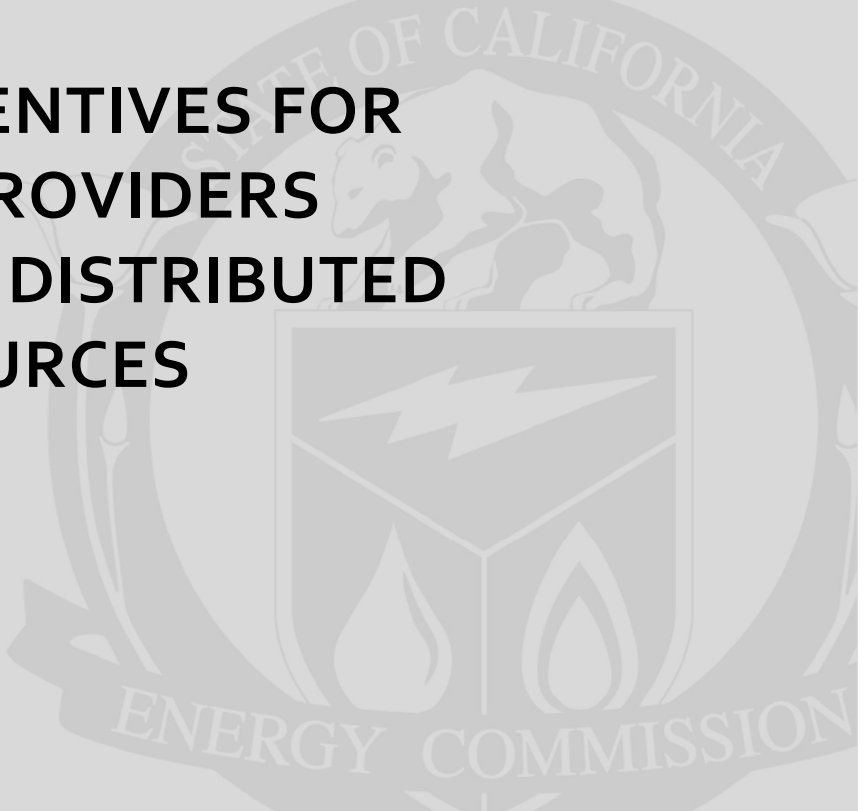


**Public Interest Energy Research (PIER) Program
FINAL PROJECT REPORT**

**CREATING INCENTIVES FOR
ELECTRICITY PROVIDERS
TO INTEGRATE DISTRIBUTED
ENERGY RESOURCES**



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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Creating Incentives for Electricity Providers to Integrate Distributed Energy Resources is the final report for the DER Public/Private Partnership Phase 2: Creating and Demonstrating Incentives for Electricity Providers to Integrate Distributed Energy Resources project (contract 500-02-014), work authorization number 121 conducted by the Electric Power Research Institute (EPRI). The information from this project contributes to PIER's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

Abstract

This project created, through stakeholder collaboration, business models and regulatory approaches that reward electricity providers for integrating distributed energy resources (DER) that yield societal benefits as well as customer and non-participant benefits. The project also planned to demonstrate the effectiveness of these business and regulatory approaches in pilot projects.

This project found that the utility-owned DER business models are more likely to achieve the win-win outcomes than customer-owned models under the current regulatory conditions. Economic models developed for this project were used to evaluate candidate utility-owned and customer-owned DER technologies and business and regulatory structures. The Individual Installation DER Model generated costs and benefits for a single DER installation, from the perspective of the three key groups of stakeholders in a regulated environment– the customer with the DER, the utility or non-participating customers, and society. The Aggregate DER Model evaluated the utility shareholder and ratepayer impacts of aggregated DER installations given assumptions of utility type and regulatory structure. The models produced simulated calculations that provide planning-level results for both baseline assumptions and user-defined scenarios.

In Massachusetts, the Massachusetts Technology Collaborative and National Grid agreed on a pilot project that would test and demonstrate the DER business models. In California, the utility-owned model was found to be the most likely to result in benefits for the customer, utility, society under the current regulatory environment. Due to time constraints in the project, a pilot project in California was not carried out. Due to the State Technologies Advancement Collaborative project requirement that multiple states participate in the project, the entire project was discontinued.

The project was funded by the California Energy Commission and the Massachusetts Technology Collaborative and through a State Technologies Advancement Collaborative Award. The State Technologies Advancement Collaborative award is funded by the National Association of State Energy Officials in conjunction with the U.S. Department of Energy and the Association of State Energy Research and Technology Transfer Institutions.

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Executive Summary

Project in Brief

The purpose of this project was to create, through stakeholder collaboration, business models and regulatory approaches that reward electricity providers for integrating distributed energy resources (DER), and which yield societal benefits as well as customer and non-participant benefits. Further, the project aimed to demonstrate in pilot/demonstration projects the effectiveness of these business and regulatory approaches that are designed to stimulate DER markets.

Economic models developed for this project were used to evaluate candidate utility-owned and customer-owned DER technologies and business and regulatory structures. The Individual Installation DER Model generated costs and benefits for a single DER installation, from the perspective of the three key groups of stakeholders in a regulated environment– the customer with the DER, the utility or non-participating customers, and society. The Aggregate DER Model evaluated the utility shareholder and ratepayer impacts of aggregated DER installations given assumptions of utility type and regulatory structure. The models produced simulated calculations that provide planning-level results for both baseline assumptions and user-defined scenarios.

In Massachusetts, the Massachusetts Technology Collaborative and National Grid agreed on a pilot project that would test and demonstrate the DER business models. In California, the utility-owned model was found to be the most likely to result in benefits for the customer, utility, society under the current regulatory environment. However, because of lack of progress in developing a pilot project in California within the time constraints of the agreement with the California Energy Commission, the work in California was discontinued. Due to the State Technologies Advancement Collaborative project requirement that multiple states participate in the project, the entire project was discontinued.

The project was funded by the California Energy Commission and the Massachusetts Technology Collaborative, and through a State Technologies Advancement Collaborative Award. The State Technologies Advancement Collaborative award is funded by the National Association of State Energy Officials in conjunction with the U. S. Department of Energy and the Association of State Energy Research and Technology Transfer Institutions.

The project built on four years of work already completed by the Electric Power Research Institute (EPRI) DER Public/Private Partnership¹, and years of work by EPRI's DER collaborative research program, as well as work accomplished by the California Energy Commission, the Massachusetts Technology Collaborative, the New York State Energy Research and Development Authority, the Regulatory Assistance Project, and others.

¹ Partners included California Energy Commission, CPS Energy (San Antonio), Massachusetts Technology Collaborative, New York State Energy Research and Development Authority, and Tennessee Valley Authority.

This document describes the resources developed in this project and results of the work up to the time the project was discontinued.

Project Objectives

Building on the foundation of work accomplished to date, this EPRI DER Partnership project was designed to:

- **Create business models and regulatory approaches² that reward electricity providers for integrating DER into their systems** where it provides demonstrable societal and customer benefits, through facilitated stakeholder collaboration
- **Adapt the most promising approaches to state-or utility-specific environments** such that utilities in the state will embrace
- **Demonstrate the most promising approaches through actual DER pilot projects** to evaluate impacts on and benefits for electricity providers' and end-users' businesses and operations
- **Conduct outreach in public and industry forums** to broaden acceptance of successful approaches by other states and electric providers.

Approach

The project used a stakeholder collaboration process which included individuals from electric utility staff, state public utility commission staff, and state energy agency staff in California and Massachusetts, as well as DER project developers and DER equipment manufacturers, and other interested parties that participate in public utility commission proceedings. The workshop and group discussions were conducted in a non-adversarial environment to encourage new ideas and interdisciplinary thinking.

Collaborative Analysis Activities

Two major workshops were used to foster discussion of the business and regulatory issues involved in stimulating greater market integration of DER. Roughly 40 people from diverse backgrounds were involved in each workshop. The first took place in Boston, September 28-29, 2006; the second in San Francisco, January 25-26, 2007. The two workshops were linked in that the second built upon the cumulative results from the first workshop plus the working groups that were formed out of the Boston meeting to follow particular lines of interest.

- **Boston Workshop** – An initial report (Appendix E) on business models and regulatory templates was prepared to provide the basis for the Boston workshop discussions. During the workshop, the discussion returned time and again to two key areas of interest: cost/benefit assessments of DER, and the issue of DER ownership. For cost/benefit, the participants vetted an economic model presented by the project team

² Some examples, discussed later, include rate-of-return adders; utility ownership participation; performance-based rewards for efficiency and environmental improvements; and incentive design that allocates costs and benefits to achieve societal goals.

for conducting calculations of costs and benefits of individual DER installations for three classes of players—customers, utilities, and society. A second model was explored that apportions the utility benefits to shareholders and ratepayers based upon different regulatory templates. The models and example calculations are discussed in Chapter 6. The agenda and list of participants can be found in Appendix B.

- **Ownership Working Groups** – The Boston group wanted to expand the discussion beyond the prevailing customer-owned DER paradigm to include utility-owned DER. Following the workshop they formed two working groups to explore the utility business cases and regulatory/legal issues associated with the two forms of ownership. These ownership working groups met regularly by teleconference through the fall of 2006, and presented their work to the San Francisco group.
- **San Francisco Workshop** – The San Francisco workshop reviewed the results of the two working groups, and evaluated and discussed the economic calculations and their implications. The agenda and list of participants can be found in Appendix C.
- **State Working Groups** – Following the San Francisco workshop, two state working groups were established in an effort to identify pilot project opportunities customized for California and Massachusetts.
 - **The Massachusetts Group** focused on the customer-owned model, since Massachusetts law has precluded most utility ownership of generation assets. The Massachusetts pilot project, while not fully defined, already had the support of planned funding from the Massachusetts Technology Collaborative.
 - **The California Group** began a search for a pilot project based upon utility-owned DER. It also considered customer-owned DER as well.

Economic Calculators

Two economic calculators were used by the participants to evaluate the costs and benefits of different approaches and scenarios:

- **The “Individual Installation DER Model”** generates costs and benefits for a single DER installation, from the perspective of the three key groups of stakeholders in a regulated environment– the customer with the DER, the utility or non-participating customers, and society.
- **The “Aggregate DER Model”** evaluates the utility shareholder and ratepayer impacts of aggregated DER installations given assumptions of utility type and regulatory structure.

The models were developed to produce “what if” calculations that provide planning-level results for both baseline assumptions and user-defined scenarios. The tools are not suited for developing financial pro-formas of individual installations or use in regulatory proceedings that focus on a particular utility. The models were developed by the project team from Energy and Environmental Economics, Inc. (E3), who adapted them from models they developed for the National Action Plan for Energy Efficiency led by the U.S. Environmental Protection Agency and DOE and the California Energy Commission 2005 Combined Heat and Power (CHP)

market and policy study. The input parameters for the models are listed in Appendix D of this report.

Findings and Results

This project created utility-owned and customer-owned business models and regulatory approaches to encourage DER integration, as well as a set of economic calculators to test these models with various technologies and in different settings. The business models, regulatory approaches, and the economic calculators are described in this report and summarized below.

Utility-Owned DER Business Structures

The utility-owned working group agreed that the utility-owned DER business structure is quite compatible with the prevailing, cost-based, rate-of-return regulation. The utility would be allowed to earn a fair return on investments that serve the public good, and they would be allowed to recover their operating expenses. When the DER facility is interconnected on the utility side of the meter, decoupling revenue from throughput would not be necessary.

However, a few issues were raised, including:

- **Utility-ownership of DER on the customer's premises could raise concerns of anti-competitive activity.** Compelling arguments in favor of utility ownership on customer premises may include the societal benefits of the DER, and that third parties would be able to make the same offer to the host site as the utility.
- **In the case of CHP, utility-owned installations may also be in a position to offer other valuable products or services to the host site** such as thermal output or standby capability. However, at least one utility was not prepared to offer this service if the thermal output was critical to the host's business, because it is a risk the utility was not willing to take.
- **Ownership of DER generating equipment by distribution companies may not be possible** in some regions under the current business or policy environment. In states where restructuring precludes utility ownership of generation assets—as in Massachusetts—the law would have to be changed.
- **There does not appear to be much interest in utility-owned DER by the California and Massachusetts regulated utilities.** Reasons for little interest in utility ownership of DER include financial risk, the units are small, reliability is considered to be unknown, and the utilities have little operating experience with them.

Nevertheless, other utilities around the country have had some success with utility ownership. Austin Energy, for example, has had success with utility-owned DG, notably the installation of combustion turbines at two sites, a hospital and an industrial park.

The utility-owned working group developed the following business models and regulatory approaches:

1. **The utility acquires and deploys DER on the host's site and interconnects on the utility side of the meter.** The utility or vendor(s) may install, operate, and maintain the

equipment. Regulatory policies would be required to ensure rate base treatment of all prudent investments in utility-owned DER facilities, and recovery of operating expenses. The throughput disincentive does not need to be addressed.

2. **The utility acquires, deploys, and operates an advanced distribution system³ that takes full advantage of DER benefits, whether owned by utility or customer.** These benefits include economic dispatchability, voltage/frequency support, capital construction deferral, and standby and spinning reserve.

Customer-Owned DER Business Structures

The prevailing paradigm for DER investment is that the equipment is purchased, installed and operated by the customer, not the utility. For customer-owned distributed energy resources to become important to regulated utilities, the current business models and regulatory structures need to change for a number of reasons, including:

- Reduced revenues and profits, due to the “throughput disincentive” that arises when customers generate some of their own power while still connected to the grid. Unless profit is not coupled to revenues (e.g., decoupling), reduced electricity sales causes a net loss of revenue, which is amplified by a still larger reduction in net income (profit). For example, a 5% reduction in sales leads to a 23% reduction in profits for a vertically integrated utility, and leads to a 57% reduction in profits for a distribution only company. This disincentive does not exist in California where decoupling is in place. In Massachusetts, a generic docket was opened in 2007 to explore options to remove this disincentive.
- The potential need to provide continuing service on call for customers that generate their own power. These customers often continue to rely on the grid to supply the remainder of their power needs or to supply power when their own supply is not available. Unless standby or other similar charges are in place, utility revenues decline while the fixed costs associated with customer interconnection remain intact. For integrated utilities, a portion of the lost revenue is offset by a reduction in the cost of generating power; whereas in the case of a wires-only company, there are few options for offsetting cost reductions.
- From the utility perspective, the scale of DER is small and the resources are not controllable. Individual applications will not likely provide grid benefits such as distribution upgrade deferral, and may not be available when needed.

A number of means of addressing these issues were considered by the stakeholders:

- **Removing disincentives is important, but not sufficient.** Regulators in a number of states have devised means of neutralizing financial harm to utilities for pursuing desirable societal objectives, such as energy efficiency. These range from decoupling revenues from profits and lost revenue adjustment mechanisms that work within the

³ An advanced distribution system includes intelligent grid capabilities such as smart two-way communications among grid and customer systems; ability for two-way power flow; intentional islanding, etc.

traditional regulatory framework to performance-based ratemaking that reward utilities for improved efficiency, service and safety. Decoupling, for example, has been in place in California for many years, yet the state's investor-owned utilities have not made DER a high priority despite strong state policies favoring energy efficiency, renewables and CHP.

- **The opportunity for regulated utilities to earn profits through a new business model or performance incentive will likely be needed for widespread DER integration to occur.**
- **Aggregation of DER provides scaleable benefits for utilities and society.** Multiple and aggregated DER units will more likely supply grid reliability improvements and enhanced resource diversity and security. A “soft start” in the market, through regulatory programs with innovative approaches that need not become binding precedents for the long-term could help get the DER integration started and achieve the scale needed to realize benefits. Furthermore, control systems and automated demand response systems could be used with customer-owned DER to enable dispatchability under utility-customer agreements.
- **The opportunity to evaluate the societal benefits of DER on the grid would be enhanced by the “soft start” approach.** Actual measurements could be made of the potential benefits of DER integration, including providing diversity of supply, least-cost solutions to new demand, deferment of capital investment, and provide ancillary system benefits, including system reliability, voltage support and spinning reserve. With quantified benefits, the business model would become clearer.

The customer-owned working group determined that the utility could facilitate customer-owned DER and through the closer working relationships, reap more benefits from the DER installation. The working group developed the following business models and regulatory treatments for utility-facilitated customer-owned DER.

1. **The utility offers incentives to customers to deploy DER in such a way that it can be dispatched by the utility or otherwise provide system-wide benefits** that would accrue to all ratepayers. Utilities might be required to invest in metering, communications and control equipment to access the DER assets. Regulatory policies would be required to ensure recovery of program expenses, incentive payments, and revenue requirements to provide power on demand. Removing the throughput incentive would be a critical first step to remove the current disincentive for utilities.
2. **The utility solicits DER to meet state mandates for renewable generation, energy efficiency, and loading order priority.** Participants felt that utilities may have trouble meeting these escalating requirements without acquiring, owning and operating some of the qualifying assets themselves. Regulation would need to remove the throughput disincentive (for the customer owned portion), and set terms and conditions for judging qualified assets. Some participants thought that regulators should consider offering higher returns on specific investments (e.g. renewables) to incent DER deployment.

3. **The utility provides support services to customers who own and operate their own DER facilities.** Such services could include managing demand response for independent system operator programs, managing VAR control and back-up power for industrial and commercial mini-grids, or providing metering and billing services for solar utilities. This service business model could help capture some of the DER benefits for utility ratepayers.

Economic Evaluation of Five Case Studies

Case studies were conducted to demonstrate the capabilities of the economic models and to explore the implications of customer versus utility ownership. While these case studies demonstrate useful results for analysis, they do not necessarily indicate the only projected outcomes, particularly in light of future technology cost reductions, and quantifiable benefits of increased DER penetration. Furthermore, the case studies indicate that not all benefits are quantifiable today, nor monetized. Most importantly, the case studies indicate the usefulness of the economic calculators which could be used in the future to allocate costs and benefits to result in win-win outcomes.

The collaborators settled on five cases: two involve roof-top photovoltaics (PV); two CHP systems; and one a waste gas facility:

- **Utility-owned waste gas facility** yielded the most attractive results of the five case studies, showing strong net benefits accruing to all three parties. The facility was a dairy fitted with a manure digester, producing biogas for sale (at \$2.00 per million BTU) to an on-site, utility-owned generator which returned hot water to the dairy at no cost.
- **Utility-owned CHP system** was uniformly attractive. All three players (customer, utility, society) showed modest net benefits.
- **Utility-owned residential PV system** was the least attractive of the five case studies in that none of the three parties (customer, utility, society) showed benefits exceeding cost. This case study is an example of where societal benefits of renewable energy supply need to be further quantified and monetized.
- **Customer-owned CHP system** results were mixed. The results were positive for both the customer and society, but not for the utility.
- **Customer-owned, commercial PV system** was slightly better, showing a positive result for the customer, but resulted in costs higher than benefits for the utility and society.

Conclusions

The results of this project re-emphasize what was understood going into the project—that new scaleable business models and innovative regulatory approaches are needed to spur market integration of DER by utilities. This project brought together a broad group of stakeholders and facilitated the collaborative creation of innovative business models and associated regulatory approaches. The collaborative stakeholder process was excellent at bringing different perspectives together in a non-adversarial setting to achieve new models. The project also

developed economic calculators to provide insights for understanding allocations of costs and benefits of DER.

However, putting the business models into practice proved more challenging than expected. The project plan was to demonstrate the business models in pilot projects. The development of a pilot project in California proved too slow to meet the project schedule, and the project was discontinued before the pilot projects could come to fruition.

The economic calculators developed for this project provided some insights into several case studies. The case study results provide a snapshot in time, but do not represent the only possible results. To achieve win-win outcomes, DER costs and benefits will likely need to be reallocated according to new business models, and these calculators will enable analysis of allocation options. Furthermore, the calculators are excellent tools for tracking the costs and benefits and will be even more valuable when the additional benefits of increased penetration of DER can be quantified. Thus, the calculators will be useful for future analysis.

This project showed that utility-owned DER has a high likelihood of win-win results in today's regulatory environment and thus the potential for capturing utility interest. Customer-owned DER, the prevailing paradigm, will take more creativity to achieve both win-win outcomes and utility interest.

Finally, while the resources developed by this project—business models, regulatory approaches, and economic calculators—have not been demonstrated, they are ready for use to go to the next step with distributed energy resources.

Recommendations

Overall, EPRI recommends that the win-win approach serve as the guide for DER integration. This approach is to identify DER which provide societal benefits, and then allocate costs and benefits to other stakeholders to achieve the win-win outcome.

In states or regions pursuing DER as a policy objective, stakeholder groups should be assembled to use the resources and tools developed in this project to take the next step with DER. States and utilities should consider encouraging utility ownership of DER assets which is most likely to allow all parties to realize the benefits of DER without major changes to the current business and regulatory structure.

States should also take into account that the existing customer-owned approach may lead to increased rates for other customers under the current business and regulatory structure until reduced costs or increased benefits arise from DER penetration.

In the near term, to move forward with DER integration in California, both customer-owned and utility-owned business models should be tested on existing DER projects, such as CHP applications located on Southern California Edison's and Pacific Gas & Electric's distribution systems. Results of analyses should be vetted with stakeholders and discussed with utility management to confirm which business models and regulatory approaches would interest the utility sufficiently to take action to integrate DER.

To continue to move forward with DER integration in Massachusetts, the Massachusetts Technology Collaborative should continue its pilot project with National Grid and include business model testing and demonstration. The Massachusetts Technology Collaborative should also use the resources of the project with other utilities in the state. Results of analyses should be vetted with stakeholders and discussed with utility management to confirm which business models and regulatory approaches would interest the utility sufficiently to take action to integrate DER.

Considering the longer-term, states should consider a “soft start” approach, which uses societal funds to pay for longer-term benefits. The point is to develop a method to achieve DER penetration for which all electricity customers potentially pay slightly more now, with the prospect of reaping the benefits once significant penetration is achieved. Significant penetration could amount to 5 to 10% of generation. Once a significant level is achieved, actual benefits of the DER can be measured and quantified, and the values used to guide programs going forward.

1.0 Introduction and Project Description

This report is an outcome of a project designed to advance the market integration of distributed energy resource (DER⁴) systems by creating rewards and incentives to integrate DER where there is value to society. This report documents business models and regulatory approaches that may be successful in encouraging DER integration by utility companies. Developing rewards for utilities will help solve the market dilemma that keeps DER projects from moving forward. As regulatory initiatives ease the way for utilities to share in the benefits from DER deployment, utility customers and society will realize benefits in the form of more optimal resource use, increased efficiency and diversity, reliability, and environmental protection.

This project, Creating and Demonstrating Incentives for Electricity Providers to Integrate Distributed Energy Resources, is a continuation of the EPRI DER Public/Private Partnership. The project was funded by the California Energy Commission and the Massachusetts Technology Collaborative, and through a State Technologies Advancement Collaborative (STAC) Award. The STAC award is funded by the National Association of State Energy Officials (NASEO) in conjunction with the U. S. Department of Energy (DOE) and the Association of State Energy Research and Technology Transfer Institutions (ASERTTI).

The project was developed to address recommendations from previous efforts of the EPRI DER Public/Private Partnership⁵ and used tools, processes, and results from these previous efforts. Recommendations resulting from the previous effort were to:

- Develop a nationally-based stakeholder collaborative to encourage win-win business and regulatory models that incentivize utilities to use all forms of distributed energy resources and reward DER customers fairly.
- Linked to the national collaborative, develop regionally-based stakeholder collaboratives to develop and implement regional approaches to innovative DER solutions.
- Apply the stakeholder collaborative process to demonstration programs to test concepts in the field, quantify DER costs and benefits, and measure success of specific projects or programs.

⁴ For project purposes, DER might include both demand-reducing and supply-enhancing resources – that is, energy efficiency and demand response, as well as distributed generation technologies such as solar photovoltaics, small wind turbines, reciprocating engines, microturbines, and fuel cells, and especially those operating on renewable fuels or yielding high overall efficiencies. Usually, the DER is small (less than 20 MW) and near the load.

⁵ A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders EPRI Palo Alto, CA: 2004. 1011026. DER Stakeholder Collaboration at Work: Shaping a California DER Procurement, EPRI, Palo Alto, CA. 1003628. 2006.

1.1. Background and Foundation for the Work

The project built on four years of work already completed by EPRI's DER Public/Private Partnership⁶, and years of work by EPRI's DER collaborative research program, as well as work accomplished by the California Energy Commission, the Massachusetts Technology Collaborative, the New York State Energy Research and Development Authority, the Regulatory Assistance Project, and others.

EPRI and others have made some progress toward encouraging utility integration of DER where it brings value to society. The following summarize progress to date, and some key findings:

- **The DER Partnership produced a framework⁷ for collaborative pilot programs in 2003 and put the framework into practice in a pilot project in California in 2004⁸.** The pilot project showed that stakeholder collaboration can overcome significant issues that could block DER and can provide win-win situations for both the DER owner and the utility. In this project, a California utility, Southern California Edison (SCE), teamed with EPRI's DER Partnership to develop a forward-thinking solicitation for distributed generation (DG) as a distribution deferral option in response to a California Public Utility Commission order. Stakeholders collaborated to resolve potential showstoppers in the solicitation process. The utility responded to several stakeholder requests, such as agreeing to provide a price signal in a DG solicitation package, and modified its model agreement to a more customer friendly approach. Although somewhat narrowly focused on considering DG in distribution planning, this effort attests to the value of stakeholder collaboration and the win-win approach. Because of the narrow focus and lack of customer opportunities that would fit the criteria, the solicitation approach did not go forward. However, SCE continues to consider DG in distribution planning.
- One of the Partnership products was a cost-benefit spreadsheet tool to calculate costs and benefits to key stakeholders of customer-sited distributed generation, and to demonstrate that the costs and benefits may be reallocated to yield positive outcomes for all. For cases where there is societal benefit but that show losses to the nonparticipating

⁶ Partners included California Energy Commission, CPS Energy (San Antonio), Massachusetts Technology Collaborative, New York State Energy Research and Development Authority, and Tennessee Valley Authority.

⁷ EPRI Report Number 1011026: A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders: Report of the E2I Distributed Energy Resources Public/Private Partnership
http://my.epri.com/portal/server.pt/gateway/PTARGS_0_314_1630_284_855_43/http%3B/myepri10%3B80/EPRIDocumentAccess/Abstract.aspx
<http://www.epri.com/OrderableItemDesc.asp?product_id=000000000001011026&targetid=267828&value=04T101.0&marketid=267715&oitype=1&searchdate=8/19/2004%20>

⁸ EPRI Report 1013628: DER Stakeholder Collaboration at Work: Shaping a California DER Procurement
http://my.epri.com/portal/server.pt/gateway/PTARGS_0_314_1630_284_855_43/http%3B/myepri10%3B80/EPRIDocumentAccess/Abstract.aspx http://www.epri.com/OrderableItemDesc.asp?product_id=000000000001013628>

ratepayers, the tool can be used to identify how benefits can be allocated to achieve the win-win outcome. This tool was further developed and used in the current project.

- **In a 2005 California Energy Commission -commissioned market study of the opportunities for combined heat and power (CHP), EPRI estimated the aggregate technical potential of CHP in the range of 15-20 GW over the time period from 2005 to 2020⁹.** As part of the same study, the CEC also contracted EPRI to use the DER Partnership cost-benefit tool adapted specifically for CHP to analyze the cost impacts resulting from various policy options designed to increase CHP market penetration. A scaleable business model for CHP would be a first step toward realizing the large-scale (15-20GW) potential of CHP in California.
- **In a separate CEC-commissioned project performed by the Regulatory Assistance Project and Synapse, researchers identified varying rate structures for DER** among electricity providers in the United States, but none of the rate structures examined has spawned widespread, proactive utility DER initiatives.¹⁰
- **The Massachusetts Technology Collaborative has been sponsoring the Massachusetts Distributed Generation Collaborative,** a stakeholder group that has been working since 2002 to investigate the role of distributed generation in Massachusetts. The group has made significant achievements in interconnection standards and procedures and has turned to broader issues. In its 2005 report¹¹ to the Massachusetts regulator, formerly the Department of Telecommunications and Energy, now the Department of Public Utilities, the DG Collaborative set an objective of achieving a societal win-win outcome with net benefits greater than costs for all stakeholders. Massachusetts distribution companies have been participating actively in the Massachusetts collaborative sessions. The Department of Public Utilities was an active participant in this project and, possibly due to this participation, has now opened a generic docket to investigate rate structures that will promote efficient deployment of demand resources.¹²

⁹ CEC Report **CEC-500-2005-060: Assessment of California CHP Market and Policy Options for Increased Penetration**
<http://www.energy.ca.gov/2005publications/CEC-500-2005-060/CEC-500-2005-060-D.PDF>

¹⁰ CEC Report **CEC-500-2006-038: Rate Structures for Customers with On-Site Generation: Practice and Innovation,**
<http://www.energy.ca.gov/2006publications/CEC-500-2006-038/CEC-500-2006-038.PDF>

¹¹ Massachusetts DG Collaborative 2005 Annual Report, Submitted to the Massachusetts Department of Telecommunications and Energy in Response to DTE Order 02-38-B
http://www.masstech.org/renewableenergy/public_policy/DG/resources/Collab_2005Collab05_05_31_FullAnnualReport.pdf

¹²Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources <http://www.mass.gov/Eoca/docs/dte/electric/07-50/62207order.pdf>

1.2. Problem Statement

As distributed energy resources become cleaner, more reliable, and more cost-effective, end users continue to be the largest market for DER options.¹³ DER may also offer electricity providers more diverse, flexible, and secure options for managing their electricity systems to benefit customers. In fact, DER applications that benefit both the end-user and the electricity system have promise for a “win-win” outcome. However, under today’s regulatory policies, most regulated electricity providers are taking a “wait and see” attitude to DER.

The EPRI DER Partnership has defined a win-win approach as one from which multiple stakeholders can benefit, and none are worse off. An element of a win-win business approach is an outcome – for example, financial gain – that benefits more than one stakeholder group simultaneously, without disadvantaging other stakeholder groups. One or more win-win elements should be achieved for a DER application to be considered a win-win business approach. For example, a win-win can occur when a customer chooses DER for flexibility and risk reduction, and when the DER can provide value to the distribution network as well. In addition, reduction of overall energy prices may be achieved by applying, for example, combined heat and power to the same project.

While some customer-side DER solutions – such as peak shaving or demand response – serve the interests of many electricity providers, other DER strategies – particularly combined heat and power and some renewable technologies – typically do not fit utility business interests. These and other base-loaded or non-dispatchable technologies result in reduced revenues along with the need to provide continuing service on call. Traditional regulatory approaches make it difficult to construct an attractive utility business case for these kinds of resources, even where they may provide least-cost solutions for local grid needs, or deliver important societal benefits such as higher conversion efficiency and improved air quality.

Furthermore, while individual end-user applications can provide some grid benefits such as distribution upgrade deferral, multiple DER units are likely to be required to supply grid reliability improvements and enhanced resource diversity and security. Traditional regulatory approaches provide little incentive for utilities to evaluate and realize these potential benefits. The opportunity to evaluate the societal benefits of DER on the grid could be enhanced by enabling a “soft start” in the market, through regulatory pilots with innovative approaches that need not become binding precedents for the long-term.

Informed stakeholders have observed that DER remains a compelling concept, but actual applications have not grown significantly over the last five years. There are many reasons, including the cost of small generators, lack of interconnection rules in some areas, and customer and investor uncertainty about energy markets. However, as groups like MADRI (Mid-Atlantic Distributed Resources Initiative) and others have discovered, two of the most significant barriers to large scale deployment of cost-effective DER solutions are uncertainty as to sustainable business models and, perhaps even more importantly, regulatory disincentives for

¹³ *Distributed Energy Resources: Current Landscape and a Roadmap for the Future*, EPRI, Palo Alto, CA: November 2004 (1008415).

electricity providers across the country to embrace DER solutions to meet customer supply and reliability needs.

The wide-scale use of DER on the customer side of the revenue meter will result in significant challenges to the ways in which regulated utilities recover their costs. New regulatory and utility business structures will be required to address the disincentives which utilities experience when they encounter customer-sited DER and the lack of incentives for utilities to encourage investment in DER to achieve system benefits and widely accepted public policy objectives.

1.3. Project Objectives

The overall project addresses business and regulatory considerations critical to successfully integrating distributed energy resources into electricity markets in general, and into investor-owned utility systems (both conventional and restructured) in particular¹⁴. The project has four stated objectives:

1. **Create business models and regulatory approaches¹⁵ that reward electricity providers** for integrating DER into their systems where it provides demonstrable societal and customer benefits, through facilitated stakeholder collaboration
2. **Adapt the most promising approaches to state- or utility-specific environments** such that utilities in the state will embrace
3. **Demonstrate the most promising approaches through actual DER pilot projects** to evaluate impacts on and benefits for electricity providers' and end-users' businesses and operations
4. **Conduct outreach in public and industry forums** to broaden acceptance of successful approaches by other states and electric providers.

This report documents the results of activities in support of the first three objectives listed above.

1.4. Project Approach

The project used a process of stakeholder collaboration to identify innovative business and regulatory structures. Stakeholders included electric utility staff, state public utility commissioners and staff, state energy agency commissioner and staff, DER project developers, and DER equipment manufacturers. These stakeholders collaborated to guide the more detailed work of EPRI and EPRI contractors who developed candidate business models and regulatory

¹⁴ This project focuses on investor-owned utilities subject to state utility commission regulatory jurisdiction, rather than on publicly-owned utilities or cooperatives governed by locally or regionally elected or appointed boards. Some of the same issues confront publicly-owned utilities interested in DER, but they face a different set of institutional imperatives and incentives than do state-regulated utilities.

¹⁵ Some examples, discussed later, include rate-of-return adders; utility ownership participation; performance-based rewards for efficiency and environmental improvements; and incentive design that allocates costs and benefits to achieve societal goals.

approaches and performed economic analyses of the impact of the business model on utility shareholders, ratepayers and DER owner/operators. The collaborators worked together in workshops and conference calls as detailed in Section 3.

Emphasis was originally placed on the following application classes:

- Combined cooling, heating, and power
- Waste gas-fueled generation (landfill gas, digester gas, flare gas, etc.)
- Solar photovoltaics (PV), small wind energy, other small renewable generation
- Standby generators dispatched during peak demand periods¹⁶

Starting at the San Francisco workshop, stakeholder working groups were formed to develop pilot projects in each state (Massachusetts and California). Development activities are described in Sections 7 and 8.

