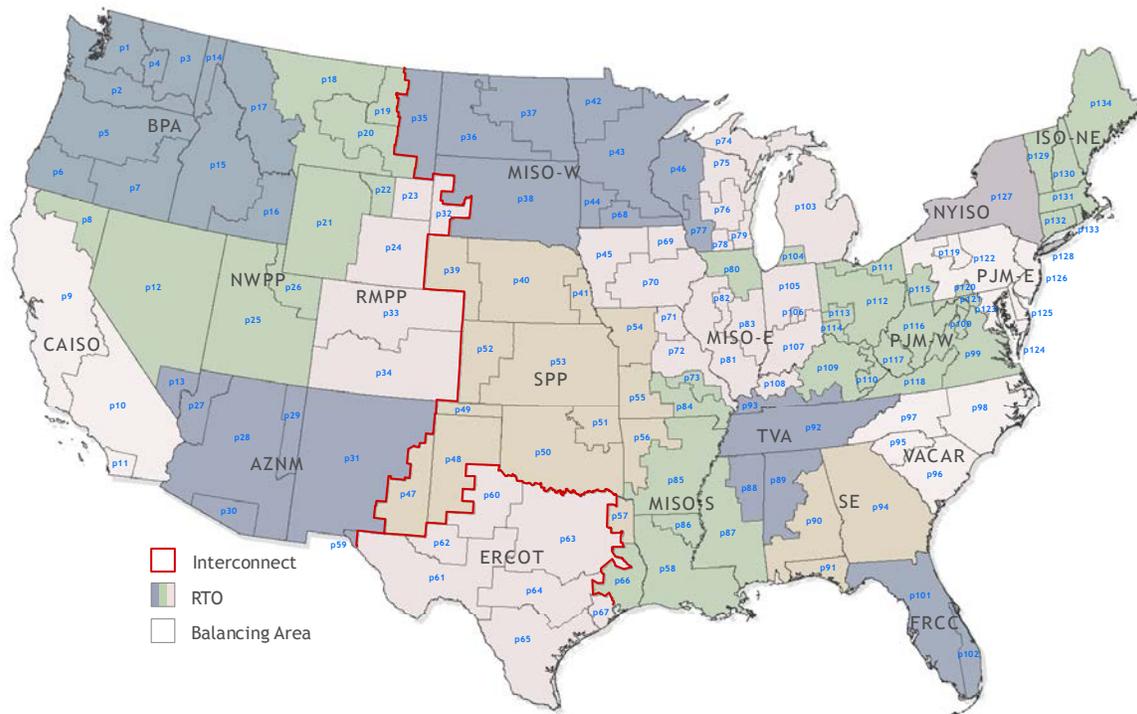


Figure 44. Map of ReEDS 134 “balancing area” regions and 18 “RTOs”

ReEDS is temporally resolved into 17 “timeslices” that each reflect a set of hours in each day within a season. For each two-year solution interval from 2010 to 2050, ReEDS dispatches all generation in each of these 17 timeslices to capture seasonal and diurnal electricity load and renewable generation profiles. ReEDS explicitly and dynamically estimates and considers the need for new inter-regional transmission (limited through 2020), increases in operating reserve requirements, and changing contributions to planning reserves that may be driven by increases in renewable generation. For this purpose, ReEDS includes statistical parameters, such as capacity value for planning reserve requirements, forecast error operating reserve requirements, and estimated curtailments.

A key difference in the ReEDS model version used in this study from that described in the 2016 ReEDS documentation (Eurek et al. 2016) is the method for calculating capacity value. ReEDS has historically used a statistical approach, which connects the underlying hourly (“8760”) load and resource data to the 17 timeslices through probability distributions, to estimate capacity value and curtailment metrics. In this study, we implement a new methodology that explicitly calculates the capacity value based on the load and variable generation (wind and PV) data for all 8,760 hours of the year. More specifically, these capacity value calculations utilize a capacity factor proxy that is applied to top hours in load and net load (load minus wind and PV) duration curves. A detailed description of this method is provided in Appendix E.

Other relevant modifications from the model version described in the 2016 ReEDS documentation and the 2016 Standard Scenarios report (Cole et al. 2016) include adjusted yearly PV growth penalties,⁴¹ updated DPV deployment projections from the dGen model, updated parameters for the ability of storage to recover curtailed energy, and the addition of residential battery storage profiles from the dGen model applied as exogenous load modifiers.

dGen

Because ReEDS does not natively project behind-the-meter energy system adoption, we use the dGen model to project the adoption of DPV and battery storage systems. We briefly describe the model here but refer the reader to the dGen model documentation (Sigrin et al. 2016) for a detailed description.

dGen is a customer adoption model that projects the adoption and operation of distributed energy technologies from the present day to 2050 for the residential, commercial, and industrial sectors of the contiguous United States. dGen projects the adoption of PV and batteries based on the “diffusion of innovations” framework, which posits that novel technologies “diffuse” into populations following a logistic pattern of early adopters, mass adoption, and late adopters. Rather than assuming all potential DPV customers are rational profit-maximizing agents who immediately adopt a profitable technology, the approach captures the diffusion of technologies through the population of potential customers based on the financial attractiveness of the investments.

⁴¹ The updated growth penalties allow utility PV to increase the deployment rate by 2 GW/year without penalty. Deployment rates above the additional 2 GW/year experience a 12% cost penalty. For example, if 10 GW of new utility PV were installed last year, 12 GW could be installed this year without penalty. Distributed PV is not impacted by growth penalties.

dGen generates thousands of statistically representative agents at the county-level to model potential adopter across the nation. Each agent has an assumed energy consumption profile, roof area, and other techno-economic attributes that are representative of the underlying population heterogeneity. DPV and battery finances are recalculated for each of the agents in each of the model's bi-annual solve years. Each agent will evaluate a discrete set of DPV and storage systems—either technology alone as well as various combinations of co-deployment—and consider adopting the system with the highest net present value.⁴² The storage systems are dispatched to minimize each customer's electric bill, with respect to the tariff to which they subscribe.

