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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Generic Investigation Into The Aggregate Electric Utility Reserve Margins Planned For Peninsular Florida.
______________________________/

Docket No. 981890-EU

NOTICE OF APPEARANCE OF COUNSEL OF RECORD

Please take notice of appearance of the undersigned counsel as counsel of record for JEA. Undersigned counsel requests that all parties, intervenors and staff serve copies of all pleadings and papers in this matter upon undersigned counsel directly.

Richard A. Mullaney, General Counsel

By: ______________________

Michael B. Wedner
Assistant General Counsel
Florida Bar No.: 287431
Office of General Counsel
117 West Duval Street
Suite 480
Jacksonville, Florida 32202
(904) 630-1700
Counsel for JEA

Certificate of Service

I HEREBY CERTIFY that a true and correct copy of the foregoing has been forwarded this 13th day of August, 1999, via U.S. Mail, to the following:

AFA 1
APP
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LEG 1
MAS 5
OPC
PAI
SEC
WAW 1
OTH

Robert V. Elias, Esquire
Leslie J. Paugh, Esquire
Division of Legal Services
FPSC
2540 Shumard Oak Boulevard
Room 370
Tallahassee, Florida 32399

Debra Swim, Esquire
Ms. Gail Kamaras
LEAF
1114 Thomasville Road
Tallahassee, Florida 32303

Done 8/27/99

DOCUMENT NUMBER-DATE
09671 AUG 16 99
FPSC-RECORDS/REPORTING

James D. Beasley
Ausley & McMullen
227 South Calhoun Street
Post Office Box 391
Tallahassee, Florida 32301

Jeffrey Stone, Esquire
Beggs & Lane
Post Office Box 12950
Pensacola, Florida 32576

John Roger Howe, Esquire
Office of Public Counsel
111 West Madison Street
Room 812
Tallahassee, Florida 32399

John W. McWhirter, Jr., Esquire
McWhirter Reeves
Post Office Box 3350
Tampa, Florida 33601-3350

Roy C. Young, Esquire
Young van Assenderp, et al.
225 South Adams Street
#200
Tallahassee, Florida 32301

Mr. Jack English
Florida Public Utilities Company
401 South Dixie Highway
West Palm Beach, Florida 33402

Mr. Ken Wiley
Florida Reliability Coordinating Council
405 Reo Street
Suite 100
Tampa, Florida 33609

Jim McGee, Esquire
Florida Power Corp.
Post Office Box 14042
St. Petersburg, Florida 33733

Joseph A. McGlothlin, Esquire
Vicki Gordon Kaufman, Esquire
McWhirter Reeves
117 Sough Gadsen Street
Tallahassee, Florida 32301

Robert Scheffel Wright, Esquire
John T. LaVia, III, Esquire
Landers and Parsons, P.A.
Post Office Box 271
Tallahassee, Florida 32302

Frederick M. Bryant, Esquire
General Counsel
Florida Municipal Power Agency
2010 Delta Boulevard
Tallahassee, Florida 32315

Thornton J. Williams, Esquire
Thornton Williams & Associates
215 South Monroe Street, #600A
Tallahassee, Florida 32202

Ms. Michelle Hershel
Florida Electric Cooperative Association
Post Office Box 590
Tallahassee, Florida 32302

John Moyle, Jr., Esquire
Moyle, Flanigan, Katz, Kolins, Raymond & Sheehan
210 South Monroe Street
Tallahassee, Florida 32301

Mr. James Swartz
City of Homestead
675 North Flagler Street
Homestead, Florida 33030

Mr. Gary Lawrence
City of Lakeland
501 East Lemon Street
Lakeland, Florida 33801

Mr. J. Paul Wetzel
City of St. Cloud
1300 Ninth Street
St. Cloud, Florida 34769

Mr. Rex Taylor
City of Vero Beach
Post Office Box 1389
Vero Beach, Florida 32961

Mr. Thomas W. Richards
Fort Pierce Utilities
Post Office Box 3191
Ft. Pierce, Florida 34948

Mr. Raymond O. Manasco, Jr.
Gainesville Regional Utilities
Post Office Box 147117
Station A-138
Gainesville, Florida 32614

Mr. Timothy Woodbury
Seminole Electric Cooperative
Post Office Box 272000
Tampa, Florida 33688

Robert Williams, Esquire
7201 Lake Ellinor Drive
Orlando, Florida 32809

Mr. Harvey Wildschuetz
City of Lake Worth Utilities
1900 Second Avenue, North
Lake Worth, Florida 33461

Mr. Dean Shaw
City of Ocala
Post Office Box 1270
Ocala, Florida 34478

Mr. Richard G. Feldman
City of Tallahassee
300 South Adams Street
Tallahassee, Florida 32301

Mr. Charles Russell
Florida Keys Electric Cooperative Association
Post Office Box 377
Tavernier, Florida 33070

Mr. T. B. Hart
Orlando Utilities Commission
Post Office Box 3193
Orlando, Florida 32802

Mr. Larry J. Thompson
Utility Board of the City of Key West
Post Office Drawer 6100
Key West Florida 33041

Mr. Ben Sharma
Kissimmee Utility Authority
Post Office Box 423219
Kissimmee, Florida 34742

Richard Zambo, Esquire
598 SW Hidden River Avenue
Palm City, Florida 34990

Jeffrey Stone, Esquire
Beggs & Lane Law Firm
Post Office Box 12950
Pensacola, Florida 32576-2950

Matthew M. Childs, Esquire
Charles A. Guyton, Esquire
Steel Hector
215 South Monroe Street
Suite 601
Tallahassee, Florida 32301-1804

Robert L. Vaden, Utilities Commission
City of New Smyrna Beach
Post Office Box 100
New Smyrna Beach, Florida 32170

Office of the Public Counsel
Shreve/Beck/Pucher
c/o The Florida Legislature
111 West Madison Street
Suite 812
Tallahassee, Florida 32399-1400

Kenneth A. Hoffman, Esquire
Rutledge, Ecenia, Purnell & Hoffman, PA
Post Office Box 551
Tallahassee, Florida 32303-0551

Joe Welborn, Esquire
Lane Mahaffey, Esquire
16313 North Dale Marbry Highway
Tampa, Florida 33618

Gail Kamaras
Legal Environmental Assistance Foundation, Inc.
1114 Thomasville Road
Suite E
Tallahassee, Florida 32303-6290

Willard Smith, Esquire
Fran Winchester, Esquire
Reedy Creek Improvement District
Post Office Box 10175
Lake Buena Vista, Florida 32830

Attorney

56

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margin planned for Peninsular Florida

Docket No. 981890-EU

Direct Testimony of Marcia K. Elder

on behalf of the

Legal Environmental Assistance Foundation, Inc.

August 16, 1999

AFA 2
APP
CAF
CMU
CTR
EAG 4+1
LEG 1
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OPC
PAI
SEC 1
WAW
OTH

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I. QUALIFICATIONS

Q: Please state your name, occupation, and business address.

A: My name is Marcia K. Elder. I am a public policy consultant and owner/president of the Intergovernmental Services consulting firm. The firm is located at 707 East Park Avenue, Tallahassee, Florida 32301.

Q: Please summarize your professional education and experience.

A: I hold a Master's Degree in Environmental Engineering from the University of Florida. My involvement with energy matters began at the undergraduate level and I have worked in the energy field for over twenty years. LEAF Exhibit A is an overview of my professional experience, as relates to such concerns.

Q: Are you familiar with the attributes of Distributed Energy Resources like Efficiency and Solar Resources?

A: Yes. I have dealt with distributed energy resource issues, particularly Efficiency and Solar Resources, from policy, technical, and programmatic standpoints, throughout my professional involvement in working on energy concerns. As part thereof, I have made numerous presentations at public forums before regulatory and legislative policy makers and have also conducted numerous educational forums on alternative energy technologies. On a personal level, I have extensive experience in using a wide range of related technologies and measures.

Q: Have you been involved in planning issues involving electric utilities?

A: Throughout my professional career, I have played an active role in energy planning matters affecting Florida's future, including as relates to electric utilities, at the state, regional and local levels.

II. INTRODUCTION

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Legal Environmental Assistance Foundation, Inc., ("LEAF").

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to make two points: 1) that the energy from Distributed Resources, particularly Efficiency and Solar Resources, merits consideration as the Commission investigates reliability concerns and reserve margin criteria; and 2) that the Commission should become better informed about how such resources could cost-effectively address reliability needs.

Q: Please outline your testimony.

A: Distributed Resources are generally discussed in Section III. Sections IV and V focus on two particular distributed resources, Efficiency and Solar. Section V summarizes my testimony and recommendations.

Q: Are you sponsoring any exhibits?

A: Yes. *Five exhibits are attached to my testimony and incorporated herein.*

III. DISTRIBUTED RESOURCES

Q: What are Distributed Resources?

A: Distributed Resources include small scale power generation technologies that provide power at or near the site of end use, as opposed to central power generation stations and associated transmission and distribution facilities. Distributed Resources also include small scale demand side management technologies which provide "distributed" electricity savings by improving end-use efficiencies.

A variety of distributed generation technologies exist, among them photovoltaic solar cells, wind turbines, fuel cells, small natural gas turbines, and internal combustion engines. Distributed demand-side resources also encompass a variety of technologies ranging from efficient lights, windows, and motors to efficient building designs and industrial processes.

According to the Regulatory Assistance Project, "Distributed Resources are demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and reliability needs of the customers served by that distribution system. Distributed resources can be installed on either the customer side or the utility side of the meter." (LEAF Exhibit C).

Q: What is the Regulatory Assistance Project ("RAP")?

A: The Regulatory Assistance Project ("RAP") is a national organization specializing in technical and policy matters concerning electric utilities and utility regulatory commissions. RAP employs former utility commissioners expert in such matters who are engaged in research, publishing and making educational presentations throughout the United States. RAP also provides free, in-house workshops for state public utility regulators. RAP has recently published a paper about using distributed resources to meet reliability concerns, Least-Cost Paths to Reliability: Ten Questions for Policy Makers, attached as LEAF Exhibit B. RAP is also evaluating and reporting on the utility issues associated with distributed energy resources under contract with the National Association of Regulatory Utility Commissioners ("NARUC"). LEAF Exhibit C, Profits and

Progress Through Distributed Resources, is RAP's draft report to NARUC, dated July 15, 1999.

Q: Can Distributed Resources cost-effectively meet energy service *reliability needs?*

Diverse groups have recognized that both demand and supply-side Distributed Resources can provide low cost, readily dispatchable, reliability solutions for utilities.

In a July 1999 Resolution (attached LEAF Exhibit D), the National Association of Regulatory Utility Commissioners ("NARUC") emphasized the importance of Efficiency Resources as a cost-effective way to increase reliability. NARUC's Resolution notes that demand-side management programs are a "proven, cost-effective means of managing load and enhancing reliability by matching electricity demand with the system's generation, transmission, and distribution capacity constraints" and a "critical component of strategies to address electric system reliability" which can "help to avoid the need to rely upon excessively costly supply resources and strained transmission and distribution facilities."

The Distributed Power Coalition of America, composed of electric utilities, national gas pipeline companies, equipment manufacturers and others supportive of distributed power generation, has testified before Congress about the economic benefits of supply-side distributed power, overall and by virtue of the fact that distributed resources do not depend on the transmission/distribution network. They note, "Distributed power should be recognized by policy makers as a set of technologies which can increase the reliability of electric utilities...while lowering the price of electricity to consumers."

Q: How cost effective are Distributed Resources?

A: The cost-effectiveness of any individual distributed resource will vary depending upon the technology. Whatever the technology type, the cost-effectiveness of Distributed Resources will increase as costs for central power supplies increase -- and the amounts paid for reliability from conventional resources can be quite high. In a recent resolution (LEAF Exhibit D), NARUC states that "the spot market cost of power repeatedly rose to the range of $1,000/MWhr for one or more hours in the day" during recent distribution and capacity constraints in several areas of the country. In the above referenced paper, Least Cost Paths to Reliability, (LEAF Exhibit B), RAP states that "demand and non-conventional supply-side resources can provide low-cost reliability solutions to utilities with reliability concerns." In terms of comparative costs, they further note that:

> The most common utility action to meet peak demand today is to build (or buy) a power plant. A conventional combustion turbine (CT) costs about $400 per KW. The annual carrying cost, including depreciation, property taxes and return, is about $80 per KW per year. If the CT is used for 800 hours per year (about 10 percent of the hours), the CT costs 10 cents per KWH. If it is used 80 hours per year (20 hours per week for four weeks), the capital cost is $1.00 per KWH. And, of course, the peaker that is never used, or is used only on the annual peak day, would have astronomical costs on a per KWH basis. Many options could provide equivalent reliability benefits at a much lower cost.

The Commission should become informed about our state's "spot market cost of power" as it gauges how to meet Florida's reliability needs.

Q: What distributed resources will your testimony address?

A: My focus is on two resources that offer significant opportunity in Florida --

Energy Efficiency Resources and Solar Resources. Their ability to serve reliability needs has been recognized by varied experts, including those noted in my testimony and their use has been encouraged by the Florida Legislature (See, e.g., Sections 187.201(12), 366.81, 377.601, 377.703, F.S.)

IV. EFFICIENCY RESOURCES

Q: What are Efficiency Resources?

A: Energy efficiency consists of a diverse range of measures and practices to make more efficient use of energy resources. As a distributed resource, Efficiency Resources are a component of the demand-side-management ("DSM") programs which utilities implement to meet their customers' energy service needs[1]. DSM consists of efficiency and load management resources, both of which include a broad array of measures and practices. Efficiency Resources reduce overall energy use and produce primarily energy savings (KWH reductions). Load Management Resources reduce energy use at times of peak demand, or shift energy use to off peak times -- producing primarily demand savings (KW reductions) or off-peak load increases. The following graphic (Figure 1) illustrates how Efficiency and Load Management Resources influence a load curve[2].

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[1]Energy service reliability needs may be met by adding demand-side resources (DSM) or supply-side resources (i.e., electrical power generation, transmission or distribution).

[2]Figure 1 is to illustrate how efficiency and load management resources generally influence a load curve. It does not depict any specific set of resources.