1.5. Project Participants

1.5.1. Funders:

- California Energy Commission
- Massachusetts Technology Collaborative
- State Technologies Advancement Collaborative (STAC) Award by National Association of State Energy Officials (NASEO) in conjunction with the U.S. Department of Energy and the Association of State Energy Research and Technology Transfer Institutions (ASERTTI). The contract is managed by the Massachusetts Division of Energy Resources

1.5.2. In-Kind Cost-Share Providers:

- California Energy Commission
- Cummins Power Generation
- Distributed Utility Associates
- Electric Power Research Institute
- Massachusetts Technology Collaborative
- National Grid
- Northeast Utilities
- Pacific Gas & Electric
- Sacramento Municipal Utility District
- Solar Turbines
- Southern California Edison

¹⁶ At the September 200 Workshop in Boston, the collaborators decided to exclude this application as it does not strongly affect the “throughput disincentive”. Such peak-shaving generators run very few hours per year and the kWh-related revenue loss to utilities is relatively insignificant.

- Tennessee Valley Authority

1.5.3. Other Stakeholders

- California Public Utilities Commission
- EnerNOC
- Environmental Protection Agency
- First Energy
- Massachusetts Department of Public Utilities
- New York State Energy Research and Development Authority
- Northern Power
- San Diego Gas and Electric
- UTC Power
- Other stakeholders are listed in Appendices A and B.

1.6. Report Structure

After this Introduction, Section 2 describes existing barriers for electric utilities with respect to distributed energy resources as well as possible solutions for going forward. Section 3 describes the activities of the collaborative over the time period September 2006 – January 2007 in which the collaborators analyzed utility business structures and associated regulatory changes that would encourage DER deployment. Section 4 describes the results of the working group that focused on utility-owned DER. Section 5 describes the results of the working group that focused on customer-owned, utility-facilitated DER. Section 6 describes the economic calculators used to quantify costs and benefits to: 1) the host site for the DER, 2) the host utility, 3) non-participating ratepayers, and, 4) society in general. Sections 7 and 8 describe the work accomplished to date toward developing pilot projects in Massachusetts and California respectively. Section 9 gives conclusions of this effort and recommendations for using the resources developed in this project for taking the next step with distributed energy resources.

Appendix A includes a glossary of terms related to DER and the definitions used for this project. Appendix B gives information on the 1st workshop on September 28-29, 2006 in Boston, MA. Appendix C gives information on the 2nd workshop, January 25-26, 2007 in San Francisco, CA. Appendix D tabulates and identifies the economic calculator input parameters for the five calculations presented in Section 6. Appendix E is the complete document on candidate business models and regulatory templates provided to the collaborators prior to the 1st workshop.

2.0 Business, Institutional, and Regulatory Issues Regarding Utility Support of DER

Electricity industry and DER stakeholders have long debated the benefits of distributed energy resources. The benefits are a function of perspective and scale. System benefits from DER when in service at customer sites are often described as deferred expenditures on transmission and distribution (T&D) infrastructure and for local voltage support, ISO or power pool capacity benefits, and standby/spinning reserve benefits. DER may also provide operating benefits (in terms of avoided overload outages or undervoltage events) if the utility can dispatch it when it might otherwise not be in service. DER host benefits are often described as reduced electricity and gas bill savings, and increased reliability.

Local, state, or federal public policy makers have set objectives that may be addressed by DER, including minimizing the need for new peaking or base load power plants or T&D infrastructure, and maximizing the use of waste fuels, renewable energy, such as rooftop PV, high efficiency end-use technologies, and combined cooling, heating and power installations for efficient use of commercial fuels.

However, utilities often lack interest in embracing DER, especially connected on the customer side of the meter. Reasons for lack of interest include lack of control of the resource, and questions of scale, resource reliability, and impact on and value to the grid. One of the key barriers is impact of DER on revenues and income. DER both reduces electricity sales and the need for investment in supply side assets.

DER interconnected with utility wires on the customer side of the retail revenue meter will reduce the need for the customer to purchase power from the utility. While the reduction of power flow through the revenue meter will reduce the electric utility operating costs, as there is no need to generate and deliver that power, the reduction in costs is generally less than the reduction in revenues; thus there will generally be a net loss of revenue and a net loss in income to the utility. This net loss to the utility is often referred to as the “throughput disincentive”. For distribution only utilities who do not generate power (and, hence, receive no benefit from not having to generate the power) the throughput disincentive is magnified by more than double as shown in Table 2-1.

Thus, the wide-scale use of DER on the customer side of the revenue meter will result in significant challenges to the ways in which regulated utilities recover their costs. New rate and utility business structures will be required to remove the disincentives which utilities experience when they encounter customer-sited DER, and to provide incentives for utilities to encourage investment in DER to achieve system benefits and widely-accepted public policy objectives.

2.1. Reduced Revenues and Profit

Like other private businesses, regulated monopolies are motivated by the need to be financially successful. The fundamental question for an electric utility faced with innovations that reduce customer use of grid-supplied electricity is the impact on utility revenues – or more precisely,

utility profits. Under traditional ratemaking methods a utility's revenues are a direct function of its sales, so DER that significantly reduces sales (whether through end-use efficiency or onsite supply) also reduces utility revenues and, absent offsetting cost reductions, utility profits. This poses a real and potentially significant barrier to DER that must be dealt with head on. Regulatory or legislative policies that require utilities to assemble the least-cost resource mix to serve demand are sensible and prudent, but they should be accompanied by complementary mechanisms that eliminate, or at least mitigate, adverse financial impacts on the utilities' bottom line – preferably in ways that reward both customer and utility.

In pursuing the goal of providing energy at the lowest total cost to society, the pricing of utility services serves two important objectives. Prices (or rates) serve to signal to energy users the economic costs of consumption, and they ensure recovery of the regulated company's "just and reasonable" costs of service. However, these objectives can conflict with each other.

Utility rates should reflect the long-run nature of the system costs incurred to meet present and future demand – i.e., they should cover at least the long-run marginal costs of service. Since all costs are avoidable in the long run, rates should be designed so that charges are avoided if service is not taken. This means that as far as possible, rates should be based on usage (per kW and kWh).

Two problems arise, however. The first is that many of the utility's costs appear to be fixed: *in the short run* they do not vary with sales, and are incurred whether service is provided or not – i.e., reduced usage (and usage-based revenues) do not necessarily reduce utility costs proportionately. The second problem, mentioned at the outset, is that traditional regulation typically ties recovery of a utility's costs (including its short-run 'fixed' costs) and profits to its kWh sales. Where profitability depends on sales volume, the utility has a strong *disincentive* to reduce sales (e.g., through end-use efficiency or customer-side DG), and a similarly strong incentive to increase sales. Since sales often can be increased in the short term with little or no increase in fixed costs, the profit margin on these sales is high and constitutes a powerful financial incentive for utility actions that may inhibit improvements in overall economic efficiency. By the same token, reduced sales in the short term can impair a utility's ability to meet its fixed-cost obligations.¹⁷

This problem affects both vertically integrated and wires-only utilities, but it is particularly acute for the latter. This is so because, in the short run, reduced sales for the wires company are not associated with significantly reduced costs: between rate cases, most wires company costs are largely fixed, so revenue losses from reduced sales impinge directly on the firm's net income. The converse is also true: increased sales lead more directly to increased profits,

¹⁷ We say "can" rather than "will" because whether net revenues actually decline depends on marginal power and delivery costs, customer growth, overall revenue levels and other factors. In some cases, the savings to the utility that result from customer-sited resources in fact yield net revenue *gains*. See, e.g., Moskowitz, David, *Profits and Progress through Least-Cost Planning*, National Association of Regulatory Utility Commissioners, 1989, and Cowart, Richard, et al., *Efficient Reliability*, Regulatory Assistance Project (NARUC), June 2001.

sometimes causing formidable utility reluctance to support improvements in customer efficiency.

Table x-x illustrates two important points about the impact of reduced sales on utility profits. First, it shows that a relatively small percentage reduction in *sales* (line h) results in a much larger percentage reduction in *profits* (net income, line n), and this is true whether the utility is vertically integrated or not. Second, the table shows that the profit erosion from DER is worse for a wires-only distribution company than it is for an integrated utility (line n).

This latter comparison shows that a 5% sales reduction for the vertically integrated utility, with 8¢ per kWh blended rate, will reduce its profits by about 23% between rate cases. The same 5% reduction in sales for a wires company, with 4¢ per kWh delivery rate, can reduce its profits by more than 50% until the next rate case, when regulators can reset rates for future periods.¹⁸ If throughput is increased, the disproportionate impact on wires-only companies works in the other direction.¹⁹

¹⁸ While perhaps not immediately apparent, the arithmetic is easily explained. A wires company has a relatively small equity rate base when compared to that of a vertically integrated utility, but the short-term profit loss from throughput reductions is relatively large, and not offset by savings in power purchase costs. The percentages shown here are illustrative; they will vary with the rate design of each distribution company.

¹⁹ Profits can be expressed in absolute terms, in a total 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 misleading. Certainly from a shareholder perspective, 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 climb from \$100 to \$150 million. But, 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%. For our purposes, “profits” (or earnings, etc.) refers only to ROE and not to absolute levels of profits.

Table 1 Lost Profits Math: Impact of Reduced Sales on Utility Profits

Ref	Utility Characteristics	Type of Utility	
		Vertically Integrated	Distribution-Only
(a)	Blended Retail Rate, \$/kWh	\$0.08	\$0.04
(b)	Annual Sales, kWh	1,776,000,000	1,776,000,000
(c)	Annual Revenues, (a)*(b)	\$142,080,000	\$71,040,000
(d)	Rate Base	\$284,000,000	\$113,600,000
(e)	Authorized Rate of Return on Equity	11.00%	11.00%
(f)	Debt/Equity Ratio	50.00%	50.00%
(g)	Required return on equity (net income) (d) * (e) * (f)	\$15,620,000	\$6,248,000
(h)	% Reduction in Sales	5%	5%
(i)	Reduction in kWh Sales, (h) * (b)	88,800,000	88,800,000
(j)	Associated Revenue Reduction	\$7,104,000	\$3,552,000
(k)	Average Cost of Generation, \$/kWh	\$0.04	n/a
(l)	Power Cost Savings from Reduction in Sales	\$3,552,000	n/a
(m)	Net Revenue Loss after Power Cost Savings	\$3,552,000	\$3,552,000
(n)	Reduction in Net Income (Profits), (m) / (g)	(22.74%)	(56.85%)

2.2. Other Barriers

The barrier of revenue reductions created by customer-side resources is important, and removing this disincentive may well be a necessary step toward more robust utility support for DER deployment. But there is ample reason to doubt that this by itself will overcome utility inertia or resistance to fully integrating DER into their portfolios. Decoupling sales from profits from has been in place in California for many years, and strong state policies favor renewables, CHP and other clean DG – yet California investor-owned utilities have not made DG a visibly high priority. While DG is not a high priority for California utilities, there are indeed programs that are paid for by all rate payers, for example, the Self-Generation Incentive Program²⁰, Emerging Renewables Program²¹, and the California Solar Initiative²², that are creating an enthusiastic, growing photovoltaics market. The biogas digester industry is growing as well.

Utilities often observe that some of the more promising DER technologies are not yet competitive with conventional utility solutions in today's markets. Many still question whether DER can add real value to their systems, or if it can, whether it can do so in more than a few isolated situations where unusual circumstances coalesce to make it a cost-effective *and profitable* solution.

²⁰ http://www.cpuc.ca.gov/PUC/energy/051005_sgip.htm

²¹ <http://www.consumerenergycenter.org/erprebate/program.html>

²² <http://www.cpuc.ca.gov/PUC/energy/Solar/index.htm>

Given today's modest DER penetration rates, utilities cannot yet capture the 'diversity' benefits that DER proponents believe will materialize as these technologies become more ubiquitous, creating a classic chicken-and-egg conundrum. Another knotty problem for utilities and regulators is the fact that some DER costs and benefits are difficult to quantify, and they often flow to different stakeholders: it is no easy task to value them, monetize them, and apportion them fairly, ensuring that those who bear a share of the costs receive a corresponding share of the benefits²³.

There are also questions of scale: for utility management focused on multi-million or -billion dollar generation or transmission projects, or on major distribution system upgrades or expansions, a few relatively small DER projects here or there skate beneath the corporate radar. At least until more effective business and regulatory models emerge, DER transaction costs remain high relative to larger utility projects, and the business of deploying large numbers of replicable DER quickly, efficiently and cheaply remains elusive not only for vendors and developers, but for utilities as well.

Many of these barriers are probably transitional, and will recede as more pieces of the DER puzzle fall into place. A major breakthrough in PV or fuel cell cost reduction or in small wind technology; fuel supply or price constraints that dramatically increase the value of efficiency; or the early implementation of smarter grids, more advanced metering, or a critical mass of DER that convincingly demonstrates aggregation and diversity benefits – any of these can change the equation dramatically and shift the balance in favor of DER that appears only marginally viable today. For these reasons – and because we are running out of conventional options – it is worth looking beyond the first step of decoupling, toward other positive business incentives that can ramp up utility interest in the success of DER that contributes to societal goals.

Utility resistance to DER, though often founded on lost revenue and profitability concerns, may also include cost shifting (more accurately described as the shifting of utility revenue allocations) from participating to non-participating ratepayers, including intra- and inter-class as well as inter-temporal shifts. Powerful customer interests and other political pressures are sometimes brought to bear on these issues, and they certainly warrant examination. However, it is important to recognize that regulators often permit or even require such shifts to advance important public policies (universal service perhaps being the best-known example).²⁴ Utility ratemaking is an exercise in cost-sharing and policy trade-offs, and regulators are expected to fairly evaluate whether such approaches are justified by the public benefits they yield.²⁵ Nonetheless, utilities tend to be very sensitive to cost-shifting, especially from one customer or customer class, whose payments to the utility are declining with declining electric energy purchases due to installation of DER, to another customer class not installing DER.

²³ Note that standby charges are charges on DER owner/operators to reserve capacity to serve the site should the DER be out of service,

²⁴ A corollary is that not every reduction in utility revenue is or should be treated as compensable, nor every increase in utility revenue rebatable.

²⁵ As one regulator once put it, "Policy should be clear about the absolutes. The rest is compromise."

2.3. Potential Options to Align Utility Interests with Policy Objectives

As stated by James Kerr II, President of the National Association of Regulatory Utility Commissioners²⁶, to encourage utilities to embrace energy efficiency, regulators need to remove the disincentive, allow recovery of costs, and offer the opportunity for positive incentives. This approach is in place in California. Massachusetts has the positive incentive in place and is currently considering how to remove the disincentive. These approaches could also be used to encourage distributed generation.

Over the last two decades, regulators have devised various means of dealing with the challenge of preserving pricing incentives for customer efficiency in the long run and neutralizing financial harm to the utility from reduced sales in the short run. Some, such as integrated resource planning (IRP) requirements and lost-revenue adjustment mechanisms, are fashioned to work within traditional cost-based pricing approaches to regulation. Others, such as various forms of ‘performance-based’ ratemaking, depart from traditional regulation by rewarding utilities not for new investment, but for improved efficiency, service and safety.

Net Lost Revenue. Within traditional cost-based regimes, a number of states imposed IRP mandates on their utilities during the late 1980s and early 1990s. Typically they required utilities to invest in the least-cost portfolio of resources, including cost-effective energy efficiency and other customer-sited resources, to meet present and future service demand. Recognizing that these distributed resources can perversely impact utility profitability, many states adopted *net lost revenue* adjustment mechanisms to compensate utilities for the portion of net revenue covering fixed costs that was foregone due to cost-effective investment on the customer side of the meter. These mechanisms compensated the utility for reduced sales but did not remove the financial incentive to increase sales, and most focused only on energy efficiency, not on other load-reducing initiatives.

Performance-Based Regulation. Seeing net lost revenue adjustments as a well-intentioned but incomplete solution, several states targeted the sales bias of traditional regulation by implementing *performance-based regulation*, or PBR.²⁷ PBR refers not to any single mechanism, to a broad array of regulatory methods that link particular behavior and preferred outcomes to specified financial rewards and, sometimes, penalties. As a comprehensive rate-making tool, PBR usually takes one of two forms, placing a ceiling either on the prices utilities can charge customers (*price cap*) or on the revenues they can collect from customers (*revenue cap*). Revenue caps are the better approach for breaking any link between DER installation on the customer side of the meter and erosion of utility revenue.

²⁶ Stated at the Electric Power Research Institute’s 2007 Summer Seminar, August 7, 2007.

²⁷ California, Maine, and Oregon all implemented some form of revenue-capped regulation in the early ‘90s. Each, for varying reasons (restructuring generally, or poor design—and thus poor performance—specifically), retreated from the approach. In this decade, California and Oregon have reconsidered decoupling and have implemented new mechanisms for several utilities. Other states in the east and mid-west are looking anew at it as well (e.g., through the MADRI process), and at least one, Vermont, has a proposal currently before it.

Under a **revenue cap**, the utility's revenues are fixed over a certain time period (typically three to five years, with adjustments upward for inflation and downward for imputed productivity gains). 'Fixed' here means set in advance, either in dollar terms, or in revenue per customer. These numbers can be forecasted to change over time (e.g., with adjustments for inflation, productivity gains, and other factors), so their trajectory can be fixed, though the numbers themselves may vary according to adopted formulas.

With a revenue cap, because the utility's revenues will not vary with sales, it is indifferent (at least from a revenue perspective) to customer DER installation. However, retail rates can still be based on usage (i.e., 'volumetric'), so that customers retain appropriate economic incentives to find cost-effective means to reduce consumption and therefore costs (i.e., prices).²⁸ These incentives can be improved by pricing reforms specifically designed for this purpose. Although the utility may be indifferent to sales volume, it is not indifferent to improving its operational efficiency which, in the short run, will increase profits and, in the long run, redound to the benefit of customers (i.e., will be captured in the revenue-requirement calculation in the next rate case).

In contrast, **price-cap** regulation, which fixes prices (not revenues) for a specified time period, does not remove the utility's sales, or throughput, incentive; its profits are still tied to sales volume while creating some inflexibility in investing for customer benefit.

In more limited applications, apart from the question of revenue and price caps, PBR can take the form of defined objectives and specified rewards – **targeted incentives** – for their achievement. Targeted incentives are often used to reward high system reliability, high customer satisfaction levels, or superior utility safety practices. Achieving the objective results in a financial reward – that is, some kind of increase in the cost of service used to calculate rates or determine allowed revenues. Success at promoting DER deployment that advances policy goals would be amenable to such an approach.

Fuel Cost Adjustment Factors. Note that most utilities in the U.S. already operate under a limited form of revenue decoupling in that their kWh rates change monthly based on the cost of fuel and purchased power. These are commonly called *fuel cost adjustment factors*, the calculation of which is established by the regulators. These add to or subtract from posted rates based on actual incurred fuel and purchased power costs incurred by the utility.

Standby Charges. A short term measure that has been implemented in tariffs by some utilities in an attempt to remedy the net loss of revenue from reduced sales due to customer-side DER is the use of *standby charges*. These are charges based on a customer's peak demand in the absence of any local DER. These charges are justified by the requirement of the utility to serve the full customer demand should the DER be out of service, and to hold non-participating ratepayers

²⁸ The method of fixing the revenues matters, and regular adjustments may be necessary. In the short run the utility's costs are not highly correlated with sales, but they are better correlated with number of customers. Thus, an adjustment related to customer count – e.g., a revenue-per-customer PBR – more closely reflects the utility's short-term financial imperatives than one linked to sales. Awareness of the nuances of utility revenue drivers (e.g., differences in customer usage characteristics) can inform good PBR design.

harmless from increasing rates that would otherwise be necessary to meet the utility's regulated rate of return on assets installed to meet the participating customer's peak demand. As might be expected, these charges, for what is essentially electrical supply insurance, are not well-received by customers who install DER in the expectation of reducing their power costs.

Performance Targets. In addition to revenue caps, *performance targets* could be used to promote DER deployment: for instance, minimum numbers of installed generators at customer sites, minimum kW or kWh of energy efficiency savings, targeted emission rates per MWh, or significant deferral of distribution investment. Rewards for these targets can take such forms as ratebasing, incentive returns on equity, fixed dollar amounts, or other bonuses. Shared savings can also be implemented, though this may be easier to do for energy efficiency. And penalties can be applied for failing to meet the standards; these are usually combined with incentives by establishing 'deadbands' or 'collars', above which rewards are given and below which penalties are imposed.

3.0 Collaborative Activities, September 2006–January 2007

This section describes the stakeholder process which is central to this project. Stakeholders had a significant impact on which business models were selected for consideration.

3.1. First Collaborator's Workshop

The First Collaboration workshop was held in Boston on September 28-29, 2006. The agenda for this workshop and a list of participants is included here as Appendix B. The workshop was well-attended and the discussions were lively. As might be expected, most participants in this workshop were from the New England area but the California Contingent included representatives from utilities, the California Energy Commission, an equipment vendor, and a DER owner/operator.

The purpose of this workshop was to present background information on the business, legal, and regulatory issues involved in providing utilities incentives for encouraging the deployment of DER that results in net benefits for three classes of players:

- The host site for the DER
- The host electric utility (combined shareholders and ratepayers)
- Society in general

Appendix E includes a white paper that guided the discussions at the 1st Workshop. The project team presented a framework for conducting economic calculations of costs and benefits for these three classes of players. This framework was based on a calculation prepared for doing similar assessments of implementing energy efficiency programs.

Note that, in the long run, net benefits that accrue to the host electric utility may or may not be shared between the utility shareholders and the utility ratepayers, depending on the way retail rates are determined by the respective regulators. If some form of revenue decoupling has been implemented by regulators, non-participating ratepayer rates may go up between rate cases if DER deployment results in fewer kWh sold than projected in the most recent rate case.

The project team also presented a procedure to separate the affects of the various business models and associated regulatory templates on both electric utility shareholders and non-participating ratepayers.

At the end of this workshop the collaborators decided to establish two working groups for further collaboration; one focused on utility-owned business models and the other focused on customer-owned, utility facilitated business models. Collaborators chose to participate in either or both of these working groups.

Collaborators also expressed interest in the two economic calculations presented: the one which calculated costs and benefits for the three classes of players listed above and the other which took the utility benefits from the first calculation and distributed them between shareholders and non-participating ratepayers based on specific regulatory templates.

3.2. Working Group Collaboration Period

The information presented at the first workshop was not specifically oriented towards the ownership classification that collaborators thought most useful. Thus, one of the major efforts that needed to be undertaken subsequent to the workshop was to flesh out the utility business cases and regulatory/legal issues for both the case of customer-owned DER and for utility-owned DER on customer sites.

From October 2006 through January 2007 the two working groups met, via teleconference, on a regular basis to review progress and refine the utility business models and associated regulatory templates. The utility-owned working group met approximately weekly. The customer-owned, utility-facilitated working group met approximately biweekly.

There was considerable interest among participants of the 1st workshop in further understanding the way costs and benefits were calculated for participating ratepayers, utility/non-participating ratepayers, and society in general, as well as how the utility/non-participating ratepayer costs and benefits are allotted. A parallel working group spent some time during the fall 2006 working through the two economic calculations described above.

3.3. Second Collaborator's Workshop

A Second Collaborator's Workshop was held January 25-26, 2007 in San Francisco, CA. The purpose of this workshop was to review the results of the two working groups since the first workshop. The second workshop agenda and participants are included here as Attachment C. As might be expected, in-person participants were largely from California but several were from New England and several more participated by teleconference from New England. As there were a number of participants in this meeting that were new to the collaboration, review of project efforts was often necessary.

Again, there was lively discussion at this workshop indicating the timely interest of the subject matter on the part of the participants. The results of the two working groups were presented along with significant time spent on the economic calculations and their implications. The example economic calculations presented are discussed further in Section 6.

At the end of this workshop, state-oriented working groups were organized for California and Massachusetts, respectively to further customize one or more of the business models for trial in pilot projects in each state, respectively. The results of the California pilot experience are described in Section 6 of this report.

The California working group put on the table a utility-owned business model based on the first model presented in Section 4. Pacific Gas and Electric (PG&E) expressed an interest in seeing if such a pilot might fit in development plans that were underway in their organization. Southern California Edison (SCE) indicated that they were in the initial stages of considering utility ownership business models and were more comfortable looking at customer-owned business models. The first model presented in Section 5 was put forth for consideration by SCE.

As part of electric utility restructuring in Massachusetts, the investor-owned utilities were required to divest themselves of central station generating assets and serve as "distribution

only” utilities. Utility ownership and operation of generating resources in support of the distribution system was not directly addressed during this restructuring. The Massachusetts utilities, however, did not choose to reopen this issue.

4.0 Utility-Owned Distributed Energy Resources Business Structures

While this project was initially focused on customer-owned DER, it became clear that utility ownership of DER could distribute benefits broadly, including benefits to non-participating ratepayers. Hence, the collaborators decided early on to include the utility ownership model in the project discussions and analysis.

During the 1st Workshop, the collaborators condensed discussions of utility-owned business structures into two key categories. This was done to provide focus for the time-limited discussions, not to preclude other options discussed in Appendix E. The two categories were:

- Utility ownership of the DER assets on customer premises, and
- Utility ownership/operation of an advanced distribution system infrastructure that takes full advantage of diverse DER benefits, whether utility-owned or customer-owned. These benefits include economic dispatchability, voltage/frequency support, capital construction deferral, standby and spinning reserve, etc. These are described more fully below with outstanding issues raised by collaborators.

During the group meetings in the fall of 2006, the collaborators chronicled the utility experience in owning/operating DER at customer sites. A list of various legal and regulatory issues that would need to be addressed was also developed, based on the collaborators' experience with such projects. This section provides the business models and regulatory policies that were created by the collaboration, as well as findings of the collaboration.

4.1. Potential Legal and Regulatory Issues

The installation and operation of DER owned by utilities and located at customer sites is a significant departure from the status quo. In addition to performance and/or cost challenges commonly associated with smaller-scale power generation, there are a number of legal and regulatory issues that must be addressed to allow utilities a clear path to proceed. These issues include:

- **Ownership by distribution utilities of equipment sited on customer premises** and allocation of costs and benefits among customers with and without DER installations. Whether the investment serves a single customer or benefits all customers in that class needs to be determined.
- **Ownership of (distributed) generation by "distribution only" utilities** in states where the electric utility industry has been restructured. Ownership may be precluded by law or by policy.
- **Anti-competitive features of utility ownership of equipment on customer premises** and the extent to which third parties assuming responsibility for operating the equipment and/or providing services would mitigate any anti-competitive concerns.
- **Pricing of valuable byproducts** (as with Combined Cooling, Heating and Power installations) or services (such as standby/emergency power) and the terms under which

the electric utility may contract to provide these to a customer and realize additional revenue.

- **Allocation of any credits other than for energy** (such as renewable credits, GHG reduction credits, etc.)

4.2. Utility-Owned DER Business Models

The following business models were created by the collaborative:

4.3. Deploying DER Assets and Infrastructure

4.3.1. Utility Business Structure

Under this business structure, the utility acquires and deploys generating equipment at the Host Customer's site and interconnects the electrical output on the utility side of the meter. The utility may or may not install, operate or maintain the equipment (possibly leaving those services to a third party). Vendors of the DER equipment could operate it on the utility's behalf, receive capacity and energy payments from the utility or the ISO, and allow the utility to use it for local reliability purposes at certain times.

This structure involves utility investment in assets and possibly operations on individual customer sites (as distinct from investments in equipment embedded in its distribution system that clearly benefits multiple customers). As such, it introduces at least the following issues:

- Ownership by distribution companies of equipment sited on customer premises. Allocating costs and benefits among customers with and without DER installations.
- Allowing ownership of distributed generation resources by utilities in states which have restructured the electric utility industry. Identifying compelling reasons for restructured electric utilities to own/operate distributed generators which arguably serve quite different functions than central generation.
- Identifying the conditions under which utility investment in generating assets associated with a single customer can be assigned to all customers in a customer class.
- Identifying and satisfying any anti-competitive concerns surrounding utility ownership/operation of equipment on customer premises.
- Identifying the terms under which additional revenue from a valuable byproduct (as with Combined Cooling, Heating and Power installations) or service (such as standby/emergency power) may be charged to the host customer.
- Providing a structure for allocating credits other than for energy (such as renewable credits, GHG reduction credits, etc.).

4.3.2. Complementary Regulatory Policies

This utility-owned DER business structure would be expected to be affected by the following regulatory policies:

- *Rate-base treatment of all prudent investments in utility-owned DER facilities.* The utility is allowed an opportunity to earn a fair return on its DER equipment investment as it

already does on its investment in transmission-distribution infrastructure and, in vertically integrated utilities, its generation facilities. A means would need to be developed to assess which utility-owned DER installations at customer sites qualify as prudent investments.

In some restructured states, laws prohibit utility ownership of generating facilities to safeguard competition in markets where the utility retains its monopoly in the wires business. In other states, courts and commissions may resist such arrangements under state anticompetitive laws or possibly federal antitrust law²⁹.

In either situation, proponents of this business structure would need to establish that these arrangements are not anticompetitive or that they warrant exemption from otherwise applicable policies, or will need to consider alternative arrangements such as ownership by DER Customers or third-party DER Providers.

- *Recovery of operating expenses.* The utility would be expected to recover, at cost, the expenses of operating and maintaining the DER as they are able to recover other costs of operation including fuel and other operating/maintenance costs.
- *Revenue decoupling.* As the electric output of the generator would be interconnected on the utility side of the meter, it would not reduce utility retail revenues. For this reason, decoupling revenue from throughput would not be necessary to implement this business strategy.

In this case, the utility would be the primary beneficiary of the DER installation. The benefits would include regulated return on equity of the DER installation investment, the possibility of benefits associated with deferred infrastructure investment and the system operating benefits, and revenue from sales of byproduct energy and/or services. With the exception of the return on equity benefit and in the long term, these benefits are shared with all of the utility's ratepayers.

4.4. Reducing Costs—Increasing Reliability

4.4.1. Utility Business Structure

For this business case, the utility invests in advanced distribution infrastructure to take full advantage of the diverse values of DER. It affords DER Customers and Providers open access to this infrastructure, but may or may not participate with them in other DER activities or services (such as ownership, installation or O&M). This business structure is discussed more fully in Appendix E. This model, involving utility investment in assets and operations that are arguably integral to its monopoly distribution function, is quite compatible with prevailing cost-based, rate-of-return regulation. It does not require major changes in traditional regulatory

²⁹ For a comprehensive discussion, see Nimmons, J., J.D., et al., *Legal, Regulatory & Institutional Issues Facing Distributed Resources Development* (Chapter 4) National Renewable Laboratory, 1996; NTIS/GPO DE96014321, SR-460-21791; also, *TAG Technical Assessment Guide, Volume 5: Distributed Resources*. EPRI, Palo Alto, CA: 1999. TR-113165-V5.

approaches, but does raise at least the following issues for regulators interested in integrating DER:

1. The cost-effectiveness of this significant infrastructure investment, and how costs and benefits should be allocated among stakeholders, including DER participants and non-participants.
2. How any benefits flowing from the investment are related to time-of-use pricing. If they are strongly related, should customer participation be voluntary or mandatory³⁰.

4.4.2. Complementary Regulatory Policies:

- *Rate-base treatment of all prudent investments in advanced infrastructure.* The utility is allowed an opportunity to earn a fair return on its investment, as it would have for any other prudent investment in assets that serve the public good. Note that this need not be a voluntary utility initiative: regulatory commissions may affirmatively find that the public interest will be served by these investments, and direct their utilities to make them and credit the income produced by advanced infrastructure assets against the utility's revenue requirement (cost-of-service).
- *Recovery of operating expenses.* The utility would be expected to recover, at cost, the expenses of operating and maintaining the advanced distribution system as they are currently able to recover other costs of operating the existing distribution system.
- *Revenue decoupling.* To the extent that the DER is interconnected on the customer side of the revenue meter, decoupling of revenue from kWh throughput may be required to minimize the throughput disincentive to the utility.
- *Open access.* Regulatory policies would be needed to foster open access to the utility distribution system at commercially viable prices.

In this case, the utility benefits would include regulated return on equity of the DER installation investment, the possibility of benefits associated with deferred infrastructure investment and the system operating benefits. With the exception of the return on equity benefit and in the long term, these benefits are shared with all of the utility's ratepayers.

Findings

This project found that the utility-owned DER business models are more likely to achieve the win-win outcomes than customer-owned models under the current regulatory conditions. This is because the many benefits of distributed generation (as compared with central station generation) are automatically passed on to utility ratepayers and shareholders when the utility owns/operates the generators. The prudent costs incurred by the utility to acquire and install

³⁰ A major justification for the cost of providing advanced distribution system infrastructure is to provide better time of use price signals to customers. This is typically accomplished by implementing a tariff under which energy and demand rates change with time of day and day of week. If customers can choose between a time of use tariff and a fixed rate tariff, customers with load profiles that result in higher utility prices under the time of use rate would have no incentive to choose that rate and, consequently, no incentive to reduce demand during peak periods. If peak reduction or shifting at a site does not occur, the benefits of advanced metering at that site are not realized.

generators become part of their rate-based capital expenses on which they earn a rate of return. The net operating costs become part of the revenue requirement on which rates are based. To the extent that the benefits of distributed generators return benefits greater than the utility rate of return on the capital costs, the benefits are distributed to ratepayers in the form of relatively lower rates. In addition, to the extent that the distributed generators relieve the utility from having to install or operate other assets to meet local loads, these additional savings are also distributed to ratepayers in the form of relatively lower rates.

This case is conceptually easier to consider as it involves relatively minor adjustments to existing utility operations. The throughput disincentive (declining utility revenues with increasing distributed generation) is not pertinent as the power is interconnected on the utility side of the revenue meter. Thus, there is no need to bring revenue decoupling into the discussion.

If and when the aggregated scale of DER reaches a critical threshold where DER reliability issues would be better understood and better managed, utility interest would likely increase. The sustainable community development work in San Diego, for example, suggests that DER applications and benefits might be easier to develop and monetize on a macro scale. Such community-wide development would aggregate energy efficiency, renewables, water, heat and cooling.

Some of the more specific findings related to utility-owned DER are as follows:

- There does not appear to be much interest in utility-owned DER by the California investor-owned utilities. Ownership entails financial risk with little upside benefit. Other reasons for little interest in utility ownership of DER are that the units are small, reliability is unknown, and the utilities have little operating experience with them. The perception is widespread that distributed generation units are not as reliable as normal sources supply, such as central station power or natural-gas peaking units, or a wires solution.
- Nevertheless, other utilities around the country have had some success with utility ownership. Austin Energy, for example, has had success with utility-owned DG, notably the installation of combustion turbines at two sites, one a hospital and the other an industrial park.
- California IOUs remain reluctant to pursue the utility-owned DER option because of the financial liabilities they might incur if and when the DER or valuable byproducts associated with the DER should fail at a critical moment in serving the customer or supporting the system. There is little history of this type of endeavor and, hence, utilities tend to view DER units as less reliable than the traditional sources of generation they would displace. Overall, the limited benefits of small scale DER do not offset the risks perceived by the utility. At present there is no strong regulatory push for utilities to enter into this type of endeavor, and therefore no willing partners to share or help offset the risk.