Model Caveats and Limitations

While ReEDS and dGen represent many aspects of the U.S. electricity system, like all models, they necessitate simplifications. We list some of the key limitations and caveats that result from these simplifications, highlighting those that are particularly relevant for the present analysis. This list is adapted from Eurek et al. (2016).

- **System-wide optimization**—ReEDS takes a system-wide least-cost perspective that does not necessarily reflect the perspective of individual decision makers, including specific investors, regional market participants, or corporate consumer choice of renewable power; nor does it model contractual obligations or non-economic decisions. In addition, like other optimization models, ReEDS finds the absolute least-cost solution that does not fully reflect real distributions and uncertainties in the parameters; however, the heterogeneity resulting from the high spatial resolution of ReEDS mitigates this to some degree.
- **Foresight and behavior**—Except for limited foresight of future natural gas prices, model decision-making does not account for anticipated changes to markets and policies. For example, anticipated tax credit expirations have historically led to acceleration of project development. By not including policy foresight and the associated behavior of specific plant developers, the models likely underestimate the year-to-year changes in renewable deployment coinciding with changes in tax credit values; however, the commenced-construction provision mitigates this tendency to some extent.
- **Project pipeline**—The model incorporates data of planned or under-construction projects, but these data likely do not include all projects in progress.
- **Manufacturing, supply chain, and siting**—The models do not explicitly simulate manufacturing, supply chain, or siting and permitting processes. Potential bottlenecks or delays in project development stages for new generation or transmission would not be fully reflected in the results.
- **Financing interactions**—Financial parameters used in the models reflect long-term historical averages as opposed to current or near-term market conditions. In addition, the models do not fully capture financing interactions with tax credits (Bolinger 2014); however, we do model changes in capital structure for utility-scale wind and PV caused

⁴² When agents evaluate systems, they are constrained by their own total consumption as well as the roof area available to them.

by changes in tax credits (Mai, Cole, et al. 2015). Other interactions with tax equity investments are not reflected in the analysis.

- **Technology learning**—Future technology improvements are considered exogenously based on the assumptions in NREL’s 2016 ATB (NREL 2016).
- **Electricity tariff structures**—dGen calculates the financial performance of DPV and behind-the-meter storage systems based on a set of approximately 4,000 tariffs curated in 2016. The existing tariff components are scaled by changes in the cost of electricity as projected by ReEDS, but the structure of the tariffs does not change (e.g., the hours that define peak time-of-use periods will not shift). Thus, any tariff evolution that might occur in a high-PV future is not captured in this work.

While there are inherent methodological and data limitations in the development of any future projection, we use a self-consistent modeling framework that considers complex interactions between numerous different policies and technologies, while ensuring electric system reliability requirements are maintained within the resolution and scope of the models. In doing so, we can comprehensively estimate the cost and value of a wide range of technology options to the system, and we use the models to estimate future deployment portfolios across a range of scenarios.

Appendix C: Additional Scenario Results

This section includes summary results from all 25 scenarios. Figure 45 through Figure 48 show the capacity and generation mixes in 2030 and 2050 across the 25 scenarios.

Table 11 shows the PV deployment and penetration levels in the 25 scenarios.

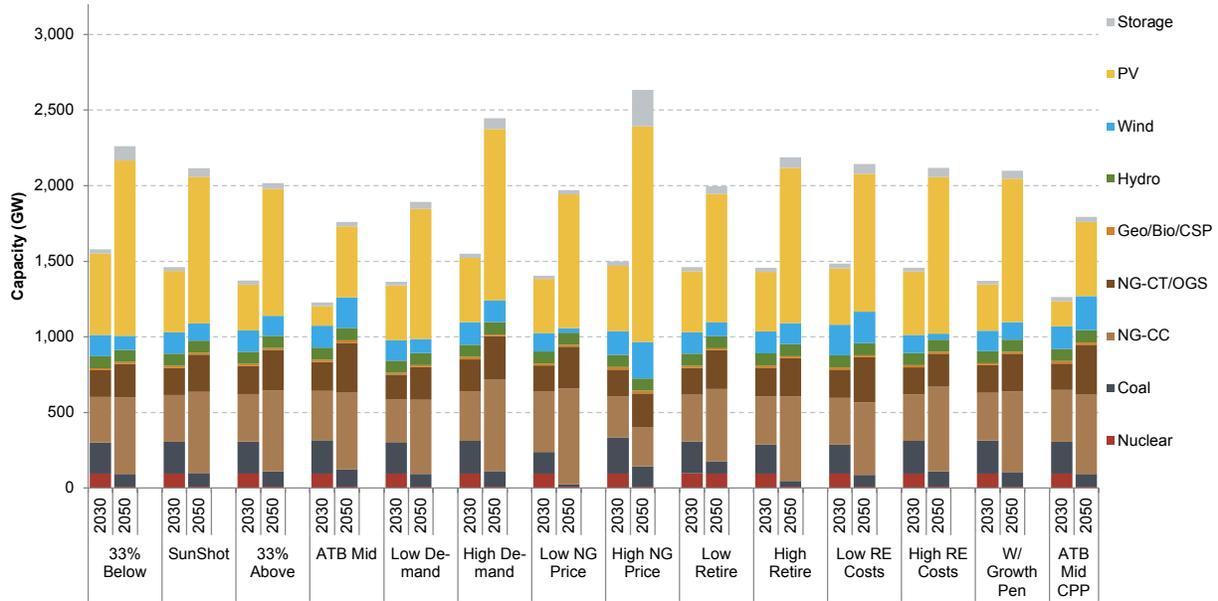


Figure 45. Cumulative installed capacity in 2030 and 2050 for all reference storage cost scenarios