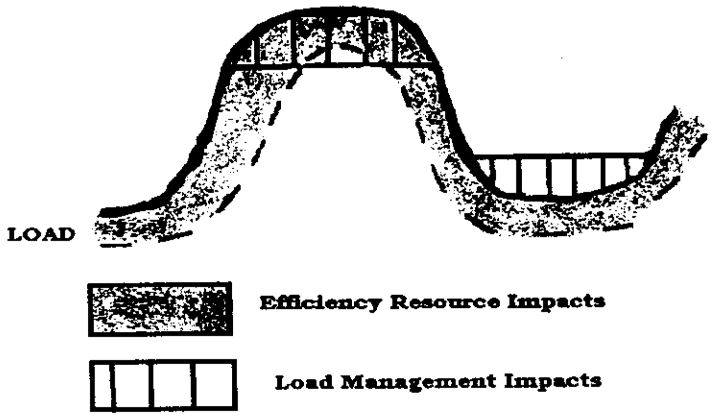

Figure 1

Q: Are Efficiency Resources delivered through Florida's current conservation programs?

A: Only partially. The conservation programs now offered by Florida's utilities focus very heavily on load management resources. As a result, the capability of Florida's utilities' to deliver Efficiency Resources remains under-developed.

Q: Should Florida's utilities expand their capabilities to deliver Efficiency Resources?

A: Yes. Developing such capabilities could provide significant reliability benefits. Through their recent Resolution (LEAF Exhibit D) NARUC has recognized these benefits and voted to:

> reaffirm NARUC's commitment to, and support for, cost-effective demand side management measures, including both energy efficiency and load management measures as a critical component of strategies to address electric system reliability concerns; and
>
> urge State public utility commissions to encourage and support programs for cost-effective energy efficiency and load management investments as both a short-term and a long-term strategy for enhancing the reliability of the nation's electric system, and reducing its costs.

Q: Can Efficiency Resources improve a utility's ability to manage risk?

A: Electric utilities face a variety of uncertainties (such as fuel price volatility, forecasting uncertainty, regulatory uncertainty, Y2K) that make long-term resource planning and acquisition a risky endeavor. Efficiency Resources have attributes that help mitigate some of these risks. By lowering an electric utility system's load requirements, Efficiency Resources reduce risk through reducing the level of reserve required[3]. They also mitigate fuel price volatility because their operation reduces system fuel costs. Further, studies by the Oak Ridge National Laboratory, the Northwest Power Planning Council, and others have found that efficiency resources have four attributes which can help utilities in limiting risk and adapting to an uncertain future: (1) flexibility; (2) short lead time; (3) availability in small increments; and (4) tendency to grow with load.

Q: How can these attributes of Efficiency Resources help utilities limit their exposure to risk and adapt to an uncertain future?

A: In several ways. First, once programs to deliver Efficiency Resources are in place, it is fairly easy to match the rate of energy savings delivered to the level of load growth. If higher-than-expected load growth occurs, efficiency implementation schedules can be ramped up fairly quickly, since the requisite lead time is short. Certain types of efficiency programs -- if well designed -- automatically synchronize with load growth. For example, new construction programs (if not capped at a particular participant level) can grow with, and simultaneously reduce, new construction-based load growth. Other reliability

[3]RAP has noted, "the best way to avoid a reliability crisis is to avoid the demand that creates it." (LEAF Exhibit B).

benefits of Efficiency Resources would occur even if load growth was perfectly predictable. The small scale and wide distribution of individual Efficiency Resources mean that if the expected savings from a particular program or measure are not fully achieved, system reliability will be less impacted than in the case of an unplanned outage of a power plant. For these reasons, Efficiency Resources have risk-mitigating advantages that can help a utility adapt to an uncertain future -- and a utility with efficiency-delivery mechanisms in place would be better equipped to manage the reliability risks associated with meeting energy service needs.

Q: Can Efficiency Resources cost effectively reduce energy use in Florida?

A: Yes. After a comprehensive evaluation, the Commission identified the energy savings of Efficiency Resources that ***cost less***[4] than supply-side alternatives (least-cost Efficiency Resources). Order No. PSC-94-1313-FOF-EG (10/25/94).

Q: Have Florida's utilities delivered these least-cost Efficiency Resources to their customers?

A: Only partially. The Commission has required utilities to deliver about one third of these least cost savings to their customers. It has also authorized or encouraged utilities to deliver the remaining two-thirds[5]. The following chart depicts this one third portion as "Commission-Required" energy savings and the

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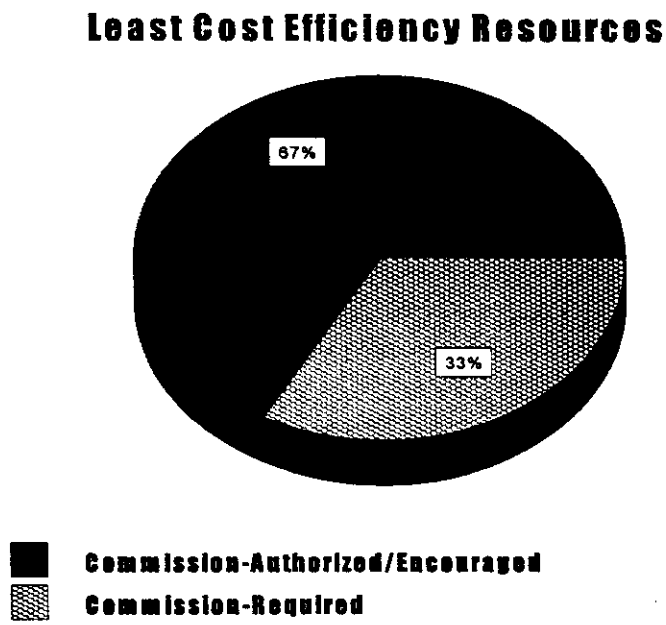
[4]The Commission's cost conclusions were based solely on direct monetary costs and did not account for the varying environmental and health costs of energy resource alternatives.

[5]The Commission ruled that the one-third portion was a minimum which utilities must meet or exceed, and that any part of the remaining two-thirds counts toward meeting that minimum. The Commission also specifically encouraged, and offered financial incentives and revenue neutrality, for utilities to deliver the remaining two-thirds in ways that provide large savings and small rate impacts. Order No. PSC-94-1313-FOF-EG (10/25/94).

two thirds portion as "Commission-Authorized/Encouraged" additional potential energy savings.



All the Efficiency Resources on the chart, whether required, or authorized/encouraged, would meet energy service needs at a cost less than their supply-side alternative[6].

Q: Has the Commission's authorization and encouragement influenced utility planning processes in favor of more Efficiency Resources?

A: Apparently not. The conservation programs offered by Florida's utilities aim to

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[6]This chart is derived from the level of MWH savings that were least cost based on the Commission's 1994 cost assumptions (in Order PSC-94-1313-FOF-EG (10/25/94). The size of the pie may differ today, because it would vary with the conditions which underlie the assumptions used in DSM cost-benefit evaluations. Though the size of the pie may change, the proportion of Commission-Required to Commission-Authorized/Encouraged savings are expected to remain fairly constant.

deliver only Commission-Required energy savings. Utility resource planning processes have summarily and routinely excluded the Commission-Authorized/Encouraged energy savings technologies at a very early stage. As a result, Florida's utilities have not developed the knowledge and mechanisms to deliver these Commission-supported least cost Efficiency Resources. As such, Florida's capability to access the significant reliability enhancements discussed above (and other benefits as discussed below) is under-developed.

Q: Do Efficiency Resources have public benefits beyond these reliability benefits?

A: Yes. In addition to saving energy, Efficiency Resources can save money since they cost less than their supply-side alternative. They also minimize the adverse environmental and health costs of energy production and use and have been shown to offer significant economic development and employment benefits.

V. SOLAR RESOURCES

Q: What are Solar Resources?

A: Solar Resources consist of technologies and approaches to use the power of the sun to meet our energy needs. They include Solar Photovoltaics (PV), Solar Thermal, and Passive Solar Technologies and Designs. PV is a technology that uses the sun's rays to generate electricity. Solar Thermal is a technology that uses the sun's rays to heat water. Passive solar technologies and designs are used for day lighting, space heating, and passive cooling. Solar Resources may be grid-connected or off-grid, customer-owned or utility owned. They have applications in all end-use sectors.

Q: Do Solar Resources have a role in utility efforts to meet Florida's energy

service reliability needs?

A: Yes. Solar Resources can be used to substitute for, or supplement, conventional utility-provided generation -- thereby reducing the level of energy service needs to be met by conventional power supplies.

Q: Has PV's capacity value in Florida been estimated?

A: Yes. The National Renewable Energy Laboratory (NREL) developed a method to determine how closely a utility's load requirements match PV's ability to generate power when needed. Using this method, NREL found that the higher a utility's summer to winter peak ratio, the more PV can contribute to that utility's capacity. NREL has estimated that PV's capacity values in Florida range from 50 to 70 percent, depending on geographic areas. NREL is also investigating load control approaches which could raise this capacity value. NREL's Research Report, Photovoltaics Can Add Capacity to the Utility Grid, is attached as LEAF Exhibit E.

Q: How could utilities employ the capacity associated with Solar Resources?

A: There are range of ways that utilities could use Solar Resources to meet Florida's energy service reliability needs. Both demand and supply-side options are available. For example, solar water heating and pool heating are demand side options, and grid-connected solar PV, whether utility or customer-owned, is a supply-side option. Florida-specific programs and approaches could be designed to best use available solar resources. For the purposes of this testimony, I am not suggesting that the Commission adopt any particular program or approach at this time, only that these options merit further examination by the Commission.

Q: Do Solar Resources have other benefits beyond contributing to a utility's capacity?

A: Yes. Solar Resources share many of the risk-mitigating attributes of the Efficiency Resources that were discussed earlier (i.e., flexibility; short lead time; availability in small increments; and reduced fuel-price volatility). Like efficiency, they can help minimize energy losses associated with the transmission/distribution network. Solar Resources are also uniquely portable and diversifiable. They can also help minimize adverse environmental and health impacts of traditional supply side alternatives and offer significant economic development benefits.

VI. SUMMARY AND RECOMMENDATIONS

Q: Please summarize your testimony.

A: Credible sources indicate that distributed resources, particularly Efficiency and Solar Resources, can meet energy service reliability needs at least cost and provide significant additional benefits. The Commission should become better informed about how such resources can be cost-effectively used to meet Florida's energy service reliability needs.

Q: Please summarize your recommendations.

A: I have two recommendations. First, ***the Commission should take specific actions to become better informed about how Distributed Resources, particularly Efficiency and Solar Resources, can meet Florida's energy service reliability needs at least cost***. Such actions should include asking the Regulatory Assistance Project to provide a free in-house workshop about using Distributed Resources to meet energy service reliability needs, and could also include a) developing a method or criteria for utilities to evaluate PV's capacity value and optimize cost-effective uses; 2) developing a way to further stimulate utility implementation of Commission-Authorized/Encouraged least cost Efficiency Resources; and 3) asking for reports or presentations from the Commission's staff, utilities, or interested parties on topics of particular interest to the Commission.

Second, ***after becoming so informed, the Commission should take actions to incorporate Efficiency and Solar Resources, into its policies and strategies for ensuring reliability of Florida's energy services***. As part thereof, the Commission should create a regulatory climate that is conducive to and does not inhibit the use of such resources. Such an effort would include appropriate regulatory incentives for utilities. It would also engage consumers in assuming responsibility for wise resource use -- to help position customers to be allies in responding to unanticipated reliability changes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of LEAF's Direct Testimony was sent by U.S. mail this 16th day of August 1999 to:

Robert V. Elias, Esquire
Leslie J. Paugh, Esquire
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Paul Sexton, Esquire
Thornton J. Williams, Esquire
Thornton Williams & Associates
P.O. Box 10109
Tallahassee, FL 32302

Matthew M. Childs, Esquire
Steel Hector & Davis
215 S. Monroe Street, Suite 601
Tallahassee, FL 32301-1804

Jeffrey A. Stone, Esquire
Beggs & Lane
P.O. Box 12950
Pensacola, FL 32756-2950

Michelle Hershel, Esquire
Florida Electric Cooperative Association
P.O. Box 590
Tallahassee, FL 32302

Joseph A. McGlothlin, Esquire
Vicki Gordon Kaufman, Esquire
McWhirter, Reeves, McGlothlin et al
117 S. Gadsden Street
Tallahassee, FL 32301

John W. McWhirter, Jr., Esquire
McWhirter, Reeves, McGlothlin et al
P.O. Box 3350
Tampa, FL 33601-3350

Sheff Wright
Landers & Parsons
P.O Box 2721
Tallahassee, FL 32301

John Roger Howe, Esquire
Office of Public Counsel
111 West Madison Street
Room 812
Tallahassee, FL 32399

James A. McGee
Florida Power Corporation
P.O. Box 14042
St. Petersburg, FL 33733

Richard A. Zambo
598 SW Hidden River Avenue
Palm City, FL 34990

Jon Moyle, Esquire
Mole, Flanigan, Katz, Kolins, et al
The Perkins House
118 North Gadsden Street
Tallahassee, FL 32301

Lee L. Willis, Esquire
James D. Beasley, Esquire
Ausley & Beasley
P.O. Box 391
Tallahassee, FL 32302

Frederick M. Bryant, Esquire
FL Municipal Power Agency
2010 Delta Boulevard
Tallahassee, FL 32315

Ken Wiley
FL Reliability Coordinating Council
405 Reo Street, Suite 100
Tampa, FL 33609

Gary Lawrence
City of Lakeland
501 East Lemon Street
Lakeland, FL 32961

Rex Taylor
City of Vero Beach
P.O. Box 1389
Vero Beach, FL 32961

Raymond O. Manasco, Jr.
Gainesville Regional Utilities
P.O. Box 147117
Station A-138
Gainesville, FL 32614

Ben Sharma
Kissimmee Utility Authority
P.O. Box 423219
Kissimmee, FL 34742

Harvey Wildschuetz
City of Lake Worth Utilities
1900 Second Avenue, North
Lake Worth, FL 33461

Charles A. Russell
Florida Keys Electric Cooperative
P.O. Box 377
Tavernier, FL 33070

Tracy E. Danese
Jacksonville Electric Authority
21 West Church Street
Jacksonville, FL 32202

Gary Sasso, Esquire
Carlton Fields
P.O. Box 2861
St. Petersburg, FL 33731

James Swartz
City of Homestead
675 N. Flagler Street
Homestead, FL 33030

J. Paul Wetzel
City of St. Cloud
1300 Ninth Street
St. Cloud, FL 34769

Thomas W. Richards
Fort Pierce Utilities
P.O. Box 3191
Ft. Pierce, FL 34948

Dean Shaw
City of Ocala
P.O. Box 1270
Ocala, FL 34478

Timothy Woodbury
Seminole Electric Coop.
P.O. Box 272000
Tampa, FL 33688

Richard G. Feldman
City of Tallahassee
300 South Adams Street
Tallahassee, FL 32301

T. B. Tart
Orlando Utilities Comm.
P.O. Box 3193
Orlando, FL 32802

Larry J. Thompson
Utility Board of the City of Key West
P.O. Drawer 6100
Key West, FL 33041

Robert C. Williams
Florida Municipal Power Agency, Suite 100
7201 Lake Ellenor Drive
Orlando, FL 32809

Utilities Commission
City of New Smyrna Beach
Ronald L. Vaden
Post Office Box 100
New Smyrna Beach, FL 32170

Reedy Creek Improvement District
Willard Smith/Fran Winchester
P.O. Box 10175
Lake Buena Vista, FL 32830

Thomas J. Maida
Foley and Lardner
300 East Park Avenue
Tallahassee, FL 32301

Kenneth A. Hoffman
Rutledge, Ecenia, Purnell & Hoffman, P.A.
P.O. Box 551
Tallahassee, FL 32302

Debra Swim

Debra A. Swim
Legal Environmental Assistance Foundation, Inc
1114 Thomasville Road, Suite E
Tallahassee, FL 32303-6290.
(850) 681-2591

MARCIA K. ELDER
OVERVIEW OF RELATED PROFESSIONAL EXPERIENCE

**Intergovernmental Services*.: Owner/President. Currently serve as Executive Director and Energy Program Director for the American Planning Association, Florida Chapter. Served as Executive Director and Vice President of the Florida Solar Energy Industries Association. Was appointed by Florida Governor and Cabinet to serve on Power Plant Siting Task Force. Served on Energy Advisory Committee to the Secretary, Florida Department of Community Affairs. Served on Energy Advisory Committee of Governor's Commission for a Sustainable South Florida. Appointed to Clean Fuel Advisory Board created by 1999 Legislature.