- Utilities in Massachusetts are not considering utility-owned DER because it is currently not allowed by law.

5.0 Customer-Owned, Utility-Facilitated Distributed Energy Resources Business Structures

Customers of electric utilities, not the utilities, have largely implemented most of the DER in place. This will probably continue to be the case in the near term. The main aspects of this ownership model are that the participating customer takes on the capital and operating responsibilities but also realizes retail value for the power.

5.1. Issues

The prevailing paradigm for DER investment is that the equipment is purchased, installed and operated by the customer, not the utility. For customer-owned distributed energy resources to become important to regulated utilities, the current business models and regulatory structures need to change for a number of reasons, including:

- **Reduced revenues and profits, due to the “throughput disincentive”** that arises when customers generate some of their own power while still connected to the grid. Unless profit is not coupled to revenues (e.g., decoupling), reduced electricity sales causes a net loss of revenue, which is amplified by a still larger reduction in net income (profit). For example, a 5% reduction in sales leads to a 23% reduction in profits for a vertically integrated utility, and leads to a 57% reduction in profits for a distribution only company. This disincentive does not exist in California where decoupling is in place. In Massachusetts, a generic docket was opened in 2007 to explore options to remove this disincentive.
- **The potential need to provide continuing service on call for customers that generate their own power.** These customers often continue to rely on the grid to supply the remainder of their power needs or to supply power when their own supply is not available. In this case, utility revenues decline while the fixed costs associated with customer interconnection remain intact. For integrated utilities, a portion of the lost revenue is offset by a reduction in the cost of generating power; whereas in the case of a wires-only company, there are few options for offsetting cost reductions.
- **From the utility perspective, the scale of DER is small and the resources are not controllable.** Individual applications will not likely provide grid benefits such as distribution upgrade deferral, and may not be available when needed.
- A number of means of addressing these issues were considered by the stakeholders:
- **Removing disincentives is important, but not sufficient.** Regulators in a number of states have devised means of neutralizing financial harm to utilities for pursuing desirable societal objectives, such as energy efficiency. These range from decoupling revenues from profits and lost revenue adjustment mechanisms

that work within the traditional regulatory framework to performance-based ratemaking that reward utilities for improved efficiency, service and safety. Decoupling, for example, has been in place in California for many years, yet the state's investor-owned utilities have not made DER a high priority despite strong state policies favoring energy efficiency, renewables and combined heat and power.

- **The opportunity for regulated utilities to earn profits through a new business model or performance incentive will likely be needed for widespread DER integration to occur.**
- **Aggregation of DER provides scalable benefits for utilities and society.** Multiple and aggregated DER units will more likely supply grid reliability improvements and enhanced resource diversity and security. A “soft start” in the market, through regulatory programs with innovative approaches that need not become binding precedents for the long-term could help get the DER integration started and achieve the scale needed to realize benefits. Furthermore, control systems and automated demand response systems could be used with customer-owned DER to enable dispatchability.
- **The opportunity to evaluate the societal benefits of DER on the grid would be enhanced by the “soft start” approach.** Actual measurements could be made of the potential benefits of DER integration, including providing diversity of supply, least-cost solutions to new demand, deferment of capital investment, and provide ancillary system benefits, including system reliability, voltage support and spinning reserve. With quantified benefits, the business model would become clearer.

5.2. Customer-Owned DER Business Models

The customer-owned working group determined that the utility could facilitate customer-owned DER and through the closer working relationships, reap more benefits from the DER installation. The working group developed the following business models and regulatory treatments for utility-facilitated customer-owned DER. The focus of the project's activities in this area were to identify ways that deployment of DER on the customer site can complement utility operations in a way that provides utilities a positive incentive to exploit the opportunities.

5.3. Soliciting DER to Reduce Costs/Increase Reliability

5.3.1. Utility Business Structure

Rather than owning its own DG assets, the utility offers customers incentives to deploy or dispatch DER to provide value to the utility and other ratepayers (e.g., by using DG or curtailing load to limit grid demand, or by minimizing line losses associated with moving central station power to the loads) when called by the utility or ISO, enabling the utility to

reduce its highest-cost wholesale purchases (depending on extent to which utility owns or buys wholesale generation service on behalf of customers who choose not to secure other wholesale power) and, with appropriate assurances, to improve reliability, increase overall fuel efficiency (CCHP or waste fuel applications) and defer or avoid distribution investment.

This role does not require utility investment in assets or operations, except possibly metering and communications and control equipment to limit DER Customer load under contractually agreed conditions. It does entail utility planning and regulatory approval of a process to inform, solicit, select and contract with participating customers; expenses (and, possibly, incentives) to establish, implement and administer the program; and incentive payments (or billing credits) for DER Customer performance meeting agreed contract conditions. Pertinent factors for such a program are likely to include:

- Operating incentives/penalties (rather than capital incentives) to the DER owner/operator that ensure that the utility actually receives the operating benefits imputed to the DER installation.
- Operating incentives that are tied to actual cost savings realized by the utility.
- Minimum performance qualifications to ensure that the DER installation meets agreed-on public purpose objectives.

5.3.2. Complementary Regulatory Policies:

- *Recovery of administrative and program expenses.* The utility would be expected to recover, at cost, the expenses of administering the program.
- *Revenue decoupling.* Decoupling of revenue from kWh throughput will be required to minimize the throughput disincentive to the utility.
- *Rate recovery of incentive payments or bill credits.* To the extent that incentive payments or billing credits are not balanced by reduced operating costs on the part of the utility, these will need to be
- *Incentives (to host customers) that might be associated with lower utility operating costs or public policy objectives.*
 - Reduced line losses to deliver central station power to the site.
 - Savings on bulk wholesale power purchases; energy or capacity.
 - Measurable reliability improvements and cost-effective investment deferrals above specified thresholds.
- *Lost opportunity.* Consider whether it is necessary or desirable to adjust utility revenue requirements to account for slower growth or returns on 'foregone capital investment' of potential concern to utility shareholders.
- *Standby charges.* Identify the extent to which standby charges (designed to reserve capacity to supply the DER customer load should the DER not be in service) should be implemented to keep non-participating customers harmless from rate increases that might otherwise result from the net loss in utility revenue associated with customer-sided DER.

This business structure is very similar to the business structures being implemented at utilities for energy conservation and demand reduction. The utility recovers the cost of the program, possibly with an added fee as an incentive to pursue qualifying opportunities. The remaining benefits are shared, in the long run, with the ratepayers.

5.4. Soliciting DER Assets to Meet Efficiency/Renewable Mandates

5.4.1. Utility Business Structure

Some states require that utilities plan for and acquire energy efficiency, demand response, renewables and clean distributed generation in a designated priority or ‘loading’ order before conventional resources or major infrastructure additions. States may also require utilities (and sometimes competitive electricity suppliers) to annually increase the percentage of preferred (usually renewable) resources in their portfolios, often targeting some required percentage by a certain date.

Utilities may choose to meet these obligations by acquiring, owning, and operating the qualifying generating assets. To the extent that these generating assets are located at customer sites and are interconnected on the utility side of the revenue meter, this approach is largely covered by the first utility-owned business strategy presented in Section 4.

The business strategy described here is the solicitation of the qualifying generation output from customer-owned installations to meet specific generation portfolio requirements imposed on utilities.

5.4.2. Complementary Regulatory Policies:

- *Rate-base treatment of all prudent investments.* Rate-base treatment of all prudent investments needed to bring priority resources into service on behalf of the utility to meet portfolio requirements.
- *Recovery of operating expenses.* Recovery of all expenses the utility incurs to plan for and acquire such resources.
- *Revenue decoupling.* Revenue decoupling will be required to the extent that customer-side energy efficiency, renewable generation, and/or clean DG are implemented on the customer side of the local revenue meter.
- *Identifying resources which qualify.* Terms and conditions will have to be developed for assigning qualifying generation that is customer-owned/operated to the utility to meet the imposed requirements.
- *Other incentives.* Since regulatory directives have the force of law, compliance with a ‘loading order’ mandate does not necessarily require special incentives. However, regulators may conclude that success is more likely if utilities are rewarded for expediting priority resources or exceeding minimum kW or kWh targets. Offering higher returns on specific investments or payments for achieving target output levels from preferred resources could help, as could expanding the set of resources covered by portfolio standards to include efficiency, demand response, and/or CCHP, as for example Vermont and Pennsylvania have done.

5.5. Providing DER Services

5.5.1. Utility Business Structure

The utility does not own, install or operate DER, but sells DER support services directly to DER customers or providers. Services could include managing customer demand response for ISO programs; managing VAR control or back-up services for mini-grids; or providing metering and billing for solar utilities.

5.5.2. Complementary Regulatory Policies:

- *Recovery of service expenses.* Include all reasonable expenses associated with network management services in the utility's revenue requirement. Consider special accounting for the delivery of ISO demand-response programs.³¹
- *Revenue decoupling.* Without decoupling, the utility retains the incentive to increase sales. If some form of decoupling is not feasible, consider a 'net lost-revenue adjustment mechanism' (which would *not* remove that incentive, but *would* compensate the utility for reduced revenues due to DER enabled by its network management services).
- *Rates.* Rate design and rate levels will influence both DER operations and cost-effectiveness.
- *Other incentives.* Allow the utility to share in any savings made possible or enhanced through the DER services it provides.

To the extent that such savings would otherwise accrue primarily or solely to the participating DER Customer, sharing arrangements can be defined in negotiating the service contract. If system-wide savings can accrue to participating and non-participating customers as well as the utility, regulators will need to review and determine their proper allocation.

5.6. Findings

The customer-owned DER model is less likely to result in win-win outcomes under the current regulatory environment because the non-participating customers' costs outweigh the benefits in the short term. The electrical output at the customer's site reduces flow of electric power through the revenue meter and, hence, reduces revenues to the utility. However, with wide-scale integration of DER, the expected benefits will result in reductions in costs to all customers, thus a reduction in rates.

The economic calculator developed for this project showed the following:

³¹ The ISO pays the curtailment service provider (CSP), which in turn pays the consumer for load reductions delivered (typically a share of the payment the CSP receives from the ISO – enough to induce the desired customer behavior, while leaving the CSP enough to cover its service costs, including profit. Sharing of ISO payments raises policy and market questions. Non-regulated CSPs will offer or negotiate a price through a standard product; the CSP's share is the difference between the price it pays the customer and the price the ISO pays to it. For regulated CSPs, the PUC will determine the sharing arrangement, taking into account traditional regulatory concerns – equity, efficiency, cost-allocation, revenue collection. The regulated CSP share should be set to cover at least the costs of marketing and providing the service.

- The DER owner and, in many cases, society often have benefits that exceed the costs. The conditions under which the electric utility benefits exceed the costs are where the customer-sited DER allows avoidance of a large capital expenditure over an extended period of time. Future work should use the economic calculators to look at how to re-allocate the costs and benefits such that the societal benefits are shared with all stakeholders.
- While some customer-side DER solutions, such as peak shaving or demand response, serve the interests of many electricity providers, other DER strategies – particularly combined heat and power and some renewable technologies – typically do not fit utility business interests. These and other base-loaded or non-dispatchable technologies result in reduced revenues along with the need to provide continuing service on call.
- Unless decoupling is in place, in the short run (until the next rate case), the excess of utility costs over benefits reduces utility profits. In the medium run (at the next rate case), the excess of utility costs over benefits is paid by ratepayers in the form of increased rates. Revenue decoupling is essentially equivalent to frequent rate cases. The general effect of revenue decoupling is to shift the excess of short run (until the next rate case) costs over benefits to ratepayers in the form of increased rates.
- However, when system costs are reduced by lower demand due to on-site generation, for example, rates are decreased. Multiple and aggregated DER units are likely to be required to impact system costs on a beneficial scale, for example, grid reliability improvements and enhanced resource diversity and security.
- Without decoupling, for both integrated utilities and distribution companies, there is a net loss of revenue, which is amplified by a still larger reduction in net income (profit). For example, a 5% reduction in sales leads to a 23% reduction in profits for a vertically integrated utility, and leads to a 57% reduction in profits for a distribution only company.
- In concept and at a meaningful scale, DER could potentially add diversity of supply, provide a least-cost solution to new demand, defer capital investment, and provide ancillary system benefits, including system reliability, voltage support and spinning reserve. In time, these benefits may truly emerge. A meaningful scale might be on the order of 100s of megawatt capacity in a distribution area with corresponding monetized benefits in the millions of dollars. But at present, without sustainable business models, DER is more likely to introduce technical complexity to the integrated operations, erode utility control, revenues and profits, and shift fixed capital costs from DER customers to other ratepayers.
- Because of the lack of business models in the current regulatory environment, regulated utilities in California and Massachusetts have not invested in significant resources and staff to encourage DER. The pilot projects planned for this project were intended to break through this barrier.

6.0 Economic Calculator for Evaluating Candidate DER Installation Types and Business Structures

6.1. Economic Calculator Description

- Two economic calculators were prepared in spreadsheet format to help collaborators evaluate the costs and benefits of candidate DER business models. The “Individual Installation DER Model” is a modification of a calculation prepared to analyze individual CHP installations. The “Aggregate DER Model” was constructed to evaluate how net utility benefits calculated by the Individual Installation Model would roughly be allocated between utility shareholders and utility ratepayers given the existing utility regulatory structure.
- The models were developed to produce “what if” calculations that provide planning-level results for both baseline assumptions and user-defined scenarios. The tools are not suited for developing financial pro-formas of individual installations or use in regulatory proceedings that focus on a particular utility.
- The models were developed by the project team from Energy and Environmental Economics, Inc. (E3), who adapted them from models they developed for the National Action Plan for Energy Efficiency led by the U.S. EPA and DOE and the California Energy Commission 2005 CHP market and policy study. The input parameters for the models are listed in Appendix D of this report.
- Calculator results are presented in this section primarily to indicate the capability of the tools and/or to illustrate the economic issues associated with DER that need to be addressed by business planners and policymakers. The cases were selected by collaborators who were also relied on to provide a number of calculation inputs including the most important costs and electric generator performance data. Nonetheless, the results presented in this section should be considered indicative of the capabilities of the calculator tools and not conclusive for the analysis of DER prospects. The calculator tools are available to produce more conclusive results in the planning for and analysis of pilot projects.
- The economic calculators were used in the project to assess the flow of costs and benefits of various business models and regulatory approaches. These tools, while not validated by the participating utilities or by actual DER projects, were not challenged, thus can be considered useful tools to take these business models and regulatory approaches to the next step—to allocate costs and benefits so that win-win outcomes result.

6.1.1. Individual Installation DER Model

Project team member E3 prepared a spreadsheet for the California Energy Commission to assess the business cases of deploying combined heat and power for three classes of participants.

- The entity undertaking the energy efficiency measure
- The host utility

- Society in general

E3 modified this spreadsheet to conduct the same set of calculations for deployment of a broader set of distributed generators with different ownership structures. This model looks at the costs and benefits of the proposed DG and business structure from the participating customer (host site), utility / non-participant, and societal perspectives. This tool evaluates a single installation at a time. This tool is relatively high level in that all of the costs and benefits are calculated on a levelized (or net present value (NPV)) basis, not an annual cash flow. The advantage of this approach is that it allows easy sensitivity analysis and can accommodate extensive business case variations.

The input-output screen of the Individual Model spreadsheet is shown in Figure 1 with identification labels.

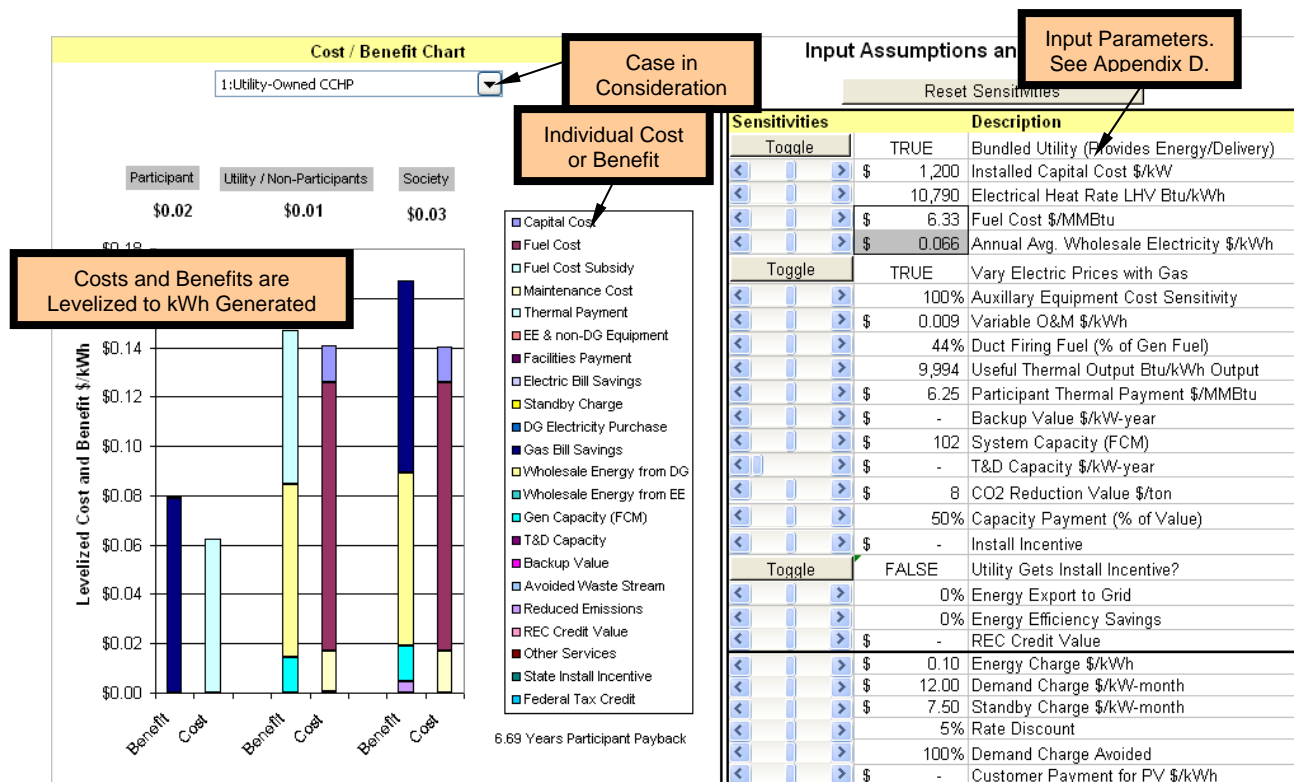


Figure 1 Individual Model Input-Output Screen

In working with the Individual Model, the following emerged as the assumptions most critical to the results:

- Capital cost
- Heat rate
- Useful waste heat (CCHP Applications)
- Customer waste heat use and 'fit' for application

- Financing
- Retail rate levels and structure
- Wholesale electric and gas assumptions
- Policy assumptions - Incentive, tax credits, payments

These have long been recognized as the primary economic factors to DER cost effectiveness.

6.1.2. Aggregate DER Model

An aggregate cost-effectiveness model was developed based on a business evaluation tool developed for the U.S. Environmental Protection Agency and the National Action Plan for Energy Efficiency. The model looks at an estimated penetration rate of DER (2.5% of energy sales over 10 years in the base case) and evaluates how net benefits calculated by the Individual Model are allocated between utility shareholders and ratepayers. Notice that this model, unlike the Individual Model, separates the impact of non-participants (through rates) and shareholders (through earnings and return on equity (ROE)). This is done by making assumptions about the rate treatment of the costs and benefits of distributed generation, and of any decoupling mechanisms in place (in cases where utility sales change). This is an annual model that computes the annual cash flow and revenue requirement for the base case (no DER) and with DG.

The Aggregate DER Model calculates the following over time on an annual basis:

- Total utility revenue (\$ from customer billings)
- Average customer electrical rate (\$/kWh)
- Participating customer net benefits (over the base case)
- Utility after-tax return on equity (% ROE)
- Total utility earnings (\$)
- Net societal benefits (\$)
- Cumulative emissions savings (tons)

The graphic results shown below for the Aggregate DER Model include data for two regulatory approaches: 1) the base case, standard ratemaking that includes the throughput disincentive, and 2) revenue decoupling with rate adjustments on an annual basis which minimize the throughput disincentive.

The model parameters which affect the calculations the most include:

- Sales growth (kWh sales are assumed here to be 2.0% per year.)
- Gas and energy price forecasts
- Rate case timing (Assumed here to be in years 1, 5, and 9)
- Timing of DER incorporation into rate base (assumed here to be 0.25% per year of year 10 kWh use)

- Decoupling and fuel adjustment (Fuel cost increases are assumed here to be passed through to ratepayers in full.)
- Percent of capital expenditure saved by customer DER (Assumed here to be 50% of customer-owned DER capacity.)
- Timing of incentive payments - upfront vs. over time

Additional general assumptions included in the Aggregate DER Model calculation results shown below are:

- 30% of base case capital expenditures are growth related
- Capital expenditure (capex) assumed to occur in multiples of whole installations to achieve necessary penetration

6.2. Case Studies Evaluated

Case studies were conducted to demonstrate the capabilities of the economic models and to explore the implications of customer versus utility ownership. While these case studies demonstrate useful results for analysis, they do not necessarily indicate the only projected outcomes, particularly in light of future technology cost reductions, and quantifiable benefits of increased DER penetration. Furthermore, the case studies indicate that not all benefits are quantifiable today, nor monetized. Most importantly, the case studies indicate the usefulness of the economic calculators which could be used in the future to allocate costs and benefits to result in win-win outcomes.

The calculations were exercised by calculating costs and benefits for the following five cases:

- Case 1 – Utility-Owned Residential Photovoltaics
- Case 2 – Customer-Owned Commercial/Industrial Photovoltaics
- Case 3 – Utility-Owned Waste Fuel-Powered Generation,
- Case 4 – Utility-Owned Combined Heating and Power
- Case 5 – Customer-Owned Combined Heating and Power

6.3. Case 1 – Utility-Owned Residential Photovoltaics

6.3.1. Case Description

In this case the utility incurs all costs to install rooftop photovoltaics on residential customer roofs. The PV is interconnected on the customer side of the revenue meter.

The utility aggregates available incentives and charges participants an amount that offsets the net cost of ownership/operation. The utility earns a standard return on the investment in the rooftop PV.

The key drivers for this case include:

- Capital cost of installed PV
- Utility ability to get state PV credit (assumed yes in base case)

- Utility ability to get federal tax credit (assumed no in base case³²)
- Decoupling / revenue adjustment

6.3.2. Individual Installation Model Results

The inputs and outputs of the Individual Model calculation are shown in Figure 2. Under the assumptions of the case, the utility realizes zero net benefits (participating customers are charged an amount that exactly offsets the net cost of owning/operating). Negative net benefits are realized by the residential participant and society. Costs of PV are the reason for this outcome today, as well as that many societal benefits are not quantified and monetized. This case should continue to be considered because acquisition and installation costs will continue to decline due to economies of PV production scale as well as technology improvements and breakthrough potential³³.

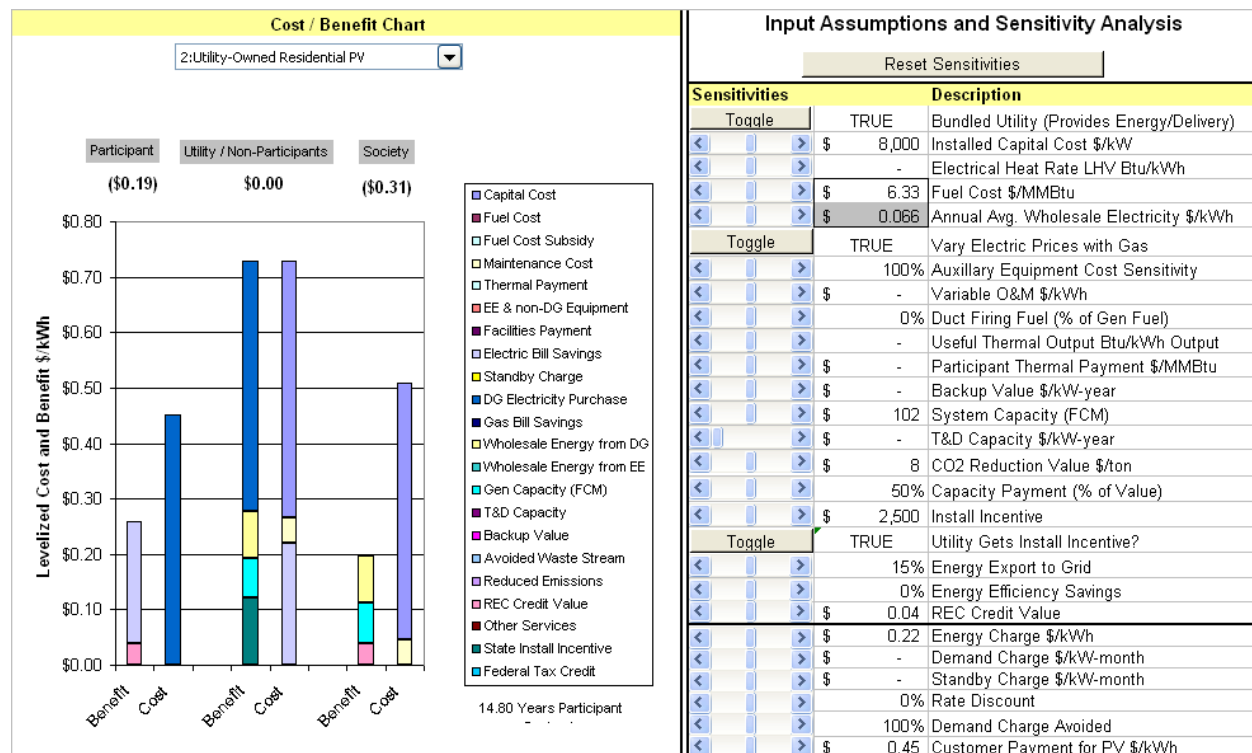


Figure 2 Utility-Owned Residential PV Case

³² At the time of this report, federal tax credits and other federal tax benefits were not available to electric utilities. Changes to such legislation and associated tax regulations would be important considerations for business models involving direct utility ownership of PV assets. Utilities interested in facilitating PV for customers could also consider business models through which advantages could be obtained for customers through roles for third-parties that would be in a position to monetize federal tax benefits.

³³ Estimates of future declines in solar PV costs are available in studies listed at www.masstech.org/dg/pv.htm.

6.4. Case 2 – Customer-Owned Commercial Photovoltaics

6.4.1. Case Description

Commercial Customers install rooftop PV at their own expense. The PV is interconnected on the customer side of the revenue meter. The customer and the utility share capacity value of the PV 50:50. The customer owns the renewable energy credits (valued at \$0.04 in the base case)

The key drivers for this case include:

- Capital and financing cost
- State installation incentive
- Federal tax credit and accelerated depreciation
- Retail rate structure

6.4.2. Individual Installation Model Results

The inputs and outputs of the Individual Model calculation are shown in Figure 3. Under the assumptions of the case, the participating customer receives net benefits, largely installation credits and federal tax credits and accelerated depreciation). Negative net benefits are realized by the utility and society. If there is no offsetting revenue to utilities, the negative costs are likely to be met by raising rates to all ratepayers, including non-participating ratepayers. The reason that this case might be considered is the prospect that acquisition and installation costs might decline in the future due to economies of PV production scale.

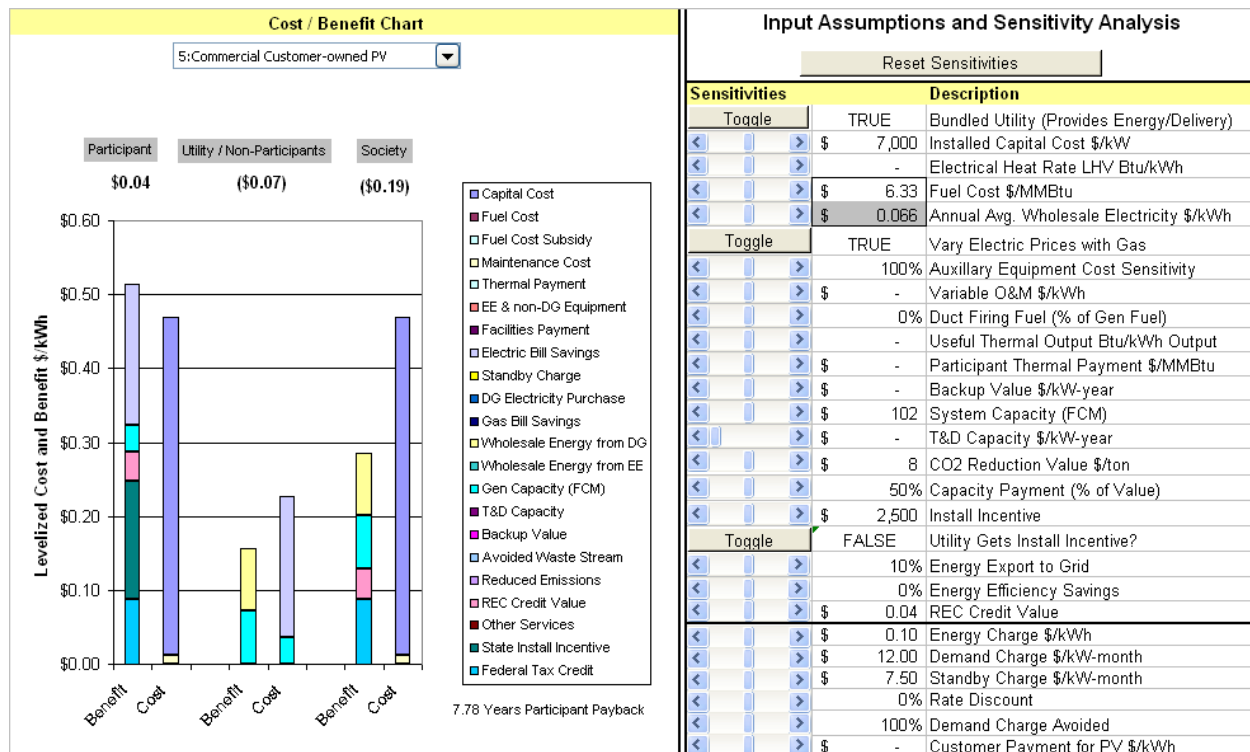


Figure 3 Customer-Owned Commercial/Industrial PV Case

6.5. Case 3 - Waste Fuel-Powered Generation

6.5.1. Case Description

This case is for utility ownership of a generator located at a biogas production facility, perhaps a dairy fitted with a manure digester. The dairy owns and operates the digester (financed by the utility), manure handling equipment, and digester effluent disposal equipment and sells digester gas “over the fence” to the utility. The utility purchases the fuel at a cost that offsets the cost of the digester. The utility returns hot water (recovered from the generator) to the digester at no cost. This business model can also be implemented for other opportunity fuels.

The key driver for this case is the low cost of fuel to the generator (\$2.00 per million BTU in the base case)

6.5.2. Individual Installation Model Results

The inputs and outputs of the Individual Model calculation are shown in Figure 4. Under the assumptions of the case, net benefits are realized by all three participants: the host site, the utility, and society.

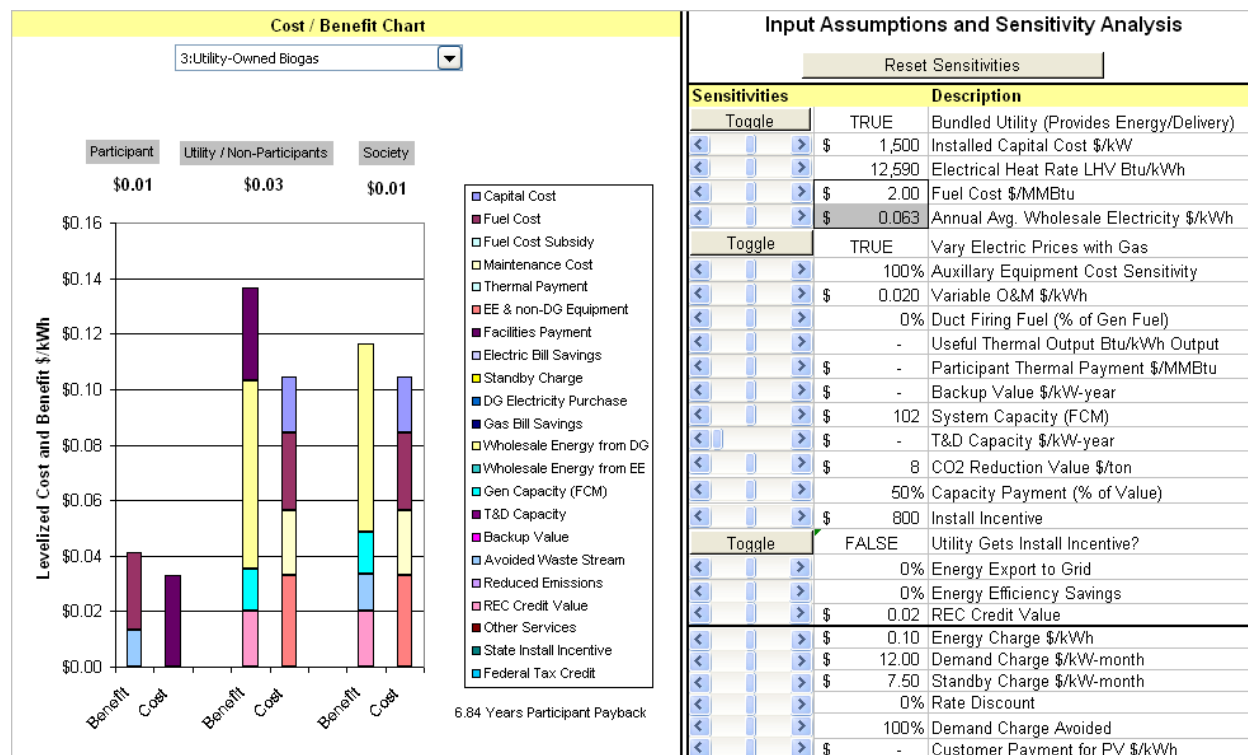


Figure 4 Utility-Owned Biogas-Fueled Individual Model Results

6.6. Case 4 - Utility-Owned CCHP Combined Cooling, Heating, and Power

6.6.1. Case Description

The calculation of costs and benefits for the utility-owned CHP case was based on these basic assumptions:

- The utility installs CCHP plant on the customer premises as a ratepayer investment. The plant includes a 6,000 kWe Solar Turbine with duct-firing to a heat recovery steam generator.
- Generation is interconnected to the utility side of the revenue meter.
- Utility benefits include sale of waste heat to the customer and reduced wholesale electricity and capacity purchases.
- The price of the waste heat delivered to the site customer is indexed to gas prices.