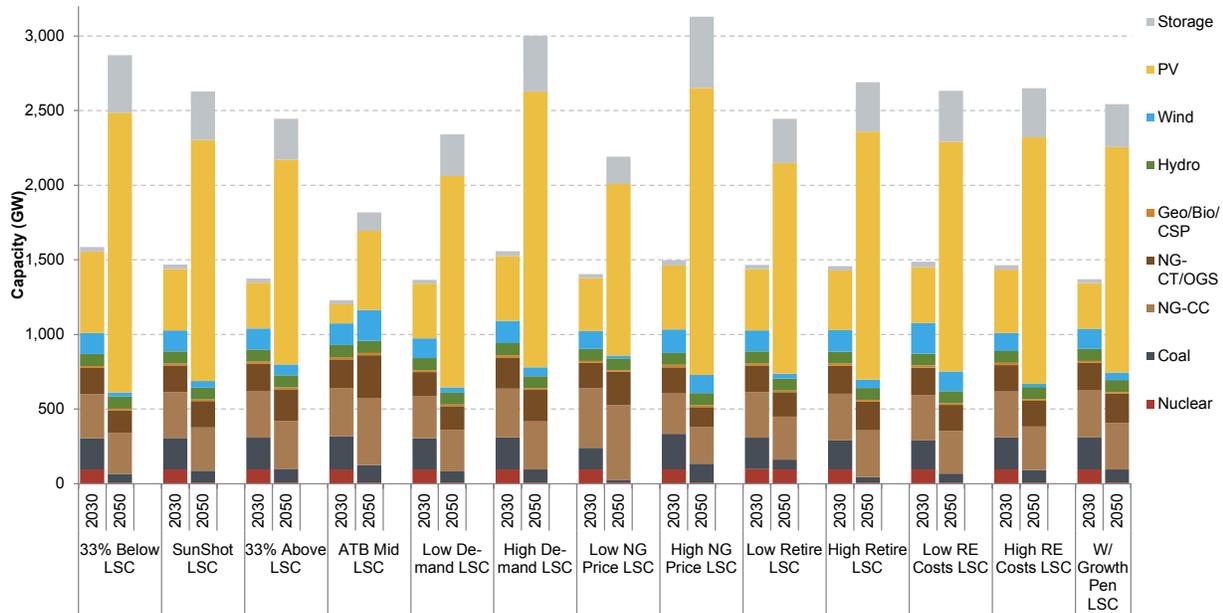


Figure 46. Cumulative installed capacity in 2030 and 2050 for all low storage cost (LSC) scenarios