**Florida Department of Transportation*: served as Director of Legislative and Energy Policy. Created Departmental Energy Policy Council.

**Florida Governor's Energy Office*: headed the Planning and Policy Research Office, including responsibilities for state energy policy, utility conservation, alternative energy sources and nuclear power issues. Appointed as Staff Director for legislatively created State Energy Policy Council.

* *Florida Department of Environmental Protection* (formerly Department of Environmental Regulation): served as liaison for the agency and the Florida Governor's's Office on low level nuclear waste management policies and initiatives; Served as Energy Policy Coordinator for the agency and Staff Coordinator for agency-wide Energy Committee; Served on legislatively created Coal Slurry Pipeline Committee and was appointed as Vice Chair by the then chairman of the PSC; Selected by Governor's Office to serve on Regional Energy Action Committee and later chaired same.

Issuesletter

Least-Cost Paths to Reliability: Ten Questions for Policy Makers

In the summer of 1998, utilities[1] in several regions of the United States faced escalating reliability problems that resulted in high price spikes, the threat of rolling blackouts and appeals for voluntary curtailment. Resolving reliability problems in a crisis atmosphere undermines customer confidence and is almost always unnecessarily expensive.

In the present movement towards competitive electricity markets, it is important to remember that electric system reliability is, in many respects, a classic public good. By the laws of physics, the essential attributes of adequacy, voltage and frequency are available to all interconnected users simultaneously. Like the textbook examples of lighthouses or national defense, most aspects of electric reliability are provided to everyone or no one, and everyone is required to pay. Public rules, imposed by governments, utilities, reliability councils and/or power pools, will determine the cost of reliability measures and the means of paying for them. In this environment, least-cost thinking can provide substantial benefits to the public and to our economy.

As summer approaches again, a number of states are facing reliability concerns, and regulatory commissions are asking utilities what steps they plan to take to ensure an adequate and reliable supply of electricity. Typically, regulators and utilities think of investment in additional transmission or generation to achieve and maintain reliability. Often overlooked are the reliability benefits that can be captured from the very sizeable energy resources held by *customers* — demand management and customer-owned generation, customer response to reliability-based market prices and simple improvements in the structure of the wholesale market.

Demand and non-conventional, supply-side resources can provide low-cost reliability solutions to utilities with reliability concerns. These resources include significant existing and new customer-owned generation, as well as load management and efficiency resources. But these resources can be efficiently tapped only if utilities and utility commissions take the necessary steps to establish the right regulatory and market conditions.

We know from long experience with interruptible contracts that many customers will accept lower levels of reliability if it means a lower cost for their electricity. Modern metering and communications technologies have created new opportunities in the demand management arena. To capture these resources, it is essential to create market structures that will reveal the cost of reliability and put accurate prices in front of customers. This Issuesletter identifies ten questions that every utility commission and governor's office concerned with reliability ought to be asking their utilities.

How much do the proposed reliability improvements cost?

WHAT DO HEALTH CARE and electricity reliability have in common? When an emergency occurs, cost takes a backseat to immediate remedial action. When it comes to electric reliability, the cost of remedial actions can be identified beforehand, and doing this can expose a wide range of less conventional power supplies to achieve the same reliability result.

Consider the following simple calculation. The most common utility action to meet peak demand

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1 We use the word utility to mean the distribution utility which is either a stand-alone entity, as occurs in some states that have restructured their electric industry, or a function within the fully regulated vertically integrated utility, as occ[redacted]

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today is to build (or buy) a power plant. A conventional combustion turbine (CT) costs about $400 per kW. The annual carrying cost, including depreciation, property taxes and return is about $80 per kW per year. If the CT is used for 800 hours per year (about 10 percent of the hours), the CT costs 10¢ per kWh. If it is used 80 hours per year (20 hours per week for four weeks), the capital cost is $1.00 per kWh. And, of course, the peaker that is never used, or is used only on the annual peak day, would have astronomical costs on a per kWh basis. Many options could provide equivalent reliability benefits at much lower cost.

The regulatory task is to get these "reliability costs" in front of customers and suppliers in ways that allow lower-cost options to surface and be used. Each of the reliability options discussed in this Issuesletter relies on knowing the price that would be paid for reliability from conventional resources.

Do wholesale prices reflect the high cost of energy during peak hours in a tight capacity market?

THE QUESTION REGULATORS should ask their utilities is how do prices in the region reflect long-term reliability costs? Before competitive markets were established, long-term reliability was met by setting reserve requirements — the amount of installed capacity above system peak loads. Many utilities in states and regions where retail competition has not yet been introduced continue to use this approach. The capital cost of that added capacity is included in rate base and allocated over many hours, masking the real cost of the reserve margin in customers' bills.

The critical questions for regulators now are: How are these costs treated in competitive markets? Will customers be exposed to these costs, or will they be hidden? Thus far the approaches vary widely. In the US, reserve margins are based on engineering concepts (e.g. a design standard for a 10-hour outage once every ten years). However, in other countries an economic standard and resulting market prices, rather than regulators or engineers, determine how much generating capacity is available to meet reliability needs.

In the UK, half-hourly spot prices reflect the value of "reliability," and this value is added to the price of power in that period. There is no engineering-based reserve margin. The calculation of the "reliability adder" is straightforward, although the first step is somewhat conceptual. Economists have estimated that reliability is worth about $3.00 per kWh to consumers and society (similar estimates have been made in the US).This is generally referred to as the value of lost load (VoLL) or, alternatively, the "value of energy not served."

Next, for every half-hour of the following day, the UK pool estimates the cost of reliability in that half-hour by multiplying the $3.00 per kWh value by the probability that there will be a shortage of power in that half-hour based on the expected demand and the availability bids received from generators. In most hours, the probability is nearly zero because the available supply greatly exceeds demand, so the reliability adder is also very close to zero. In a very tight half-hour, the probability may approach 100 percent, in which case the reliability/security adder is $3.00 per kWh (1.0 X $3.00 = $3.00). Of course, as the price approaches $3.00 per kWh, supplies that were not available become available, and customers who see real-time prices decide that some of their electricity use can wait. In ten years of operation, this system has balanced supply and demand successfully. In short, market prices are used to deliver adequate generating capacity.

Markets in this country generally do not use the UK approach. Both installed and operating reserve requirements are set more commonly on an engineering basis, although to some extent market mechanisms are being used to compensate owners for the costs of capacity. For example, NEPOOL sets an "Installed Capability" reserve requirement and has created a market-based system that operates monthly for those with surplus capability to sell to those who are capability short. This approach will have the effect of recovering the cost of installed reserves over more hours (i.e. monthly) than the UK's half-hourly, market-based approach, so peak period prices will be much lower than those in the UK.

The questions regulators should ask their utilities are: Do wholesale power prices in the region reflect or hide reliability costs? Are market approaches being considered?

How many customers see real-time prices?

ASSUME, through market mechanisms or otherwise, a reasonable estimate of real-time costs, including the cost of meeting peak loads, is available. The next question is: Do customers see these prices? In theory, all customers should see real-time prices which would enable them to make their own value decisions at all times, especially during very expensive peak periods. But residential and small commercial customers do not have the sophisticated metering needed to price on a real-time basis. For most customers, high costs in a few hours each year appear as a small increase in average monthly prices Large customers have the needed meters, but most are not on real-time prices, preferring instead the comfort of predictable prices. Thus, we find we have labored hard to create a competitive, market-based system, but few, if any, customers actually see the resulting prices in a way that would trigger an expected market response.

Fortunately, there are other options that achieve similar results. Real-time, buy-back rates for customers with installed generation as described in question four is one option. New approaches to interruptible load as described in questions five and six have been shown to work in a number of states.

Demand bidding as described in seven is another way to show customers real-time prices even though they are not "on" real-time prices.

Do you have peak purchase rates for customer-generated power?

IN MANY SERVICE TERRITORIES, there exists a large amount of stand-by generation owned by commercial customers at facilities such as hospitals, schools and large commercial buildings and by industrial customers at industrial sites. Although these generators were installed primarily for emergency power, many of them could operate more frequently. Utilities could organize these customers into an available power source by establishing purchase power rates together with an effective communications network. This type of approach also encourages customers to consider installing one of the newer "distributed" types of generation, such as fuel cells or microturbines.

How extensively have interruptible rates been marketed and how much have they effectively paid for interruptions?

FOR TOO MANY YEARS in too many places "interruptible contracts" have been an excuse for targeted rate reductions to a few large industrial customers. Often, customers have been paid (through lower rates) but have not been called to interrupt for years. In some cases, when they finally are called, unprepared customers either fail to interrupt or simply opt for a firm power back-up rate which is also priced well below the real cost of providing reliable service at peak periods. In these cases, utilities and their customers are paying for reliability enhancements that the system is not receiving. If called upon load reductions are not delivered, reliability benefits are not achieved, reserve margins will have to be higher, and the costs of reliability will be greater. One possibility? Utilities and regulators could adopt interruptible rate tariffs that compensate customers for actual, not just potential, interruptions.

Many utilities have interruptible rates available to some industrial customers, but experience shows that there are additional customers who would participate in interruptible rates if the prices paid for interruption reflected their value to the system, and if the benefits of those rates were seriously marketed. Similar kinds of interruptible rates could be established for residential and commercial customers by offering controlled loads for air conditioning, heating, lighting and other specific end uses.

3

Have load-shedding cooperatives been organized?

ENCOURAGING COMMERCIAL businesses to form load-shedding cooperative arrangements can produce large and highly reliable demand reductions. The agreement to shed is made between the utility and the coop. This allows coop members to have a variety of arrangements among themselves as to which business backs down load, when and in what amounts, as well as how profits will be shared. Commercial businesses in several major metropolitan areas cities, including Orange County, CA, Chicago and Boston, have had such coops operating for many years.

Does your spot market include a bidding system for demand-side reductions?

SPOT MARKET PRICES are generally determined a day in advance by utilities or in some regions by an independent system operator, power exchange or similar entity. Demand for each half hour (or other measured period) is projected and a dispatch, or "merit" order for all available power plants, is devised to meet that demand using either marginal costs or bid prices to rank order the plants, and using the cheapest plants first. The cost of the last unit needed to meet demand in that time period sets the spot market price for all energy sold in that period.

A central shortcoming to most of these dispatch systems is that the demand projections used to set the market clearing price are based on load estimates, not on bids, and therefore do not reflect any demand response to the supply-side bids. The result is higher prices for all consumers. Fixing this problem requires a process that allows demand-side reductions to be bid into the dispatch schedule with bids for demand reduction at specific prices. The bids for demand reduction could be received simultaneously with supply bids, or in a second round auction held to see what load chooses to back down given spot prices. (The "multi-settlements", or second round bidding, approach is currently being proposed by the New England ISO and has been endorsed by regulators in that region.) It is important to realize that the benefits of lower clearing prices will accrue broadly across the system, whether or not demand-reducing bids are compensated directly in the market or are simply the result of better pricing information. Either approach can work and either could produce lower prices, lower demand and improve reliability.

What are you doing to facilitate a competitive wholesale market and remove barriers to competitive wholesale suppliers?

IN RECENT YEARS, the uncertainty associated with restructuring has caused utilities to postpone capital investment, including investment in new plants. This has aggravated and precipitated reliability problems. Competitive independent power producers (merchant plants) have demonstrated the ability to respond to market conditions and quickly bring on new plants in as little as two years. Competitive producers have stepped in where wholesale markets are

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The Regulatory Assistance Project
177 Water Street
Gardiner ME 04345-2149

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well developed and have reasonably predictable power or transmission rules. Statutes and practices that discourage or prohibit the development of merchant plants are a barrier to creating a wholesale market that allows competitors to respond to price signals. Removing these obvious (and antiquated) utility and regulatory barriers are important steps.

9 Have you identified and aggressively implemented energy efficiency programs to mitigate peak load demand?

THE BEST WAY TO AVOID a reliability crisis is to avoid the demand that creates it. In the early 1990s, utilities were fairly skilled at designing and implementing energy efficiency programs aimed at peak shaving. Continuation or resumption of efficiency programs that target commercial lighting and HVAC systems as well as a wide variety of household uses are undoubtedly the cheapest source of reliability. It is a great loss to our national electric system that the demand-side programs of so many utilities have been greatly diminished or have disappeared altogether in recent years. Utility spending on demand-side resources declined by one-third, from $1.6 billion to $1.05 billion, between 1994 and 1996 alone. Incremental energy savings have plunged even more dramatically, from nearly 10 billion kWh in 1993 to 4.3 billion kWh in 1996. Restoring support for investment in energy efficiency should be high on the policy option list for regulators.