Other quantitative assumptions are listed in Appendix D. The key parameters for this application are:

- The overall efficiency of the CCHP plant
- The ability of customer to use all of the waste heat
- The spark-spread between natural gas and wholesale electricity prices

6.6.2. Individual Installation Model Results

The inputs and outputs of the Individual Model calculation are shown in Figure 5. Under the assumptions of the case, net benefits are realized by all three participants: the host site, the utility, and society.

6.6.3. Aggregate DER Model Results

For the CCHP case utility-owned Aggregate DER Model calculations, it was assumed that:

- A 6,000 kW CHP plant was brought on-line in year 2 and second, identical plant in year 6.
- Retail electric rates were adjusted via rate cases in years 1, 5, and 9.
- The base case is a natural gas-fired combined cycle plant.

Aggregate DER Model results are shown graphically in Figure 6 and Figure 7.

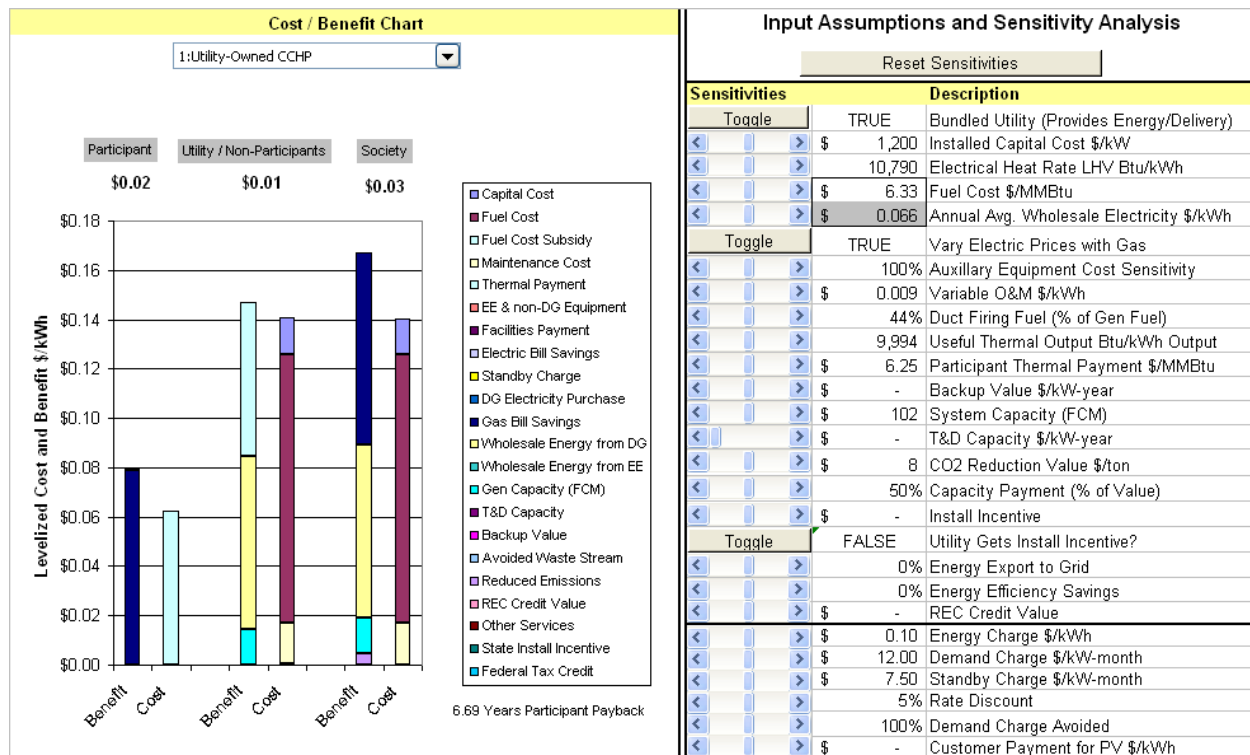


Figure 5 Utility-Owned CCHP Case

Customer Effects

- Utility non-participating customer bills decrease because of net decreased costs to utility (capacity, capital expenditures).
- Utility non-participating customer rates decrease because bills have decreased with no throughput change
- Participating customers receive same rate as non-participating customers
- Participating customer save from a decrease in natural gas consumption versus base case

Utility Effects

- Utility ROE exceeds target because sales growth higher than actual cost increase
- Utility earnings increase because of growth in actual sales. This offsets impact of decreased rate base.

Societal Effects

- Benefits to participating customer create net societal benefits
- Emissions are reduced against the base case (combined cycle gas plant and gas-fired boiler)

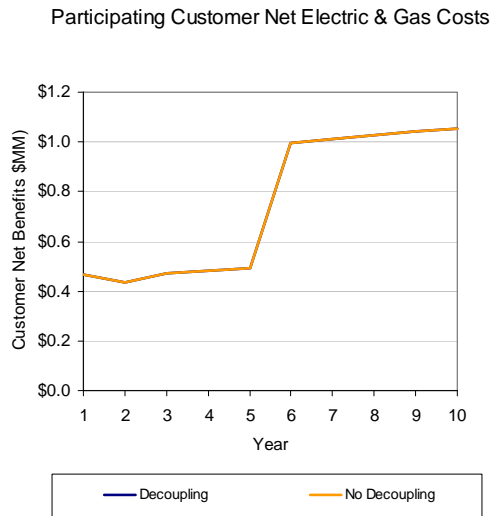
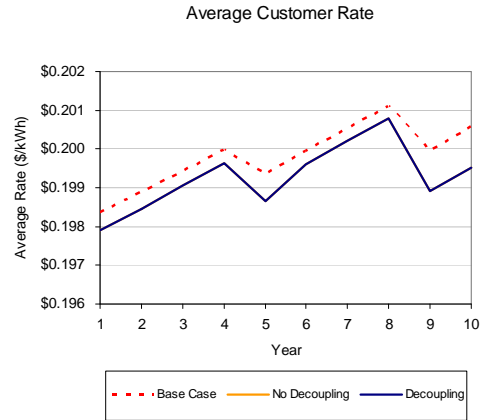
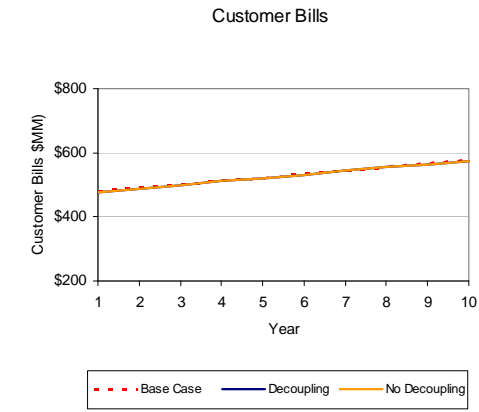


Figure 6 Aggregate DER Model Results, Utility-Owned CCHP, Customer Affects

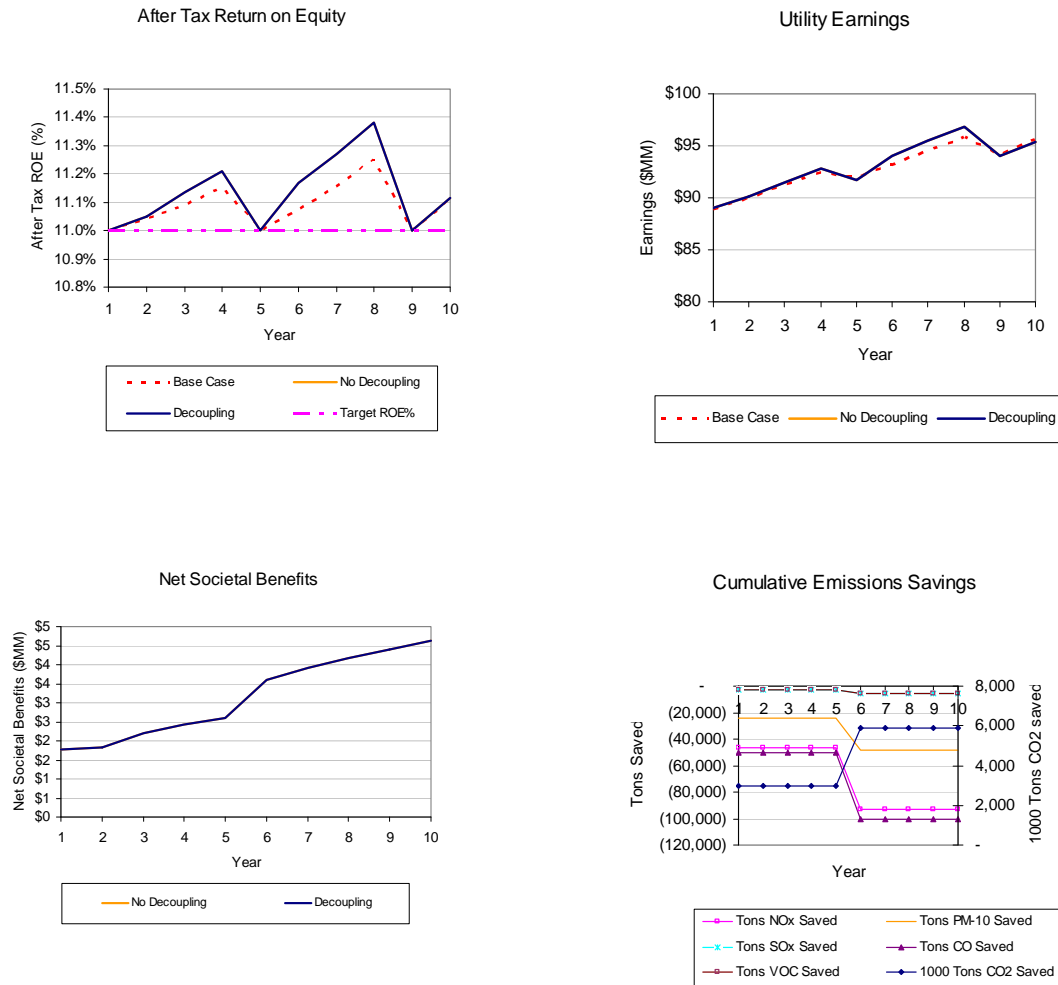


Figure 7 Aggregate DER Model Results, Utility-Owned CCHP, Utility and Societal Affects

6.7. Case 5 - Customer-Owned CCHP Combined Cooling, Heating, and Power

6.7.1. Case Description

The calculation of costs and benefits for the customer-owned CHP case was based on these basic assumptions:

- The customer installs CCHP plant on their premises to displace retail electric power purchases. The plant includes a 6,000 kWe Solar Turbine with duct-firing to a heat recovery steam generator.
- Generation is interconnected to the customer side of the revenue meter.
- Waste heat displaces natural gas for steam generation

- Capacity value – Forward Capacity Market in Massachusetts or resource adequacy payment in California is shared 50% customer, 50% utility

Otherwise, the customer-owned CCHP case is nearly identical to the utility-owned CCHP case. This allows evaluation of the effect of ownership status on the net benefits to all participants.

The key drivers for this case include:

- Overall efficiency, good waste heat use
- Standby charges
- Decoupling / revenue adjustment

6.7.2. Individual Installation Model Results

The inputs and outputs of the Individual Model calculation are shown in Figure 8. Under the assumptions of the case, net benefits are realized by host site and society but negative net benefits are realized by the utility/non-participating ratepayers.

6.7.3. Aggregate DER Model Results

For the CCHP customer-owned case Aggregate DER Model calculations, it was assumed that:

- Customer(s) bring a 6,000 kW CHP plant on-line in year 2 and second, identical plant in year 6.
- Retail electric rates were adjusted via rate cases in years 1, 5, and 9.
- The base case is a natural gas-fired combined cycle plant.
- 30% of utility capital expenditure is growth related.
- Growth-related capital expenditures are reduced by 50% of the CCHP plant rating (kW)

Aggregate DER Model results are shown graphically in Figure 9 and Figure 10.

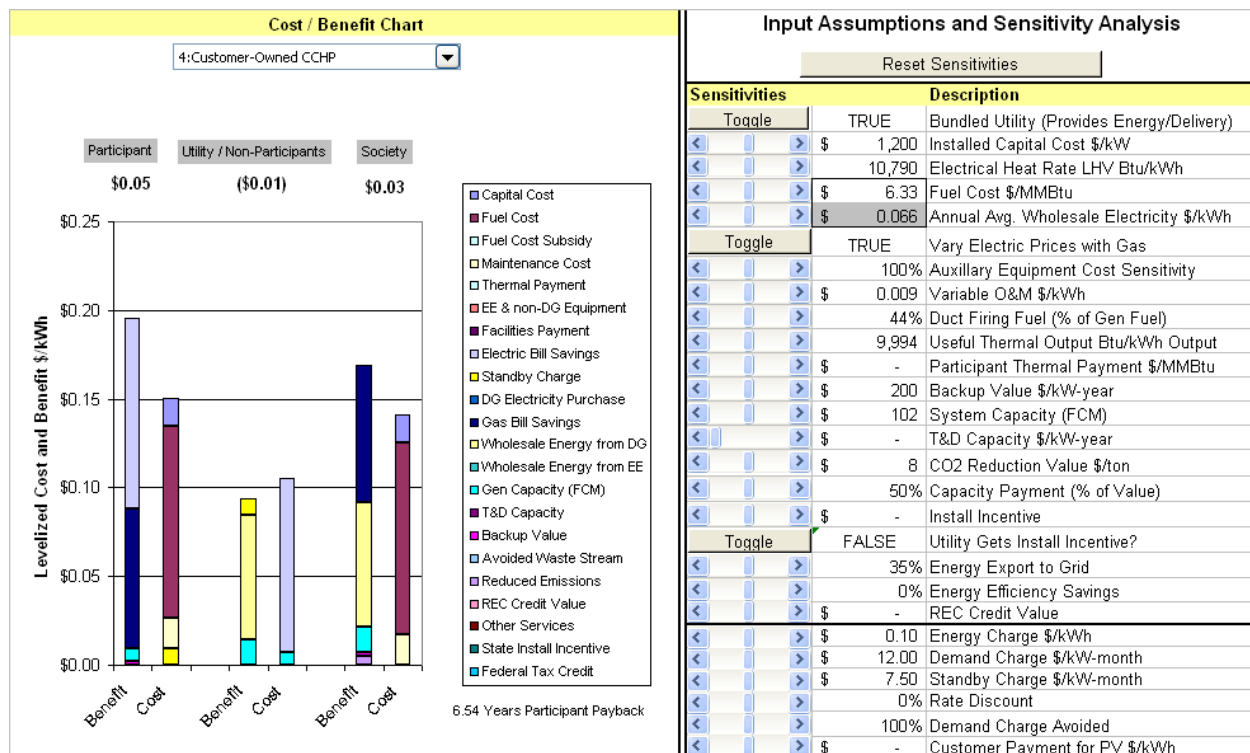


Figure 8 Customer-Owned CCHP Individual Model Results

Ratepayer Effects

- With decoupling in place, utility customer bills increase because of increased costs of DER program (net negative benefits for the utility/non-participating customer). This is somewhat offset by decreased capital expenditures and operating costs
- With no decoupling, customer bills are lower than base case in some years
- Utility customer rates increase because of the throughput reduction

Participating Customer Effects

- Avoided electricity costs and natural gas savings yield net savings to participating customers
- Participating customers pay capital & operating costs of their CHP plant

Utility Effects

- Utility earnings decrease over time with decreasing rate base. This is somewhat offset by growing sales associated with assumed system load growth.

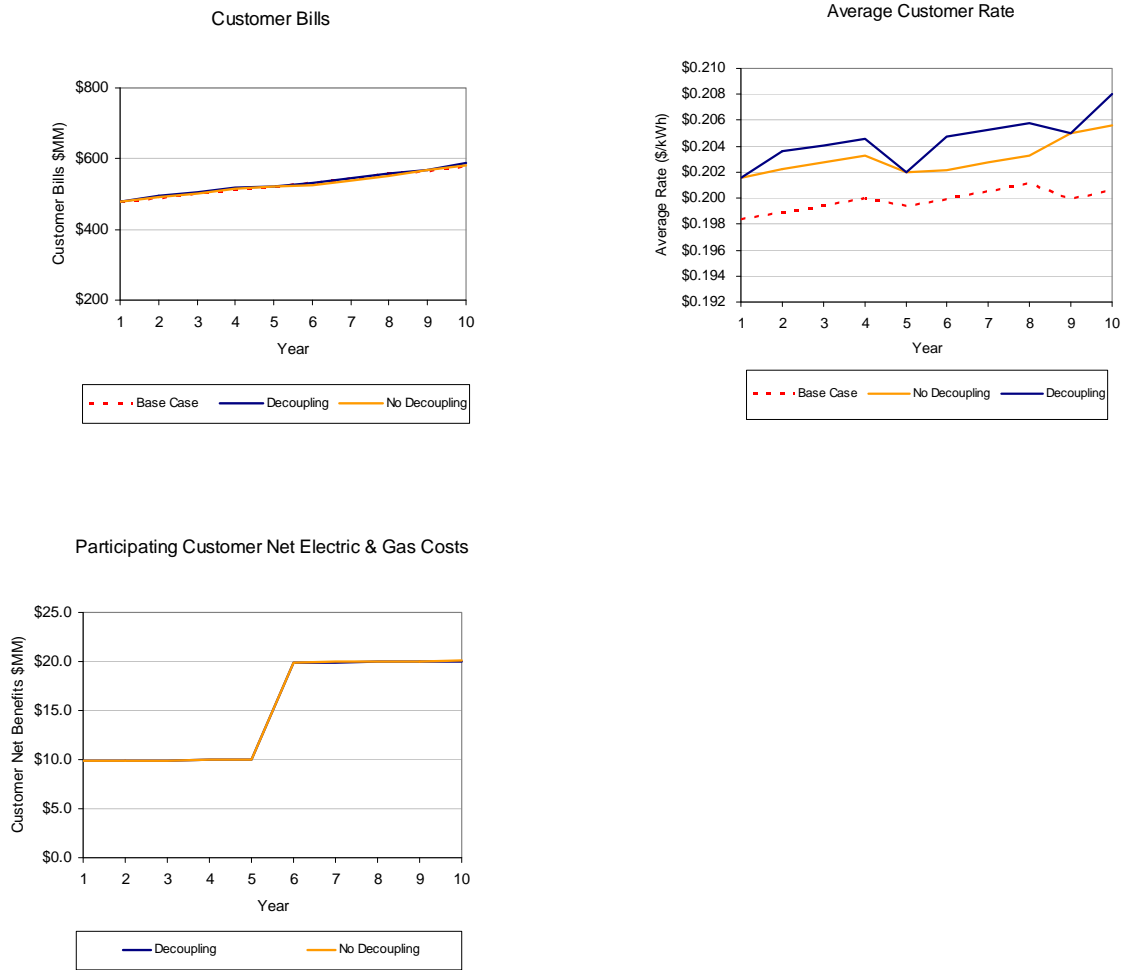


Figure 9 Customer-Owned CCHP Ratepayer Affects

- The rate of sales increases over those used to set rates which impacts ROE, earnings
Target return is achieved in rate case years

Societal Effects

- Benefits to Participating Customer are greater than the additional ratepayer DER-related costs, creating net societal savings (gas savings vs. base case, and backup value)
- Emissions savings are measured against base case (gas plant) and are identical to the utility-owned case

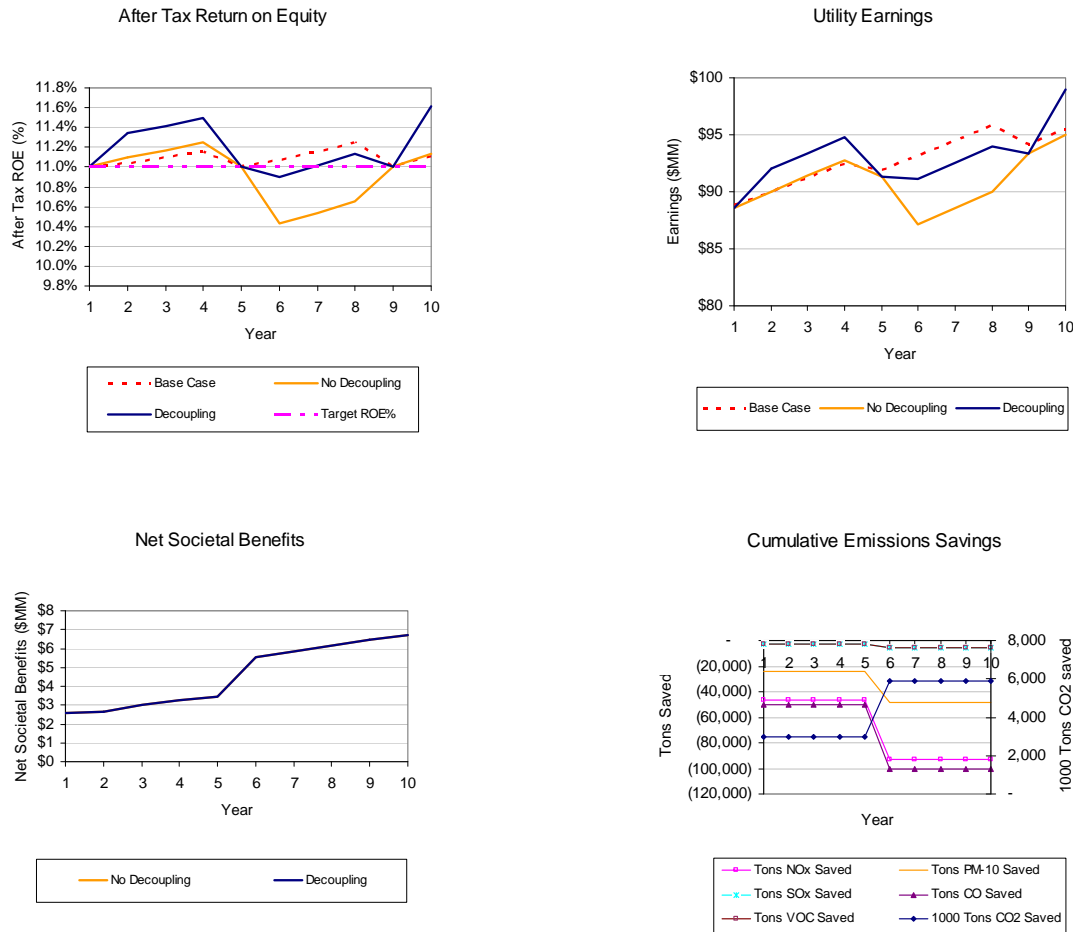


Figure 10 Customer-Owned CCHP Utility and Society Affects

6.8. Preliminary Observations on the Effects of Ownership in CCHP cases

It is important to note that the model calculation CCHP parameters are nearly identical in both cases: utility-owned CCHP and customer-owned CCHP. This allows a direct comparison of the effects of ownership on the net benefits to all concerned.

When the utilities own and operate the CCHP plants, modest net benefits were realized by all. In the long run, the net benefits realized by the utility are also shared between shareholders and ratepayers as a reduction in the costs of operations over the base case.

When customers own and operate CHP plants, they receive the most benefits from the installation, which might be expected as they receive retail value from the power generated. In this case, utility costs may not decline as much as utility revenues do and, hence, retail rates may increase if necessary to make up for the revenue loss. If revenue increases, rates are decreased. Retail rates are modified whether revenue decoupling is in place or not. If not, rates are modified at the next rate case. If decoupling is in place, rates are modified yearly or more often.

7.0 Development of Massachusetts Pilot Project

Massachusetts is on the verge of regulatory change with respect to DER. Two generic dockets (D.T.E. 07-6 and D.P.U. 07-50) were opened in 2007 by the Massachusetts regulator, formerly the Department of Telecommunications and Energy, now the Department of Public Utilities, to investigate rate structures that will promote efficient deployment of demand resources including distributed generation.^{34 35} These actions are in part the result of the five years of effort by the Massachusetts Distributed Generation Collaborative, which was directed by the Department of Public Utilities and facilitated by the Massachusetts Technology Collaborative (MTC).

The work of the DG Collaborative has included a review of the role of distributed generation in Massachusetts with the active participation of all four investor-owned Massachusetts distribution companies. The DG Collaborative has made significant achievements in interconnection standards and procedures, and as well as in broader areas. In its 2005 and 2006 reports³⁶ to the Massachusetts regulator, the DG Collaborative set an objective of achieving a societal win-win outcome with net benefits greater than costs for all stakeholders. The DG Collaborative submitted a report³⁷ to Massachusetts by the EPRI DER Public/Private Partnership outlining a framework for developing win-win strategies.

The Renewable Energy Trust (the Trust) of the MTC also has an ongoing related activity with Massachusetts distribution utilities to develop two or more Congestion Relief Pilots, each of which will include prototype installations of renewable DG and other distributed energy resources in a specific location on the distribution company's transmission and distribution (T&D) system.³⁸ MTC has awarded grants for pilot activities to two Massachusetts utilities to date, National Grid and NSTAR, and steps have been taken to contact customers in two particular pilot locations to assess their potential interest in renewable or other on-site generation in conjunction with demand response and energy efficiency options. In 2006, pilots were initiated with National Grid in a portion of Everett, MA and with NSTAR in a portion of Marshfield, MA.

³⁴ Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources <http://www.mass.gov/Eoca/docs/dte/electric/07-50/62207order.pdf>

³⁵ Order Opening Investigation ... into standby rates and alternative rate structures that will promote efficient deployment of distributed generation: <http://masstech.org/2007-03-23-DG-DTE-07-6-Order.pdf>

³⁶ Massachusetts DG Collaborative 2005 Annual Report, Submitted to the Massachusetts Department of Telecommunications and Energy in Response to DTE Order 02-38-B, and for more recent reports, see <http://www.masstech.org/dg/collab-reports.htm>.
http://www.masstech.org/renewableenergy/public_policy/DG/resources/Collab_2005Collab05_05_31_FullAnnualReport.pdf

³⁷ A Framework for Developing Win-Win Strategies for Distributed Energy Resources in Massachusetts: <http://www.masstech.org/dg/2005-05-MA-DG-EPRI-Win-Win.pdf> .

³⁸ MTC Congestion Relief Pilots: http://www.masstech.org/renewableenergy/public_policy/DG/resources/CongestionReliefPilots.htm

The goal of these MTC pilots is to test realistic, representative cases of customer-sited renewable energy generation combined with demand-response controls, load shedding, energy efficiency, storage and other distributed resources that provide benefits to the electric system as well as to host customers and other entities. This initiative seeks to find new “win-win” opportunities for clean distributed energy resources and to collect meaningful data on all the net benefits and costs from such DER, and all the revenues on which a business model for DER could be built. MTC has worked with utility personnel and representatives of interested customers to customize the pilots to meet stakeholder needs, with the intent of developing a “win-win” vision of clean DER that will provide benefits to the end users that are willing to host renewable generation, to the utility, and to Massachusetts ratepayers generally.

During 2007, MTC and National Grid offered their work in Everett to also serve as a basis for a DER Partnership pilot for this STAC project. Funding for a new phase of the Congestion Relief Pilot in Everett was approved by the MTC Board of Directors (June 28, 2007).³⁹ According to the funding request:

“The pilot is installing and assessing, at real customer sites, the combination of hardware, software, contracting, financing, and cost/benefit allocations that will lead to substantial growth of distributed renewable installations as part of a portfolio of distributed energy resources to provide benefits to customers and the distribution system. This and other Congestion Relief Pilots are proceeding in parallel to and in collaboration with the DG Policy Collaboration Initiative and the EPRI Distributed Energy Resources Partnership, through which significant work has been undertaken on the closely related topics of the “role of DG in distribution planning” and the development of “win/win” business and regulatory frameworks for DER.”

This chapter describes the Massachusetts activities that occurred to develop a Massachusetts DER Partnership pilot project in conjunction with the MTC Congestion Relief Pilots up to the time the STAC project of the EPRI DER Public/Private Partnership was discontinued. The Massachusetts public sector sponsors of this STAC project included the Department of Public Utilities, the Division of Energy Resources and the Massachusetts Technology Collaborative (MTC).

7.1. Pilot Project with National Grid

National Grid agreed in the spring of 2007 to act as the host utility to conduct a Massachusetts pilot project for the STAC project (referred to here as the DER Partnership pilot to differentiate it from the parallel MTC Congestion Relief Pilot). In association with the MTC-funded Congestion Relief Pilots initiative, the host utility is aggressively marketing demand response, renewable generation, CCHP, and other customer sited distributed technologies to customers within a region of the City of Everett where these DER resources are expected to provide significant value to the distribution system.

³⁹ Earlier awards were also made to National Grid for this activity in December of 2005 and January of 2007.

The DER Partnership pilot aspect of this effort was to test and demonstrate DER business models. The DER Partnership pilot project would leverage up to \$650,000 in MTC funding. Cost share is a requirement of the State Technologies Advancement Collaborative (STAC) effort.

In support of the DER Partnership pilot in Massachusetts, a Massachusetts Distributed Resource Work Group was formed with utility involvement and interested stakeholders during the January workshop and met by conference call in April 2007. The call included a presentation by EPRI subcontractor Regulatory Assistance Project on decoupling.⁴⁰ Participants included staff of the Massachusetts Department of Public Utilities, which subsequently initiated its decoupling docket (D.P.U. 07-50) as noted above.

Once the Massachusetts Department of Public Utilities opened the D.P.U. 07-50 investigation into “Rate Structures that will Promote Efficient Deployment of Demand Resources” on June 22, 2007, which will include a regulatory analysis of decoupling, as well as incentives for energy efficiency and potentially other DER, one of the goals of this project had been achieved: to encourage this kind of regulatory focus on ways to stimulate DER. This regulatory progress is due in part to the work of the DER Partnership. Since Massachusetts stakeholders will have ample opportunity to express positions on various forms of decoupling in the regulatory process, it was agreed that it was no longer necessary for the DER Partnership pilot to include a review of decoupling. The DER Partnership pilot was to analyze potential impact of creating an incentive structure for DER similar to existing demand side management (DSM) incentives.

It was planned for the EPRI team to work with the Massachusetts Distributed Resource Work Group to review the following in preparation for the DER Partnership pilot project:

- Findings that apply to Massachusetts from the DER Partnership effort to create business models and regulatory approaches
- Additional incentive opportunities, such as modification of the existing utility shareholder incentives for energy efficiency to apply to DER as well.
- Exploration of alternative types of financial arrangements that might stimulate increased DER acceptance by customers.

A report was to be prepared that described the Massachusetts-specific business models and regulatory approaches for DER. The report would also recommend a framework for establishing utility incentives for DER specifically in Massachusetts to be utilized in the upcoming regulatory proceeding, as brought by one or more utilities in Massachusetts. It would also summarize alternative business and financial models for stimulating increased DER acceptance by customers in Massachusetts.

One approach that is already being tested by National Grid in the Congestion Relief Pilot is to make energy audits more comprehensive by incorporating feasibility analyses of non-DSM measures, such as PV and CHP. Under the Congestion Relief Pilot, this marketing work continues. If the DER Partnership pilot had continued, the EPRI Team would have evaluated

⁴⁰ See http://masstech.org/renewableenergy/public_policy/DG/resources/2007-04-04-Decoupling-EPRI-STAC.ppt

the Pilot results with respect to scalability and value to the state of Massachusetts as well as other states, and submitted a final report to the project participants and STAC.

The EPRI team would also have used the experience gained in California and Massachusetts pilot projects to evaluate the process for developing state- and utility-specific business models and regulatory templates, and distilled it into a model process for others to follow.

EPRI had planned to tie the model process to pilot project results to demonstrate its value and build confidence, develop a presentation package for all stakeholders to use in public and private forums, and to recommend the model process for action in the participating states and in other states.

7.2. Insights and Observations

- **Even with funding related to the Congestion Relief pilots, it takes considerable time to gain customer and utility commitment to DER activities.** Without the business models in place, the focus of customers and the utilities are on their primary business areas, not necessarily DER.
- **The National Grid and NSTAR Congestion Relief pilot activities are a valuable opportunity to test business models.**

7.3. Recommendations

Overall, EPRI recommends that the win-win approach serve as the guide for DER integration. This approach is to identify DER which provide societal benefits, and then allocate costs and benefits to other stakeholders to achieve the win-win outcome.

In Massachusetts, which is pursuing DER as a policy objective, stakeholder groups should be assembled to use the resources and tools developed in this project to take the next step with DER. The Commonwealth of Massachusetts should consider encouraging utility ownership of DER assets which is most likely to allow all parties to realize the benefits of DER without major changes to the current business and regulatory structure.

To continue to move forward with DER integration in Massachusetts, Massachusetts should continue the Congestion Relief Projects with National Grid and NSTAR and use the results of the DER Partnership effort to build sustainable interest through business models and regulatory approaches that incentivize utilities to encourage DER.

Specifically, the Massachusetts Technology Collaborative should include testing and demonstration of business models under the Congestion Relief pilot project with National Grid. MTC should also use the resources of the STAC project with other utilities in the state. Results of analyses should be vetted with the appropriate stakeholder work groups and discussed with utility management to confirm which business models and regulatory approaches would interest the utility sufficiently to take action to integrate DER.

Considering the longer term, Massachusetts should consider a “soft start” approach, which uses a limited amount of societal funds to pay for longer term benefits. The point is to develop a

method to achieve DER penetration for which all electricity customers potentially pay slightly more now, with the prospect of reaping the benefits once significant penetration is achieved. Significant penetration could amount to 5 to 10% of generation. Once a significant level is achieved, actual benefits of the DER can be measured and quantified, and the values used to guide Massachusetts programs going forward.

Massachusetts should also consider DER options as part of a portfolio of solutions in implementing “sustainable communities.”

8.0 Development of California Pilot Project

At the January 2007 Workshop, a working group was assembled to pursue a pilot project in California. There was no known funding available for new DER pilot projects (unlike the situation in Massachusetts); therefore, any candidate pilots would have to draw upon initiatives that were already in progress.