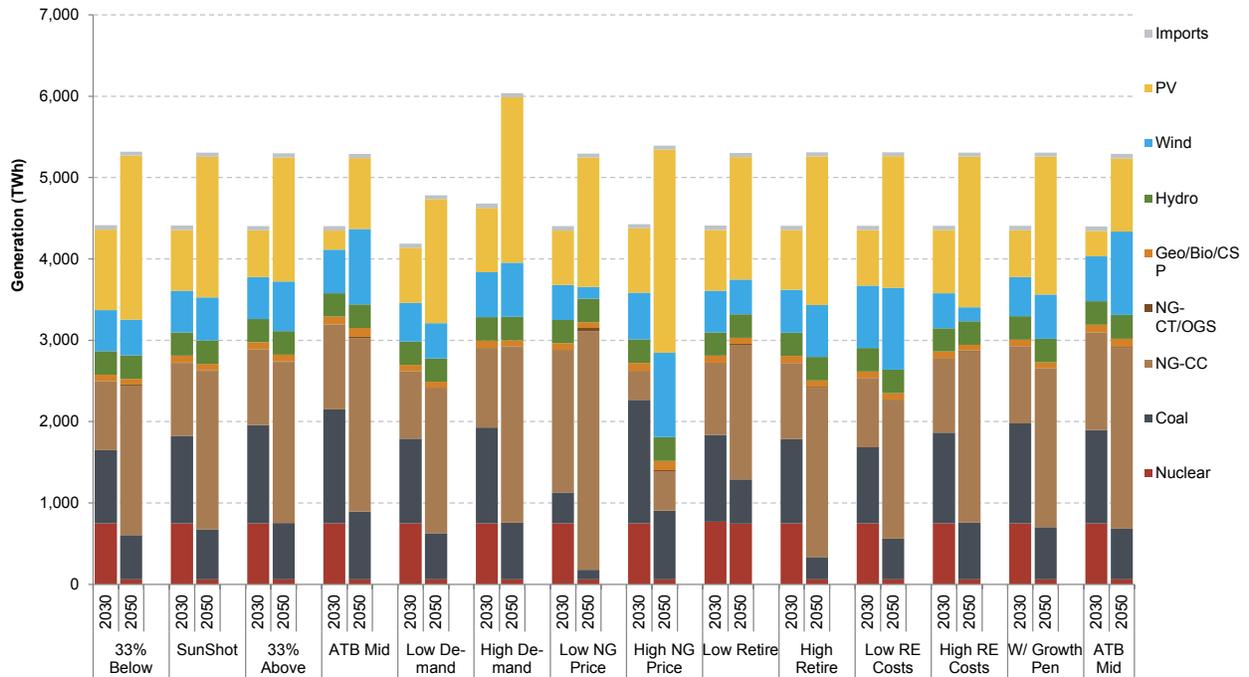


Figure 47. Generation in 2030 and 2050 for all default storage cost scenarios

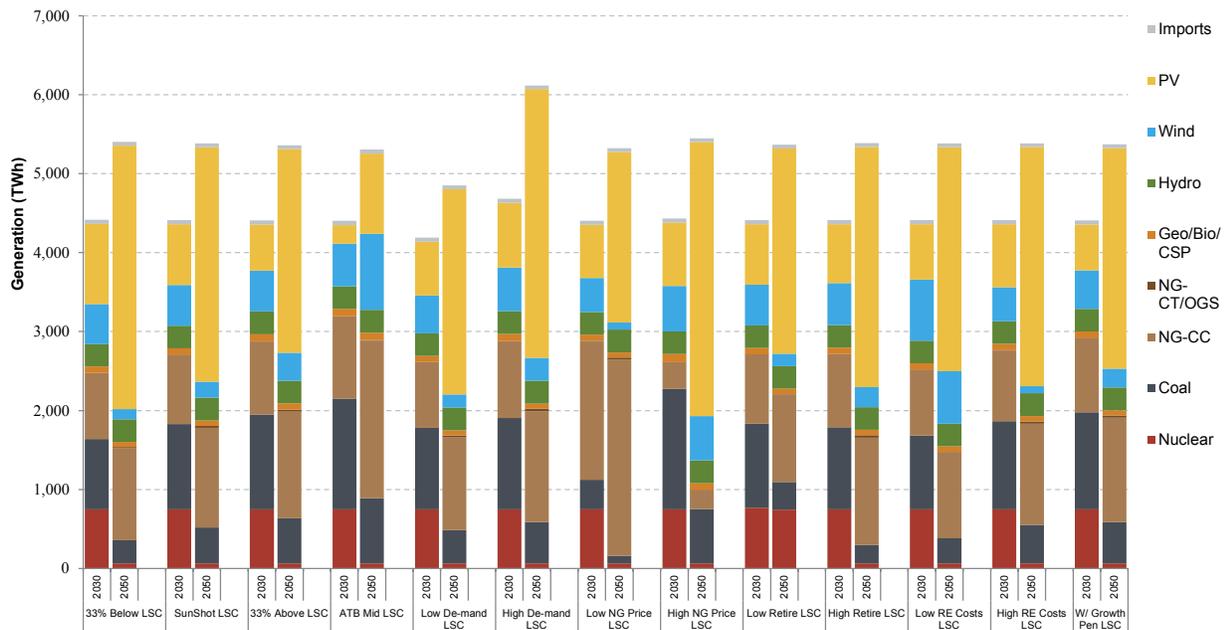


Figure 48. Generation in 2030 and 2050 for all low storage cost (LSC) scenarios

Table 11. Summary PV Deployment and Penetration in 2030 and 2050 among the 25 Scenarios Included in this Analysis

Scenario	PV Capacity (GW)		PV Penetration	
	2030	2050	2030	2050
SunShot	405	971	17%	33%
Low Demand	365	862	16%	32%
High Demand	426	1,134	17%	34%
Low NG Price	357	884	15%	30%
High NG Price	431	1,426	18%	46%
Low Retire	404	850	17%	28%
High Retire	395	1,027	17%	34%
Low RE Costs	372	912	16%	30%
High RE Costs	418	1,035	18%	35%
W/ Growth Penalty	307	948	13%	32%
SunShot LSC	412	1,618	17%	55%
Low Demand LSC	365	1,416	16%	54%
High Demand LSC	435	1,849	17%	56%
Low NG Price LSC	356	1,148	15%	41%
High NG Price LSC	429	1,923	18%	64%
Low Retire LSC	410	1,412	17%	48%
High Retire LSC	397	1,663	17%	56%
Low RE Costs LSC	376	1,538	16%	53%
High RE Costs LSC	425	1,652	18%	56%
W/ Growth Penalty LSC	307	1,511	13%	52%
33% Below	537	1,158	22%	38%
33% Above	303	840	13%	29%
33% Below LSC	545	1,875	23%	62%
33% Above LSC	306	1,370	13%	48%
ATB Mid	127	470	5%	16%
ATB Mid LSC	127	532	5%	19%
ATB Mid CPP	167	491	7%	17%

Appendix D: Pathways to Low-cost PV

The higher deployment scenarios explored here would depend upon the ability of the PV industry and supporting research and development organizations to make further technology advancements and cost reductions. The PV SunShot scenario for utility-scale PV systems with the median U.S. solar resource and without the federal investment tax credit (ITC) represents approximately a 50% decrease in LCOE from current (2017) levels by 2030, with an additional 33% reduction in LCOE by 2050.

There are a variety of pathways that exist to achieve the ultralow cost targets considered in the DOE’s SunShot goals (Jones-Albertus et al. 2016; Woodhouse et al. 2016). Figure 49 shows six key inputs that drive the LCOE with their projected high and low values for the 2020 timeframe. At the extremes, we calculate LCOEs of 1.4 and 9.9 cents per kWh for U.S. utility-scale PV systems with the median solar resource and without the federal ITC. We also show a discrete set of inputs that could lead to the 3 cents per kWh target by 2030 and the 2 cents per kWh target by 2050, as well as a less aggressive set of assumptions that yield 4 cents per kWh. For example, the 3 cents per kWh target could be achieved with a 30 cents per W module price, 50 cents per watt total balance-of-system hardware and soft costs, a 0.4%/yr system degradation rate, 40-year system lifetime, \$10/kW-yr average annual operations and maintenance (O&M) expense, and a 6.0% weighted average cost of capital (WACC). The figure includes illustrative pathways for achieving the SunShot targets defined and used throughout this work, but do not represent the only pathway possible. We do not assume a specific cost reduction pathway; instead, we assume that some combination of cost reductions in the six key categories is achieved and leads to the LCOE levels given by the scenario definitions.