10 Do you have a system in place to request (and pay for) voluntary curtailments?

THE CALL FOR VOLUNTARY CURTAILMENTS need not be a desperate last moment appeal. Establishing a process for routine requests can create a reliable, voluntary backing down of demand by educating customers as to its value without invoking fear. For example, Central Maine Power Company's routine use of Kilowatt Savings Time (KST) on peak setting winter evenings in the 1980s created a knowledgeable public, reliable damping of peak demand and no sense of public crises. Customers accepted KST as a way of saving money for all customers.

Last summer Commonwealth Edison (Unicom) experimented with a program for making similar public appeals in its Chicago service territory. Edison's program has paid for voluntary curtailments by placing a large sum of money (one million dollars) in a special fund each time an alert day is called. The funds are administered by a specially constituted independent board.

Conclusion

POLICYMAKERS SHOULD ENCOURAGE the reliability market to be as broad and interactive as possible by insisting that all cost-effective resources be developed by utilities and others charged with maintaining system reliability. Accomplishing this requires creation of the needed price signals, communication networks and clear procedures that allow both demand- and supply-side market responses to the costs of maintaining reliability.

The Regulatory Assistance Project
177 Water Street
Gardiner, Maine 04345-2149
Tel (207) 582-1135 Fax (207) 582-1176
Email: rapmaine@aol.com
Web: www.rapmaine.org

Project Directors:
Cheryl Harrington David Moskovitz
Richard Cowart
in association with
Carl Weinberg Peter Bradford

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DRAFT - SEND COMMENTS TO Davidmosk@aol.com - DRAFT

DRAFT REPORT TO NARUC

Profits and Progress Through Distributed Resources

July 15, 1999

Regulatory Assistance Project
177 Water Street, Gardiner, ME 04345

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Tel: (207)582-1135 Fax: (207)582-1176
E-mail: rapmaine@aol.com http://www.rapmaine.org

DRAFT REPORT TO NARUC
Profits and Progress Through
Distributed Resources
July 15, 1999

Regulatory Assistance Project

I. INTRODUCTION AND EXECUTIVE SUMMARY

Technological advances in other industries are dramatically impacting the electric utility industry at both the macro and micro level. At the macro level, the aerospace industry has delivered the highly efficient, inexpensive, quickly constructed turbine-based technologies (the turbine in a GE combined-cycle power plant has its origin as an aircraft jet engine) which have been a driving force behind electric utility industry restructuring.

Less well known, but even more dramatic are technologies born in the military (M-1 tank and Patriot missile electric power source power new microturbines) and automotive industries (fuel cell car engines will be fuel cell power plants) which bring mass produced small and micro scale power plants. These are distributed resources are located in the utility's distribution system and can be on either side of a customer's electric meter.

Many, but not all, of these small technologies are highly efficient, cleaner than central station generation, and mobile. Then there are other distributed resources based on renewables (wind and photovoltaics) and energy efficiency that is always cleaner and often cheaper. Most importantly, thanks to small size and mass production, the cost of these technologies is dropping fast. As distributed resources combine with the advances in control and information technologies deployed in the distribution system and in customers premises, it is clear that distributed resources can play a central role if markets allow these resources to compete.[1]

Creating a market environment in which cost-effective distributed resources can compete needs the attention of utility regulators. The task is complicated because distributed resources produce multiple services and each one needs the equivalent of a market. For example, distributed generators deliver energy and capacity but the increasingly competitive generation market is centered around large scale generators. Here, regulator's role is to assure that entry is not impaired and wholesale power market rules accommodate their small size. A much tougher job for utility regulators stems from the fact that distributed resources also compete against monopoly distribution facilities; here the sole market is mostly in the hands of state regulators. Harnessing market forces in distribution services requires innovative policies and establishing a regulatory and distribution utility environment that encourages, or is at least neutral, to the deployment of any cost-effective resource that meets customer and utility needs.

The early utility response to distributed resources is mixed. Some utilities are actively engaged in trying to find distributed resources business opportunities. Examples include the half dozen utility affiliates that have joined with Allied Signal to market its micro-turbine, Plug Power (Detroit Edison affiliate) developing and marketing a home-scale fuel cell, and Duquesne Power and Light investing in H Power, a fuel cell developer.

Other utilities acting on their own and through the Electric Power Research Institute (EPRI) are developing knowledge and expertise on how distributed resources can help them meet

[1]Sun Microsystems recently began marketing "Jini", an Internet based technology that allows inexpensive computer chips embedded in home appliances to communicate through power line carriers and the internet with in home or offsite control systems. See <http://www.sun.com/jini>

their distribution needs. Chicago's Commonwealth Edison recently unveiled the "Neighborhood Project," a joint effort of Edison and environmental and community activists to explore how distributed resources can be deployed to reduce costs and improve service on a neighborhood-by-neighborhood basis.

In the bad news category are the defensive utility strategies that work to slow the spread of distributed resources. These strategies are generally described as barriers to deployment. They include onerous and non-uniform interconnection requirements, high rates for standby or backup power, special contracts to discourage self-generation, and recent rate design proposals to substantially increase fixed monthly charges and decrease volumetric charges.[2] See Boxes ___ and ___.

This report looks at the relationship between the use of distributed resources and utility profits.

Our conclusions are:

) **Where the distributed resource is located is critical.**

Distributed resources installed on the utility side of the meter do not jeopardize profitability.

Distributed resources located on the customer's side of the meter almost always hurt

[2] These types of rate design changes have large customer impacts and are strongly opposed. For example, under the rate design change described a customer using 1000 kWh a month would experience a 50% rate reduction and a customer using 100 kWh per month would experience a 500% rate increase. Relatively minor increases in customer charges have triggered referendums calling for elected commissioners and the enactment of laws rendering customer charges illegal. (Add citation***)

utility profits. This is true for both demand-side and supply-side resources. From the utilities' perspective, demand- or supply-side resources installed on the customer side of the meter produce the same effect: sales go down and as a result revenues and profits go down.

Locating distributed resources in high-cost areas can help. The significant distribution cost savings resulting from distributed resources located in high-cost areas can reduce utility financial losses or even add to profits if the distributed resources are deployed *only* in high-cost areas.

2) **How utilities are regulated is the most important determinant of whether utilities have an incentive to deploy or obstruct distributed resources located on the customer's side of the meter.** Regulation, as it is practiced in most states, creates overwhelmingly adverse financial impacts on utilities when customers install distributed resources on their side of the meter. If this condition persists, we can expect utilities to resist distributed resources. Barriers will fall slowly, new barriers will be erected, and the deployment of cost-effective distributed resources will be delayed.

By far the predominant form of regulation currently in use in the US is traditional cost-of-service regulation. Where performance-based or alternative kinds of regulation are employed, the predominant form is price cap, as distinguished from revenue cap, based regulation. Price cap regulation generally discourages distributed resources. Revenue cap regulation does not. Where utilities are vertically integrated and generation is regulated, most states have fuel adjustment clauses. In these states, the effect of the fuel clause is that utilities can sell a kwh that costs 15¢ to produce for

7¢ and make money.

3) **Industry structure does not have much impact upon profitability.** The profits of the regulated utility go up or down based on the way regulation works. If the regulated entity is a wires-only company and its revenues are derived from volumetric charges, profits go down when distributed resources cause sales to go down. Having an unregulated affiliate, MicroCo. Does not change the conclusion. MicroCo's deployment of distributed resources on the customer's side of the meter reduces the utility's revenues and profits. The business strategy that makes most sense is for MicroCo to operate everywhere except in its utility affiliates service

The business strategies and regulatory proposals from combined gas and electric companies will be especially interesting to watch. A very profitable strategy for a combined utility would be to market gas fired distributed resources in areas that are high cost for electric distribution and low cost for gas distribution.

There are a number of policies regulators have available to align utility profitability with the deployment of cost-effective distributed resources. The most promising include:

1) Revenue-based PBR. Performance-based regulation can either take the form of price caps or revenue caps. Revenue caps approaches for distribution utilities remove the disincentive to customer-side distributed resources.

2) Distributed Resource Credits. A system of geographically deaveraged credits can give customers and others better economic signals to install distributed resources in high cost areas without the adverse consequences of de-averaged retail prices for all customers.

3) Distributed Resources Development Zones. High cost areas can be designated to give customers and developers information on where distributed resources are most desirable. Economic incentives, such as direct payments or waivers of standby charges, can be used to direct development to these areas.

4) Symmetrical pricing flexibility. Flexibility to lower prices to discourage non cost effective distributed resources should be tied to the obligation to increase prices in high cost areas to encourage cost-effective distributed resources.

Getting utility profitability aligned with the deployment of cost effective distributed resources is an important step, but it does not guarantee success. Even if regulation is able to completely align utility profits in the deployment of distributed resources, there may be other factors that overwhelm the power of any incentives. Such diversionary factors may include rate impacts, competitive and other risks, and issues of control or the lack thereof, each of which can undermine the incentives created in a PBR.

II. DISTRIBUTED RESOURCES: WHAT ARE THEY AND WHY SHOULD WE CARE ABOUT THEM?

A. What Are Distributed Resources?

Distributed resources are demand- and supply-side resources that can be deployed throughout an electric distribution system, as distinguished from the transmission system, to meet the energy and reliability needs of the customers served by that distribution system. Distributed resources can be installed on either the customer side or the utility side of the meter.

Some supply-side

DISTRIBUTED RESOURCES BENEFITS
(Note: this box is being expanded with more description of each line)

Benefits of distributed resources fall into a number of categories.

- Energy and capacity
  - Reduced line losses
  - Improved power factor
  - Ancillary services
- Distribution and transmission
  - Reduced and deferred investment
  - Reduced strain
  - Reduced restoration cost after outage
- Environment
  - Reduced emissions
  - Reduced land use impacts
- Reliability
  - Shorter and less extensive outages
  - Lower reserves
  - Ancillary services
- Financial
  - Shorter lead times
  -

resources, such as generators driven by gasoline and diesel-fueled reciprocating engines, are mature technologies whose cost and performance characteristics are well known. Others, such as micro-turbines and fuel cells, are cutting-edge technologies borrowed and adapted from the defense, automotive, and aerospace industries. Many of these newer technologies are already more economical, more reliable, and cleaner than the familiar backup generators. More importantly, many exhibit a very strong likelihood of continued and significant cost and reliability improvements.

Demand-side distributed resources comprise a long list of load management and energy efficiency options – reducing peak electricity demand, high efficiency buildings, advanced motors and drives for industrial applications, and many others.
[3]

Barriers To Distributed Resources
Insert list of barriers including non utility barriers such as zoning, fire codes, and others

It is not necessary to define distributed resources more narrowly to understand the implications these resources have for the distribution company's profitability.
[4] The only distinguishing characteristics for the purposes of this discussion are that these facilities are installed at the distribution level and they can be on either side of the meter.

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[3] "Customer side of the meter" is not synonymous with "demand-side," although there is a good deal of overlap. The "customer side of the meter" is just that — that part of the electric system that is on the customer's side of the meter. It refers generally to all aspects of customers' demand for grid-supplied electricity. Customer actions that are relevant to this discussion include improvements in the efficiency with which electricity is consumed or generating equipment that displaces service that would otherwise be provided by the utility. "Demand-side" simply refers to actions which improve the efficiency with which electricity is consumed or moves electricity use from peak to off-peak periods.

[4]The size of distributed resources will, however, influence regulatory requirements in other ways. For example, interconnection and metering specifications will vary according to the size of the resource in question. To keep transaction costs low, the application of policies such as net metering and standard tariffs will also depend on size.

In most cases, distributed resources will be quite small, ranging from less than one kilowatt (kW) to only a few hundred kW, but there are examples of larger installations (generally in commercial and industrial settings). The practical size limit for generators in the distribution system is about 35 to 40 megawatts (MW).

B. Why Should Regulators Care Whether These Resources Are Used?

There are five reasons regulators should care about distributed resources deployment. The first three are compelling enough: they can save money and improve reliability, reduce pollution, and give customers service and choice (thus ameliorating market power).

The fouth reason falls slightly outside the scope of traditional regulation but is nevertheless

Rate Design Can Discourage Distributed Resources

There is a new set of utility rate design proposals that will discourage distributed resources. Utilities are starting to propose increased fixed monthly customer charges and decreased usage charges for distribution services. An extreme example is ___ that is proposing to raise its customer charge to ___ and decrease its energy charge dramatically. This will certainly make distributed resources far less attractive to customers.

These proposals are also interesting because they reveal a conundrum faced by utilities that propose high customer charges and oppose revenue caps. Consider the following two options:

> Option 1 - change rates from 5¢ per kWh with no customer charge to $25 per month with no energy charge,
>
> Option 2 - leave rates unchanged at 5¢ per kWh and adopt a PBR in the form of a revenue cap of $25 per month per customer.

Option 1 discourages distributed resources, causes politically unacceptable shifts of revenue from high use to low use customers, and is inconsistent with sound rate design principles. Option 2 leaves prices unaffected but interestingly, in terms of the financial effect on the utility, both options produce the same effect. Under either option, increased sales do not increase profits.

important Distributed resources have favorable local economic and job effects. For example, jobs are created in the distributed resource industry at rates roughly 2 to 5 times greater than in the central station and transmission sub-sector.

But the fifth reason is particularly critical, and is the focus of this report: only regulators can implement the reforms needed to allow distributed resources to compete fully and fairly, in service to the public interest.

Cost-Effectiveness

Distributed resources' cost effectiveness depends on perspective and what benefits are being counted. For a utility, distributed resources are cost effective when the capacity, energy, T&D, ancillary services, and system reliability benefits exceed the cost of the distributed resources. If the distributed resource is on the utility side of the meter, the utility's cost is the capital and operating cost of the resource. If the distributed resource is on the customer side of the meter, the utility's cost is the loss of revenues from the customer.

To customers, the capacity and energy savings are based on avoiding retail purchases. Other customer benefits, which often are much larger than the capacity and energy savings, include the value customers place on increased reliability plus any non-electricity benefits (heat, hot water, air conditioning, etc.).