8.1. Pilot Project Discussions with Pacific Gas & Electric

As the utility-owned model was found to be the most likely to result in benefits for all parties (customer, utility, society) under California's current regulatory environment, and considering that Pacific Gas & Electric had indicated that this ownership model was being considered within the company for various business initiatives, the project team decided to pursue a utility-owned DER pilot program with PG&E.

Discussions began with PG&E on the suitability of several specific company initiatives to serve as the platform for a pilot project. The first company initiative that was considered was a dairy digester gas-fueled generation project. While this application promised sufficient benefits for a win-win-win result, it remained critically dependent on the availability of a limited resource, dairy digester gas. The California Energy Commission recommended that this application was not scalable for widespread use, so it was not pursued further.

The California Energy Commission suggested that a combined heating and power-based pilot would be more useful because of the environmental and efficiency benefits, and the loading order in California. Because PG&E had no company initiatives that focused on CHP, nor were they enthusiastic about starting such an initiative, the team explored other initiatives being put together by PG&E, including a sustainable community effort that might include CHP. This was found to be too premature to serve as the pilot in the time frame of the current project.

Other considerations included utility-ownership of photovoltaics under the California Solar Initiative, but no action was taken because the initiative already had significant funding and attention. The California Energy Commission suggested considering a plan brought to them by the California Oil Producer's Electric Cooperative (COPE) in which stranded gas co-produced with petroleum would be used to fuel local generation instead of being flared out. Some of the gas that would be used in boilers for petroleum and water separation could be used for additional electrical power production. COPE estimated that the cumulative production of electricity from stranded gas projects could potentially yield 200MW. PG&E was not enthusiastic about this project, saying that because the resource was not renewable, it was not likely to ever lead to a replicable model sufficient to demand their attention. PG&E referred COPE to a standard form power purchase agreement that it proposed for small CHP applications.

After several months of little progress due to a number of reasons including change in management assignments and other priorities, the project team decided that a pilot project was unlikely with PG&E during the window of time available for the project.

8.2. Pilot Project Discussions with Southern California Edison

Southern California Edison indicated from the beginning that they were not prepared to entertain a utility-owned pilot project. Thus, discussions proceeded on how a customer-owned pilot might be organized, focusing on CHP applications. SCE personnel from the industrial customer service group were brought into the discussions and agreed to consider a pilot project given a number of following constraints and considerations described here.

As there was insufficient time in the overall project schedule to allow new hardware installations, the pilot would look at existing fleet of CHP projects in the SCE service territory. The pilot would examine how business structures and associated regulatory templates might change SCE's view of the desirability of these projects. SCE offered to provide to the project team cost and long-term (>12 months) performance data on two classes of CHP installations:

1. Self Generation Incentive Program (SGIP) projects in their service territory; and
2. Non-SGIP CHP projects in operation connected to their wires.

SCE also offered project planning data for a third class of CHP projects. These were CHP projects for which detailed planning had been done but which were not implemented, primarily because there were insufficient benefits to justify the costs. SCE offered to make this data available for analysis as part of the pilot project.

In light of the fact that the capital incentives associated with the SGIP program did not ensure that the generators were in service during peak periods, and that the capacity factors of these projects were modest, SCE wanted to focus on performance incentives rather than capital incentives. The incentives should be tied to savings that SCE could actually realize. Furthermore, the qualifying CHP installations should meet minimum fuel use efficiency standards comparable to a combination of gas-fired central generation and modern, gas-fired heating appliances.

The plan was to agree on a business structure/regulatory template that met SCE's requirements, and then apply this template to the cost and performance data in SCE's possession using the economic calculator. The calculator would be used to quantify the net benefits to the host site, to society in general and to SCE/non-participating ratepayers. The regulatory template would also be used to assign costs/benefits between the utility and their non-participating ratepayers. The analysis was expected to take four to six months to complete.

Discussions began on developing the business structure/regulatory template. It was planned to be based on the Standard Performance Contract that SCE offers to industrial customers for energy efficiency projects⁴¹. The "straw-man" structure had the following characteristics:

- **The CHP host site would purchase power from SCE** through one of the standard "Time of Use" rates.

⁴¹ www.sce.com/RebatesandSavings/LargeBusiness/SPC/

- **The primary benefit that the host site received for installing and operating CHP system would be a reduction in retail power purchases during the various time blocks.** This benefit would be greater during the peak periods than during off-peak periods.
- **An added incentive would be paid to the host site** based on the average system line losses that SCE experiences during the various time-of-use periods. For example, if system line losses were 5%, the added benefit to the CHP host would be 5% of the energy rate (kWh rate) during that time period. This would be a surrogate for the actual benefits SCE would experience due to generation at the customer site.
- **In order to qualify for the incentive payments during specific time-of-use blocks, the CHP systems would have to meet equivalent electrical efficiencies** commensurate with the marginal central station electrical efficiency during the time-of-use block.
- **SCE could declare a “critical peak” period with advanced notice during which performance incentives would be increased** and during which a penalty could be imposed for non-performance on the part of the CHP operator. The ability to declare “critical peak” hours would be limited on a yearly basis.

These discussions were proceeding when the CEC indicated that they felt it was unlikely that results consistent with the project work statement could be achieved in the remaining project time, and that no further effort should be expended on the pilot project planning.

8.3. Insights and Observations

- It takes considerable time to get utility DER projects going; from inception to installation can be a matter of years. The sales cycle of distributed generation to utilities is exceedingly long, as much as two years; whereas with an eager customer (sometimes utilities) it could be a few months. Typically, there is not a sense of urgency on the part of utilities because of perceived and real uncertainty and risk, and that utilities typically don't expect real economic benefit. Currently in California, there is no DER push from regulators.
- The data on existing DER projects that SCE would have provided remains a valuable resource that could be utilized. EPRI believes the data should be analyzed; it could provide some good insight into the flow of benefits from CHP installations.
- PG&E was interested in PV ownership, but needed to get access to the tax credits or the rebate to make it financially interesting.
- There does not appear to be much interest in utility-owned DER by the California investor-owned utilities. Ownership entails financial risk with potentially little upside benefit. Other reasons for little interest in utility ownership of DER are that the units are small, reliability is unknown, and the utilities have little operating experience with them. The need to operate CHP units to meet host heating needs, not utility power needs was also a concern as was the one-off, customized nature of CHP.

8.4. Recommendations for California and California Energy Commission

Overall, EPRI recommends that the win-win approach serve as the guide for DER integration in California and all states. This approach is to identify DER which provide societal benefits, and then allocate costs and benefits to other stakeholders to achieve the win-win outcome.

California should take into account that the customer-owned approach may impose rate increases for other customers in the short term under the current regulatory environment, presenting a difficult barrier to utility interest when developing strategies for improving adoption of DER. The state should also recognize that the utility lack of interest is because of financial risk, and create means of dealing with the risks inherent in both customer-owned and utility-owned DER in order to see broader DER adoption to meet a public policy initiative.

In the near term, to move forward with DER integration in California, the state should re-assemble the stakeholder group formed in this project and use the resources and tools developed in this project to consider both customer-owned and utility-owned business models. While the collaborative process takes longer than working without stakeholders, innovative projects are more likely to go forward with the stakeholder approach especially if they have participated throughout the process. This is because the stakeholders have learned about innovative approaches and how these approaches may benefit their own interests as well as others.'

The business and regulatory models should be tested on existing DER projects, such as combined heating and power applications located on Southern California Edison's and Pacific Gas & Electric's distribution systems. Results of analyses should be vetted with stakeholders and discussed with utility management to confirm which business models and regulatory approaches would interest the utility sufficiently to take action to integrate DER. The economic calculators should be used to demonstrate where the costs and benefits flow, and to analyze how to adjust them to deliver a win-win outcome. These analyses should be discussed with utility management to gain their support and acceptance.

Considering the longer term, California should consider a "soft start" approach, which uses societal funds to pay for longer term benefits. The point is to develop a method to achieve DER penetration for which all electricity customers potentially pay slightly more now, with the prospect of reaping the benefits once significant penetration is achieved. Significant penetration could amount to 5 to 10% of generation. Once a significant level is achieved, actual benefits of the DER can be measured and quantified, and the values used to guide programs going forward.

California should also consider DER options as part of a portfolio of solutions in implementing "sustainable communities."

9.0 Conclusions and Recommendations

This section describes the resources developed for and used in the project and provides conclusions about the work and recommendations for going forward with DER.

9.1. Resources Developed

This project created business models and regulatory approaches for both utility-facilitated, customer-owned DER and utility-owned DER, and economic calculators to assess DER the business models for various technologies and installations.

9.1.1. Business Models Developed

A number of utility business models were identified which might provide electric utilities with sufficient incentive for them to pursue installation and interconnection of distributed electric utilities. The business models were divided into two groupings by collaborators based on whether the distributed energy resource is owned by the electric utility (generally interconnected on the utility side of the site revenue meter) or by the customer (generally interconnected on the customer side of the site revenue meter).

Utility-Owned DER

The utility-owned working group developed the following business models and regulatory approaches:

1. **The utility acquires and deploys DER on the host's site and interconnects on the utility side of the meter.** The utility or vendor(s) may install, operate, and maintain the equipment. Regulatory policies would be required to ensure rate base treatment of all prudent investments in utility-owned DER facilities, and recovery of operating expenses. The throughput disincentive does not need to be addressed.
2. **The utility acquires, deploys, and operates an advanced distribution system⁴² that takes full advantage of DER benefits, whether owned by utility or customer.** These benefits include economic dispatchability, voltage/frequency support, capital construction deferral, and standby and spinning reserve.

Utility-Facilitated, Customer-Owned DER

The customer-owned working group determined that the utility could facilitate customer-owned DER and through the closer working relationships, reap more benefits from the DER installation. The working group developed the following business models and regulatory treatments for utility-facilitated customer-owned DER.

1. The utility offers incentives to customers to deploy DER in such a way that it can be dispatched by the utility or otherwise provide system-wide benefits that would accrue to all ratepayers. Utilities might be required to invest in metering, communications and

⁴² An advanced distribution system includes intelligent grid capabilities such as smart two-way communications among grid and customer systems; ability for two-way power flow; intentional islanding, etc.

control equipment to access the DER assets. Regulatory policies would be required to ensure recovery of program expenses, incentive payments, and revenue requirements to provide power on demand. Removing the throughput incentive would be a critical first step to remove the current disincentive for utilities. This is not necessary in California as decoupling is already in place.

2. The utility solicits DER to meet state mandates for renewable generation, energy efficiency, and loading order priority. Participants felt that utilities may have trouble meeting these escalating requirements without acquiring, owning and operating some of the qualifying assets themselves. Regulation would need to remove the throughput disincentive (for the customer owned portion), and set terms and conditions for judging qualified assets. Some participants thought that regulators should consider offering higher returns on specific investments (e.g. renewables) to incentivize DER deployment. In California, there is a provision for higher returns on renewables.
3. The utility provides support services to customers who own and operate their own DER facilities. Such services could include managing demand response for ISO programs, managing VAR control and back-up power for industrial and commercial mini-grids, or providing metering and billing services for solar utilities. This service business model could help capture some of the DER benefits for utility ratepayers.

9.2. An Economic Calculator to Assess Costs and Benefits.

A spreadsheet-based economic calculator tool was developed to assess the costs and benefits of implementing a single DER project for three groups:

- The participating customer
- The electric utility
- Society in general

This economic calculator was vetted by interested collaborators.

A second spreadsheet-based tool was developed to aggregate DER, input as a penetration level, and to indicate how the electric utility costs and benefits are split between utility shareholders and ratepayers (including non-participating ratepayers) under various regulatory schemes. This calculator was also vetted by collaborators.

9.3. Findings

Utility-Owned DER

This project found that the utility-owned DER business models are more likely to achieve the win-win outcomes than customer-owned models under the current regulatory conditions. This is because the many benefits of distributed generation (as compared with central station generation) are automatically passed on to utility ratepayers and shareholders when the utility owns/operates the generators. The prudent costs incurred by the utility to acquire and install generators become part of their rate-based capital expenses on which they earn a rate of return. The net operating costs become part of the revenue requirement on which rates are based. To

the extent that the benefits of distributed generators return benefits greater than the utility rate of return on the capital costs, the benefits are distributed to ratepayers in the form of relatively lower rates. In addition, to the extent that the distributed generators relieve the utility from having to install or operate other assets to meet local loads, these additional savings are also distributed to ratepayers in the form of relatively lower rates.

This case is conceptually easier to consider as it involves relatively minor adjustments to existing utility operations. The throughput disincentive (declining utility revenues with increasing distributed generation) is not pertinent as the power is interconnected on the utility side of the revenue meter. Thus, there is no need to bring revenue decoupling into the discussion.

There are a few legal and regulatory issues that need to be resolved for utility ownership to be a successful avenue for DER, such as concerns of anti-competitive activity and the lack of interest in entering into the business of offering by-products of generation, such as heat from a CHP system. Furthermore, some states or regions do not allow utility ownership of generation due to policy decisions or by law. Finally, the fact that current federal tax laws do not allow utilities to receive the 30 percent investment tax credit applicable to solar and fuel cells has hampered utility investment in these technologies.

While under the current regulatory environment, utility-owned DER provides a higher likelihood of achieving win-win outcomes, this model has not been embraced because utilities have not found that benefits outweigh costs. When the aggregated scale of DER reaches a critical threshold where DER benefits would be better quantified and issues such as reliability would be better understood and managed, utility interest will likely increase. The sustainable community development work in San Diego, for example, suggests that DER applications and benefits might be easier to develop and monetize on a macro scale. Such community-wide development would aggregate energy efficiency, renewables, water, heat and cooling.

Customer-Owned DER

In contrast to the utility-owned case, there are generally no legal constraints to customers installing DER on their premises to displace utility purchases. The greatest regulatory challenge is when customer-owned DER results in society and the non-participating ratepayers experiencing an excess of costs over benefits.

Even when revenue decoupling keeps electric utility shareholders financially indifferent to customer-owned DER, it does not provide an incentive to promote customer-owned DER. Incentives to utilities will be paid by ratepayers in the form of higher rates in the short term, with expected reductions in the future due to the benefits of wide-scale integration of DER.

In general, the DER owner and, in many cases, society, have benefits that exceed the costs. The conditions under which the electric utility benefits exceed the costs are where the customer-sited DER allows avoidance of a large capital expenditure over an extended period of time. Future work should use the economic calculators to look at how to re-allocate the costs and benefits such that the societal benefits are shared by all stakeholders.

While some customer-side DER solutions, such as peak shaving or demand response, serve the interests of many electricity providers, other DER strategies – particularly combined heat and power and some renewable technologies – typically do not fit utility business interests. These and other base-loaded or non-dispatchable technologies result in reduced revenues along with the need to provide continuing service on call, the costs of which may be covered by standby or other similar charges.

Unless decoupling is in place, in the short run, the excess of utility costs over benefits reduces utility profits. In the medium run, the excess of utility costs over benefits is paid by ratepayers in the form of increased rates.

On the other hand, when system costs are reduced by lower demand due to on-site generation, for example, rates are decreased. Multiple and aggregated DER units are likely to be required to impact system costs on a beneficial scale, for example, grid reliability improvements and enhanced resource diversity and security. Thus, when DER penetration is sufficient to bring benefits that outweigh the cost, rates are decreased.

In concept and at a meaningful scale, DER could potentially add diversity of supply, provide a least-cost solution to new demand, defer capital investment, and provide ancillary system benefits, including system reliability, voltage support and spinning reserve. In time, these benefits may truly emerge. A meaningful scale might be on the order of 100s of megawatt capacity in a distribution area with corresponding monetized benefits in the millions of dollars. But at present, without sustainable business models, DER is more likely to introduce technical complexity to the integrated operations, impact utility control, revenues and profits, and shift fixed capital costs from DER customers to other ratepayers.

9.3.1. *Economic Modeling*

The economic calculators proved to be useful tools for comparing approaches and options on a high-level basis. The results are not definitive but illustrative of where the benefits and costs flow, and whether net benefits are widely shared with the three key stakeholders – customers, utilities/ratepayers, and society.

The case studies conducted demonstrated the capabilities of the economic models and the implications of customer versus utility ownership. While these case studies demonstrated useful results for analysis, they did not necessarily indicate the only projected outcomes, particularly in light of future technology cost reductions, and quantifiable benefits of increased DER penetration. Furthermore, the case studies indicated that not all benefits are quantifiable today, nor monetized. Most importantly, the case studies illustrated the usefulness of the economic calculators which could be used in the future to analyze allocations of costs and benefits to result in win-win outcomes.

9.3.2. *The Collaborative Process*

The collaborative process brought many stakeholders together from a wide range of interests to participate in the work described here. There was active interest in the subject and the prospects of identifying utility business cases and associated regulatory templates that would provide incentives to utilities to undertake or encourage deployment of DER. As hoped for, the effort

was a collaboration with relatively unconstrained give-and-take as opposed to the adversarial posture that the participants would probably take in public utility commission proceedings. The collaboration involved regulatory staff from both Massachusetts and California. It is likely the new proceeding in Massachusetts to consider regulatory disincentives and incentives for demand resources is in part due to the involvement of the Massachusetts regulatory staff in the DER Partnership.

Overall, the project team found that the collaborative stakeholder process is excellent at bringing different perspectives together to listen to one another in a non-adversarial setting and to understand and come to new agreements. It was good for considering new business models, different regulatory approaches, and vetting the calculator, and getting buy-in on the calculator's usefulness. However, the collaborative stakeholder process had not yet achieved as much innovation as anticipated prior to the Pilot phase of this project. The process also takes a considerable amount of time. The expected benefits—of building mutual trust and reaching long-lasting agreement on new approaches—should far outweigh the challenges.

9.4. Conclusions

The results of this project emphasize that new scaleable business models and innovative regulatory approaches are needed to spur market integration of distributed energy resources by utilities.

This project brought together a broad group of stakeholders and facilitated the collaborative creation of innovative business models and associated regulatory approaches. The collaborative stakeholder process was excellent at bringing different perspectives together in a non-adversarial setting to achieve new models. The project also developed economic calculators to provide insights for understanding allocations of costs and benefits of DER.

This project also showed that putting business models into practice proved more challenging than expected. The development of the California pilot project proved too slow to meet the schedule requirements of the project and led to discontinuation of the entire project, since the STAC project required multiple state involvement. Unfortunately, the project was discontinued before the DER Partnership pilot projects could come to fruition.

The economic calculators developed for this project indicated that to achieve win-win outcomes, DER costs and benefits will likely need to be reallocated according to new business models. These calculators will enable analysis of allocation options, and tracking costs and benefits, especially when the additional benefits of increased penetration of DER can be quantified.

This project showed that utility-owned DER has a higher likelihood of win-win results in today's regulatory environment and thus the potential for capturing utility interest. Customer-owned DER, the prevailing paradigm, will take more creativity to achieve both win-win outcomes and utility interest.

Finally, while the resources developed by this project -- business models, regulatory approaches, and economic calculators -- have not been demonstrated, they are ready for use to go to the next step with distributed energy resources.

9.5. Recommendations

Overall, EPRI recommends that the win-win approach serve as the guide for DER integration. This approach is to identify DER which provide societal benefits, and then allocate costs and benefits to other stakeholders to achieve the win-win outcome.

In states or regions pursuing DER as a policy objective, stakeholder groups should be assembled to use the resources and tools developed in this project to take the next step with DER. States and utilities should consider encouraging utility ownership of DER assets which is most likely to allow all parties to realize the benefits of DER without major changes to the current business and regulatory structure.

States should also take into account that the existing customer-owned approach may lead to increased rates for other customers under the current business and regulatory structure, until reduced costs or increased benefits arise from DER penetration.

In the near term, to move forward with DER integration in California, both customer-owned and utility-owned business models should be tested on existing DER projects, such as combined heat and power applications located on Southern California Edison's and Pacific Gas & Electric's distribution systems. Results of analyses should be vetted with stakeholders and discussed with utility management to confirm which business models and regulatory approaches would interest the utility sufficiently to take action to integrate DER.

To continue to move forward with DER integration in Massachusetts, the Massachusetts Technology Collaborative in continuing its pilot project with National Grid, and the similar pilot that is underway with NSTAR, should include business model testing and demonstration. The Massachusetts Technology Collaborative should also use the resources of the project with other interested utilities in the state. Results of analyses should be vetted with stakeholders and discussed with utility management to confirm which business models and regulatory approaches would interest the utility sufficiently to take action to integrate DER.

Considering the longer term, states should consider a “soft start” approach, which uses a limited amount of societal funds to pay for longer term benefits. The point is to develop a method to achieve high-value DER penetration for which all electricity customers potentially pay slightly more now, with the prospect of reaping the benefits once significant penetration is achieved. Significant penetration could amount to 5 to 10% of generation and could take several years, but less if the soft start approach is successful in creating incentives for utilities to integrate DER where it brings value to society. Once a significant level is achieved, actual benefits of the DER can be measured and quantified, and the values used to guide programs going forward.

Appendix A

Distributed Energy Resources Glossary

The following defines terms as used in this document.

Advanced infrastructure: As used here, this refers to the installation of intelligent devices that can sense and respond to changes in the supply, demand and characteristics of electricity on the utility's distribution system, as well as advanced metering devices that provide pricing and other information that customers need to modify their consumption behavior and control their equipment.

Aggregator: An entity that assembles generators or customer loads to achieve economies of scale and diversity among the generators or loads being combined, or to facilitate the sale and purchase of electric energy, transmission, and other services on behalf of those it serves.

Anticompetitive behavior: Behavior that protects a firm's market power or position, such as predatory pricing or monopoly leveraging.

Antitrust: Laws and regulations (primarily Federal, but also adopted by many States) designed to protect trade and commerce from unfair business practices, including predatory actions to achieve, maintain or extend monopoly power, price-fixing conspiracies, and corporate mergers likely to reduce competition in particular markets.

Balancing account: A utility account used to match the collection of actual revenues against actual costs after an adjustment for unanticipated changes in expenditures; fuel costs of major plant additions are often put into balancing accounts.

Below-the-line: All income statement items of revenue and expense *not* included in determining utility net operating income; considered as shareholder-related rather than customer-related costs.

Business model: A description of how a company intends to create value in the marketplace through a combination of products, services, delivery mechanisms, and positioning relative to other market participants, and how it intends to make money over time by capturing a share of the value it creates.

Capacity charge: See '*Demand Charge*'.

Capex: Capital expenditures. See **Capital Investment**.

Capital investment: Here, refers to utility investment in long-term physical assets such as land or equipment and machinery that must be depreciated or amortized, and on which regulators allow the utility to recover its capital and a fair rate of return; distinguished from *expenses* incurred for ongoing operations, which are typically recovered through rates, but are not included in the utility's ratebase and do not earn a return for utility shareholders.

Cost allocation: The apportionment of utility system costs to customer rate classes.

Cost-based service: A pricing approach that assigns utility costs and revenues to the particular customer classes that cause them, and charges those classes accordingly.

Cost of capital: The rate of return available on securities of equivalent risk in the capital market. Investors typically require compensation that reflects the level of risk: the higher the investment risk, the higher the cost of capital. If a utility is financed by both debt and equity, its cost of capital is a weighted average of the costs from both sources.

Cost-of-service regulation: The traditional form of U.S. utility regulation which determines prices (rates) based on the costs of serving different customers and producing different services, and which links a utility's rate of return to those costs. A cost of service study measures a utility's costs incurred in serving each customer class, including a reasonable return on investment. Critics argue that COS regulation provides little incentive to contain costs.

Cost-shifting: More properly described as shifting *revenue burdens* from one group of utility customers to another; usually used in a negative sense to imply that one group is unfairly compelled to subsidize another. In fact, utility regulators have long permitted or required such shifts to advance important public policies, and ratemaking often involves cost-sharing and policy trade-offs (see, e.g. '*universal service*').

Cross-subsidy: Pricing below incremental costs in one market and covering those losses out of the positive cash flows from another market. (Differential markups above incremental costs are not necessarily cross-subsidies, because they may reflect different demand elasticities, and both customer types may contribute to joint costs.)

Critical peak pricing (CPP): CPP enables medium and large customers to lower their electric bills and operating costs by shifting or reducing electricity usage during "critical peak" times when the utility determines that overall power demand, extreme system conditions, or wholesale electricity prices are approaching acute levels (for most utilities, on hot summer afternoons). Customers who have the flexibility to shift their usage – e.g., from the noon-to-6 p.m. peak period during up to some specified number of summer events – might receive a discount on all their part-peak and on-peak usage on all other summer days.

Curtailed service provider, or CSP: Entities that handle retail offerings of ISO demand-response programs; may include vertically integrated utilities, regulated transmission or distribution utilities, competitive electricity suppliers or other default service providers in restructured markets, or a stand-alone entity. The ISO typically notifies the CSP when interruptions are needed, and the CSP notifies the customer. The ISO pays the CSP, and the CSP pays the consumer for load reductions delivered.

Deadband (or collar): Often part of performance-based ratemaking schemes that include targeted incentives. An example would be a deadband established around a target rate of return, with earnings inside the deadband accruing solely to shareholders, and earnings outside of it being shared between ratepayers and shareholders. This sharing may be symmetric or asymmetric.

Decoupling (or Revenue decoupling): A regulatory process that sets utility rates so that a utility's *earnings* do not depend on its level of *sales*. Traditional ratemaking sets *rates* based on the utility's costs, and allows *revenues* to vary as sales volumes change (until rates are reset in the next rate case): if sales decline, earnings decline; if sales rise, earnings rise. In contrast, decoupling sets *revenues* based on the utility's costs, and lets *rates* float up if sales decline, or down if sales rise (again, until the next rate case). As described by utility economist Jim Lazar at NARUC's August 2006 workshop on utility incentives⁴³, decoupling 'is a mechanism to ensure that utilities have a reasonable opportunity to earn the same revenues that they would under conventional regulation, independent of changes in sales volume *for which the regulator wants to hold them harmless* – i.e., not necessarily independent of *all* changes in sales volumes (such as those due to weather, business cycles or other factors the utility cannot influence).

Demand charge: Also referred to as a 'capacity charge', this charge is designed to reflect the customer's contribution to the peak demand on the utility. Based on the maximum amount of electricity used at a given time, the demand charge is assessed according to the peak demand and can be one factor in a two-part pricing method used for utility cost recovery (the energy charge being the other). When metering does not identify the time of the *system* peak, the *customer's own peak* kW demand is sometimes used for billing purposes.

Demand resources: installed equipment, measures or programs that reduce end-use demand for electricity. Such measures include, but are not limited to, energy efficiency, demand response load reductions, and distributed resources.

Distribution-only utility: In states that have restructured – i.e., divested the generation function from vertically integrated utilities historically responsible for both generation and delivery (transmission and distribution) – the 'distribution-only' utility is the regulated entity responsible for owning, operating, maintaining, improving and expanding the distribution system as necessary to provide adequate service to customers. This term does not have the same meaning in every state because in some, the utility entity responsible for distribution also retains some of its historical generation and resource planning functions.

Diversity benefits: Benefits expected to accrue to the utility system at such time as substantial numbers of DER and substantial DER capacity (relative to the utility's total load or its load on particular circuits) are deployed. For example, one or a few onsite generators may not allow a utility to defer or avoid new capacity (since existing capacity may be needed to serve host customers if the generators fail); however, multiple onsite generators along the same circuit may permit deferral or avoidance (since the chances that all of them will go down at the same peak moment are small).

Embedded (or 'Sunk') cost: A cost that has already been incurred and so cannot be avoided by any strategy going forward – e.g., a cost that cannot be avoided by reducing output because the cost was incurred previously, such as the original cost of an asset (less depreciation, but including operating and maintenance expenses and taxes).

⁴³ www.naruc.org/associations/1773/files/Presentation%204.pdf

Energy charge: The portion of the charge for electric service based on electric energy, in kWh, consumed or billed.

Energy efficiency: Using less energy/electricity to perform the same function; *doing the same with less*. (The term ‘energy conservation’ sometimes connotes *doing less with less* – i.e., going without in order to save energy – is less popular these days.)

Expense: Utility expenditures made for ongoing operations, which are typically recovered through rates, but not included in the utility’s ratebase on which its rate of return is established; distinguished from *capital investment* in long-term physical assets such as land, equipment and machinery that must be depreciated or amortized, and on which regulators allow utility recovery of capital plus a fair rate of return.

Distributed energy resources or DER: Here, DER includes both demand-reducing and supply-enhancing resources – that is, energy efficiency and demand response resources, as well as distributed generation technologies – located at or near the load they serve. Examples include solar photovoltaics, small wind turbines, reciprocating engines, microturbines and fuel cells, and especially those operating on renewable fuels or yielding particularly high overall efficiencies (usually through combined heating, cooling and power [CCHP]).

Distributed generation, or DG: A subset of DER that includes parallel or stand-alone electric generation or CCHP units generally located within the electric distribution system at or near the point of consumption; usually ranging in size from a few kilowatts to as much as 10-20 MW capacity. See ‘DER’ examples.

Dynamic pricing: Dynamic pricing or rates allow ‘dispatchable’ prices that can be initiated on short notice to reflect real-time system or market conditions: these better reflect wholesale electricity costs, and provide stronger incentives for customers to modify their usage in ways that serve regulatory goals. In contrast, most utilities charge fixed average prices for electricity. Some rate designs of this type, such as inverted-tier rates, provide incentives to lower total monthly usage by charging higher prices as usage increases. Others, including time-of-use rates for larger commercial and industrial customers, are fixed rates designed to mimic the utility’s daily cost variations. Although they do provide some incentives for efficiency, fixed rate forms cannot reflect weather-related cost variations or unanticipated price spikes.

Fixed costs: Utility costs to provide service that remain constant *in the short run*, regardless of the level of output or amount of service provided. Examples include administrative overhead or loan repayments. Fixed costs are contrasted with *variable costs*, which increase as output or production increases. *In the long run*, all costs are variable (e.g., as increasing demand on the system requires construction or replacement of substations, poles and wires).

Fuel adjustment clause: A term in a utility rate schedule that provides for periodic (e.g., monthly or quarterly) adjustment of the retail electric rate to account for changes in fuel and related costs. The adjustment typically reflects variations from a specified base cost per unit determined when rates are approved, and can be either a debit or a credit.

Incentive: Used here to mean any positive motivational influence, inducement or reward for a specific behavior that is designed to encourage that behavior. Not necessarily financial, and not equivalent to a subsidy (although subsidies are one form of inducement).

Incentive ratemaking: Using performance-based ratemaking mechanisms (such as revenue or price caps) instead of traditional cost-plus ratemaking, to provide an incentive to the utility to pursue higher efficiency by letting it retain a larger share of any savings it creates. See '*Performance-Based Regulation*'; contrast '*Cost-of-Service Regulation*'.

Integrated resource planning or 'IRP': A resource planning process to evaluate the optimal mix of utility resources and options to achieve specified economic, environmental and social goals. IRP considers both demand-side measures to reduce electricity usage and supply-side options to redistribute generation among fuel types, locations, etc.

Independent system operator or 'ISO': A Federally regulated entity that coordinates regional transmission in a neutral, non-discriminatory manner, independent of other market participants, by monitoring and controlling in real-time the dispatch of flexible plants to ensure that loads match resources available to the system. The ISO is responsible for maintaining instantaneous balance of the grid system, and for ensuring its safety and reliability.

Loading order: A legislative or regulatory requirement that utilities and/or other load-serving entities plan for and acquire resources in a certain preferred order. California's loading order, for example, requires utilities to seek cost-effective energy efficiency, demand response, renewables and clean distributed generation *in that order*, and before acquiring or developing conventional power plants and major infrastructure additions.

Lost revenues: See *net lost revenues*.

Lost profit: Sometimes used to refer to profits (i.e., total utility revenue minus utility operating costs) expected under the utility's 'business as usual' case, but potentially unrealized due to customer reductions in grid-supplied electricity resulting from DER activities on the customer side of the meter.

Marginal cost pricing: Setting prices (or rates) to equal the incremental cost of producing the last unit (e.g., kilowatt-hour).

Mini-grid: Distribution equipment located within a limited geography such as an industrial or business park, college campus or new housing development, which is independent from the local utility network; sometimes connected with the grid through a single interconnection point.

Mobile generators: Usually refers to small, skid- or trailer-mounted generators that can be moved by truck from one location to another, and readily connected to a utility's distribution system for emergency or other use.

Natural monopoly: A situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms. Natural monopolies occur in industries which exhibit decreasing average long-run costs due to size (economies of scale). According to

economic theory, a public monopoly governed by regulation is justified when an industry exhibits natural monopoly characteristics.

Net revenue or net margin: Revenues *less* related commodity costs and revenue taxes as derived for individual rates or classes of service.

Net income (or profit): In accounting, total revenue minus operating costs (including depreciation); from the income statement.

Net lost revenues: Gross revenue losses associated with selling less electricity as a result of DER programs, *minus* any production or purchased power costs avoided because of the reduced sales.

Net lost revenue adjustment: A regulatory mechanism to compensate utilities for the portion of net revenue covering fixed costs that the utility did not collect due to cost-effective investment in demand reduction on the customer side of the meter. Compensates the utility for reduced sales, but does not remove the financial incentive to increase sales; usually focuses on energy efficiency but not other load-reducing initiatives.

Obligation to serve: A utility's legal requirement to provide service to anyone in its service territory willing to pay its established rates. Utilities have traditionally assumed this obligation in exchange for an exclusive monopoly franchise.

Open access: FERC Order No. 888 requires utilities to allow others to use their transmission and distribution facilities, to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee. Some states have also established their own open access requirements for portions of their distribution systems not subject to FERC jurisdiction.

Opportunity fuels: Any of a number of fuels that is not widely used, but has the potential to be an economically viable source of power generation. Usually derived from waste or as a byproduct of agricultural, industrial or municipal activities, these fuels typically exhibit lower heating values or more difficult combustion than conventional fuels, but are far less subject to market volatility. Examples include anaerobic digester gas, biomass-produced gas, crop residues, landfill gas, wood waste, municipal solid waste, refuse-derived fuel, food processing waste and textile waste.

Performance-based regulation or PBR: Any of many different rate-setting mechanisms which link rewards (generally profits) directly to desired results or targets. Unlike traditional regulation, PBR sets rates, or components of rates, for a period of time based on external indices rather than a utility's cost-of-service. Usually takes the form of a 'revenue cap' or a 'price cap', and may include 'targeted incentives' to encourage behaviors that meet or exceed specific performance measures, such as prices relative to those of similar utilities, customer service quality, employee safety, etc. Generally believed to provide utilities with better incentives to reduce their costs than does cost-of-service regulation.