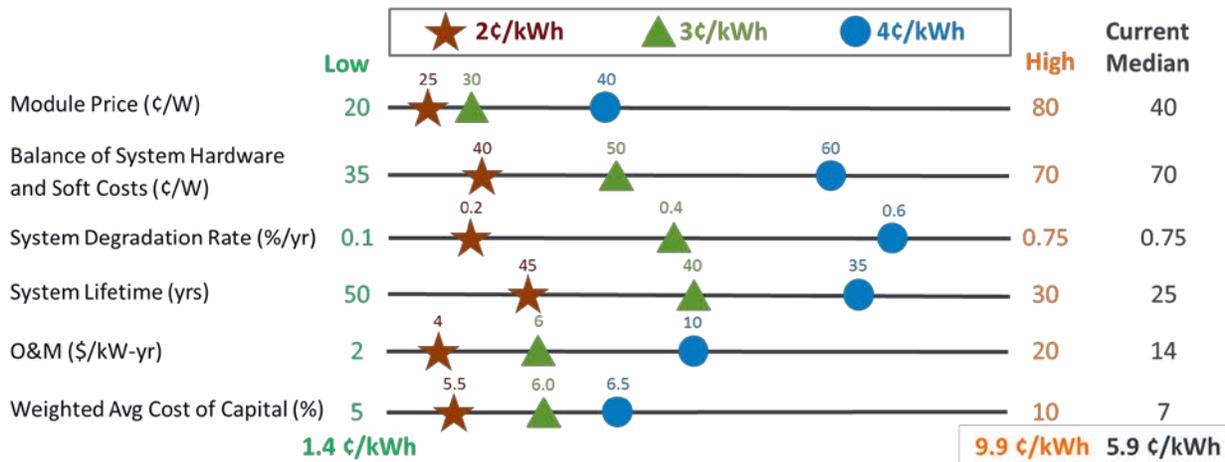


Figure 49. Six categories of LCOE input parameters and overall results under a range of assumptions.

The colored triangles, stars, and circles are illustrative cost reduction pathways that align with the 2, 3, and 4 cents/kWh scenarios, respectively.

Appendix E: 8760-Based Method for Representing Variable Generation Capacity Value

Capacity expansion models (CEMs) are widely used to evaluate the least-cost portfolio of electricity generators, transmission, and storage needed to reliably serve demand over the evolution of many years or decades. Various forms are used to evaluate systems ranging from local utilities and regional entities (WECC 2013; ABB 2016b; Mai, Barrows, et al. 2015) to national systems (Eurek et al. 2016; Blanford, Merrick, and Young 2014; EPRI 2017; U.S. Energy Information Administration (EIA) 2014). The ReEDS model used in this analysis is one example of such a national CEM. Capacity expansion models can be computationally complex, and to achieve acceptable solve times are often forced to estimate key parameters using simplified methods.

Existing grid integration analyses have shown that power systems will require greater levels of flexibility to accommodate higher levels of variable generation (VG) resources, such as wind and PV, which are variable and uncertain (Mai et al. 2014; Lew et al. 2013). In addition, at higher penetration levels, the contribution that VG resources can provide to reliability—specifically resource adequacy—becomes more sensitive to the interaction of both the existing system and potential new generators. For example, VG’s useful capacity and energy contribution declines as more VG is added to the system due to the coincident nature of the resource. While many CEMs account for at least some aspect of this trend, many of the aforementioned modeling simplifications can result in inaccurate representations, particularly at high VG penetrations when the sensitivity and magnitude of these impacts are amplified.

Curtailed and capacity value (CV) are key parameters that reflect the flexibility and reliability impacts, respectively, of VG resources. This appendix focuses on a new method for estimating CV in the ReEDS CEM.⁴³ Other factors that reflect the impact of VG on an evolving power system, which are not included in our alternative methods, include ramping capabilities, transient stability, system inertia, frequency response, inertia, and market rules (Miller et al. 2014; Ela et al. 2014).

Capacity Value

Capacity value (CV) is a metric of the contribution of installed capacity to planning reserves that is typically used by power system planners in long-term reliability assessments. For example, a 100-MW generator with a 30% CV would be expected to reliably contribute 30 MW of capacity during the highest “risk” hours. These hours are by definition those with the highest loss of load probability (LOLP) and are often (but not always) the hours with the highest load. The preferred method for assessing the CV of wind and PV generation is a probabilistic approach grounded in the well-known LOLP and related reliability metrics. Traditional methods include convolution-based LOLP or effective load carrying capability (ELCC); for example, Keane et al. (2011) for wind and Duignan et al. (2012) for PV. ELCC can be calculated with a reliability model or by directly using historical hourly load and VG data, but some studies suggest that eight years of data are required to account for inter-annual variability and converge on long-term values

⁴³ CV is synonymous with capacity credit throughout the literature. It is equivalent to the additional load that the electrical system could serve while maintaining the same level of reliability, which is the effective load carrying capability (ELCC).

(Hasche, Keane, and O'Malley 2011; Milligan et al. 2017). Using these methods, CV can be calculated for conventional generators, VG resources, and storage.

Ideally CV values account for the impact of broader system components, such as transmission, storage, and the characteristics of the thermal fleet. For example, the impact of geo-spatial diversity—including the spatial distribution of VG resources, intra- and inter-regional transmission interconnections, and outages of these units and lines—can impact the contribution of local generators, storage devices, and reserve requirements to meeting resource adequacy and real time energy balancing requirements (Milligan et al. 2017; Ibanez and Milligan 2012). Transmission additions and operational changes, such as the implementation of a dispatch protocol for VG resources in MISO have resulted in significant curtailment reductions in the United States (Bird et al. 2016), highlighting the importance of transmission and market representations in CEMs. Storage charging and discharging modifies the underlying net load profiles, which can reduce curtailment during charging periods and modify and/or complement the contribution from VG resources during discharging periods. Thermal fleet operating constraints can limit the useful contribution from those units as well as that from VG resources.