Not all distributed resources are cost-effective. Distributed resources cost effectiveness varies -- by utility and customer and by location. The clear trend is that more distributed resources are becoming cost-effective in more locations.

1. Save Money and Improve Reliability

The first and probably the most important reason that regulators and customers should care about distributed resources is that they offer opportunities to save money and improve reliability. (See Box __ for a summary of how distributed resources improve reliability.) What was once thought to be a bright line between generation on the one hand and

transmission and distribution (T&D) on the other turns out to be not so bright after all. Distributed resources deliver the full array of generation services (all with lower line losses); they can also substitute for distribution and transmission system investment. The type of distributed resource, where it is installed, and when it operates all influence the benefits the resource provides.

Remarkably, in ten of eleven utility studies, the value of distributed resources that flowed from reduced investment in T&D and from enhanced system reliability *exceeded* their capacity and energy savings.
[5]

It is likely that most utility distribution systems in the country have at least some specific areas where it is very costly to deliver electricity. On average, the cost of distribution plant in the United States is about 2.5 cents per kWh. Typically, high-cost areas are those where distribution lines are being installed for the first time or are near capacity and need to be upgraded or replaced. The per-kWh cost in such areas may be an order of magnitude higher than the average distribution cost. Our discussions with distribution companies reveal that distribution costs of 20 cents per kWh in high-cost area are not uncommon.

2. Reduce Pollution

[5] See *Policies to Support a Distributed Energy System*, Starrs and Wenger, Renewable Energy Policy Project, <http://www.repp.org/articles/pv/3/3.html>.

Distributed resources can reduce pollution. Though some distributed resources, such as reciprocating engines, may produce more emissions than state-of-the-art combined cycle gas-fired facilities, many distributed resources, such as photovoltaics and fuel cells, produce significantly less pollution than those new central station technologies. Still others, such as micro-turbines, provide opportunities to reduce emissions by improving the efficiency with which energy is consumed, through improved heat rates and combined heat and power applications.

Reliability Benefits

Reliability benefits accrue in at least five ways.

1) Lower Reserve Margins. The level of reserves required to deliver a given level of reliability varies with the size of generating units and the forced outage rate of those units. The larger the unit size and the higher the forced outage rate, the greater the level of reserves required to deliver a given level of reliability. Distributed resources, because of their very small size, will almost always reduce the amount of reserve capacity needed to meet a given level of reliability. Resources with low forced outage rates would further reduce required reserves.

2) Reduced Transmission Loading. Reliability is also influenced by the capability of transmission facilities. If located in the right place and operated at the right time, distributed generation can increase reliability by freeing transmission lines to serve reliability purposes.

3) Reduced Outages. The extent of outages (number of customers affected) and the time needed to restore service after an outage can be reduced by the deployment of distributed resources.

4) Improved Customer Reliability. An individual customer's reliability can be improved when distributed generation is located on their site and sized to meet all or at least the essential portion of their load. This provides the customer with the opportunity to continue to receive electric service when the remainder of the electric system is down.

5) Improved Neighborhood Service. It is possible that improved control and communication technology installed in the distribution system will make it safe and economical to "island" parts of the system. A whole neighborhood or large subdivision might be able to temporarily disconnect from the grid and receive service from distributed resources within the area. This would increase reliability to customers in the island and by "freeing up" electricity could help customers that continue to be grid connected if the problem was supply related.

3. Enhance Customer Service and Choice

> **Customer Choice**
>
> Home sized emergency generators cost between $250 and $500 per KW and at $1 per gallon of gasoline have running costs (fuel only) that range from 7¢ to 25¢ per kWh.
>
> Are these generators "cost effective"? Probably not to those steeped in utility economics but they are apparently very cost-effective to customers. Y2K concerns have been fueling an already brisk market for home sized emergency generators. One large mail order company, Northern Tool Company, warns its customers of four to six month back orders on most of the twenty or so models it sells.
>
> Imagine how customers will respond when silent, reliable, and maintenance-free PVs or fuel cells, or quiet cogenerating micro-turbines are cheaper than these already popular home generators.

Some states are moving ahead with electric industry restructuring, while others are waiting to see if retail competition's promises of lower costs and improved service will be realized. **But with or without retail customer choice and whatever the structure of a state's electric sector, distributed resources give customers more ways to meet their energy needs, improve the reliability of their service, and lower their costs. Distributed resources also provide a valuable and important check on utility market power.**[6]

4. Regulators Public Interest Role

[6] Distributed resources provide especially important checks on market power in transmission-constrained areas where these resources may be the only effective competition to centrally-generated electricity.

Regulators should care about distributed resources. Distributed resources can be cost-effective, reduce pollution, and enhance customer choice, but existing regulatory practices unintentionally discourage the use of these resources. If the use of distributed resources is unprofitable for a regulated utility, we should expect barriers to their deployment to be erected and maintained. If, on the other hand, the deployment of distributed resources is made profitable, barriers that currently exist are likely to be quickly overcome with the active assistance of the utility.

III. PROFITABILITY

A. Profitability Defined

Our concern in this paper is the incentives that cause utilities to take, or avoid taking, specific actions. Thus, the question we focus on is: What happens to a utility's profits if it does "X" or if its customers do "Y"? The incentive (or disincentive) is the action's incremental effect on profits, not the level of profits.

Profits can be expressed in absolute terms, such as $100 million, or as a rate, such as dollars per share or percentage return on equity (ROE). Focusing on the absolute return can be very misleading. Rate of return is the more important measure of profitability. Profitability improves if the rate of return (earnings per share) goes up. For example, through increased sales or a merger or acquisition a firm can grow and see its earnings grow from $100 to $150 million. Still, if its costs or related capital requirements grew faster than its revenues, its rate of return and earnings per share would decline.

Shareholders would not be happy with management if earnings went up by $50 million but earnings per share, and hence ROE, dropped by 10%.

[7]

B. Profitability to Whom?

1. The Utility

The term "utility" is somewhat ambiguous these days, in light of industry restructuring. For the purposes of this paper, "utility" is the regulated entity, regardless of its form. The regulated entity, or utility, may be a wires-only distribution company (DISCO), a vertically integrated company, or something in between.

This report examines the impacts of distributed resources deployment on utility profitability. "Deployment" is used instead of "investment" because distributed resources may be installed and owned by the utility, customer, energy service provider, or any other entity. In each case, there will be predictable effects upon the utility's profitability.

2. Utility Affiliates

[7] A good example of the difference between profits and profitability is the recently announced decision of Lockheed Martin-Marietta, a major defense and technology company, to sell $1 billion of assets (including several product lines) in order to improve profitability. If the move is successful, Lockheed's absolute revenues and earnings will drop, but its rate of return (earnings per share) will go up.

Many regulated utilities also have affiliates engaged in unregulated activities; some of those activities are directly related to distributed resources. When considering whether the deployment of distributed resources is profitable to the utility, we do not consider the profits for the unregulated businesses.

Consider a utility, UtilCo, that has three unregulated affiliates: GenCo owns and operates large power plants, Retailco markets electricity to retail customers, and MicroCo sells distributed resources to retail customers. Next, consider whether the nature of each affiliate directly affects the costs, revenues, or profits of UtilCo. As any generating company, GenCo will try to expand its market and reduce its costs. Retailco will want to sign up as many profitable customers as it can. GenCo and Retailco may be profitable or unprofitable, but neither's actions cause UtilCo's regulated revenues or costs to change.[8] UtilCo can be expected to do what it can to favor the interests of those (both within and outside its service territory), but these actions have no direct bearing on the regulated utility's profitability.

MicroCo's story is very different. The deployment of distributed resources on the UtilCo customer's side of the meter reduces UtilCo's revenues and profits. In this case the business strategy that makes most sense is for MicroCo to operate everywhere except in UtilCo's service area.
[9] Meanwhile, UtilCo might create barriers to others trying to install the same types

[8] UtilCo's would see increased profits if RetailCo's marketing activities caused sales to increase.
[9] UtilCo's service area would probably be used in the early stages to test products and gain initial experience. Also, if UtilCo knew a customer was serious about adding a distributed resource having MicroCo get the business is better than letting the business go elsewhere.

of facilities in its local service territory.[10]

Next, imagine the regulatory response to a utility request to increase prices for delivery service (*that is*, distribution) to redress a substantial loss of revenue due to distributed resource deployment in its service area. An order denying the rate increase and telling the utility to create an unregulated subsidiary to accelerate distributed resources deployment outside the utility's territory and use the profits to make up the losses is unlikely. On the other hand, if the utility were UtilCo, and losses were directly attributable to MicroCo's installation of distributed resources in low cost parts of UtilCo's service area, an order denying the rate increase because the utility imprudently refrained from ceasing MicroCo's activities or restricting them to high-cost areas is plausible.

3. Does the Utility's Structure Matter?

Two related issues are at the core of many restructuring debates — utility structure and the utility's ownership of generation. It is natural to expect these overarching issues to have a major impact on utility profitability. As it turns out, however, though both have major implications for many utility matters, neither has a very significant effect on the issue addressed by this report – distributed resources and utility profitability.

A utility may be a "wires only" distribution company or, at the other extreme, it may be a vertically integrated monopoly. In between reside a number

[10] This business strategy is not unique to distributed resources. For example, some Florida utilities are actively engaged in promoting, and are profiting from, the creation of a competitive electric industry outside of Florida, while at the same time are acting to delay the introduction of competitive access in their home state.

of hybrids. One example is a corporate structure where the utility regulated wires business is functionally separated from its unregulated activities (which may include distributed resources) and "codes of conduct" have been established to keep the relationships between the divisions honest.

Our conclusion is simple: structure does not have much impact upon profitability. The profits of the regulated utility go up or down based on the way regulation works. If the regulated entity is a wires-only company and its revenues are derived from volumetric charges, profits go down when distributed resources cause sales to go down. The possible exception to this is when distributed resources are restricted to the highest cost areas of the distribution system. Also, as discussed in greater detail in Section ____, if the regulated entity is a vertically integrated utility with a fuel adjustment clause (FAC), the same profit implications exist.
[11]

This does not mean the structure of the utility is unimportant or that the structure has no other implications for distributed resources. Clearly, the choice of utility structure is important. The utility's structure affects market power, state and federal jurisdiction, and a host of other important considerations. But, when it comes to distributed resources, corporate structure has little effect upon utility profitability.

4. Does it Matter Whether Distributed Resources Are Owned by the

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[11] If the regulated entity is a vertically integrated utility without a FAC, and energy costs (fuel or purchased power) are very high, the utility's profits may suffer more from supplying power a than it would if the customer installed a distributed generator.

Utility?

Contrary to first impressions, utility profitability (rate-of-return, as opposed to earnings) is not directly affected by who owns the distributed resources.

The question of utility ownership of distributed resources has many complex facets.[12] How that ownership affects profitability is one of the easier ones, although it is made confusing by the commonly held, and erroneous, view that adding to rate base (investing in capital, "gold plating") improves profitability.[13] There are a few simple economic concepts that inform us on this issue. First, as already discussed, profitability (as distinguished from profits) improves when the rate of return or earnings per share go up. Adding $1 million to profits does not help if the associated costs reduce the rate of return from 10% to 9%. It follows that profitability goes up only if the rate of return on new investment exceeds the rate of return on existing investment. As a general rule, profits go up if the utility can increase revenues without increasing costs.

Consider first the case in which distributed resources are located on the utility side of the meter and hence sales, and revenues, are unaffected by their deployment. In this instance, investment in cost-effective distributed resources substitutes for even higher levels of investment in distribution plant. Less

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[12]These issues are being fully and forcefully debated in a California Proceeding Docket R. 98-12-015. Some parties, including the Office of Ratepayer Advocates and many competitive suppliers of distributed resources, are arguing strenuously that the distribution utility role should be limited and ownership should be prohibited. Distribution utilities are arguing that their role is more expansive and ownership should be an option.

[13]The Averch-Johnson effect, named for the economists who first postulated it, describes a utility's tendency to overinvest, or "gold plate." Simply put, the theory holds that a utility will overinvest in capital *if* its rate-of-return exceeds its cost of capital. The same tendency would exist *if* its profits on new investment are expected to exceed the average level of its profits. Neither condition is typical of regulated utilities.

investment with the same level of revenues means higher profits. It also follows that if another entity built and owned the distributed resources (e.g. an IPP that sells power to the wholesale market), the utility would see the same revenues and would have *no capital investment.*

Table 1 shows the basic calculations for the two cases. In both, $100 of additional capital must be added. In the "Expensing" case, a customer or a third party adds the capital and the utility pays for it as an annual operating cost of $20 per year. In the "Owning" case, the utility makes the investment.

Table 1

Assumptions

	Base Case		Capital Addition Case ($100)	
Net Plant	1000		1100	
Debt (amount and	500	0.08	550	0.08
Equity (amount and cost)	500	0:12	550	0.12
Equity (shares)	100		110	

	Base Case	**Expensing Before and After New Rates**		**Owning Before and After New Rates**	
		Add'l $20 O&M **Before**	Add'l $20 O&M **After**	Add'l Cap **Before**	Add'l Cap **After**
Revenue	1200	1200	1220	1200	1220
O&M	1000	1020	1020	1000	1000
Depreciation	100	100	100	110	110
Net Operating Income	100	80	100	90	110
Interest	40	40	40	44	44
Earnings	60	40	60	46	66
ROE	**12.00%**	**8.00%**	**12.00%**	**8.36%**	**12.00%**
EPS	**0.60**	**0.40**	**0.60**	**0.42**	**0.60**

IV. REGULATION TODAY

How utilities are regulated is the most important determinant of whether utilities have an incentive to deploy or obstruct cost effective distributed resources. Our survey of current practices in state regulation reveals three features that are relevant to this issue. First, by far the predominant form of regulation currently in use in the US is traditional cost-of-service regulation. Second, where performance-based or alternative kinds of regulation are employed, the predominant form is price- based (as distinguished from revenue-based) regulation. Third, where utilities are vertically integrated and generation is regulated, most states have fuel adjustment clauses. (See Appendix A for more detail).

A. Regulation: The Basics

The key to understanding the problem distributed resources pose to utilities is having a clear answer to a deceptively simple question: How do utilities make money? Two things combine to make the answer less than obvious. First, most observers are unaware of how utility economics differ from the economics of an ordinary competitive business. Even veterans may not understand this, because the issue is exposed only during rate cases and, in many states, it has been a very long time since a traditional rate case has occurred. Second, the details of regulation have a profound, but usually not obvious, effect on the answer.