Portfolio standard: A legislative or regulatory requirement that electricity providers obtain a minimum percentage of their demand (or energy) from renewable or other preferred energy

resources by a certain date; also, the specified percentage of electricity generated by eligible resources that a retail seller is required to procure. These requirements may be achieved through market approaches that use tradable credits to achieve compliance at the lowest cost, similar to the Clean Air Act credit-trading system (which permits lower-cost, market-based compliance with air pollution regulations). About twenty states (representing over 42% of US electricity sales) have adopted portfolio policies, and others have nonbinding goals in lieu of a mandatory standard.

Price cap: Price cap regulation seeks to control a utility's rates by linking future prices to inflation and productivity, rather than to utility capital investment. A typical price cap formula is 'RPI minus X', meaning that the price automatically adjusts for the previous year's retail price inflation (RPI) and for expected productivity or efficiency improvements (X) over the period when the formula is in place. Price caps generally encourage utilities to minimize costs and maximize sales, although they may moderate these tendencies by including performance measures and targeted incentives to encourage improved reliability and employee safety, DSM activities, etc

Profit: See *net income*.

Purchased power adjustment: A clause in a rate schedule that provides for automatic adjustments to customer bills when energy from another electric system is acquired and it varies from a specified unit base amount; intended to pass through to utility customers changes in wholesale power costs.

Rate: The authorized charges per unit or level of consumption for a specified time period for any of the classes of utility services provided to a customer.

Rate base: The base investment on which regulators permit a utility to earn a specified rate of return, generally representing the amount of property 'used and useful' in public service. The rate base may be based on fair value, prudent investment, reproduction cost, or original cost. Depending on the jurisdiction, it can be adjusted to take into account accumulated depreciation and may provide for working capital, materials and supplies, and deductions for accumulated depreciation, contributions in aid of construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Rate design: The type of prices used to signal consumers and recover costs. Examples include *block pricing*, *multipart prices*, *seasonal rates*, *time of use rates*, and *bundled services*. Rate design follows cost allocation (which determines how much revenue to collect from each rate class), and governs the relative level of rate charges such as customer charges, energy and demand charges, block structure, seasonal and time-of-use charges, etc., to be included in tariffs.

Rate of return: The ratio (percentage) of profits (or earnings) compared to capital or assets; the percentage applied to the rate base to determine the net operating income that a utility is allowed to earn.

Rate-of-return regulation: A regulatory method that provides the utility with the opportunity to recover prudently incurred costs, including a fair return on investment. *Revenue requirements*

equal operating costs plus the *allowed rate of return* times the *rate base*. This mechanism limits the profit (and loss) a company can earn on its investment. See '*cost of service regulation*.'

Real-time pricing: The instantaneous pricing of electricity based on its cost at the time the customer uses it. RTP rates can be highly variable, and are typically very high when system demand peaks (e.g., on a hot summer weekday afternoon). Real-time rates differ from time-of-use (TOU) rates in that they are based on actual (not forecasted) prices that can fluctuate frequently during a day, and they vary with weather and other immediate influences rather than on a predetermined schedule.

Regulated utility: A utility, usually investor-owned, that is subject to State and/or Federal commission regulation to achieve social or political objectives (such as controlling monopoly power or benefiting disadvantaged customer groups). Regulated utilities are expected to charge fair, nondiscriminatory rates and to render safe, reliable service to the public on demand. In return, they are generally free from substantial direct competition and permitted (although not guaranteed) to earn a fair return on investment.

Return on equity: The rate of earnings realized by a utility on its shareholders' assets, calculated by dividing the earnings available for dividends by the equity portion of the rate base.

Revenue: The total amount of money received by a utility from sales of its products and services, gains from asset sales or exchange, interest and dividends earned on investments, and other increases in shareholder equity except those arising from capital adjustments.

Revenue cap: A revenue cap limits the growth in a utility's overall revenues, rather than directly limiting its prices. Revenue caps generally encourage utilities to minimize both costs and sales. They can encourage utilities to maximize prices, so in practice they often include performance measures, and are calculated based on revenue per customer. Utilities and regulators often prefer revenue to price caps because they need not affect current allocations of the revenue requirement among customer classes, or actually set retail prices (whereas price caps may constrain the ability to shift costs among or within customer classes, if the cap is applied to individual rather than average rates.) Revenue cap formulas are similar to those for price caps: they establish a base revenue requirement, and then index it for inflation, productivity, trends in customer or sales growth, etc.

Revenue decoupling: Typically a multi-year ratemaking arrangement that severs the link between a utility's sales and its revenues. Removes both the 'throughput' incentive to increase sales to maintain earnings, and the disincentive for conservation, and insulates utility earnings from sales shortfalls.

Revenue requirement: In rate-of-return regulation, the total revenue a utility must collect to pay ongoing operating expenses and provide a fair return to investors.

Sales: The number of kilowatt-hours sold in a given period of time; usually grouped by classes of service, such as residential, commercial, industrial, and other. Other sales include public

street and highway lighting, other sales to public authorities and railways, and interdepartmental sales.

Soft start: An approach to get DER integration started using societal funds to pay in the short term for longer term benefits that accrue after significant DER penetration is achieved. A soft start could be created through regulatory programs with innovative approaches that need not become binding precedents for the long-term. For example, DER targets could be defined and performance incentives paid for meeting targets.

Solar utility: A company that owns solar equipment on customer property; sells solar-generated electricity to the property owner (usually discounted from the local utility's price); maintains the system in operation; and bills for and collects revenue. Customers continue to receive grid electricity from the local utility as well as solar electricity from the solar utility. Other technologies could also provide on-site power using this model.

Special contract: Any contract that provides utility service under terms and conditions other than those listed in the utility tariff. For example, an electric utility may enter into a special contract with a large customer to provide electricity at a lower-than-tariff rate in order to dissuade the customer from taking advantage of other options (e.g., deregulated competition or onsite cogeneration) that would result in the loss of the customer's load. Regulators may review special contracts to ensure that these negotiated arrangements do not unfairly burden other customers.

Standby charges: Charges that a utility may collect (via published tariffs) from a DG host customer, essentially for reserving a certain capacity in fixed assets (generating plants, transmission and/or distribution system) that the customer might demand. Specific tariff forms vary but standby charges are typically imposed on a \$ per kW (reserved) per month basis. Standby tariffs may be designed to hold non-participating customers harmless from rate increases that might otherwise occur when implementation of customer-owned DER would result in utility revenue reductions greater than utility cost reductions.

Sunk (or Embedded) cost: A cost that has already been incurred and so cannot be avoided by any strategy going forward – e.g., a cost that cannot be avoided by reducing output because the cost was incurred previously, such as the original cost of an asset (less depreciation, but including operating and maintenance expenses and taxes).

Targeted incentives: Incentives adopted in association with PBR mechanisms to encourage or discourage specific utility activities and mute potentially negative effects of some PBR approaches. These incentives vary considerably, and depend largely on the regulatory goals and environment of each jurisdiction. Examples include reward/penalty mechanisms for DSM, renewable resources, purchased power savings, generation capacity factors, emissions performance, and number and duration of customer outages.

Throughput incentive: The motivation to increase commodity sales when revenues are tied to sales.

Time-of-use (TOU) rates: The establishment of rates that vary by time of day or by season to reflect changes in a utility's cost of providing service. TOU rates are usually divided into three or four blocks per 24-hour period (e.g., on-peak, mid-peak, off-peak, super off-peak), and by seasons of the year (e.g., summer, fall, winter, spring). TOU rates differ from real-time rates in that they vary on a forecasted, predetermined schedule, rather than with actual prices that fluctuate many times a day and are weather-sensitive.

Universal service: The policy adopted by most legislatures and utility commissions of making utility products and services accessible to all citizens at affordable prices. This policy typically involves subsidies from customers who are less costly to serve on a per-unit basis (such as densely packed urban users), to customers who are more costly to serve (such as rural customers at the end of a long feeder).

Utilization factor: For a circuit, an annual utilization factor is the ratio of the average load on the circuit (in amps) divided by the maximum load carried by that circuit during the year. For the overall system, it is the ratio of average distribution loading for all circuits divided by total load at system peak.

Variable costs: Utility costs to provide service that vary with the level of output. Examples include fuel or operating and maintenance costs. These costs increase as output increases, unlike *fixed costs*, which are unchanged when output changes.

Vertically integrated utility: A utility that owns and controls all components of production, sale, and delivery for its product or service (sometimes as a result of mergers with firms involved in different stages of the business). Before many states restructured their electricity industries, most U.S. investor-owned utilities were vertically integrated, with a single firm owning assets and being responsible for generation, transmission, and distribution systems, as well as for retail metering and billing activities. This arrangement still prevails in a number of states.

Volumetric charge: A charge for using the transmission and/or distribution system that is based on the volume (in kW or kWh) of electricity delivered.

Win-win: A win-win approach for DER is where multiple stakeholders benefit, and none are worse off. Stakeholders in the regulated utility business model include the DER owner/host, the utility stockholders and non-participating ratepayers, and society. An element of a win-win business approach is an outcome – for example, financial gain – that benefits more than one stakeholder group simultaneously, without disadvantaging other stakeholder groups. One or more win-win elements should be achieved for a DER application to be considered a win-win business approach. For example, a win-win can occur when a customer chooses DER for flexibility and risk reduction, and when the DER can provide value to the distribution network as well.

Appendix B

1st Workshop (Boston)

Agenda

Creating and Demonstrating Incentives for Electricity Providers to Integrate Distributed Energy Resources

Stakeholder Workshop #1

Holiday Inn-Boston Airport
225 McClellan Highway
Boston, MA 02128

Thursday, September 28, 2006

8:00 AM	Welcome and introductions <div style="display: flex; justify-content: space-between; padding: 0;"> <div style="width: 30%;"> <i>David Thimsen</i> <i>Tim Healy</i> <i>Gerry Bingham</i> </div> <div style="width: 30%;"> <i>EPRI</i> <i>EnerNOC</i> <i>MA DOER</i> </div> <div style="width: 30%;"> <i>Fran Cummings</i> <i>John Sugar</i> </div> <div style="width: 30%;"> <i>MTC</i> <i>CEC</i> </div> </div>
8:30	How we got here and what we're trying to do <div style="display: flex; justify-content: space-between; padding: 0;"> <div style="width: 60%;"> <ol style="list-style-type: none"> 1. Previous DER Partnership projects 2. Fundamental challenge and project approach </div> <div style="width: 35%;"> <i>Ellen Petrill, EPRI</i> <i>David Thimsen, EPRI</i> </div> </div>
9:00	Getting on the same page: utilities, regulation, and restructured markets <div style="display: flex; justify-content: space-between; padding: 0;"> <div style="width: 30%;"> <i>Gerry Bingham</i> <i>John Sugar</i> </div> <div style="width: 65%;"> <i>Massachusetts Division of Energy Resources</i> <i>California Energy Commission</i> </div> </div>
9:30	3. Overview: business models, regulatory templates, and economic impacts for stakeholders <div style="display: flex; justify-content: space-between; padding: 0;"> <div style="width: 30%;"> <i>John Nimmons</i> </div> <div style="width: 65%;"> <i>John Nimmons & Associates, Prime Consultant</i> </div> </div>
9:45	4. How can utilities create and capture value through DER? – Strawman business models <div style="display: flex; justify-content: space-between; padding: 0;"> <div style="width: 30%;"> <i>Jim Torpey</i> </div> <div style="width: 65%;"> <i>Madison Energy Consultants</i> </div> </div>
10:30	Break
10:45	Stakeholder perspectives and discussion on business models <div style="display: flex; justify-content: space-between; padding: 0;"> <div style="width: 30%;"> <i>Ellen Petrill, Facilitator</i> </div> <div style="width: 65%;"> <i>EPRI</i> </div> </div>
12:15 PM	Business models wrap-up: stakeholder preferences & ranking (for Working Group consideration) <i>EPRI Team</i>
12:30	Lunch
1:30	5. Which regulatory approaches will best facilitate preferred business models? <div style="display: flex; justify-content: space-between; padding: 0;"> <div style="width: 30%;"> <i>Wayne Shirley</i> <i>John Nimmons</i> </div> <div style="width: 65%;"> <i>Regulatory Assistance Project</i> <i>John Nimmons & Associates</i> </div> </div>

2:30	Stakeholder perspectives on regulatory approaches to facilitate business models <i>David Thimsen, Facilitator EPRI</i>
3:30	Break
3:45	Regulatory wrap-up: stakeholder concerns, new issues, and ranking (for working group consideration) <i>David Thimsen, Facilitator EPRI</i>
4:00	6. Valuing the impacts: How will different business models and regulatory approaches impact stakeholder financial interests, and how can we find win/wins? <i>Snuller Price Energy & Environmental Economics (San Francisco)</i>
4:45	First day wrap-up, second day preview <i>David Thimsen</i>
5:00	Adjourn

Friday, September 29, 2006

8:00 AM	Welcome back <i>David Thimsen EPRI</i>
8:15	Review Day 1, form working groups to address issues for each business model <i>Ellen Petrill & EPRI Team</i>
9:00	Working group breakouts – to plan work between now and winter 2007 workshop <i>EPRI Team Facilitators</i>
10:15	Break
10:30	Working group reports on work plans <i>Working group spokespersons</i>
11:30	What's next <i>David Thimsen EPRI</i>
12:00	Adjourn

Participants

Project Team

Petrill	Ellen	EPRI	Director, Public/Private Partnerships
Thimsen	David	EPRI	Senior Project Manager
Nimmons	John	John Nimmons and Associates	President
Shirley	Wayne	Regulatory Assistance Project	Director
Price	Snuller	E3	Partner
Smart	Michele	E3	Senior Consultant
Torpey	Jim	Madison Energy Consultants	President

Governmental Organizations

Bingham	Gerry	MA DOER	Grant Manager
Cummings	Fran	MTC-RET	Policy Director
Daniel	Ghebre	MA DTE	EPD Engineer
Keating	Robert	MA DTE	Commissioner
leComte	Ron	MA DTE	Director EPD
Pielli	Katrina	US EPA	Clean Energy Program Manager
Sugar	John	CEC	Manager

Electric Utilities

Bishop	Don	NU/WMECO	Manager, Regulatory Policy
Morissette	John	NU/CL&P	Supervisor Distributed Resources
Boroughs	Ralph	TVA	Project Manager
Dossey	Tom	Southern California Edison	Project Manager
Ebner	Jennifer	SDG&E	Engineer
Iammarino	Mike	SDG&E	Principal Administrator
Bradford	Brian	NSTAR	
Gundal	Frank	NSTAR	Manager Products & Services
LaMontagne	Henry	NSTAR	Director Rates
Rabadjija	Neven	NSTAR	
Roughan	Tim	National Grid	Director Distributed Resources
Zschokke	Peter	National Grid	VP, Regulatory Strategy

Equipment Suppliers and Project Developers

Bjorge	Bob	Solar Turbines	Manager, Market Development
Casten	Sean	Turbosteam	CEO
Cowell	Steve	CSG	CEO
Healy	Herb	UTC Power	Sales
Brief	Kristin	EnerNOC	Corporate Development Analyst

Giudice Healy	Phil Tim	EnerNOC EnerNOC	Senior Vice President CEO
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End Users

Piaskoski Wheless	Roman Ed	GSA/PBS LA County Sanitation Districts	Energy Coordinator Engineering Manager
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Other Organizations

Ackerman Borghesani Dayton Kaplan Oppenheim Takahashi Zalcman	Eric Roger Dave Seth Jerrold Kenji Fred	EEI The Energy Consortium CESI Conservation Law Foundation LEAN Synapse Energy Economics Pace	Senior Manager Chairman President Senior Attorney Counsel Research Associate Executive Director
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Appendix C

2nd Workshop (San Francisco)

Agenda

Creating and Demonstrating Incentives for Electricity Providers to Integrate Distributed Energy Resources

Stakeholder Workshop #2

PG&E Headquarters Building
77 Beale Street
San Francisco, CA 94105

Thursday, January 25, 2007

<u>Time</u>	<u>Item</u>	<u>Topic</u>
8:00 - 8:15	1	Introductions and Workshop Purpose
8:15 - 8:45	2	California Public Utilities Commission Perspective (invited)
8:45 - 9:00	3	Project Overview: What we've done, where we are now, and what's next?
9:00 - 10:00	4	Business Cases Examined: What DER applications might yield win/wins? <ul style="list-style-type: none"> • Customer-Owned DER: combined heat & power; PV with energy efficiency • Utility-Owned DER: combined heat & power; PV with energy efficiency; biogas
10:00 - 10:30		– Break –
10:30 - 12:00	5	Economic Modeling Approach & Results: Who benefits & who pays? <ul style="list-style-type: none"> • Single Installations: stakeholder costs and benefits • Aggregate Impacts: customer bills & rates; utility earnings & ROE; societal impacts
12:00 - 1:30		– Lunch –
1:30 - 2:30	6	Working Group Reports: Business Case Priorities and

- Customer Ownership Working Group
- Utility Ownership Working Group

- Customer Ownership Cases
- Utility Ownership Cases

– Break –

- What does the Collaborative want to achieve through demonstrations?
- Which business approaches and applications can most usefully be demonstrated?
- What kinds of pilot projects can best demonstrate them?
- Can we overlay business & regulatory models on projects already under way?
- What pilot approaches are best suited to each State?
- Who needs to participate for a successful pilot project, and in what roles?

First Day Wrap-up

Friday, January 26, 2007

Topic

11:45

11:45 - **Wrap Up and Adjourn**
12:00

Participants

Project Team

Petrill	Ellen	EPRI	Director, Public/Private Partnerships
Thimsen	David	EPRI	Senior Project Manager
Rastler	Dan	EPRI	DER Program Manager
Nimmons	John	John Nimmons and Associates	President
Shirley	Wayne	Regulatory Assistance Project	Director
Price	Snuller	E3	Partner
Smart	Michele	E3	Senior Consultant
Torpey	Jim	Madison Energy Consultants	President

Governmental Organizations

Grueneich	Dian	CPUC	Commissioner
Morse	Jay	California PUC	
Bingham	Gerry	MA DOER	Grant Manager
Reyes	Jesse		
Cummings	Fran	MTC-RET	Policy Director
Phelps	Nathan	MTC-RET	
Daniel	Ghebre	MA DTE	EPD Engineer
Hall	Jeff	MA DTE	
Keating	Robert	MA DTE	Commissioner
leComte	Ron	MA DTE	Director EPD
Pielli	Katrina	US EPA	Clean Energy Program Manager
Perlmutter	Barry	MA DTE	Senior Analyst
Bhalotra	Meera	MA DTE	Rate Analyst
Byron	Jeffrey	CEC	Commissioner
Sugar	John	CEC	Manager
Palomo	Jose	CEC	Project Manager
Kelly	Linda	CEC	Program manager

Electric Utilities

Bishop	Don	NU/WMECO	Manager, Regulatory Policy
Morissette	John	NU/CL&P	Supervisor Distributed

Boroughs	Ralph	TVA	Resources
LaFlash	Hal	PG&E	Project Manager
James	Kenneth	PG&E	
Murphy	Julia	PG&E	
Buller	Susan	PG&E	
Rawson	Mark	SMUD	
Dossey	Tom	Southern California Edison	Project Manager
Iammarino	Mike	SDG&E	Principal Administrator
Bradford	Brian	NSTAR	
McDonnell	Patrick	NSTAR	
Zschokke	Peter	National Grid	VP, Regulatory Strategy

Equipment Suppliers and Project Developers

Hughes	Mark	Solar Turbines
Wong	Eric	Cummins West
Blunden	Julie	SunPower Corporation
Ribiero	Lori	Blue Wave Strategies

End Users

Wheless	Ed	LA County Sanitation Districts	Engineering Manager
Richter	Susan	Wyeth Pharmaceutical	

Other Organizations

Ackerman	Eric	EEI	Senior Manager
Borghesani	Roger	The Energy Consortium	Chairman
Oppenheim	Jerrold	LEAN	Counsel
Salamone	Charlie	Cape Power Systems	
Horgan	Susan	Distributed Utility Associates	

Appendix D

Economic Calculator Input Parameters

The tables below list the parameters incorporated into the economic calculations presented in Section 6. Note that parameters in blue are adjustable by the user in the spreadsheet calculation. The values indicated in these tables are those used to generate the results in Section 6.

General Assumptions

Electricity Market and Fuel Cost

Table D-1 lists the electricity costs and natural gas costs employed for the calculations. The costs are inflated in future years. Wholesale Energy Market Price is the long-term average wholesale cost of energy (kWh). The Generation Capacity Market Price is the wholesale value of the generator capacity. This is referred to differently in various locations, i.e.

- California: Resource Adequacy Payments
- Massachusetts: Forward Capacity Market
- New York: UCAP

Most natural gas utilities have a “cogeneration” rate which results in delivered gas costs close to those of gas turbine combined cycle plants (state-of-the-art in gas-fired electrical generation). For this reason, a single rate was used for both cases. The commercial and industrial gas rates represent the increased costs associated with distribution systems to serve these smaller gas users.

Emissions Rates

Table D-2 lists the emissions rates assigned to the various power generation technologies considered. These are used in combination with the value data in Table D-3 to quantify the benefit (cost) of any reductions (increases) in emissions over the base case.

Utility Assumptions

Tables D-4 to D-15 list a number of assumptions/inputs surrounding the utility electrical capacity, throughput, loads and rates, costs and financing, and regulatory environment.

Distributed Generation Installation Assumptions

Table D-16 lists DG projects assumptions for the utility-owned case. Table D-17 lists DG project assumptions for the customer-owned case.

Specific Case Assumptions

Table D-18 lists the assumptions associated with the utility-owned and customer-owned CCHP cases. Table D-19 lists the assumptions for the biogas-fueled generation case. Table D-20 lists the assumptions for the two photovoltaics case.

Table D-2 Electricity Market and Fuel Cost Assumptions

Year	Wholesale Energy Market Price	Generation Capacity Market Price	Natural Gas Costs \$ / MMBtu		
			Cogen and Combined Cycle	Commercial	Industrial
2005	\$ 0.065	\$ 85.00	\$ 6.74	\$ 7.49	\$ 6.89
2006	\$ 0.066	\$ 86.70	\$ 6.27	\$ 7.02	\$ 6.42
2007	\$ 0.064	\$ 88.43	\$ 5.75	\$ 6.50	\$ 5.90
2008	\$ 0.056	\$ 90.20	\$ 5.31	\$ 6.06	\$ 5.46
2009	\$ 0.060	\$ 92.01	\$ 5.81	\$ 6.56	\$ 5.96
2010	\$ 0.061	\$ 93.85	\$ 5.94	\$ 6.69	\$ 6.09
2011	\$ 0.062	\$ 95.72	\$ 6.04	\$ 6.79	\$ 6.19
2012	\$ 0.062	\$ 97.64	\$ 6.14	\$ 6.89	\$ 6.29
2013	\$ 0.063	\$ 99.59	\$ 6.24	\$ 6.99	\$ 6.39
2014	\$ 0.064	\$ 101.58	\$ 6.32	\$ 7.07	\$ 6.47
2015	\$ 0.064	\$ 103.61	\$ 6.39	\$ 7.14	\$ 6.54
2016	\$ 0.065	\$ 105.69	\$ 6.45	\$ 7.20	\$ 6.60
2017	\$ 0.065	\$ 107.80	\$ 6.52	\$ 7.27	\$ 6.67
2018	\$ 0.066	\$ 109.96	\$ 6.57	\$ 7.32	\$ 6.72
2019	\$ 0.066	\$ 112.16	\$ 6.63	\$ 7.38	\$ 6.78
2020	\$ 0.067	\$ 114.40	\$ 6.68	\$ 7.43	\$ 6.83
2021	\$ 0.067	\$ 116.69	\$ 6.78	\$ 7.53	\$ 6.93
2022	\$ 0.068	\$ 119.02	\$ 6.85	\$ 7.60	\$ 7.00
2023	\$ 0.068	\$ 121.40	\$ 6.92	\$ 7.67	\$ 7.07
2024	\$ 0.069	\$ 123.83	\$ 6.99	\$ 7.74	\$ 7.14
2025	\$ 0.069	\$ 126.31	\$ 7.06	\$ 7.81	\$ 7.21
2026	\$ 0.070	\$ 128.83	\$ 7.13	\$ 7.88	\$ 7.28
2027	\$ 0.071	\$ 131.41	\$ 7.20	\$ 7.95	\$ 7.35
2028	\$ 0.071	\$ 134.04	\$ 7.27	\$ 8.02	\$ 7.42
2029	\$ 0.072	\$ 136.72	\$ 7.34	\$ 8.09	\$ 7.49
2030	\$ 0.072	\$ 139.45	\$ 7.41	\$ 8.16	\$ 7.56
2031	\$ 0.073	\$ 142.24	\$ 7.48	\$ 8.23	\$ 7.63
2032	\$ 0.073	\$ 145.09	\$ 7.55	\$ 8.30	\$ 7.70
2033	\$ 0.074	\$ 147.99	\$ 7.62	\$ 8.37	\$ 7.77
2034	\$ 0.074	\$ 150.95	\$ 7.69	\$ 8.44	\$ 7.84
2035	\$ 0.075	\$ 153.97	\$ 7.76	\$ 8.51	\$ 7.91
2036	\$ 0.075	\$ 157.05	\$ 7.83	\$ 8.58	\$ 7.98
2037	\$ 0.076	\$ 160.19	\$ 7.90	\$ 8.65	\$ 8.05
2038	\$ 0.077	\$ 163.39	\$ 7.97	\$ 8.72	\$ 8.12
2039	\$ 0.077	\$ 166.66	\$ 8.04	\$ 8.79	\$ 8.19

Table D-3 Emissions Rates

Rates per Technology:	Coal	Biogas ICE	Gas Combined Cycle	Gas CHP	PV
Tons CO ₂ per MWh	1.012	0.443	0.429	0.400	0
lbs NO _x per MWh	0.672	0.68	0.078	1.049	0
lbs PM-10 per MWh	0.144		0.040	0.552	0
lbs SO _x per MWh	1.150		0.004	0.058	0
lbs CO per MWh	1.438		0.010	1.058	0
lbs VOC per MWh	0.028		0.0006	0.060	0

Table D-4
Year 1 Cost for Monetized Emissions - (Sensitivity)

CO ₂	\$ 8.00 per ton
NO _x	\$ 0.00 per lb
PM-10	\$ 0.00 per lb
SO _x	\$ 0.00 per lb
CO	\$ 0.00 per lb
VOC	\$ 0.00 per lb
Escalation Rate (zero if levelized costs)	0 %

Table D-5 Load & Rates

Peak Load - Year0	600 MW
Annual Load Factor - Year 0	45 %
Forecast Sales Growth Rate	2.0 %
Rate Base Assets (book and tax)	\$1,600 million
Average Cost of Power - Year 0 (revenues divided by production)	\$0.12 / kW

Table D-6
Average Energy Cost Forecasts
Distribution utility = market purchases
Vertical utility = production cost and market purchases

Average Cost of Purchased Power or Average Production Cost	\$ 61.06 / MWh
Average Marginal Transmission/Distribution Losses (for Energy Savings)	6 %
Capacity - Planning Reserve Requirement (increase over peak load)	18 %
Levelized Annual Capacity Cost	\$102.49 / kW-yr

Table D-7 Electric Marginal Costs

Use Market Price for Marginal Cost false = use wholesale price above true = select market	FALSE
Select market if Market Price is active	

Table D-8 Capital Expenditure and Depreciation

Average Asset Book Depreciation	30 years
Tax depreciation	20 years
Total Year0 CapEx	\$70 million
Percent Capex Growth Related	30%

Table D-9 Financing and Taxes

Debt Cost	7.00%
Debt %	50%
Target Return on Equity	11.00%
Equity %	50%
Weighted Average Cost of Capital (WACC)	9.00%
Utility After-tax WACC	7.60%
All-in (federal & state) tax rate	40.00%

Table D-10 Other Utility Expenses, Maintenance

O&M, other expense as % of yr0 revenue	5 %
Annual expense - Year0	\$14.19 million

Table D-11 Rate Setting

1=Regular Cycle 2=Earnings Band	1
Years between rate cases	4
Switch for PBR (1=use PBR, 0=no PBR)	0
Band on earnings (+/- ROE) (for earnings band rate cycle)	2.0 %
PBR inflation %	2.5 %
PBR X-factor % (subtracted)	0.5 %
PBR Z-factor % (added)	0.0 %
Total PBR Rate Adjustment %	2.0 %
Term of PBR (years)	7

Table D-12 Shareholder Incentives

Target Incentive (% of DER & EE Budget)	0 %
Additional EE Implemented (resulting from above incentive) OR see below - Upfront \$/nameplate kW incentive for shareholders, funds program costs	0 %

Table D-13 Revenue Requirement and Decoupling Inputs

Base Case	TRUE
With EE/DER Case	TRUE

Table D-14 Sensitivities

% Variation in actual average purchased energy/capacity cost (no DER/EE)	0 %
% Variation in actual EE/DER marginal energy cost	0 %
% Variation in actual sales growth rate	0 %
% EE/DER Decrease in Ave & marginal energy cost	0 %

Table D-15 Marginal Electric Generation Technology for Emissions

Peak Period	Gas turbine combined cycle
Off-Peak Period	Gas turbine combined cycle

Table D-16 DER Program

DER Administration Costs and Budget	\$ 3.50 / kW installed
-------------------------------------	------------------------

Financing

Table D-17 Utility Owned DG Financing

Borrowing rate	7%
Target Return on Equity (Hurdle rate)	11.0%
Leverage (debt/total financing)	50%
Tax rate	40%
After-tax WACC	7.600%
Term of financing	20
Utility Carrying Charge (%)	9.9%

Table D-18 Customer-owned Commercial DG Financing

Borrowing rate	8%
Equity hurdle rate	15.0%
Leverage (debt/total financing)	75%
Tax rate	45%
After-tax WACC	7.050%
Term of financing	10
Customer Carrying Charge (%)	14.3%

Case-Specific Assumptions

Table D-19 Combined Cooling, Heating and Power

	Utility-Owned CCHP	Customer-Owned CCHP
Base Case Year	2007	2007
Utility or Customer Owned 1=utility, 2=customer	1	2
Interconnection 1=Customer side of the meter 2=Utility side of the meter	2	1
Technology Type	3	3
DG Nameplate Capacity (A/C Output)	5,998 kW	5,998 kW
DG Installed Cost	\$ 1,200 per net kW	\$ 1,200 per net kW
Fixed O&M	\$ 60 per kW-year	\$ 60 per kW-year
Variable O&M	\$ 0.0094 per kWh	\$ 0.0094 per kWh
Electric Heat Rate Fuel LHV	10,790 Btu per kWh	10,790 Btu per kWh
Useful Thermal Output without Supplementary Fuel	5,489 Btu per kWh	5,489 Btu per kWh
Supplementary fuel to prime mover ratio	44 %	44 %
Useful Thermal Output	9,994 Btu per kWh	9,994 Btu per kWh
Annual Operating	8000 hours per year	8000 hours per year
Wholesale Market Price Multiplier (Value / Annual Average)	1	1
Fuel Type (Index)	3	3
Book Life	20 years	20 years
Export Rate Treatment; 1=Net Metered 2=Wholesale 3=No Value	3	3
State Incentive Index	3	3
State Incentive	\$ 500 per kW	\$ 500 per kW
Qualifying Incentive Size	1,000 kW	1,000 kW
Federal Incentive Index	3	3
Federal Tax Credit	0 %	0 %
Maximum Federal Tax Credit Amount \$/kW	\$ 0.00	\$ 0.00
Utility Qualifies to Receive Upfront State Incentive	FALSE	FALSE
Utility Qualifies to Receive the Federal Tax Credit	FALSE	FALSE
Utility DG Financing Index	1	0
Participant Discount Rate Index	1	1
Customer DG Financing Index	0	1
Utility Aux. / EE Financing Type Index	1	1
Description of Utility Aux. Equipment	None	None
Installed Cost of Utility Purchased Aux. Equip.	\$ 0.00	\$ 0.00

% Participant Paid through on-bill financing	100 %	100 %
Book life of utility Aux. Equip	20	20

Table D-20 Combined Cooling, Heating and Power (continued)

Description of Customer Aux. / EE Equipment	None	None
Installed Cost of Customer Purchased Aux. Equip.	\$ 0.00	\$ 0.00
Customer Financing Type Aux. Equip	1	1
Book life of customer aux. equip	20	20
Percent Waste heat displacing natural gas end uses	100 %	100 %
Efficiency of Displaced Natural Gas Use	80 %	80 %
Percent Peak Operation	50 %	50 %
Percent Energy Exported	0 %	0 %
DG Utility Peak Coincidence Factor	100 %	100 %
Incentive as a Percent of Gen Cap Avoided Cost	50 %	50 %
Incentive as a Percent of T&D Cap Avoided Cost	50 %	50 %
Marginal Plant Type (Peak)	1	1
Marginal Plant Type (Off-Peak)	1	1
Constrained Area T&D Avoided Cost (Base Case is \$0 for all cases)	\$ 37.74 per kW-year	\$ 37.74
Customer Profile Index	1	4
Original Consumption – kWh	3,500,000 kWh	35,000,000 kWh
Original Consumption - coincident kW	600 kW	6,000 kW
Original Consumption - billed kW	1,000 kW	10,000 kW
Annual Gas Usage for Existing Boiler	1,000,000 MMBtu	10,000,000 MMBtu
Annual Electric Usage for Chilling	500,000 kWh	5,000,000 kWh
EE Savings (% of kWh, coincident kW, billed kW saved)	0 %	0 %
EE Savings (% of natural gas saved)	0 %	0 %
Installed Cost of EE Equip.	\$ 0.00	\$ 0.00
% Participant Paid	0 %	0 %
Utility On-bill Financing	FALSE	FALSE
Rate Type	3	1.00
Discount on Energy Charge	5 %	0 %
Discount Basis 1=all consumption, 2=DG output	2	1.00
DG Avg. Demand Charge Reduction (% of Nameplate DG kW)	0 %	100 %
Standby kW	0 kW	5000 kW
DG Backup Case Index	3	1
Base Case Backup? (1=yes, 2=no)	2	1
Customer Backup Value	\$ 0.00 per kW	\$ 200.00 per kW
Required DG Size for Backup	500 kW	500 kW

Table D-21 Combined Cooling, Heating and Power (continued)