CEM Simplifications

The ideal calculation of CV in CEMs would require an explicit co-optimized investment-dispatch treatment with many years of time-synchronous VG and load data at an hourly or subhourly resolution. Because of data and computational limitations, existing CEMs typically approximate these variability metrics with simplified methods, including the use of a subset of hours from a full year, screening curves, and other duration-curve-based approaches to evaluate generator performance and select the optimal mix of units (Sullivan, Eurek, and Margolis 2014; Ueckerdt et al. 2017). However, such simplifications reduce the accuracy of the CEMS to capture the impact of VG on the broader power system. At higher VG penetration levels, these inaccuracies can become amplified and have a greater impact on modeling results. Examples of approximation methods for CV primarily include approaches that:

- Relate the addition of new capacity and LOLP—for example, Z-method (Dragoon and Dvortsov 2006) and Garver's method (D'Annunzio and Santoso 2008; Garver 1966)
- Approximate CV as the capacity factor based on the hours of highest risk—for example, Hale, Stoll, and Mai (2016); Milligan and Parsons (1999); Madaeni, Sioshansi, and Denholm (2013); Pietzcker et al. (2017)—or predefined by VG resource supply bins (Patrick Sullivan, Krey, and Riahi 2013).

We are contributing to this broader set of approximation methods by implementing an alternate approach that characterizes the contribution of VG to system capacity during high load and net load (load minus VG) hours. This method utilizes hourly generation and load values across all hours of the year (“8760 data”), thereby capturing tail events that can be missed by simplification methods that only use a set of all hours from a year that are not explicitly selected based on LOLP, or by statistical methods that require assumptions about the load and resource distributions that may not match actual distributions. Our methods also capture the interactions between VG and conventional generators and takes into account how the system evolves within each of the scenarios. Other methods, such as those based on cost functions or exogenous regressions, lack this sort of self-consistent framework and could therefore result in erroneous

extrapolations. Furthermore, our approach offers flexible application to any year and model given availability of 8760 data.

New ReEDS CV Methodology

Figure 50 shows how the current ReEDS timeslice approach misses key information in the load and net load duration tails that are captured by an 8760 methodology. The solid lines show the current ReEDS methodology which utilizes 17 representative timeslices (identified by numbers above curves), and the dashed lines show the new method using the 8760 time series. The new 8760-based ReEDS methodology is better able to capture the highest and lowest load hours on the duration curves, thereby providing a more accurate representation of key variability metrics. In addition to what is presented here, additional details of the methodology can be found in Frew et al. (2017).

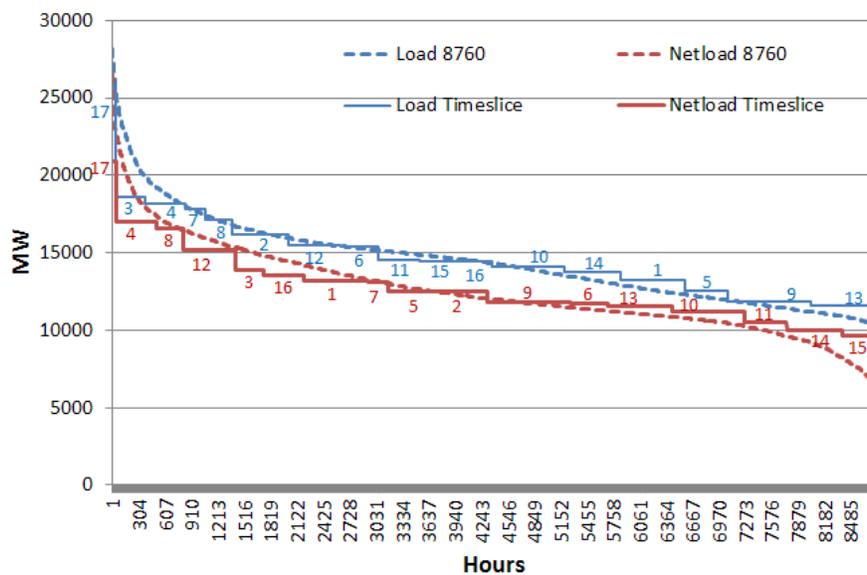


Figure 50. Representative load and net load duration curves for a single ReEDS region
Timeslice identifiers are shown the duration curves.

To calculate CV metrics, we call an R-based script outside the core GAMS-based ReEDS code between each two-year solve period. This script implements the 8760 load and VG time series, as well as generator and storage capacities, timeslice-based generation, and transmission flows from the previous two-year solve period in ReEDS. The raw 8760 load data are adjusted based on ReEDS inter-regional transmission flow to account for the imports and exports between regions. The script returns the existing CV by VG technology type and region and marginal CV by VG technology type, resource class, and region.

The new ReEDS method for calculating CV utilizes duration curves of load and net load and is similar to the approach used by NREL’s Resource Planning Model (RPM) (Hale, Stoll, and Mai 2016). Figure 51 illustrates this methodology. The load duration curve (LDC) reflects the total load in a given modeling region, which is sorted from the hours of highest load to lowest load and is shown by the blue line. The net load duration curve (NLDC) represents the total load

minus the time-synchronous contribution from VG, where the resulting net load is then sorted from highest to lowest, as shown by the solid red line.⁴⁴ The NLDC(δ) can also be created by subtracting the time-synchronous generation of an incremental capacity addition from the NLDC, where the resulting time series is again sorted from highest to lowest; this is shown by the dashed red line.