The good news is that by challenging a few widely held misconceptions, understanding how utilities make money becomes clear.
[14]

1. Misconception Number One: Cost-of-Service regulation creates incentives.

[14] This information relates to how regulation works in most states. A few states have adopted PBR and a few others have a variety of "balancing" accounts that can change the incentives faced by utilities.

The notion that there are two approaches to regulation. Cost-of-Service (COS) regulation on the one hand and Incentive, or Performance-based Regulation (PBR) on the other, is a vast oversimplification that does more to confuse than inform the issue. **All regulation is incentive regulation.** Regulation in any form gives firms incentives to behave in ways that maximize profits. [15] The question then is: What incentives does a particular regulatory approach create and how powerful are those incentives? The answer to this question is not even remotely informed by the names given to a particular regulatory scheme. In certain circumstances, the cost-cutting and performance incentives of COS can be much more powerful than those of PBR. The devil is in just a few of the details.[16]

2. Misconception Number Two: What was said in rate cases matters.

Rate cases seem to be never-ending examinations of the "reasonableness" of costs, disputes about the "prudence" of investments, and arcane "rate of return" debates over the costs of capital and its structure (debt/equity ratio). One might be led to believe that rate case decisions on this cost or on that, on the rate of return, and on revenue requirements actually have some real world consequence. They do not.

Rate cases have only one consequence that lasts beyond the last day of the rate case: prices have been set. Once the rate case is completed and prices are set,

[15] This is even true of ostensibly non-profit utilities — cooperatives and municipals — who act naturally to preserve their fiscal health, which is to say that they seek to ensure positive net income.
[16] The important details are who bears what risks, the level of exposure, and the length of regulatory lag or the period between financial reviews. See ___ and ___ for more details.

everything said in the hearing process is irrelevant to the fundamental question of how utilities make money. From the day prices are set, utility profits are ruled by a simple formula:

PROFIT = REVENUE - COSTS

The REVENUE part of the formula is easily computed, but it has nothing to do with the line from the rate case order labeled "revenue requirement" or "allowed revenue."

[17] The utility's actual revenue is governed by the following relationship:

REVENUE = PRICE * QUANTITY

Prices were set at the end of the rate case and are fixed until the end of the next rate case. In arithmetic terms, price is a constant, so revenue is directly related to quantity, or sales. Ignoring the subtleties of rate design (*i.e.*, the structure of prices — energy charges, demand rates, and customer charges), if sales go up 2%, revenues will go up by the same percentage.

The COST part of the profit equation is more complicated and takes us to the next myth.

3. Misconception Number Three: If sales go up, costs go up.

The system of regulation that we have used in this country for over a hundred years is based on what is sometimes called the unit cost theory.

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[17] Indeed, in states that use a historic test year, the line in question refers to a period that may be two or more years ago.

Introducing and explaining a few rate case terms will help. Rate cases all begin with a "test year." In most states it is a historic year and in a few it is a projected, or future, year.

[18] Whether historic or future, the test year is a fixed period of time and all costs and revenues to be examined in the rate case will be for that year. If test year revenues fell short of test year costs (including a reasonable rate of return) the revenue requirement is increased. New prices are set by taking the new revenue requirement and dividing it by test year sales.

The unit cost theory says the test year rate case defines the relationship between revenues, expenses, and investment and says furthermore that this *relationship remains constant.* The unit cost theory allows regulators to choose to use a historic test year, a fully projected (or future) test year, or any test year in between. Thus, we can use a historic test year, say 1998, to process a rate case in 1999, and set prices that will be in effect in 2000. Or we can use a projected test year, say 2000, to process a rate case during 1999 to set prices for 2000. According to the unit price theory both exercises will yield the same prices. The future test year will have a higher revenue requirement (the numerator) than the historic test year numerator but it will also have higher sales (the denominator). With the numerator and denominator moving in lockstep the end result is that prices in 2000 will be the same.
[19]

[18] If you've ever wondered why there is even a choice between two so very different periods the answer is the unit cost theory.
[19] If, for some reason, it is believed that the unit cost theory is violated and revenues, expenses, and investment are growing at different rates there is a special ratemaking adjustment (not available in all states) called "attrition" (when costs are growing faster than revenues) or "accretion" (when revenues are growing faster than costs). It should come as no surprise that during periods of high inflation utilities frequently requested and were often given

So much for the theory. The reality is that utility costs and revenues do not move in lockstep as sales change. In fact, it is far more accurate to say they are independent! Statistical analysis of utility costs (excluding fuel and purchased power) has consistently shown that there is no meaningful relationship between costs and kWh sales in the short-run.

This has profound effects on how utilities make money. Recall the basic profit formula:

PROFIT = REVENUE - COSTS

Revenues are directly related to sales and costs are independent of sales. This means profits and sales are directly related. If sales go up 2%, revenues go up 2%, and profits go up 2%. Likewise, if sales drop, revenues and profits drop.

4. **Misconception Number Four: For a vertically integrated utility, high marginal fuel and purchased power costs hurt profits.**

Most vertically integrated regulated utilities live in a fantasy world of economics. Where else can you make a product at a cost of 15¢, sell it for 7¢, and see profits go up as sales grow? But that is exactly what happens for vertically integrated utilities with a fuel and purchased power adjustment clause.

How can this be? A fuel adjustment clause (FAC) essentially takes a utility's cost and turns it into a customer's cost. Under typical FACs, fuel and purchased power costs flow through to customers on a dollar for dollar basis.

"attrition" adjustments, which resulted in larger rate increases. More recently, sales growth has been high and inflation low, one might expect requests for "accretion", but these have been rare while proposals for rates freezes have been common.

Absent disallowances for imprudently incurred costs, fuel and purchased power costs have no impact on utility profits.

For those accustomed to the workings of competitive markets, this result is counterintuitive. Assume that it is a hot summer day and the most expensive sources of power are pressed into service. Let's say that the marginal running cost of a very inefficient diesel plant operating on only 5 of 6 cylinders is 15¢ per kWh. The 15¢ kWh is sold to a customer at the regulated price of 7¢. Under utility accounting, the 7¢ regulated price is made up of 5¢ base cost (intended to cover the utility's costs that are not within the scope of a FAC) and 2¢ to cover the average cost of fuel.

[20] When the kWh is sold, the 2¢ and the 15¢ fuel cost are reflected in the FAC accounting system. The 13¢ shortfall is recovered from all customers later, when the FAC is reviewed and updated. The five cents, however, is the utility's to keep.[21] The end result is the kWh cost 15¢ to produce. It was sold for 7¢, it added 5¢ to the utility's bottom line, and a 13¢ "loss" on fuel ended up being paid for by customers.[22]

B. Distributed Resource Profitability Implications

[20] The actual accounting entries vary from state to state but the effect is as described here.

[21] It goes to the utility's bottom line, insofar as the utility's base (non-FAC costs) have not changed as a result of the sale.

[22] In a few states, vertically integrated utilities do not have a FAC. In these cases, the incentives are in some respects a little better and in others a little worse. The end result is probably not too different but a more specific conclusion depends on the utility's actual cost and price structure. If prices are high relative to market prices for electricity, the same connection between profits and sales exists. Each kWh sold brings in more revenue than cost. If prices are low relative to market prices, a condition that rarely occurs, the utility may be able to deploy distributed resources in profitable ways.

Three important scenarios flow from what we have learned so far.

1.

Distributed Resources Located on the Customer's Side of the Meter

The general, and by far predominant, condition is that, where REVENUE **and COST are independent, profits increase if revenues increase and profits fall if revenues fall. This means that any distributed resource that causes revenues to fall hurts utility profits. Any supply- or demand-side resource located on the customer's side of the meter will have this affect. So will all net metering installations.**

Energy Efficiency As A Distributed Resources

Although much of this report focuses on distributed generation, energy efficiency and load management resources are generally much cheaper, cleaner, and more widely available. The profitability implications for these demand-side distributed resources are essentially the same as they are for distributed generation installed on the customer's side of the meter.

Note that the effect on utility profits does not depend on the cost-effectiveness of the distributed resources. Very cost-effective distributed resources, even zero-cost distributed resources, hurt utility profits if the distributed resources are installed on the customer's side of the meter.

2.

Distributed Resources Located on the Utility's Side of the Meter

If the distributed resources are installed on the utility side of the meter, there is no revenue loss. Where no special attention is paid to where on the system distributed resources are installed or how the resources are operated in relation to the distribution system, the utility's cost savings will mostly be limited to system-wide savings, which include the capacity and energy value of the distributed resources and the value of increased system reliability. The impact on utility profits depends on whether the system-wide benefits exceed the capital and operating costs of the distributed resources.

3. Distributed resources located in high cost areas.

In special cases, perhaps covering as much as five percent of a utility's service area, the installation of distributed resources will be in high-cost areas of the system where significant distribution and reliability cost savings may be achievable.

As summarized in the following table, the impacts of distributed resources on utility profits depend on whether the resource is on the utility- or the customer-side of the meter. From the utility's perspective, the questions that location raises are: 1) Is the cost of the distributed resource simply its capital and operating cost? Or 2) Is it the loss in revenues when the resource is installed by a customer? And 3) Which has the worse effect upon the utility's profits?

Utility Costs and Benefits Depending on Location of Distributed Resource		
	Distributed Resource Location	
	Utility Side of Meter	Customer Side of Meter
Costs	Capital and operating cost of the distributed resource	Revenue loss
Benefits	Capacity and energy System reliability Distribution benefits (in high cost areas)	Capacity and energy (if supplied by the utility) System reliability Distribution benefits (in high cost areas)
Effect on Profits	Neutral to positive depending on location and operation	Negative, with the possible exception of high-cost locations

V. REGULATORY REFORM OPTIONS

There are a number of regulatory reform options that can align a utility's profit motive with support for deployment of cost-effective distributed resources.

A. Performance-based Regulation: Price caps vs. Revenue caps

A number of states have experimented with performance-based regulation (PBR).

While performance-based regulation can take many forms, the predominant structural feature that distinguishes one class of PBR from another is whether it is price- or revenue-based. Performance-based regulation generally establishes a fixed period of regulatory lag, generally in the three- to five-year range. During this period the utility is subject to either fixed prices (price caps) or fixed revenues (sometimes fixed revenues per customer). Either may be adjusted by a predetermined formula (typically aimed at capturing the countervailing effects of inflation and improvements in productivity). Price-based approaches make customer-side distributed resources very unattractive to utilities, as every lost kWh of sales results in a loss of revenue.[23] In contrast, revenue-based approaches make utilities indifferent to customer-side distributed resources. Revenue-based PBRs have been adopted in several states as well as parts of the United Kingdom and Australia.

Net Metering, Standard Interconnection Requirements, CTC Collection, Distribution IRP, and Other Policy Options

A number of policy options to encourage distributed resources have been adopted or suggested. These include: net metering, allowing distributed resources to avoid CTC charges, planning requirements for distribution utilities, and mandated open access distribution. This report does not address these policies because, while they may be needed and very effective in encouraging distributed resources, they do not address the profitability issue. To the extent these policies are successful, they tend to reduce utility profits, which explains why the policies are generally opposed by utilities.

A brief description of the mechanics and financial implications of a revenue per customer PBR follows.

[23] Rate freezes, rate case moratoriums, or "stay-out" provisions are all produce the same incentives as a price cap PBR.

[24]

1. Mechanics

An issue in any PBR is the starting point or baseline level of rates and revenues. This typically entails a cost-of-service review to ensure that the starting point is neither too high nor too low. This review (in effect, a rate case) yields a reasonable level of test-year revenues, which then constitutes the starting point for a revenue per customer PBR.

The revenue requirement (distribution only) is allocated to each rate or customer class and is divided by the test year number of customers to yield an average revenue per customer by customer class. Assume for illustrative purposes that the average revenue per customer per month is $25. (Although this looks like a customer charge, it is not a rate that customers pay. Prices customers pay prices that continue to be set as before.) Assume that the price customers pay is 5¢ per kWh.

At the end of a year, two figures are compared: the *actual* revenue the distribution utility collected at the 5¢ per kWh and the *allowed* revenue, calculated as $25 times the number of customers. Any difference, positive or negative, is reflected as an adjustment to the 5¢ price for the coming year.

2. **Implications**

[24] More detailed descriptions of the mechanics of a revenue-based PBR appear in several documents including ___***

For the utility, this type of PBR mirrors what would happen if prices were changed from 5¢ per kWh to a flat customer charge of $25. In either approach, the utility's revenue and profits are no longer tied to sales. Profits are increased by reducing costs and adding new customers as efficiently as possible. But we must emphasize that, although the behavioral incentives that the two approaches present the utility are identical, only the revenue-cap PBR is tenable. First and foremost, the objectives of economic efficiency and equity require that rates be set to reflect the long-run marginal costs of consumption. That is, they must signal to consumers the true societal costs of their consumption so that consumers can make fully informed decisions to allocate their (and society's) scarce resources to their most highly valued uses. Second, the political opposition to a high, fixed and unavoidable charge per customer would be overwhelming.

B. De-averaged Distribution Credits and Distributed Resources Development Zones

Another reason that utility profitability is not well served by the deployment of distributed resources is that the prices charged for the services displaced by distributed resources do not often reflect the true costs of those services. If all distribution utility prices were exactly reflective of marginal distribution costs, the deployment of distributed resources would have a very different impact on utility profits. By way of example, recall that average distribution rates are about 2.5 cents per kWh and that in high-cost areas distribution rates are as high as 20 cents per kWh. In theory, regulators could simply de-average distribution prices, requiring the utility to charge something approaching zero in areas that have excess distribution capacity, and something near 20 cents in areas with constrained distribution facilities. Such prices would send the "right" price signals to consumers and would likely cause distributed resources to be installed precisely where they make the most sense. De-averaging prices along these lines, however, is unlikely for compelling practical and political reasons.[25]

The recent debate over the use of nodal or zonal transmission pricing to manage transmission congestion raises the same issues. Distribution plant at or near capacity is directly analogous to congested transmission. Congestion pricing for transmission is widely seen as an appropriate way to use market tools to facilitate efficient investment in, or substitutions among, transmission construction, alternative power plant dispatch, and siting new power plants. In essence, transmission congestion pricing is a way of geographically de-averaging prices for transmission service.