Renewable Energy Credit (REC)	\$ 0.00 per kWh	\$ 0.00 per kWh
Ownership of REC (utility = 1, customer=2, neither=3)	0	0
Avoided Waste Stream - Other Customer Benefits	\$ 0.00 per year	\$ 0.00 per year
Thermal Charge to Customer for Waste Heat	\$ 6.25 per MMBtu	\$ 0.00 per MMBtu
Utility Payment to Customer for Fuel	\$ 0.00 per MMBtu	\$ 0.00 per MMBtu
Utility Subsidy for Natural Gas Delivery Charge	\$ 0.00 per MMBtu	\$ 0.00 per MMBtu
Payment for DG Generated Electricity	\$ 0.00 per kWh	\$ 0.00 per kWh
Include Incentives as INCREMENTAL non-participant cost?	FALSE	FALSE
Inflation Rate	2 %	2 %
Levelization Period	20 years	20 years

Table D-22 Utility-Owned Biogas

Base Case Year	2007
Utility or Customer Owned (1=utility)	1
Behind the meter or Grid Connected (1=Behind, 2=Utility)	2
Technology Type	4
DG Nameplate Capacity (A/C Output)	200 kW
DG Installed Cost	\$ 1,500 per net kW
Fixed O&M	\$ 25 per kW-year
Variable O&M	\$ 0.02 per kWh
Electric Heat Rate Fuel LHV	12,590 Btu per kWh
Useful Thermal Output without Supplementary Fuel	0 Btu per kWh
Supplementary fuel to prime mover ratio	0%
Useful Thermal Output	5,018 Btu per kWh
Annual Operating	7,446 hours per year
Wholesale Market Price Multiplier (Value / Annual Average)	1
Fuel Type (Index)	4
Book Life	20 years
Export Rate Treatment; 1=Net Metered, 2=Wholesale, 3=No Value	3
State Incentive Index	4
State Incentive	\$ 800 per kW
Qualifying Incentive Size	500 kW
Federal Incentive Index	4
Federal Tax Credit	0 %

Table D-23 Utility-Owned Biogas (continued)

Utility Qualifies to Receive the Federal Tax Credit	FALSE
Maximum Federal Tax Credit Amount \$/kW	\$ 0.00
Utility Qualifies to Receive Upfront State Incentive	FALSE
Utility DG Financing Index	1
Participant Discount Rate Index	1
Customer DG Financing Index	0
Utility Aux. / EE Financing Type Index	1
Description of Utility Aux. Equipment	Digester (1500 cows)
Installed Cost of Utility Purchased Aux. Equip.	\$ 500,000
% Participant Paid through on-bill financing	100 %
Book life of utility Aux. Equip	20
Description of Customer Aux. / EE Equipment	None
Installed Cost of Customer Purchased Aux. Equip.	\$ 0.00
Customer Financing Type Aux. Equip	1
Book life of customer aux. equip	20 years
Percent Waste heat displacing natural gas end uses	0 %
Efficiency of Displaced Natural Gas Use	100 %
Percent Peak Operation	50 %
Percent Energy Exported	0 %
DG Utility Peak Coincidence Factor	100 %
Incentive as a Percent of Gen Cap Avoided Cost	50 %
Incentive as a Percent of T&D Cap Avoided Cost	50 %
Marginal Plant Type (Peak)	1
Marginal Plant Type (Off-Peak)	1
Constrained Area T&D Avoided Cost (Base Case is \$0 for all cases)	\$ 37.74 per kW-year
Customer Profile Index	3
Original Consumption - kWh	250,000 kWh
Original Consumption - coincident kW	50 kW
Original Consumption - billed kW	50 kW
Annual Gas Usage for Existing Boiler	-
Annual Electric Usage for Chilling	-
EE Savings (% of kWh, coincident kW, billed kW saved)	0 %
EE Savings (% of natural gas saved)	0 %
Installed Cost of EE Equip.	\$ 0.00
% Participant Paid	0 %
Utility On-bill Financing	FALSE
Rate Type	1

Table D-24 Utility-Owned Biogas (continued)

Discount on Energy Charge	0 %
Discount Basis (1=all consumption, 2=DG output)	1
DG Avg. Demand Charge Reduction (% of Nameplate DG kW)	0 %
Standby kW	0 kW
DG Backup Case Index	3
Base Case Backup? (1=yes, 2=no)	2
Customer Backup Value	\$ 0.00 per kW
Required DG Size for Backup	0 kW
Renewable Energy Credit (REC)	\$ 0.02 per kWh
Ownership of REC (utility = 1, customer=2, neither=3)	0
Avoided Waste Stream - Other Customer Benefits	\$ 20,000 per year
Thermal Charge to Customer for Waste Heat	\$ 0.00 per MMBtu
Utility Payment to Customer for Fuel	\$ 2.00 per MMBtu
Utility Subsidy for Natural Gas Delivery Charge	\$ 0.00 per MMBtu
Payment for DG Generated Electricity	\$ 0.00 per kWh
Include Incentives as INCREMENTAL non-participant cost?	FALSE
Inflation Rate	2 %
Levelization Period	20 years

Table D-25 Photovoltaics

	Utility-Owned Residential PV	Commercial Customer-owned PV
Base Case Year	2007	2007
Utility or Customer Owned (1=utility)	1	2
Behind the meter or Grid Connected (1=Behind, 2=Utility)	1	1
Technology Type	1	1
DG Nameplate Capacity (A/C Output)	5 kW	100 kW
DG Installed Cost	\$ 8,000 per kW	\$ 7,000 per kW
Fixed O&M	\$ 71.40 per kW-year	\$ 71.43 per kW-year
Variable O&M	\$ 0.00 per kWh	\$ 0.00 per kWh
Electric Heat Rate Fuel LHV	0 Btu per kWh	0 Btu per kWh
Useful Thermal Output without Supplementary Fuel	0 Btu per kWh	0 Btu per kWh
Supplementary fuel to prime mover ratio	0 %	0 %

Table D-26 Photovoltaics (continued)

Useful Thermal Output	-	-
Annual Operating	1576.8 hours per year	1576.8 hours per year
Wholesale Market Price Multiplier (Value / Annual Average)	1.2	1.2
Fuel Type (Index)	1	1
Book Life	30 years	20 years
Useful Thermal Output	-	-
Annual Operating	1576.8 hours per year	1576.8 hours per year
Wholesale Market Price Multiplier (Value / Annual Average)	1.2	1.2
Fuel Type (Index)	1	1
Book Life	30 years	20 years
Export Rate Treatment; 1=Net Metered, 2=Wholesale, 3=No Value	1	1
State Incentive Index	1	1
State Incentive	\$ 2,500 per kW	\$ 2,500 per kW
Qualifying Incentive Size	5 kW	100 kW
Federal Incentive Index	1	1
Federal Tax Credit	30%	30%
Maximum Federal Tax Credit Amount \$/kW	\$ 2,000 per kW	No limit
Utility Qualifies to Receive Upfront State Incentive	TRUE	FALSE
Utility Qualifies to Receive the Federal Tax Credit	FALSE	FALSE
Utility DG Financing Index	2	0
Participant Discount Rate Index	1	1
Customer DG Financing Index	0	1
Utility Aux. / EE Financing Type Index	1	1
Description of Utility Aux. Equipment	EE Program Cost	None
Installed Cost of Utility Purchased Aux. Equip.	\$ 0	\$ 0
% Participant Paid through on-bill financing	100 %	100 %
Book life of utility Aux. Equip	20	20
Description of Customer Aux. / EE Equipment	None	None
Installed Cost of Customer Purchased Aux. Equip.	\$ 0	\$ 0
Customer Financing Type Aux. Equip	1	1
Book life of customer aux. equip	20 years	20 years
Percent Waste heat displacing natural gas end uses	0 %	0 %
Efficiency of Displaced Natural Gas Use	100 %	100 %
Percent Peak Operation	100 %	100 %
Percent Energy Exported	15 %	10 %
DG Utility Peak Coincidence Factor	40 %	40 %
Incentive as a Percent of Gen Cap Avoided Cost	50 %	75 %
Incentive as a Percent of T&D Cap Avoided Cost	50 %	50 %
Marginal Plant Type (Peak)	1	1

Table D-27 Photovoltaics (continued)

Marginal Plant Type (Off-Peak)	1	1
Constrained Area T&D Avoided Cost (Base Case is \$0 for all cases)	\$ 37.74 per kW-year	\$ 37.74 per kW-year
Customer Profile Index	2	5
Original Consumption - kWh	16,000 kWh	800,000 kWh
Original Consumption - coincident kW	3	250
Original Consumption - billed kW	0	300
Annual Gas Usage for Existing Boiler	0	0
Annual Electric Usage for Chilling	0	160,000
EE Savings (% of kWh, coincident kW, billed kW saved)	0 %	0 %
EE Savings (% of natural gas saved)	0 %	0 %
Installed Cost of EE Equip.	\$ 0	\$
% Participant Paid	50 %	50 %
Utility On-bill Financing	TRUE	FALSE
Rate Type	2	1
Discount on Energy Charge	0	0%
Discount Basis (1=all consumption, 2=DG output)	1	1
DG Avg. Demand Charge Reduction (% of Nameplate DG kW)	0 %	50 %
Standby kW	0	0
DG Backup Case Index	3	3
Base Case Backup? (1=yes, 2=no)	2	1
Customer Backup Value	\$ 0.00 per kW	\$ 0.00 per kW
Required DG Size for Backup	0 kW	0 kW
Renewable Energy Credit (REC)	\$ 0.04 per kWh	\$ 0.04 per kWh
Ownership of REC (utility = 1, customer=2, neither=3)	2	2
Avoided Waste Stream - Other Customer Benefits	\$ 0 per year	\$ 0 per year
Thermal Charge to Customer for Waste Heat	\$ 0.00 per MMBtu	0
Utility Payment to Customer for Fuel	\$ 0.00 per MMBtu	0
Utility Subsidy for Natural Gas Delivery Charge	\$ 0.00 per MMBtu	0
Payment for DG Generated Electricity	\$ 0.452 per kWh	0
Include Incentives as INCREMENTAL non-participant cost?	FALSE	FALSE
Inflation Rate	2 %	2 %
Levelization Period	20 years	20 years

Appendix E

Business Models and Regulatory Templates to Engage Regulated Utilities in Distributed Energy Resource Activities

This background material served as the basis for the 1st Collaborators Workshop in Boston, September 24-25, 2006.

BUSINESS MODELS AND REGULATORY TEMPLATES

TO ENGAGE REGULATED UTILITIES IN DISTRIBUTED ENERGY RESOURCE ACTIVITIES

Project:

Creating and Demonstrating Incentives for Electricity Providers to Integrate DER

Background paper for the opening workshop
Boston, Massachusetts
September 28-29, 2006

Lead Sponsors:

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Energy & Environmental Economics

September 17, 2006

I. INTRODUCTION

II. STRAWMAN BUSINESS MODELS

A. What's a 'business model' for a utility considering DER?

B. DER Business Models: *Where are the profit opportunities for utilities?*

1. Categorizing Potential Business Approaches
2. General Descriptions of Utility Business Roles

Category A: Providing DER-related services

ROLE 1: SELL NETWORK MANAGEMENT SERVICES, WITHOUT OWNING DER ASSETS

ROLE 2: INVEST IN DG AT OR NEAR CUSTOMER SITES, AND OFFER PREMIUM SERVICES

Category B: Deploying DER Assets and Infrastructure

ROLE 3: INVEST IN DER EQUIPMENT AT CUSTOMER SITES, WITHOUT PROVIDING SERVICES

ROLE 4: INVEST IN ADVANCED GRID INFRASTRUCTURE

Category C: Using DER to Reduce Costs and/or Improve Grid Reliability

ROLE 5: INVEST IN DER TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, AND/OR TO IMPROVE SYSTEM PERFORMANCE

CASE A – LOWERING PEAK GENERATING COSTS

CASE B – INCREASING DISTRIBUTION UTILIZATION OR IMPROVING RELIABILITY

ROLE 6: OFFER DER CUSTOMERS INCENTIVES TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, AND/OR TO IMPROVE GRID PERFORMANCE

3. Detailed Breakdown of Business Approaches
4. Quantification and Comparison of Business Model Values – Where are the numbers?

C. Other, Regulatory-Driven Approaches

RESOURCE PLANNING DIRECTIVES

PORTFOLIO STANDARDS

III. BUSINESS, INSTITUTIONAL & REGULATORY ISSUES FOR UTILITY DER ACTIVITIES

A. 'Reduced Profit' Barriers to Utility Support for DER Deployment

B. Other Barriers to Utility DER Activities

IV. APPLICATION OF REGULATORY TEMPLATES TO UTILITY BUSINESS ROLES

Category A: Providing DER-related services

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ROLE 5: INVEST IN DER TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, AND/OR TO IMPROVE GRID PERFORMANCE.

ROLE 6: OFFER DER CUSTOMERS INCENTIVES TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, &/OR IMPROVE GRID PERFORMANCE

REGULATORY-DRIVEN APPROACHES: RESOURCE PLANNING DIRECTIVES & PORTFOLIO STANDARDS

RELATED ISSUES

Rate Design

GLOSSARY

ATTACHMENT A: MATRICES – BUSINESS MODEL DESCRIPTIONS AND VALUE PROPOSITIONS

I. INTRODUCTION

The Project. This Project addresses business and regulatory considerations critical to successfully integrating distributed energy resources (DER⁴⁴) into electricity markets in general, and into investor-owned utility systems (both conventional and restructured) in particular.⁴⁵ The Project has four objectives:

1. to identify through research, analysis and stakeholder collaboration, *utility business models* and *state regulatory approaches* that will reward electricity providers for integrating into their systems DER that advances societal policy goals (energy, environmental and economic);
2. to adapt the most promising of these solution sets to state- and/or utility-specific regulatory and business environments in which the collaborating stakeholders operate;
3. to test the efficacy and usefulness of these customized approaches through pilot projects in Massachusetts and California; and
4. to disseminate the results through outreach in public and private forums.

This Paper. This paper lays the groundwork to achieve the first of these four objectives. It introduces potential utility business roles and complementary regulatory approaches designed to help integrate clean and efficient DER into U.S. electricity markets in ways that benefit multiple stakeholders, without significantly harming others – our working definition of a ‘win/win’ outcome.

These business and regulatory constructs are presented as a starting point for the collaborative workshops scheduled to take place in Boston on September 28 and 29, 2006. There are many ways to approach this topic, and the business approaches outlined here are offered not as fully formed business models, but simply as strawmen for discussion, refinement, reorganization, elaboration, and perhaps elimination from further consideration if stakeholders conclude that some are not likely to result in win/win outcomes.

Section II clarifies what we mean by ‘business models’. It then distinguishes three broad categories of business activities that utilities might undertake: (1) providing DER-related services; (2) deploying DER assets and infrastructure; and (3) using DER to reduce costs and/or improve grid reliability. Within these categories, the paper suggests six possible utility roles for stakeholder consideration – some focusing on service offerings, others on asset ownership and control, and others on incentivizing customer actions. As

⁴⁴ For project purposes, DER includes both demand-reducing and supply-enhancing resources – that is, energy efficiency and demand response, as well as distributed generation technologies such as solar photovoltaics, small wind turbines, reciprocating engines, microturbines, and fuel cells, and especially those operating on renewable fuels or yielding high overall efficiencies.

⁴⁵ This project focuses on investor-owned utilities subject to state utility commission regulatory jurisdiction, rather than on publicly-owned utilities governed by locally or regionally elected or appointed boards. Some of the same issues confront publicly-owned utilities interested in DER, but they face a different set of institutional imperatives and incentives than do state-regulated utilities.

described, each role includes a number of attributes which distinguish it from the others, and which together suggest the outlines of a possible business model. However, stakeholders are invited to rearrange and combine these attributes to refine the models presented, or to create new models that might yield promising pilot demonstrations in later stages of this project.

Focusing first on business roles that might enable utilities to create profitable business opportunities around DER, is a prerequisite for identifying important legal and regulatory issues that each business approach will encounter, and ultimately for addressing and resolving those issues creatively. So, after outlining the strawman business models, Section III reviews some key economic, regulatory and legal concerns that shape the views of utilities and their regulators toward DER. Section IV considers what combinations of business constructs and complementary regulatory approaches might yield win/win solutions for integrating societally beneficial DER into larger electricity markets.

This paper focuses on *qualitative* aspects of DER business models and regulatory approaches. These are important and necessary in their own right, but also because they define the parameters for the *quantitative* financial analysis needed to assess whether these models can be profitable for utilities, and how they might impact other important stakeholders. EPRI's team has developed various modeling tools that provide this kind of financial information. It is now adapting those specifically for use in valuing the business and regulatory approaches that the Boston workshop participants decide are most promising. Although this paper does not address the new economic and financial analysis tools that will be made available this Fall, the team will describe them at the workshop. We will also present numerical illustrations to show how the tools will help stakeholders evaluate approaches that they believe deserve a closer look.

II. STRAWMAN BUSINESS MODELS

A. What's a 'business model' for a utility considering DER?

As quoted by leading Harvard Business School experts on the subject:

'Business model is one of those terms of art that were central to the internet boom: It glorified all manner of half-baked plans. All it really meant was *how you planned to make money*.' ⁴⁶

'... a business model is *a description of how your company intends to create value in the marketplace*. It includes that unique combination of products, services, image and distribution that your company carries forward. It also includes the underlying organization of people, and the operational infrastructure that they use to accomplish their work.' ⁴⁷

'... a business model is *the method of doing business by which a company can sustain itself – i.e., generate revenue*. The business model spells out how a company makes money by specifying where it is positioned in the value chain.'

⁴⁸

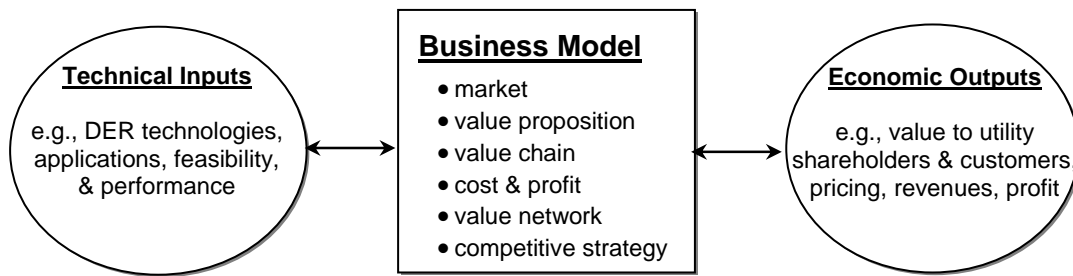
⁴⁶ Chesbrough, H. and Rosenbloom, R.S, *The Role of the Business Model in Capturing Value from Innovation*, Industrial and Corporate Change, V.11, No.3; quoting Michael Lewis, at p. 552, n. 24; emphasis added.

⁴⁷ Id., at p. 532, n. 5, quoting KMLab, Inc.; emphasis added.

⁴⁸ Id., at p. 533, quoting Professor Michael Rappa of North Carolina State University; emphasis added.

For our purposes, the ‘company’ in these quotes is the regulated utility, and the business models will illustrate ways the utility might generate revenues and sustain a business around various types of DER-related activities. Our initial focus is from the utility’s perspective, on values that accrue to the utility itself. However, what’s good for the utility is not necessarily good for other stakeholders whose interests regulators safeguard, so the utility’s business assessment must also consider how its activities will affect other stakeholders, and whether regulators are likely to permit, encourage, or constrain those activities.

The Harvard authors usefully describe the business model as a ‘mediating construct between technology and economic value’, illustrated as follows: ⁴⁹



The authors go on to suggest that the *functions* of a business model are to:

- articulate the **value proposition** – i.e., the value created for users by the offering based on the technology;
- identify a **market segment** – i.e., the users to whom the technology is useful and for what purpose, and specify the revenue generation mechanisms for the firm;
- define the structure of the **value chain** within the firm required to create and distribute the offering, and determine complementary assets needed to support the firm’s position in this chain;
- estimate the **cost structure and profit potential** of producing the offering, given the value proposition and value chain structure chosen;
- describe the **position of the firm** within the value network linking suppliers and customers, including identification of potential complementors and competitors; and
- formulate the **competitive strategy** by which the innovating firm will gain and hold advantage over rivals.’ ⁵⁰

The general descriptions of utility business roles below, and especially the detailed matrices which follow them, generally reflect the framework just described. We have, however, adapted it somewhat to reflect the multi-faceted nature of DER and the special challenges faced by utilities operating in a regulated environment. ⁵¹

⁴⁹ Id., pp. 532-536.

⁵⁰ Id., p. 533.

⁵¹ The article cited focused on a specific copier and related office equipment and software developed by Xerox Corporation and its (also) unregulated spin-offs. Regulated utilities considering DER confront other issues – including the fact that DER do not represent a unitary product or a single type of application, but widely differing technologies suitable for a wide range of applications and targeted to very different types of customers; that those who can *use* DER and those who can *benefit* from its

B. DER Business Models: Where are the profit opportunities for utilities?

This section describes ways that a regulated utility might profit by enabling or facilitating DER development by others; by deploying and owning DER assets itself; and/or by using DER to reduce its costs and/or enhance the reliability of its grid.

Some of the activities described are not commonly undertaken within the regulated utility: under historic views of utilities as ‘natural monopolies’, they are arguably more suited to below-the-line treatment, unregulated affiliate activities, or competitive providers. They are nevertheless included in the discussion because our focus is what regulated utilities can do to advance DER market integration, and what regulatory innovations are needed to make that possible. As states continue to sort out the proper balance between regulation and competition in the electricity business, and to weigh those considerations against new resource and environmental imperatives, utility roles may need to evolve beyond those that made sense in the last century. Considering regulated models other than ‘business as usual’ contributes to that, even if participants ultimately conclude that certain activities are better pursued below the line, or through non-utility entities.

1. Categorizing Potential Business Approaches

The following discussion posits three broad categories that together encompass six, more specific roles through which utilities might *create value* as part of various DER business models proposed for discussion at the workshop. The three categories are:

Category A: Providing DER-related services

Category B: Deploying DER assets and infrastructure

Category C: Using DER to reduce utility costs and/or improve grid reliability.

Within these three general categories, utilities might create value by taking on the following roles:

A: Providing DER-Related Services
Role 1: Sell network management services, without owning DER assets
Role 2: Invest in DG at or near customer sites, and offer premium services
B: Deploying DER Assets and Infrastructure
Role 3: Invest in DER equipment at customer sites, without providing services
Role 4: Invest in advanced grid infrastructure
C: Using DER to Reduce Costs and/or Improve Grid Reliability
Role 5: Invest in DG to reduce wholesale power or system expansion costs, and/or improve system performance

integration into the system are not necessarily the same group, and do not comprise a single market segment; and that utility regulators, if not utility management, are accountable to multiple constituencies whose interests often compete.

Role 6: Offer DER customers incentives to reduce wholesale power or system expansion costs, and/or to improve grid performance

Each of these roles is first described in general terms below, highlighting its most salient characteristics. Following these general descriptions are two detailed matrices that systematically compare specific attributes of each approach along a number of dimensions which, taken together, comprise the strawman business models proposed for discussion at the Boston workshop. The matrices are intended to break down the general descriptions into more discrete elements (described later) for more complete analysis and comparison. Neither the utility roles, nor all of the attributes assigned to them, are necessarily mutually exclusive: workshop participants might choose to rearrange or repackage them in various ways to craft more profitable or robust business models.

2. General Descriptions of Utility Business Roles

Category A: Providing DER-related services

ROLE 1: SELL NETWORK MANAGEMENT SERVICES, WITHOUT OWNING DER ASSETS

Description & Value. The utility sells network management services directly to DER customers or to aggregators (e.g., mini-grid operators or solar utilities).⁵² These services might include managing customer demand response for ISO programs; managing VAR control or back-up services for mini-grids; or providing metering and billing for solar utilities. They enable customers to save money, and customers and aggregators to maximize the value of their equipment.

These services generate revenues for the utility in the form of management fees and/or service charges (e.g., for metering, billing or backup services), and possibly a share of any ISO payments for demand response. For these revenues to create incremental value to motivate utility participation, regulatory mechanisms may need to build in profit opportunities, such as allowing the utility to capitalize the costs of its network management services and earn a return on them as it could on capital investment.

This role – in which utilities help their customers reduce demand for traditional utility services, and their potential competitors leverage or streamline operations – will have limited appeal to utilities unless regulators ensure utility recovery of profits, or at least of unamortized investment, in facilities built to serve any load the utility views as ‘lost’ to these operations. For example, if a new solar utility sells solar-

⁵² A *mini-grid operator* is a non-utility entity that owns and/or operates equipment located in a limited geography (e.g., a neighborhood or industrial park). This equipment is linked electrically but is independent from the local utility network, normally with only one interconnection point with the utility grid.

A *solar utility* is a company that owns solar equipment on individual customer property. The solar utility sells solar-generated electricity to the property owner (usually at a discount from the local utility’s price) and is responsible to ensure the continued operation of the solar equipment. In addition to maintenance, the solar utility takes on billing and revenue collection. In this case the customer continues to receive grid electricity from the local utility as well as solar electricity from the solar utility. The solar utility can be viewed as a proxy for other technologies that could provide on-site power using this model.

generated electricity to the distribution utility's customers, the distribution utility may need to be afforded an opportunity to recover the cost-based portion of revenue lost from each solar utility customer.

Examples:

- Potomac Electric (Washington, D.C.) acted as a Curtailment Service Provider⁵³ for its customers to enable their participation in PJM's demand response program. Services included a web-based software platform that helped customers manage their curtailment activities and track their results. Customers who used the services shared part of their PJM program revenue with Potomac Electric.
- A number of utilities offer substation monitoring and maintenance services to larger commercial and industrial customers, charging for time and materials or levying monthly service fees.

Relevance to Target Applications: CCHP & Efficiency • Opportunity Fuels & Distributed Renewables • Peak Generation & Demand Response.

This services construct may not be viable in today's limited DER markets, but could be workable in the higher-penetration markets considered as the eventual goal of this project. With many installations of targeted applications in a distribution utility's service area, coordinating demand response, load management and generation from all these sources will be critical to ensure reliability, optimize their system contributions, and maximize their value for users and aggregators. In this 'substantial penetration' scenario, the utility could also provide billing, scheduling and maintenance services for these units.

ROLE 2: INVEST IN DG AT OR NEAR CUSTOMER SITES, AND OFFER PREMIUM SERVICES

Description & Value. In this role, the utility owns DG equipment and uses it to provide premium power and/or enhanced reliability services to individual customers. The equipment might be located on either the customer or the utility side of the meter, depending on how the customer's facility is configured.

This is not a passive investment whose value derives from the investment alone, but an active one whose value is enhanced by providing services that individual customers are willing to pay for. Also, this role focuses on benefits for individual customers – unlike Role 3 below, where any dispatch control the utility retains can benefit the utility itself and large numbers of its customers (e.g., through reduced procurement costs, or improved reliability for parts of the grid.)

Depending on the kind of equipment, the investment cost could be paid by many customers (if it benefits an entire poor-performing circuit), or by a single customer (if it delivers premium power). In either case the utility would seek to capitalize the equipment and earn at least its authorized rate of return – although equipment dedicated to a single customer might well be treated as 'below-the-line', meaning that the utility profits only if the investment pays for itself. Where cost recovery is allowed, it presumably

⁵³ In general, 'curtailment service providers' (CSPs) are entities that handle retail offerings of ISO demand-response programs. A CSP could be a traditional vertically integrated monopoly utility, a regulated electric delivery utility in a competitive market, a different default service provider (DSP), a competitive electricity supplier, or a stand-alone entity. The ISO notifies the CSP when interruptions are needed, and the CSP notifies the customer. Non-regulated CSPs could negotiate the terms of the agreement or be part of a standard product or products. For regulated CSPs, agreement terms would be subject to PUC approval and embodied in tariffs or special contracts. Payment and sharing arrangements are described at note 25, *infra*.

would include a carrying cost and margin for any equipment provided, as well as associated expenses for design, installation, operation and maintenance. Premium services may also improve customer satisfaction, which for some utilities can translate to performance rewards for shareholders.

The economics of these applications can be improved by siting the equipment within a constrained area of the utility's grid, provided that the utility's contract with the host entitles it to use the DG to relieve the local constraint. If it does, the utility might charge the host customer for only part of the installation cost, and other benefiting customers (through rates) for the remaining costs.

Examples:

- Madison Electric (Wisconsin) offers to install, own and operate backup generators at commercial customer locations (e.g., 500 kW). Customers can use the backup capacity if they lose power because customer equipment or the grid fails. The utility has the right to dispatch the generator if local grid reliability is threatened.

Relevance to Target Applications: CCHP & Efficiency • Opportunity Fuels & Distributed Renewables • Peak Generation & Demand Response.

CCHP & Efficiency – The utility might own the CCHP system at the customer's site, and sell premium power (e.g., from a fuel cell) and/or heating and cooling services to the customer.

Opportunity Fuels – The utility might own a digester gas fuel cell system at a wastewater treatment plant, sell power (premium or otherwise) to the host facility, and sell fuel cell thermal output to heat the plant's digesters.

Distributed Renewables – The utility might own solar PV systems with battery backup; manage the owner's sale of Renewable Energy Credits; and provide power when the grid goes down.

Peak Generation & Demand Response – The utility could provide backup generation and controls on customer systems or sites to facilitate demand response under available ISO programs.

Category B: Deploying DER Assets and Infrastructure

ROLE 3: INVEST IN DER EQUIPMENT AT CUSTOMER SITES, WITHOUT PROVIDING SERVICES

Description & Value. The distribution utility owns and deploys equipment (such as demand response switches, or fuel cell or solar PV systems) located at the customer's site. It might or might not actually install, operate or maintain the equipment. It might be indifferent to its customer's selection of a vendor to perform those functions; or it might issue a competitive solicitation for a single vendor or a preferred vendor for each DER technology to assume those responsibilities for a certain geographic area. The utility would lease the hardware to the customer for a fee, and the utility or a third party would operate it.

Unlike Role 2, the value of this role for the distribution utility does not derive primarily from providing *services*, but from investing in *assets*. Like Role 4 below, this approach creates value for the utility by adding to its plant-in-service account and providing the opportunity to earn a return on new ratebase investment – albeit on the customer side of the meter – as well as recovering its expenses associated with the program. If the utility retains some dispatch control through its arrangement with the site host, the DER investment could help mitigate high generation supply costs, as well as enhance grid

operations, flexibility, resiliency and reliability. Depending on how DER benefits are allocated between participating customers and others, the utility might recover its investment via special tariffs or lease fees charged to participating customers, and/or through rates charged to all customers.

For demand response devices, the utility could operate the system or a vendor could operate the demand response network on the utility's behalf, and would be compensated in the form of capacity and energy payments from the utility or the regional ISO (PJM, NEISO, etc.). The utility's agreement with the vendor could also allow the utility to use the demand response network for local reliability purposes when the vendor would not otherwise dispatch it in the wholesale market.

Examples:

- Comverge, a provider of utility energy management solutions, has presented this kind of concept to the MADRI Working Group. The distribution utility would own demand response switches and automated thermostats at customer sites. Comverge would operate the demand response network and pay the utility a fee for the use of its equipment. Comverge would participate in PJM's Economic Load Response Program as a Curtailment Service Provider and receive capacity payments (ALM Credits) from PJM. The distribution utility would have the right to dispatch the load response network when necessary to ensure local grid reliability.
- Georgia Power, a summer-peaking utility, offers a voluntary Critical Peak Pricing option to residential customers. The utility installs an advanced meter and smart thermostat at the homes of participating customers with central air conditioning. The utility signals the thermostat when critical peak pricing events are called, allowing the home's temperature to rise a few degrees and reducing the customer's demand for the duration of the event. In return, the customer receives a special tariff with discounted prices during non-critical hours, enabling participants to reduce their electricity bills by hundreds of dollars annually.

The unique aspect of the program is that customers pay a \$4.50 monthly service fee to participate. According to Georgia Power, the customer service fee covers about one-third of the infrastructure investment. The remaining two-thirds of the required investment is included in utility rate base accounts and recovered in a similar fashion to other distribution benefits, earning the normal utility rate of return. The program allows the utility to lower its overall costs of generation procurement and pass those savings to all customers.

Relevance to Target Applications: CCHP & Efficiency • Opportunity Fuels & Distributed Renewables • Peak Generation & Demand Response.

This approach, in which the utility owns equipment on the customer side of the meter, could apply to all the target applications listed here, although it may raise some distinct issues for generation resources in states that have restructured.

ROLE 4: INVEST IN ADVANCED GRID INFRASTRUCTURE

Description & Value. Under this approach, the utility invests in advanced grid infrastructure that enables its distribution system to take full advantage of the diverse stakeholder values offered by distributed renewables, clean and efficient local generation, and demand response resources. The utility affords customers and DER providers open access to this infrastructure – but it does not install, own, operate, or maintain DER, or provide other DER-related services to customers or third parties.

At the simplest level, this approach can create value for the distribution utility by adding to its plant-in-service account and providing the opportunity to earn a return on significant new equity investment. This would increase earnings, but not shareholders' rate of return on equity. These grid investments enable and facilitate DER, but the value of this approach does not depend on DER alone: the investment also enhances grid control, flexibility, resiliency and reliability. The infrastructure investments enable the utility to more effectively manage its existing assets and planned additions; to the extent that targeted incentives or similar approaches reward reliability improvements, the utility may reap those rewards as well.

To fully integrate DER into U.S. electricity markets, utility operators need to understand the characteristics and manage the availability of those resources. To do this effectively requires the installation of two new types of equipment on utility distribution systems:

1. *'Smart Grid' devices* – Distribution circuits and transformers must incorporate intelligence that can understand and respond to conditions along the circuits in near real-time. As conditions change due to customer load variations or external circumstances (wind damage, squirrel munchings, etc.), the changes must be recognized, localized, and communicated to an intelligence center at the substation or control facility. With these capabilities, the circuit can respond to distributed generation throughout the grid, or reduced customer demand resulting from active load management. It can also call on dispatchable DER to mitigate high wholesale prices, or to reinforce local grid reliability.

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⁵⁴ To illustrate one way that a "smart grid" might work, the following pilot proposal filed by Rockland Electric with the NJBPU on May 24, 2006 (and still pending as of this writing) may be helpful:

"A. Distribution Automation

The development of the intelligent electric distribution system would include the monitoring, automation, and intelligent control of two Darlington Substation 13 KV distribution circuits, in Ramsey, New Jersey. Equipment control logic would be employed for fault clearing and the automatic operation of the loop system. These devices would all be equipped with a supervisory control override and communicate with a distribution control system computer, to be located at RECO's control center. After the traditional automatic operation of the loop scheme, the control system computer would poll the automatic devices and motor operated air break ("MOAB") switches for status and system parameters sensed during the fault. The computer would analyze this information to optimize further circuit configuration through remote control of the MOAB's, restoring additional customers without violating load and voltage constraints, and isolating the faulted area to the minimum number of customers affected that would be allowable by the scheme and conditions.