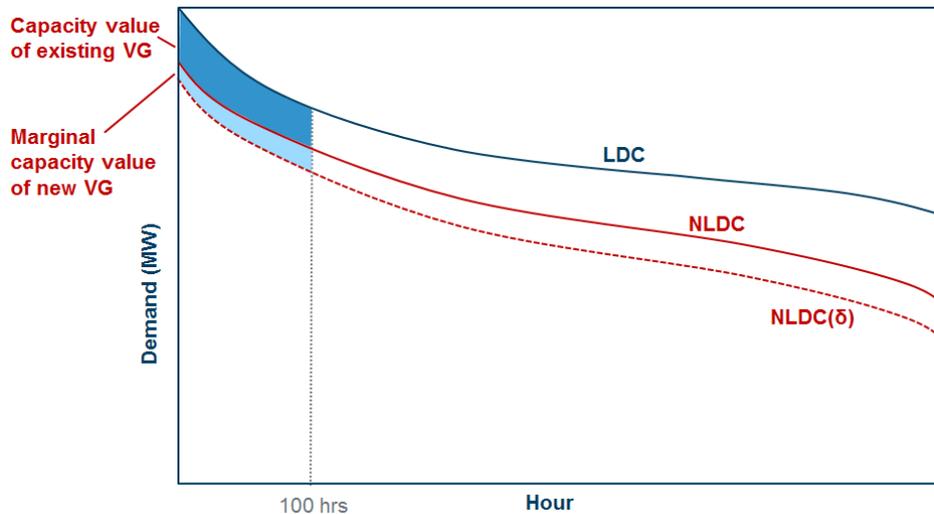


Figure 51. Load duration curve (LDC) based approach to calculating CV

The amount of load that the existing VG capacity can meet while maintaining the same level of reliability is the ELCC. We calculate the ELCC as the difference in the areas between the LDC and NLDC during the top 100 hours of the duration curves, as shown by the dark blue shaded area in Figure 51. These 100 hours are a proxy for the hours with the highest risk for loss of load (i.e., LOLP).⁴⁵ Similarly, the contribution of an additional unit of capacity to meeting peak load is the difference in the areas between the NLDC and the NLDC(δ), as shown by the light blue shaded area. We assume 100 MW for the incremental capacity size in ReEDS. These areas are divided by the corresponding installed capacity and number of top hours (100 in this case) to obtain a fractional annual-based CV result. These CV values are then fed into ReEDS to quantify each VG resource’s capacity contribution to the planning reserve requirement, which is based on NERC planning reserve margin assessments and the peak load by region. Thus, these CV metrics inform the investment decision of new VG by impacting the *capacity*-based value of those new VG additions.

In the new ReEDS CV method, these calculations are done at regional and technology levels for the existing CV and at regional, technology, and resource class levels for marginal CV. For existing units, the user can define the regional level to either the 134 ReEDS regions or the 18 broader RTO regions; the default is the RTO level. All marginal calculations are performed at the 134 region level. Future work will refine the intra- and inter-regional transmission impacts.

⁴⁴ Residual LDC is an equivalent term to NLDC used in the literature.

⁴⁵ We currently use only a single year of wind, PV, and load data to calculate CV. Expansion of this method to use multiple years of data would increase the robustness of this calculation.

Validation of New ReEDS CV Method

Because CV represents an explicit calculation based on the load and net load profiles, the new ReEDS method CV outputs were verified against a manual calculation of the difference between the load and net load in each their respective top 100 hours. Existing and marginal PV and wind CV outputs from this comparison are shown in Figure 52. In this figure, the wind generation level was held constant while PV capacity alone was increased to achieve higher RE penetration levels. Thus, the marginal PV CV values diminish at higher RE penetration levels due to the coincident nature of the PV resource, while the marginal CV of wind slightly increases in response to the shifting peak net load period to more windy (and less sunny) hours. This reduction in marginal PV CV is consistent with the literature, which shows rapid decrease in capacity contribution beyond 20% penetration levels (Munoz and Mills 2015).

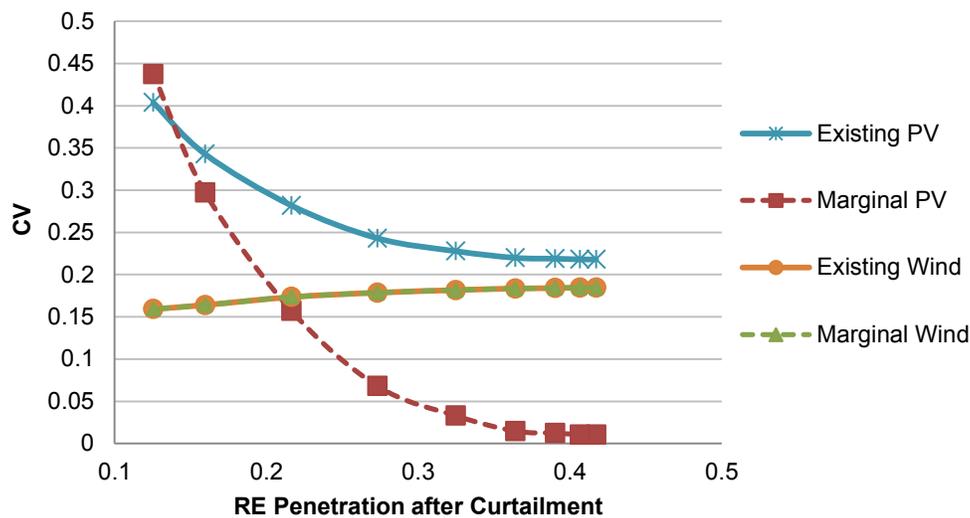


Figure 52. Marginal PV CV outputs from ReEDS and manual calculation with fixed minimum generation of 7.5 GW

Comparison of Existing and New ReEDS CV Methods

Results to date suggest the hourly method in the new ReEDS method more accurately represents VG CV in ReEDS from the existing approximation method without prohibitive computational burdens. The marginal CV outputs for PV in the Austin, Texas (Figure 53), and southern California (Figure 54) areas show a more realistic reduction in value with higher penetration levels than the existing ReEDS statistical method. Note that because the existing ReEDS method calculates CV at the timeslice level, while our new method reports annual CV outputs, we show the existing method CV outputs from the timeslice with the largest marginal value in the planning reserve margin constraint. This is often (but not always) the summer afternoon or evening timeslices.