There are, however, several important differences between the transmission and distribution systems. First, the transmission system is relatively uncomplicated and, unlike the distribution system, is made up of only a few components (lines, loads, and generators). Second, the architecture of the transmission system is a network, providing multiple paths from generation to loads, whereas the distribution system is more tree-like, typically with only single paths from substations to disaggregated loads. These differences suggest it makes more sense to identify stable high-cost zones and develop regulatory policies to reduce costs in those zones rather than implement a fluid (and costly) "real-time" pricing system to reveal changes in costs and locations at the distribution level. Third, de-averaged transmission prices are charged to retail suppliers, not to retail customers. Retail suppliers may pass along to their customers those de-

[25] On an embedded (or historic) cost basis, the "deaveraging" debate tends to be an urban (low cost) versus rural (high cost) battle. On a marginal cost basis, the high-cost areas tend to be those marked by high growth, which are often urban and suburban areas.

averaged wholesale prices; by the way of de-averaged retail prices. Generally, they have not. To present the right economic signal to customers who are considering distributed resource options, de-averaged retail prices are required. While this may be a practical option someday, a great deal of consumer education and preparation will be required to make it practical.

Turning the experience with transmission congestion pricing into practical regulatory options for the distribution system leads to two related proposals: de-averaged distribution credits and distributed resources development zones.

1. De-averaged Distribution Credits

De-averaged distribution credits may be a practical alternative to de-averaging all distribution prices. Under a program of geographically de-averaged distribution credits, the utility would establish financial credits for distributed resources installed in a given area. The credit amount would be a function of the distribution cost savings generated by the distributed resources. Credits would be limited in duration and magnitude, in order to match the timing and need for distribution system reinforcements. For example, credits might be available to the first 20 MW of distributed resources installed in the next year, because, after that period, loads are expected to grow to make such a distribution line unavoidable. The dollar amount of the credits should at most equal the value (savings) derived from deferring the distribution upgrade. Credits would also vary by location of the distributed resources. Credits would be highest in areas of greatest need and would be zero in low-cost areas.

[26] For example, customers in an area with 20¢ cent distribution costs might be offered a 15¢ credit.[27] This would certainly produce a strong economic incentive for customers and others to invest in distributed resources in that area. Because the credit is 15¢ cents instead of the 20¢ the utility would incur to upgrade facilities, there is an opportunity for savings to be shared.

2. Distributed Resources Development Zones

Utility profits do not suffer if distributed resources are confined to high-cost areas. The problem for utilities is how to confine distributed resources to any particular geographic area. Location-based buy-back rates are one way to focus action in some areas. An alternate approach is to establish distributed resources development zones. These would be high-cost areas within which distributed resources vendors could be encouraged to target customers. Incentives could include direct financial assistance, assistance in contracting with and marketing to customers, low- or no-cost siting at utility substations and other properties, and any of a variety of other approaches.

Clearly, if utilities are allowed to own distributed resources, policies will have to be developed to ensure that competitors are treated fairly. For example, absent policy intervention, distribution utilities would be the only entities that know where the high-cost distribution areas are and the only entities positioned to

[26] Variations of the deaveraged distribution credits could be a sliding scale standby rate or a hookup feebate. For example, standby rates could be on a sliding scale ranging from high to negative. Negative standby rates, which look like distribution credits to customers, would be charged in high-cost areas. A hookup feebate would be a revenue neutral charge that collects from customers installing distributed resources in low cost zones and pays customers who install distributed resources in high cost zones.

[27] Demand-side resources would be much less costly.

benefit from cost savings related to distributed resource deployment. Because distribution system savings are key drivers of distributed resource economics, utilities would have an unbeatable competitive advantage. Failing to address this problem would deprive the public of the innovation that would come from a vigorous competitive market for distributed resources. Location-based buy-back rates and distributed resource economic zones can address this competitive issue.

C. Pricing flexibility

"Economic development rates," "load retention rates," "co-generation deferral rates," and "competitive contract rates" are a few of the names given to special pricing arrangements designed to increase or retain loads. Many utilities have asked for this kind of rate flexibility and most requests have been approved. While the arguments differ slightly from program to program, the common thread is a certain freedom to lower prices to levels approaching marginal production costs, to encourage a customer to expand loads or discourage it from reducing loads through self-generation or other means.

For example, to support "co-generation deferral rates," utilities argue that cogeneration is, in many cases, not actually cost-effective when compared to the utility's own marginal cost of supply, and that it only appears cost-effective to customers because retail prices are well above the utility's marginal cost. In these cases, utilities have asked for flexibility to lower prices to discourage customers from installing on-site generating options.

An important characteristic that distinguishes distributed resources in this context

is the significantly greater scope (in breadth and depth) of benefits that such resources offer. The value of distributed resources is location-dependent. Even if reducing rates to discourage distributed resources were a reasonable response in one location, it would be an unreasonable response in others. The utility should have the burden of distinguishing between these locations. One option for regulators is to allow pricing flexibility for low-cost areas along the lines just described, *but only* if a utility simultaneously increases the prices (perhaps through a de-averaged buy-back rate) for high-cost areas.
[28] It does not make sense to have a utility actively discouraging the installation of distributed generation and other resources in low-cost areas if it is not simultaneously encouraging them in areas where costs are clearly above retail prices.

D.

Targeted Incentives for Distributed Resources

PBRs can be designed with targeted incentives for the deployment of distributed resources. Distributed resources are in the public interest because of the cost savings they offer. Therefore, one logical regulatory approach is to create a targeted incentive by allowing the utility a share of the savings they produce. If a utility can demonstrate that it has reduced its distribution cost by installing distributed generation or targeted demand-side investments, regulators could allow the utility to keep some fraction of the savings as a reward. Targeted incentives of this nature worked successfully for demand-side options in the past.

E. Stranded Cost Balancing Accounts

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[28]Simply treating each request to lower prices on its own location-specific facts is not an adequate response. The utility has no incentive to file for increased prices where existing low prices discourage distributed resources.

Stranded costs recovery plays a role in who has an incentive or disincentive to deploy distributed resources. If stranded costs are recovered volumetrically, customers will have an incentive to invest in distributed resources. Conversely, the imposition of exit fees will discourage customers from installing distributed resources.

The details also matter from the utilities' perspective. Most, if not all, restructured states collect stranded cost through a per kWh charge. In some states, the stranded cost charge is fixed and can be imposed for a specified period of time. Lost sales in these states precipitated by customer-side distributed resources (or by any other cause for that matter) reduce the utility's recovery of stranded costs. In other states, the total amount of stranded cost recovery is fixed and tracked in a balancing account. The per-kWh charge or the duration of the charge is allowed to change until the account is reduced to zero. The latter approach reduces the utility's disincentive to the deployment of distributed resources, since recovery of stranded costs is ensured, regardless of changes in sales.

F. Short-term Opportunities

Existing distributed generation and pricing policies have implications for line extensions and system expansions. There are large numbers of generators installed in

schools, hospitals, factories, office buildings, hotels, grocery stores, commercial establishments, farms, and residential homes. Yet little attention has been paid to communication and pricing systems that would allow the potential benefits of these existing resources to be tapped.[29]

Line extensions and system expansions are areas ripe for near-term action. Customers rarely are required to pay for line extensions unless the expansion is both extensive and

Sprawl and Smart Growth

Considering distributed resource issues together with efforts to address the environmental and economic issues relating to urban sprawl may make seemingly radical pricing options more practical. The environmental consequences of sprawl include land use impacts, transportation and related air pollution impacts. But increasingly, states are focusing attention on the economic drivers and consequences of sprawl. For example, a study by the State of Maine Planning Office looked at the total cost of home ownership in an established urban area compared to a new distant subdivision. The first cost of the urban home was higher until one factored in the added cost of transportation and insurance. More important, the subdivision economics were skewed because many costs, including adding the necessary electric, gas, water, sewer, telephone and road infrastructure were not reflected in the cost of the home. Charging the full marginal costs for the expansion of the infrastructure would have a generally positive effect on land use decisions, reducing the tendency to sprawl.

[29] See RAP's reliability IssuesLetter <http://www.rapmaine.org/Reliability.htm> for options to use distributed generation for increased reliability in the near term.

[30] Very expensive additions to serve fast growing suburbs are simply folded into overall utility rates. From the perspective of the developer of a large subdivision or the customers buying homes in the subdivision, the expansion of the grid is free. If the cost for the expansion were borne by the developer and customers, development siting and distributed resources investment would be more rational.[31]

VI. CONCLUSIONS

Our initial conclusions take into account the critical variables affecting utility profitability from distributed resources deployment: utility structure, the nature of the distributed resources, and the form of regulation. The effect of these variables on utility profitability is summarized below.

Utility Structure: The financial incentives favoring or disfavoring distributed resources deployment are generally unaffected by corporate structure. They are affected by the relationship between a utility's cost and price for distribution services. The worst situation for a utility is to have low distribution costs and high distribution prices.

Location of the Distributed Resource: The location of the distributed resource is critical. Distributed resources installed on the utility side of the meter do not jeopardize profitability. The primary, and negative impact on utility profitability of distributed resources deployment occurs when they are installed on the customer side of the meter. This is true for

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[30]Charging customers the full marginal cost for these facilities is a small step in the direction of deaveraged prices. It is a step made practical by the small number of people affected, by the fact that the charge will be generally considered in the context of a land development decisions, and by growing public support for anti-sprawl measures.
[31] The Wall Street Journal reports that a very large subdivision (35,000 units) being built in Texas, is considering installing fuel cells in homes and businesses and tying them together with a local grid. Avoiding the cost of expanding the utility's transmission and distribution system was cited as a motive.

both demand-side and supply-side resources. From the utilities' perspective, demand- or supply-side resources installed on the customer side of the meter produce the same effect: sales go down and as a result revenues and profits go down.

Locating distributed resources in high-cost areas has significant potential benefits. The significant distribution cost savings resulting from distributed resources located in high-cost areas can reduce utility financial losses or even add to profits if the distributed resources are deployed *only* in high-cost areas.

Form of Regulation: The form of regulation also matters greatly, particularly whether the utility is subject to PBR and, more importantly, whether the PBR is price- or revenue-based. Price regulation generally discourages distributed resources. Revenue regulation does not.

Other Regulatory Variables: The deployment of distributed resources are affected by whether the utility has a fuel clause or similar regulatory provision; the nature of stranded cost recovery provisions, including the level of stranded costs, stranded costs recovery mechanism (volumetric charges, exit fees, or other mechanisms that affect behavior); and whether there are balancing accounts for stranded costs.

Regulatorys have a number of policies available to align utility profitability with the deployment of cost-effective distributed resources. Some, such as revenue based PBR, go directly to the heart of the problem and fix the way regulation works. Others, such as Distributed Resource Credits, Distributed Resources Development Zones, and placing restrictions on pricing flexibility, aim at making distributed resources profitable to utilities by trying to direct distributed resources deployment to high cost parts of the utility's system.

Getting utility profitability aligned with the deployment of cost effective distributed resources is an important step, but it does not guarantee success. Even if regulation is able to completely align utility profits in the deployment of distributed resources, there may be other factors that overwhelm the power of any incentives. Such diversionary factors may include rate impacts, competitive and other risks, and issues of control or the lack thereof, each of which can undermine the incentives created in a PBR.

Consider the experience that many regulators had during the mid 1990s. A number of powerful PBRs were established that encouraged utilities to invest in energy efficiency. Utilities responded, and energy efficiency investment and performance increased dramatically. Then conditions in the industry changed and utility executives became preoccupied with utility restructuring, competition, and stranded cost recovery. The shift of utility focus to these issues substantially detracted from the effectiveness of PBRs, and notwithstanding the profitability of investment in energy efficiency, utility investment in efficiency dropped substantially.

VII. Next Steps

Based on this report, NARUC should consider follow-up research in four areas:

1) **Simplified Cost Analysis.**
More work needs to be done on identifying deaveraged distribution costs and quantifying distributed benefits and creating simple ways to analyze distributed resources policy options and apply them to utility planning and investment methods. To date, the work on quantifying benefits has focused on very detailed site by site benefit analysis. This kind of work is necessary, but the very nature of distributed resources demands that the experience being gained be translated into

much simpler methods. The transaction costs of case-by-case and line-by-line analysis is a burden the most cost-effective distributed resources could not bear.

2) Further Development of Policy Options

Each of the policy options described in this report warrant a separate paper that explores the related policy and implementation issues in more depth. For example, De-averaged Distribution Credits; How should the credits be designed? Should credits be paid on an energy or capacity basis? How soon before a planned distribution upgrade should the credits begin? What happens if too few distributed resources are installed to defer the distribution upgrade?

) Accommodating Distributed Resources in Wholesale Markets

Many of the benefits of distributed resources spill over into areas regulated by FERC. For example, transmission pricing policies may be needed to assure that distributed resources receive the benefits of any transmission system savings, ISOs and powers exchanges policies may be needed to assure that capacity, energy, and ancillary services produced by distributed resources can sold into the market.

4) Related Rate Design Issues

Rate design for distribution services can have a large effect on customer incentives to install distributed resources. A large body of rate design research exists which can be reviewed and applied to distribution utility issues.

Appendix A

(Forthcoming)

Resolution Supporting Energy Efficiency and Load Management As Cost-Effective Approaches to Reliability Concerns

WHEREAS, Both utility-sponsored and market-based energy efficiency programs have a demonstrated record of lowering demand for electricity -- according to the U.S. Energy Information Administration, in1997, cost-effective utility DSM programs provided over 25,000 megawatts of peak load reduction and saved more than 56 million megawatt-hours annually; and

WHEREAS, Despite energy efficiency's proven track record, utility spending on energy efficiency programs has been dramatically curtailed, falling from $2.7 billion dollars in 1993 to only $1.6 billion in 1997, according to the U.S. Energy Information Administration; and

WHEREAS, Several areas of the country have recently experienced electric distribution and supply reliability problems and major price volatility, for example:

> Utilities from Maine to Virginia cut the voltage they supplied to customers by 5 percent on at least one occasion during a five-week period in early summer, 1999, because their three regional power pools were approaching or exceeding their prior peak load;
>
> New England experienced its first power warning ever in June 1999, and experienced two more power warnings in the following five weeks;
>
> Delmarva experienced rolling blackouts that affected 400,000 customers in early July 1999;
>
> Utilities throughout the midwest lowered the voltage they supplied to customers in June of 1998 because of severe capacity constraints; and
>
> Denver experienced rolling blackouts on July 17, 1998, when demand exceeded electricity supply.

WHEREAS, During these distribution and capacity constraints, the spot market cost of power repeatedly rose to the range of $1,000/MWhr for one or more hours in the day; and

WHEREAS, According to the North American Electric Reliability Council, generating capacity additions are not keeping pace with demand growth - 24,400 MW of generation additions are planned by 2002, but demand is projected to increase by approximately 36,000 MW; and

WHEREAS, the North American Electric Reliability Council also reports that transmission systems are increasingly challenged to accommodate the demands of evolving competitive electricity markets, and

WHEREAS, According to a study performed by Applied Energy Group, Inc., nine of ten regional reliability councils in the United States will have a shortage of generating capacity by

2007; and

WHEREAS, Energy efficiency and load management programs are proven, cost-effective means of managing load and enhancing reliability by matching electricity demand with the system's generation, transmission, and distribution capacity constraints, and such programs help to avoid the need to rely upon excessively costly supply resources and strained transmission and distribution facilities; and

WHEREAS, For the last 15 years, NARUC has encouraged investment in cost-effective energy efficiency programs; now therefore be it

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened in its 1999 Summer Meeting in San Francisco, California, reaffirms NARUC's commitment to, and support for, cost-effective demand-side management measures, including both energy efficiency and load management measures, as a critical component of strategies to address electric system reliability concerns; and be it further

RESOLVED, That NARUC urges State public utility commissions to encourage and support programs for cost-effective energy efficiency and load management investments as both a short-term and long-term strategy for enhancing the reliability of the nation's electric system, and reducing its costs; and be it further

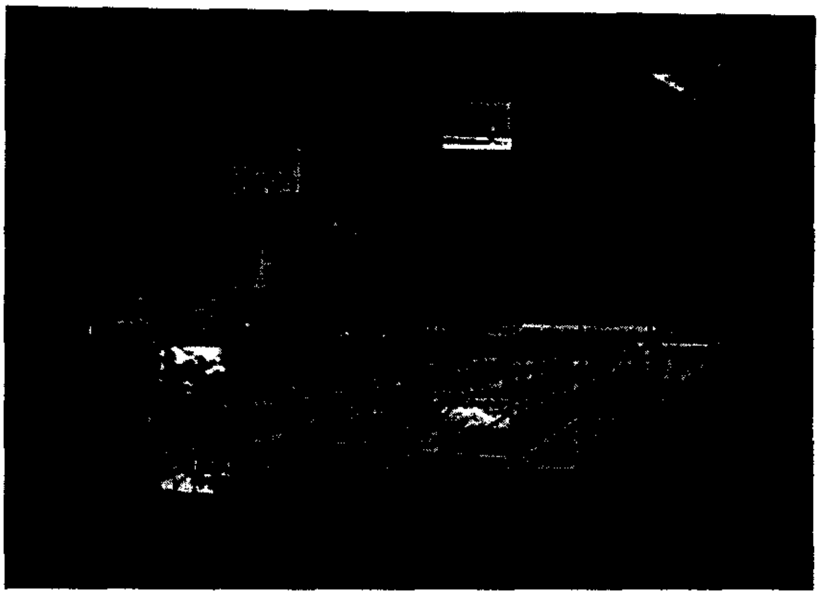
RESOLVED, That NARUC urges power pools and independent system operators to encourage and support market mechanisms that facilitate cost-effective energy efficiency investments, distribution enhancements, and load management by suppliers, marketers, and end-use customers; and be it further

RESOLVED, That NARUC urges Congress, as it considers legislation to restructure the nation's electric industry, to include in such legislation workable mechanisms to support cost-effective State, utility, and market participant energy efficiency programs in order to enhance the reliability of the nation's electric system.

Sponsored by the Committees on Energy Resources and Environment and Electricity

Adopted by the NARUC Board of Directors July 23, 1999

Photovoltaics Can Add Capacity To The Utility Grid



Mapping the effective load-carrying capacity of PV to highlight service territories that can benefit from photovoltaics

Note: This document has been modified from its original (print) format.

PV Isn't Just an Energy Source

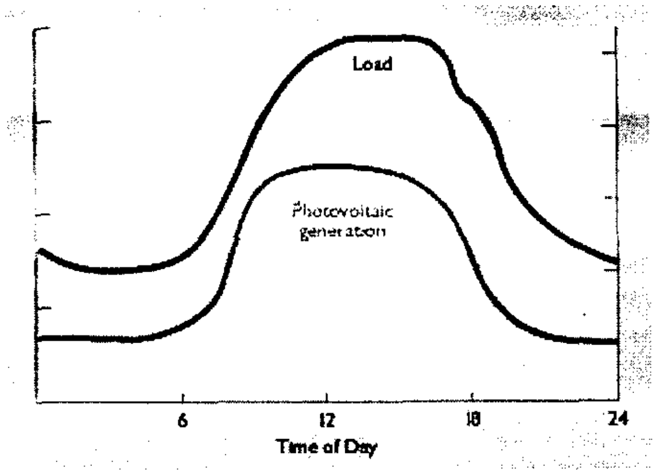
Photovoltaics (PV) can contribute to or receive credit for a utility's capacity. But how is this possible for a power source that is not dispatchable? The key is that many applications that require energy and drive a utility's load are synchronous with the intensity of the solar resource. Therefore, we want to determine the locations where PV can provide power **when it is needed.** For these areas, we can consider PV as more than an energy source—it also contributes to a utility's **capacity.**

In other words, the value of PV to a utility's capacity depends on load matching: the value is greatest when PV power output most closely matches the utility's load requirements.

First, Let's Define a Few Terms

Effective load-carrying capacity (ELCC) is the ability of a power generator—whether PV or conventional—to effectively contribute to a utility's capacity, or system output, to meet its load. Therefore, ELCC for a photovoltaic system represents PV's ability to provide power to the utility **when it is needed.** It is the **capacity credit** of the PV power plant.

LEAF Exhibit E
Docket 981890-EU



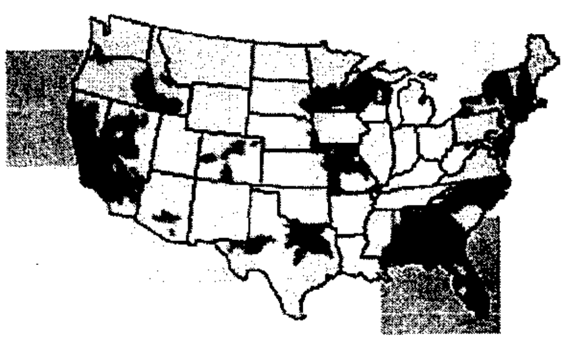
Utility load and PV output versus time of day.

A typical example of high ELCC for PV occurs when the utility system load reflects commercial customers' demand for midday air-conditioning; this load is a good match to PV's power output. The PV ELCC is lower for residential customers who have a high air-conditioning demand in the late afternoon; the load is not matched as well to the intensity of the solar resource.

Summer-to-winter peak-load (SWP) ratio is another parameter that must be understood to appreciate the true value of PV to a utility. This parameter—based strictly on the characteristic shape of the utility's load—compares the peak summer demand to the peak winter demand.

A high SWP ratio, say 1.25 or greater, indicates that summertime demand greatly exceeds wintertime demand. The greater the SWP ratio, the more closely the load is likely to match the actual solar resource. This is because the solar resource is much greater in the summer—hours of sunlight are longer and the intensity of the sun is greater because it is higher in the sky.

So, How Do We Determine ELCC?



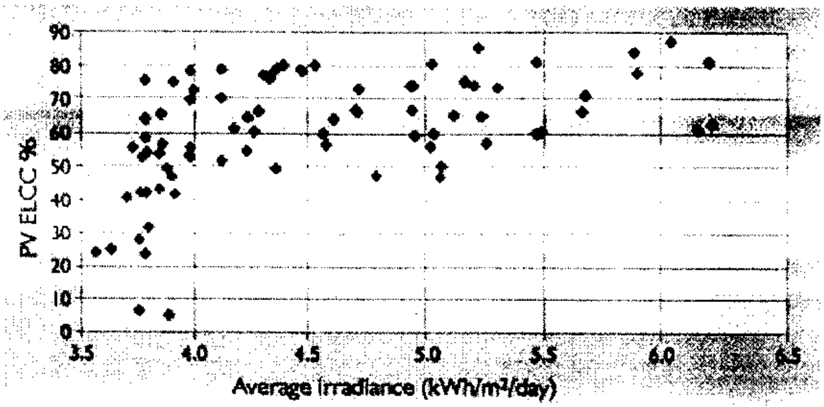
The service territories of the 40 utilities whose loads were used to determine PV ELCC.

Much information is available about the distribution of the solar resource across the United States, but until recently, little has been available on the distribution of PV's ELCC. Therefore, we have developed a method to determine how closely utility load requirements match PV's ability to generate power when it is needed.

We started with a 2-year set of hourly load data for 40 utilities whose service territories covered different sections of the country. Then, using information from geostationary satellites, we estimated PV power generation at points in time and space that coincided with the load data.

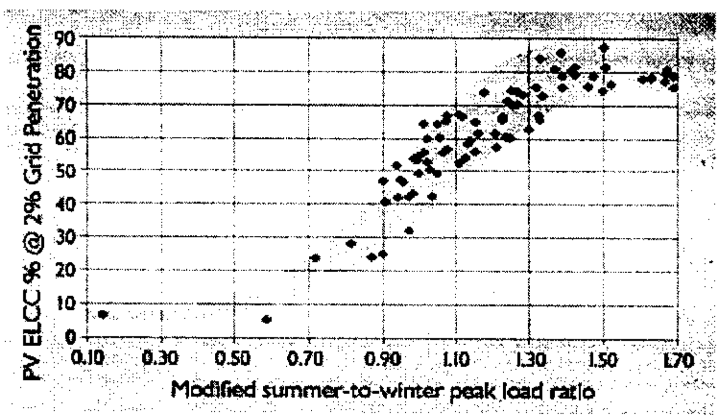
What Does the ELCC Method Tell Us?

The PV ELCC is not related to overall solar energy output.



PV ELCC % vs. solar intensity

However, the PV ELCC is highly correlated with load-shape characteristics.



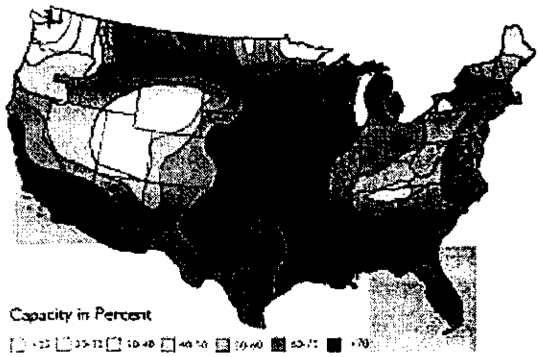
PV ELCC % (at 2% grid penetration) vs. modified SWP ratio

The intensity of the solar resource is obviously critical to PV power generation. But in determining PV's value to a utility, the magnitude of the sun's intensity is less important than its relationship to load requirements.

In fact, all utilities studied—whether winter-peaking or highly summer-peaking—fit the pattern that shows PV ELCC increasing as a function of increasing SWP ratio.

ELCC may exceed 80% of the rated PV output when the load is driven by the sun, for example, when the SWP ratio is above 1.5. In that case, a 1-kilowatt PV system would have an ELCC of 800 watts. In other words, a PV system rated at 1 kilowatt could be considered a dispatchable power source of 800 watts.

Can You Picture the ELCC of PV across the United States?

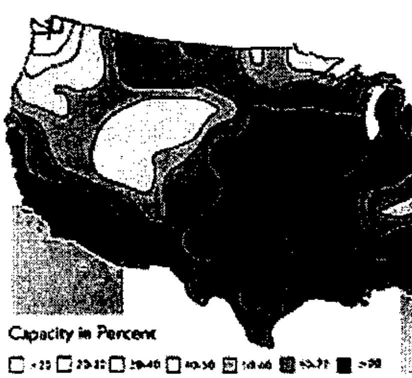


PV ELCC map of U.S. (based on 500 utility loads)

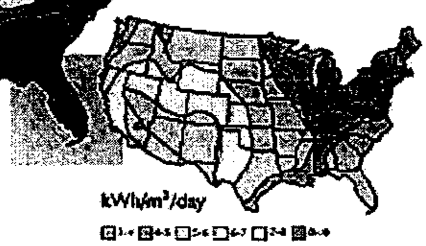
This load-shape relationship provides an analytical tool that allows us to map the distribution of PV's ELCC across the nation. That is, by knowing a utility's load-shape characteristics, we can calculate an SWP ratio and determine an ELCC value for PV. Using SWP ratios from some 500 U.S. utilities, we applied this method to determine the PV ELCC values, which were then plotted, gridded, and contoured to produce the map at left.

To continue to refine this method, we are studying other PV grid-penetration levels, refining the relationship between load shape and PV ELCC, and analyzing multiyear, monthly, and customer trends.

PV's Value as a Technology that Adds Capacity



PV ELCC map of U.S. (based on 500 utility loads)



"Traditional" solar-energy map

- **PV has tangible value to utilities in generating capacity.**
- **Regions of high ELCC do not always overlap with regions traditionally targeted for solar energy.** For example, note the high ELCC values in southern California, the central states, and the Mid-Atlantic seaboard states. The "traditional solar areas" of Florida and the arid Southwest states have lower PV ELCC values despite their greater solar intensity values, because PV output doesn't match the loads as well in those areas.

- **Areas of high PV ELCC are associated with regions that have certain characteristics:**

  - Intense summer heat waves
  - High daytime commercial demand
  - Small electric-heating demand.

- **Isolated pockets with high PV ELCC values may exist within a region having lower PV ELCC values.** For example, high-density urban areas may have a high daytime demand in the commercial sector and thus have a high ELCC value for PV.

  These new findings about PV's ELCC should make decisions on capacity additions and demand management a little easier for U.S. utilities.

For More Information, Contact:

The State University of New York at Albany,
Atmospheric Sciences Research Center
Richard Perez and Robert Seals
(518) 442-3808
(518) 442-9071 (fax)
e-mail: perez@asrc.albany.edu

Christy Herig
National Renewable Energy Laboratory
Center for Photovoltaics and Electronic Materials
(303) 384-6546
(303) 384-6490 (fax)
e-mail: herigc@tcplink.nrel.gov

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