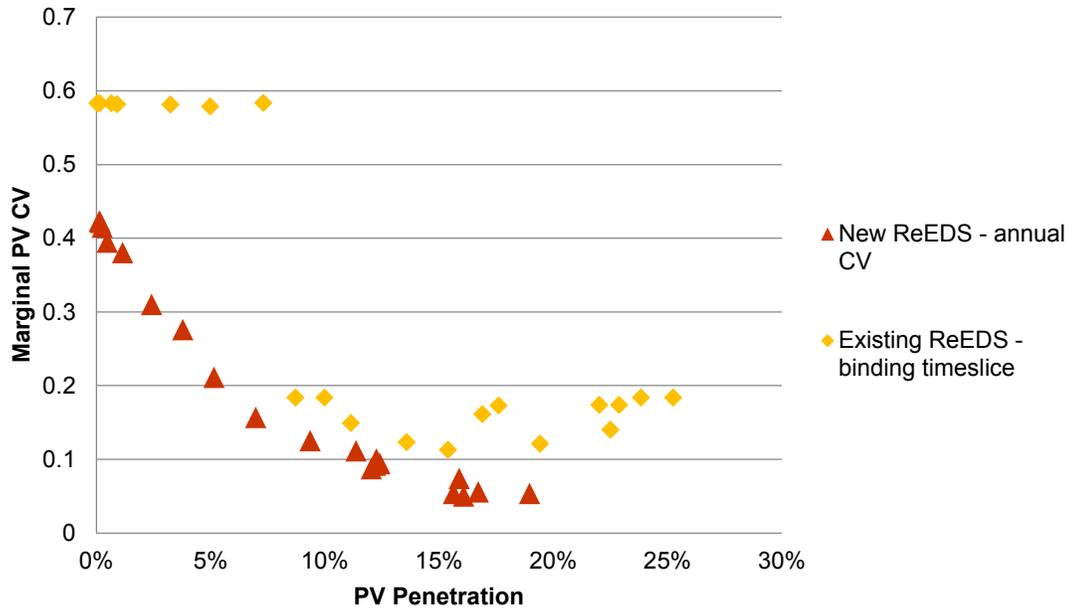


Figure 53. Incremental PV CV in the Austin, Texas, region using the existing and new ReEDS method

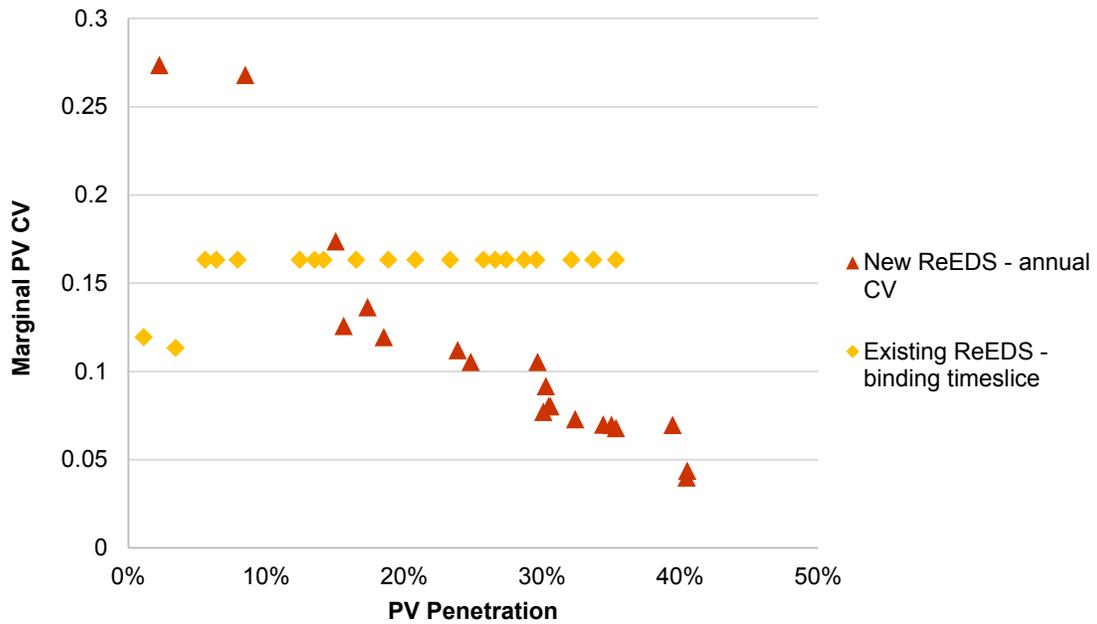


Figure 54. Incremental PV CV in the southern California region using the existing and new ReEDS method

Previous work has shown that the existing ReEDS CV method yields abrupt changes in CV between the different timeslices, particularly between the summer afternoon and evening periods (Sigrin et al. 2014). These results can be seen by the sharp drop in the marginal CV around the 7% PV penetration level in Figure 53, where the reserve margin binding timeslice shifts from summer afternoon to evening (yellow diamonds). Furthermore, the existing ReEDS method often estimates persistent CV for PV even at relatively high penetration levels due to the coarse timeslices, as shown again by the yellow diamonds in at higher penetration levels in both Figure 53 and Figure 54. The new method, which looks across all hours to calculate an annual CV results in a smoother and more rapid decline in CV.