"During normal system operation, intelligently controlling switched capacitor banks can optimize reactive power requirements and voltage, as well as minimizing system losses. Capacitor banks will be equipped with communications capabilities and would be placed under computer control and switched based on real time analysis of system parameters. Additional current sensors will be installed along the circuitry at strategic points and communications will also be established with these devices.

"The centralized control system computer will operate with "Distribution Engineering Workstation" ("DEW") open architecture software. This platform allows for additional applications to be developed and easily integrated into the software package, providing necessary flexibility to allow development of real time control modules that work in conjunction with existing applications such as power flow, reconfiguration for restoration, capacitor optimization, loss minimization and demand side management goals.

"The Darlington Substation is equipped with modern relays and remote terminal equipment, and an existing fiber optic communications infrastructure. The proposed smart grid improvements to the equipment and communications infrastructure

2. *Advanced Metering Infrastructure (AMI)* – Customers must have access to information that enables them to modify their behavior and control their equipment in response to price signals or potential system problems. Conventional meters do not provide this capability. New metering technologies do, and utility investment in these technologies can play a critical role in realizing potential DER benefits.

Developing a smart grid or installing advanced metering infrastructure may be more important for some kinds of DER (e.g., peaking technologies) than others (energy efficiency or baseload CCHP). Moreover, these actions will not necessarily lead directly to DER deployment – but without them, DER is less likely to achieve significant penetration of centralized electricity systems. For their part, regulators should be interested in these additions to utility plant-in-service accounts as ways to enable price-responsive demand in the near term, and a more robust and reliable grid in the longer term.

Thus, one potential business role for distribution utilities entails redesigning existing systems from ‘dumb’ to ‘smart’ grids by incorporating these control and communication features. The utility would also select, purchase, install and maintain advanced meters and communication devices to enable the exchange of price and usage information between customers and utility control and billing centers. The utility would phase in these investments over a specified time period; would be allowed to include them in distribution ratebase; and would have the opportunity to earn a reasonable return on them over time.

In this role, the distribution utility owns, operates and maintains the advanced customer meter, but the customer controls the metering information and communication capability, and can choose any vendor or service company to provide advanced site control and capabilities to respond to utility signals.

Examples:

- Pacific Gas and Electric has filed a plan and received California PUC approval to install \$1.2 billion of advanced metering infrastructure throughout its service territory. Southern California Edison recently proposed a similar \$1.3 billion plan.
- Rockland Electric has filed a proposal with the New Jersey Board of Public Utilities to undertake a pilot project to create a “smart grid” within a specific substation area in Bergen County.
- Public Service Electric and Gas of New Jersey is considering the viability of large-scale investment in advanced metering infrastructure (in support of default and competitive service provision) as a new ratebase-generated revenue stream; the company is now conducting a two-year pilot, called *myPower*, to test AMI features in its service territory.

would increase RECO’s data acquisition and remote diagnostic capability. The improved communications would be coupled with advanced substation computer network software to allow for better data processing and management, both locally and remotely.

“B. Advanced Metering Infrastructure

“In conjunction with Smart Grid development of the electrical system, a key component to its success will be the deployment and integration of an AMI system. This would enable the expansion of system benefits to customers beyond the meter. The pilot project would encompass the installation of the TWACS® fixed network metering system for all 6,128 customers served from Darlington Substation’s Transformer Banks 143 and 243.”

Relevance to Target Applications: CCHP & Efficiency • Opportunity Fuels & Distributed Renewables • Peak Generation & Demand Response.

To the extent that distributed renewable technologies such as solar PV are naturally available at times of peak electricity demand, advanced metering infrastructure will allow customers and utilities to value their output at its true, time-specific economic value rather than some average value that may otherwise under- or over-value the resource at particular times (e.g., during system peaks for PV, or in the middle of the night for some biogas facilities). This time-based value may become a significant portion of the total system value for these distributed renewable systems.

Similarly, if opportunity fuel sources or demand response devices are dispatchable, metering and communications infrastructure that can reveal the time and location-specific costs of serving demand enable a utility or ISO to fairly value the output (or savings) of customer-sited resources that obviate the need for grid-supplied power.

Category C: Using DER to Reduce Costs and/or Improve Grid Reliability

ROLE 5: INVEST IN DER TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, AND/OR TO IMPROVE SYSTEM PERFORMANCE

CASE A – LOWERING PEAK GENERATING COSTS

Description & Value. The utility owns (or leases from a vendor) and operates distributed generation equipment, injecting power into the grid and using it to reduce utility power acquisition costs. In this role, the utility would dispatch its DG whenever the marginal cost of operating it is less than what the utility would otherwise pay for wholesale power. Where power costs are not simply passed through to customers, this can create value for the utility in the form of savings on power costs that were used in setting its revenue requirement. Where purchased power costs are passed through to customers, this approach still provides value for the utility as a physical hedge to help manage supply costs for its customers.

CASE B – INCREASING DISTRIBUTION UTILIZATION OR IMPROVING RELIABILITY

Description & Value. Many distribution grids have a very low utilization factor,⁵⁵ often less than 50%. Strategically sited and operated DER can significantly increase this factor. This may enable the utility to save money by deferring or avoiding new construction, and to collect additional revenues from any increased utilization (at least between rate cases). Utilities can also use DER to enhance system reliability when DER costs are lower than the costs of traditional utility construction; in some PBR regimes, utilities receive targeted financial incentives for improved reliability.

Utilities can also install portable DG units to provide temporary reliability support for an individual circuit, until demand grows to a point where a permanent installation is appropriate. The units can then be

⁵⁵ An annual utilization factor for a *circuit* is the ratio of the average load on the circuit (in amps) divided by the maximum load carried by that circuit during the year. Similarly, a *system* utilization factor is the ratio of average distribution loading for all circuits divided by total load at system peak.

moved to other parts of the network where they may be able to support another one to three years of load growth, and so on. This approach can often reduce the total investment required over time to maintain equivalent levels of system reliability.

Examples:

- Detroit Edison (DTE) has an active program to use DG as an alternative to wires and poles investments when considering expansions of its distribution network. Many of its DER investments are mobile generators used as substation alternatives for 1-5 years, depending on the load growth experienced along circuits and at substations; most are installed on DTE's side of the meter. These investments are considered distribution system equipment, and treated for ratemaking purposes like other more conventional distribution equipment.
- Metropolitan Edison has leased from a third party a series of 2 MW generators, located at eight of its Pennsylvania substations to generate up to 100 MW of peak power to reduce purchased power costs from the PJM pool. Since a rate freeze is in effect, the utility cannot pass on additional wholesale costs, so any money it saves on buying LMP energy goes to the bottom line.

Relevance to Target Applications: CCHP & Efficiency • Opportunity Fuels & Distributed Renewables • Peak Generation & Demand Response.

This business construct could be used for any of these applications that can provide power to the grid at a lower price or higher value than central generation alternatives. It may be particularly relevant where the utility cannot recover higher costs associated with peak times through time-based rates.

ROLE 6: OFFER DER CUSTOMERS INCENTIVES TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, AND/OR TO IMPROVE GRID PERFORMANCE

Description & Value. As an alternative to owning DG assets, a utility could offer customers incentives to reduce their facility demand (using DG or curtailing load) when called by the utility or the ISO. Where utilities are responsible for providing power at fixed tariff rates, peak demand reduction may enable the utility to reduce its highest-cost wholesale purchases. The utility may be able to retain these savings and record customer incentive payments as operating expenses payable through rates, or may choose to pass on part of the savings to customers who have agreed to reduce demand when requested. Many variations of these 'curtailable' rates are already in place at utilities, mostly in markets where generation has not been unbundled from distribution.

The utility may be able to capture distribution-related benefits (as described in Role 5) from customer-owned equipment, by offering customers incentives to respond to utility requests to reduce or reschedule load. The cost of the incentives again might be recovered as utility network operating costs, and any savings due to DER might be equitably allocated between utility shareholders and nonparticipating ratepayers.

Examples:

- NSTAR Electric's 2004 rate case decision allowed the utility to book up to 5% of its demand-side management expenditures as after-tax shareholder incentives if certain performance goals were met.⁵⁶

⁵⁶ From Docket 04-11, available at <http://www.mass.gov/dte/electric/04-11/819order.pdf>

- National Grid (NG) is undertaking a pilot program in selected areas of its Western Massachusetts service territory. It has identified areas of the distribution network where additional system capacity is needed to serve current or near-term growth. NG offers customers who agree to curtail load for limited periods (normally in the summer) a \$/kWh payment for measured load reduced at the utility's call. These customers are also eligible to participate in the New England ISO's load reduction program.

3. Detailed Breakdown of Business Approaches – Attachment A

The discussion to this point has introduced six basic roles around which utilities might consider building profitable business models. Attachment A contains two matrices that provide a more detailed breakdown of the attributes that define each role, and the values each might contribute toward a successful business model. These tables simply offer some structure for thinking about how the roles just described can create value in the marketplace; how they can take advantage of special skills or resources that utilities bring to the table; and how they might generate a sustainable utility business that delivers benefits to (or at least does not harm) other stakeholders.

The first matrix is essentially *descriptive*; it distinguishes one approach from another according to the following attributes:

- whether the utility invests in physical assets
- whether any assets the utility invests in are on its side of the meter, or on the customer side
- whether any such assets can be included in ratebase and earn a regulated return
- what activities the utility engages in, and what services it provides to others
- the type and source of any revenues or savings flowing from the utility's activities and services
- the roles that customers and third parties (developers, aggregators, etc.) might play
- key regulatory issues likely to arise from the types of activities the utility proposes

The second matrix focuses on the *values* that each role can create for key stakeholders, and how the utility can capture a share of the value that its activities create. Specifically, this matrix shows:

- values created for the utility
- values created for participating customers (those who actually implement or install DER)
- values created for non-participating customers (other ratepayers whose interests regulators safeguard)
- how the utility will deliver the values its activities make possible
- the utility's cost structure and profit potential
- the utility's position relative to others in the DER value network

These role descriptions and matrices offer starting points for structuring the inquiry and stimulating discussion, but they are not intended to limit stakeholder creativity. Workshop participants should feel free to annotate the descriptions and matrices in any way that can advance the dialogue – e.g., by adding or eliminating activities or services, revenue or savings sources, values accruing to stakeholders, delivery mechanisms or elements of potential profit. Participants are encouraged to combine or reorder any of the attributes or values identified where that can shape more viable pilot demonstrations later in the project.

4. Quantification and Comparison of Business Model Values – *Where are the numbers?*

The ultimate test of a business model is whether it describes a way for a company to create value in the marketplace, to capture a share of that value, and to sustain a business. The discussion to this point has not attached dollar values to any of the costs or benefits that flow from the business approaches described, or quantified these values in a way that could help utility management or regulators evaluate the models relative to alternative courses of action.

EPRI's DER team has previously developed modeling tools to quantify DER costs, benefits and returns to various stakeholders. We are adapting these now for use in analyzing the business approaches presented here. That work will be completed once the collaborating stakeholders decide which combinations of business approaches and complementary regulatory mechanisms are worth a closer look in the months following the Boston workshop. EPRI's team will use stakeholder input developed at this workshop to complete and implement the modeling tool design during October. The tool will then be available for use by the working groups to be formed at the workshop, to flesh out the most promising models between October and early next year, when a second workshop is planned.

At the Boston workshop, EPRI's team will describe the modeling tools and present examples of the kinds of information and numbers they will yield, once they are adapted for the business and regulatory approaches that workshop participants find most promising. **C. Other, Regulatory-Driven Approaches**

The utility roles described above have potential revenue (or cost avoidance) streams associated with them. Regulatory-driven approaches are also worth mentioning here, although they do not in themselves yield utility revenues or cost avoidance opportunities, and do not comprise 'business models' as we have defined them. Still, where policymakers believe that societal interests compel utility involvement to achieve DER benefits that have not been or cannot readily be monetized, regulatory directives and incentives may afford opportunities to align utility business interests with public policies favoring end-use efficiency, demand response, renewables, and clean, efficient forms of distributed generation and CHP.

RESOURCE PLANNING DIRECTIVES

Some state regulators – notably California's – have endorsed and adopted a preferential 'loading order' for new energy resources.⁵⁷ Utility resource planning and acquisition must include cost-effective energy efficiency, demand response, renewables and clean distributed generation *in that order* and before turning to conventional power plants and major infrastructure additions. To the extent that distribution utilities in such states are also responsible for generation resource planning and acquisition, these utilities have opportunities to participate in the resource additions.

In states without 'loading order' directives, policymakers may still choose to reward utilities that implement or facilitate DER with various forms of incentive (e.g., ratebasing with or without rate-of-return adders, aggregation or deferral incentives, \$/kW payments for achieved DER, etc.⁵⁸) that will

⁵⁷ See *Energy Action Plan* and *Energy Action Plan II*, adopted jointly by California's Energy Commission and Public Utilities Commission in May 2003 and October 2005, respectively, at http://www.energy.ca.gov/energy_action_plan/index.html or <http://www.cpuc.ca.gov/static/energy/electric/energy+action+plan/index.htm>.

⁵⁸ See, e.g., *Distributed Resources: Incentives*, prepared for the Edison Electric Institute by NERA Economic Consulting; May, 2006.

encourage utilities to add resources as desired by State policy. These and other incentive approaches are discussed later in this paper.

PORTFOLIO STANDARDS

Distribution-only utilities can also be encouraged to add DER to their networks using other kinds of incentives. Many state policymakers have now determined that at least some forms of DER should become part of the state's electricity market through 'portfolio standards' requiring utilities to acquire specified percentages of new resources from certain preferred resource types. Most portfolio standards have so far concentrated on renewable resources (variously defined), but recent policy developments have begun to include energy efficiency and demand response among resources eligible for portfolio standard treatment, and some have suggested including CCHP as well.

Although most states that have separated generation from distribution place renewable compliance responsibilities on competitive electricity suppliers, it may be appropriate to target any DER portfolio requirement to distribution utilities. The rationale is that distribution utilities are the entities that understand the complexities of local system planning and operations, and are best positioned to focus distributed resources in the places where they will provide maximum ratepayer value. The following simplified example suggests how such a requirement could be implemented:

- Each local distribution company (LDC) would be responsible to procure or supply its required megawatts of DER via multi-year contracts. Each would issue an RFP offering such a contract to entities that can supply DER within a target area (based on utility-identified congestion areas). Bidders respond with a \$/kW/year price for their DER, and each utility chooses the lowest responsible bids that meet program specifications.
- DER providers must meet annual performance standards in order to receive payments.
- Power acquired through this mechanism would be allocated to all or certain classes of customers. It might comprise an initial block which customers purchase first, and all consumption above that would be supplied as usual, by competitive or default service providers or the vertically integrated utility, as the case may be.

REGULATORY MECHANISM

- The State could establish a kilowatt-hour charge that all customers would pay for the power allocated to them from DER. Reasonable costs incurred by utilities to procure and operate distributed resources would be recovered through this surcharge, ensuring timely recovery of expenses.
- Utilities choosing to meet all or part of their portfolio requirement by installing utility- owned equipment could add these investments to ratebase, subject to PUC oversight and approval.
- LDCs could be awarded an incentive of \$X/kW for eligible DER actually deployed in target areas, or could pay a penalty of \$Y/kW for any shortfall in meeting their requirement.

Examples:

- New York regulators have encouraged Consolidated Edison (ConEd) to use demand response and energy efficiency as resources where the distribution grid is capacity-constrained or in need of significant upgrades. ConEd has issued two RFPs seeking performance-based bids (\$/kW reduced) from vendors who agree to target specified areas of New York City's grid, and has issued a number of contracts.

- Utah Power & Light issued an RFP for vendors to supply demand response resources to the utility in exchange for an annual \$/kW payment for a ten-year contract term. A contract has been issued, the program has started, and payments will be made for measured and monitored savings.
- For more than three decades ending in the 1990s, Vermont residential consumers were supplied their initial monthly purchases of electricity by contracts between the state and out-of-state (primarily federally subsidized) producers. The initial block was generally in the range of 250 kWh/month. All electricity in excess of this amount was supplied by the local utility.

Relevance to Target Applications: CCHP & Efficiency • Opportunity Fuels & Distributed Renewables • Peak Generation & Demand Response.

Reasons to establish a preferred loading order or a portfolio standard would be to encourage applications like these, which theoretically have high-value but non-monetized societal benefits. Estimating this value will be important in shaping the mandates on which these approaches rest.

* * *

III. BUSINESS, INSTITUTIONAL & REGULATORY ISSUES FOR UTILITY DER ACTIVITIES

A. 'Reduced Profit' Barriers to Utility Support for DER Deployment

Like other private businesses, regulated monopolies are motivated by the need to be financially successful. The fundamental question for an electric utility faced with innovations that reduce customer use of grid-supplied electricity is the impact on utility revenues – or more precisely, utility profits. Under traditional ratemaking methods a utility's revenues are a direct function of its sales, so DER that reduce sales (whether through end-use efficiency or onsite supply) also reduce utility revenues and, absent offsetting cost reductions, utility profits. This poses a real and potentially significant barrier to DER that must be dealt with head on. Regulatory or legislative policies that require utilities to assemble the least-cost resource mix to serve demand are sensible and prudent, but they should be accompanied by complementary mechanisms that eliminate, or at least mitigate, adverse financial impacts on the utilities' bottom line – preferably in ways that reward both customer and utility.

In pursuing the goal of providing energy at the lowest total cost to society, the pricing of utility services serves two important objectives. Prices (or rates) serve to signal to energy users the economic costs of consumption, and they ensure recovery of the regulated company's "just and reasonable" costs of service. However, these objectives can conflict with each other.

Utility rates should reflect the long-run nature of the system costs incurred to meet present and future demand – i.e., they should cover at least the long-run marginal costs of service. Since all costs are avoidable in the long run, rates should be designed so that charges are avoided if service is not taken. This means that as far as possible, rates should be based on usage (per-kW and –kWh).

Two problems arise, however. The first is that many of the utility's costs appear to be fixed: *in the short run* they do not vary with sales, and are incurred whether service is provided or not – i.e., reduced usage (and usage-based revenues) do not necessarily reduce utility costs proportionately. The second problem, mentioned at the outset, is that traditional regulation typically ties recovery of a utility's costs (including its short-run 'fixed' costs) and profits to its kWh sales. Where profitability depends on sales

volume, the utility has a strong *disincentive* to reduce sales (e.g., through end-use efficiency or customer-side DG), and a similarly strong incentive to increase sales. Since sales often can be increased in the short term with little or no increase in fixed costs, the profit margin on these sales is high and constitutes a powerful financial incentive for utility actions that inhibit improvements in overall economic efficiency. By the same token, reduced sales in the short term can impair a utility's ability to meet its fixed-cost obligations.⁵⁹

This problem affects both vertically integrated and wires-only utilities, but it is particularly acute for the latter. This is so because, in the short run, reduced sales for the wires company are not associated with significantly reduced costs: between rate cases, most wires company costs are largely fixed, so revenue losses from reduced sales impinge directly on the firm's net income. The converse is also true: increased sales lead more directly to increased profits, sometimes causing formidable utility reluctance to support improvements in customer efficiency.

Error! Reference source not found. illustrates two important points about the impact of reduced sales on utility profits. First, it shows that a relatively small percentage reduction in *sales* (line h) results in a much larger percentage reduction in *profits* (i.e., net income, line n), and this is true whether the utility is vertically integrated or not. Second, the table shows that the profit erosion from DER is worse for a wires-only distribution company than it is for an integrated utility (line n).

This latter comparison shows that a 5% sales reduction for the vertically integrated utility, with 8¢/kWh total rates, will reduce its profits by about 23% between rate cases. The same 5% reduction for a wires company with 4¢/kWh delivery rates can reduce its profits by more than 50% until the next rate case, when regulators can reset rates for future periods.⁶⁰ If throughput is increased, the disproportionate impact on wires companies works in the other direction.⁶¹

⁵⁹ We say "can" rather than "will" because whether net revenues actually decline depends on marginal power and delivery costs, customer growth, overall revenue levels and other factors. In some cases, the savings to the utility that result from customer-sited resources in fact yield net revenue *gains*. See, e.g., Moskowitz, David, *Profits and Progress through Least-Cost Planning*, National Association of Regulatory Utility Commissioners, 1989, and Cowart, Richard, et al., *Efficient Reliability*, Regulatory Assistance Project (NARUC), June 2001.

⁶⁰ While perhaps not immediately apparent, the arithmetic is easily explained. A wires company has a relatively small equity rate base when compared to that of a vertically integrated utility, but the short-term profit loss from throughput reductions is relatively large, and not offset by savings in power purchase costs. The percentages shown here are illustrative; they will vary with the rate design of each distribution company.

⁶¹ Profits can be expressed in absolute terms, in a total 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 misleading. Certainly from a shareholder perspective, 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 climb from \$100 to \$150 million. But, 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%. For our purposes, "profits" (or earnings, etc.) refers only to ROE and not to absolute levels of profits.

Table 28 Lost Profits Math: Impacts of Reduced Sales on Utility Profits

Ref.	Utility Characteristics	Type of Utility	
		Vertically Integrated	Distribution-Only
(a)	Average Retail Rate/kWh	\$0.08	\$0.04
(b)	Annual Sales, kWh	1,776,000,000	1,776,000,000
(c)	Annual Revenues, (a)*(b)	\$142,080,000	\$71,040,000
(d)	Rate Base	\$284,000,000	\$113,600,000
(e)	Authorized Rate of Return on Equity	11.00%	11.00%
(f)	Debt/Equity Ratio	50.00%	50.00%
(g)	Required return on equity (net income), (d)*(e)*(f)	\$15,620,000	\$6,248,000
(h)	% Reduction in Sales	5%	5%
(i)	Reduction in kWh Sales, 0.05 * (b)	88,800,000	88,800,000
(j)	Associated Revenue Reduction	\$7,104,000	\$3,552,000
(k)	Average Power Cost/kWh	\$0.04	n/a
(l)	Power Cost Savings from Reduction in Sales	\$3,552,000	n/a
(m)	Net Revenue Loss after Power Cost Savings	\$3,552,000	\$3,552,000
(n)	Reduction in Net Income (Profits), (m)/(g)	(22.74%)	(56.85%)

The economic challenge, then, is how to preserve pricing incentives for customer efficiency in the long run, while neutralizing any financial harm to the utility from reduced sales in the short run, which can constitute a serious obstacle to DER deployment – perhaps due less to concern over the short-run loss, than to anxiety over the long-run prospect of continuing revenue erosion and limits on utility growth. Over the last two decades, regulators have devised various means of dealing with this challenge. Some, such as integrated resource planning (IRP) requirements and lost-revenue adjustment mechanisms, are fashioned to work within traditional cost-based pricing approaches to regulation. Others, such as various forms of ‘performance-based’ ratemaking, depart from traditional regulation by rewarding utilities not for new investment, but for improved efficiency, service and safety.

Within traditional cost-based regimes, a number of states imposed IRP mandates on their utilities during the late 1980s and early 1990s. Typically they required utilities to invest in the least-cost portfolio of resources, including cost-effective energy efficiency and other customer-sited resources, to meet present and future service demand. Recognizing that these distributed resources can perversely impact utility profitability, many states adopted ‘*net lost revenue*’ adjustment mechanisms to compensate utilities for the portion of net revenue covering fixed costs that was foregone due to cost-effective investment on the customer side of the meter. These mechanisms compensated the utility for reduced sales but did not remove the financial incentive to increase sales, and most focused only on energy efficiency, not on other load-reducing initiatives.

Seeing ‘net lost revenue’ adjustments as a well-intentioned but incomplete solution, several states targeted the sales bias of traditional regulation by implementing ‘*performance-based regulation*’, or

‘PBR’.⁶² PBR refers not to any single mechanism, to a broad array of regulatory methods that link particular behavior and preferred outcomes to specified financial rewards and, sometimes, penalties. As a comprehensive rate-making tool, PBR usually takes one of two forms, placing a ceiling either on the prices utilities can charge customers (*price cap*) or on the revenues they can collect from customers (*revenue cap*). Revenue caps (sometimes referred to as ‘decoupling’) are the better approach for breaking any link between DER installation on the customer side of the meter and erosion of utility revenue.

Under a revenue cap, the utility’s revenues are fixed over a certain time period (typically three to five years, with adjustments upward for inflation and downward for imputed productivity gains). ‘Fixed’ here means set in advance, either in dollar terms, or in revenue per customer. These numbers can be forecasted to change over time (e.g., with adjustments for inflation, productivity gains, and other factors), so their trajectory can be fixed, though the numbers themselves may vary according to adopted formulas.

Because the utility’s revenues are fixed and will not vary with sales, it is indifferent (at least from a revenue perspective) to customer DER installation. However, retail rates can still be based on usage (i.e., ‘volumetric’), so that customers retain appropriate economic incentives to find cost-effective means to reduce consumption and therefore costs (i.e., prices).⁶³ These incentives can be improved by pricing reforms specifically designed for this purpose. Although the utility may be indifferent to sales volume, it is not indifferent to improving its operational efficiency which, in the short run, will increase profits and, in the long run, redound to the benefit of customers (i.e., will be captured in the revenue-requirement calculation in the next rate case).

In contrast, price-cap regulation, which fixes prices (not revenues) for a specified time period, does not remove the utility’s sales, or “throughput,” incentive: its profits are still tied to sales volume while creating some inflexibility in investing for customer benefit.

In more limited applications, quite apart from the question of revenue and price caps, PBR can take the form of defined objectives and specified rewards – ‘targeted incentives’ – for their achievement. Targeted incentives are often used to reward high system reliability, high customer satisfaction levels, or superior utility safety practices. Achieving the objective results in a financial reward – that is, some kind of increase in the cost of service used to calculate rates or determine allowed revenues. Success at promoting DER deployment that advances policy goals would be amenable to such an approach.

B. Other Barriers to Utility DER Activities

Potential revenue reductions created by customer-side resources are important, and neutralizing them through revenue caps or other decoupling mechanisms may well be a necessary step toward more robust

⁶² California, Maine, and Oregon all implemented some form of revenue-capped regulation in the early ’90s. Each, for varying reasons (restructuring generally, or poor design—and thus poor performance—specifically), retreated from the approach. In this decade, California and Oregon have reconsidered decoupling and have implemented new mechanisms for several utilities. Other states in the east and mid-west are looking anew at it as well (e.g., through the MADRI process), and at least one, Vermont, has a proposal currently before it.

⁶³ The method of fixing the revenues matters, and regular adjustments may be necessary. In the short run the utility’s costs are not highly correlated with sales, but they are better correlated with number of customers. Thus, an adjustment related to customer count – e.g., a revenue-per-customer PBR – more closely reflects the utility’s short-term financial imperatives than one linked to sales. Awareness of the nuances of utility revenue drivers (e.g., differences in customer usage characteristics) can inform good PBR design.

utility support for DER deployment. But there is ample reason to doubt that this by itself will overcome utility inertia or resistance to fully integrating DER into their portfolios. Decoupling has been in place in California for many years, and strong state policies favor energy efficiency, renewables, CHP and other clean DG – yet no California investor-owned utility has made DER, or at least DG, a visibly high priority.

Utilities often observe that some of the more promising DER technologies are not yet competitive with conventional utility solutions in today's markets (imperfect as they are). Many still question whether DER can add real value to their systems, or if it can, whether it can do so in more than a few isolated situations where unusual circumstances coalesce to make it a cost-effective *and profitable* solution.

Given today's modest DER penetration rates, utilities cannot yet capture the 'diversity' benefits that DER proponents believe will materialize as these technologies become more ubiquitous, creating a classic chicken-and-egg conundrum. Another knotty problem for utilities and regulators is the fact that some DER costs and benefits are difficult to quantify, and they often flow to different stakeholders: it is no easy task to value them, monetize them, and apportion them fairly, ensuring that those who bear a share of the costs receive a corresponding share of the benefits.

There are also questions of scale: for utility management focused on multi-million or -billion dollar generation or transmission projects, or on major distribution system upgrades or expansions, a few relatively small DER projects here or there skate beneath the corporate radar. At least until more effective business and regulatory models emerge, DER transaction costs remain high relative to larger utility projects, and the business of deploying large numbers of replicable DER quickly, efficiently and cheaply remains elusive not only for vendors and developers, but for utilities as well.

Many of these barriers are probably transitional, and will recede as more pieces of the DER puzzle fall into place. A major breakthrough in PV or fuel cell cost reduction or in small wind technology; fuel supply or price constraints that dramatically increase the value of efficiency; or the early implementation of smarter grids, more advanced metering, or a critical mass of DER that convincingly demonstrates aggregation and diversity benefits – any of these can change the equation dramatically and shift the balance in favor of DER that appears only marginally viable today. For these reasons – and because we are running out of conventional options – it is worth looking beyond the first step of decoupling, toward other positive business incentives that can ramp up utility interest in the success of DER that contributes to societal goals.

As noted earlier, other kinds of 'targeted' performance incentives in addition to revenue caps could be used to promote DER deployment: for instance, minimum numbers of installed generators at customer sites, minimum kW or kWh of energy efficiency savings, targeted emission rates per MWh, or significant deferral of distribution investment. These rewards can take such forms as ratebasing, incentive returns on equity, fixed dollar amounts, or other bonuses. Shared savings can also be implemented, though this may be easier to do for energy efficiency. And penalties can be applied for failing to meet the standards; these are usually combined with incentives by establishing 'deadbands' or 'collars', above which rewards are given and below which penalties are imposed.

Utility resistance to DER, though often founded on lost revenue and profitability concerns, may also find expression in non-financial concerns such as 'cost-shifting' (more accurately described as the shifting of utility revenue burdens) from participating to non-participating customers, including intra- and inter-class as well as inter-temporal shifts. Powerful customer interests and other political pressures are sometimes brought to bear on these issues, and they certainly warrant examination. However, it is important to recognize that regulators often permit or even require such shifts to advance important public policies (universal service perhaps being the best-known example).⁶⁴ Utility ratemaking is altogether an

⁶⁴ A corollary is that not that every reduction in utility revenue is or should be treated as compensable, nor every increase in

exercise in cost-sharing and policy trade-offs, and regulators are expected to fairly evaluate whether such distortions are justified by the public benefits they yield.⁶⁵

IV. APPLICATION OF REGULATORY TEMPLATES TO UTILITY BUSINESS ROLES

Section II described six business constructs and two ‘regulatory-driven’ approaches to DER deployment as starting points for collaborative discussion. Each utility role is identified again below, followed by regulatory policies that should be considered to help implement it effectively. Again, these combinations of business approaches and regulatory policies indicate but do not exhaust the possibilities. Stakeholders can suggest other regulatory approaches that might help implement any of the models, and can consider applying regulatory approaches identified here with one model to a different model wherever appropriate.

Category A: Providing DER-related services

ROLE 1: SELL NETWORK MANAGEMENT SERVICES, WITHOUT OWNING DER ASSETS

The utility does not own, install or operate DER, but sells DER support services directly to DER customers or to aggregators. Services could include managing customer demand response for ISO programs; managing VAR control or back-up services for mini-grids; or providing metering and billing for solar utilities.

Complementary Regulatory Policies:

- *Recovery of service expenses.* Include all reasonable expenses associated with network management services in the utility’s revenue requirement. Consider special accounting for the delivery of ISO demand-response programs.⁶⁶
- *Revenue decoupling.* Without decoupling, the utility retains the incentive to increase sales. If some form of decoupling is not feasible, consider a ‘net lost-revenue adjustment mechanism’ (which would *not* remove that incentive, but *would* compensate the utility for reduced revenues due to DER enabled by its network management services).
- *Rates.* Rate design and rate levels will influence both DER operations and cost-effectiveness.

utility revenue rebatable.

⁶⁵ As one regulator once put it, “Policy should be clear about the absolutes. The rest is compromise.”

⁶⁶ See note 10, *supra*, describing curtailment service providers which deliver these programs. The ISO pays the CSP, which in turn pays the consumer for load reductions delivered (typically a share of the payment the CSP receives from the ISO – enough to induce the desired customer behavior, while leaving the CSP enough to cover its service costs, including profit. Sharing of ISO payments raises policy and market questions. Non-regulated CSPs will offer or negotiate a price through a standard product; the CSP’s share is the difference between the price it pays the customer and the price the ISO pays to it. For regulated CSPs, the PUC will determine the sharing arrangement, taking into account traditional regulatory concerns – equity, efficiency, cost-allocation, revenue collection. The regulated CSP share should be set to cover at least the costs of marketing and providing the service.

- *Other incentives.* Allow the utility to share in any savings made possible or enhanced through the DER services it provides.

To the extent that such savings would otherwise accrue primarily or solely to the participating customer, sharing arrangements can be defined in negotiating the service contract. If system-wide savings can accrue to participating and non-participating customers as well as the utility, regulators will need to review and determine their proper allocation.

ROLE 2: INVEST IN DG AT OR NEAR CUSTOMER SITES, AND OFFER PREMIUM SERVICES

The utility owns DG equipment on either side of the meter, and uses it to provide premium power and/or enhanced reliability services to individual customers who would pay service fees set to include carrying costs for any equipment provided, as well as cost recovery and margins for associated design, installation, operation and maintenance expenses. If the customer agrees to let the utility use the DG to mitigate local grid constraints, the utility might recover a share of its DG costs through rates charged to other benefiting customers. This approach might be considered a combination of Roles 3 & 4.

This construct involves utility investment in assets and possibly operations on either the utility or the customer side of the meter. The assets are not used to provide service to utility ratepayers generally (unlike Role 4), but are designed to benefit a single customer or perhaps a small group of customers. Utility revenues flow not from a passive equipment leasing arrangement (as in Role 3), but from actively providing premium services to select customers. However (like Roles 3 and 6), the utility-owned DG assets may be used at times to relieve grid constraints or otherwise improve system reliability for the benefit of non-participating customers. These characteristics raise the following questions:

1. In a restructured state, can distribution companies own generation facilities at all? Should the state equate central generation (now wholly or partially divested) with DG used primarily to deliver premium services to one or a few retail customers, and perhaps secondarily to relieve local congestion or improve local reliability?
2. Can distribution companies in the state own equipment sited on customer property? On the customer side of the meter? How should regulators allocate costs and benefits among customers with and without DER installations?
3. Does utility ownership of equipment on customer premises, or delivery of premium services to select groups of customers but not others, present anticompetitive and/or antitrust concerns?

Complementary Regulatory Policies:

- *Rate-base treatment of all prudent DG investments used to deliver premium services, with rate recovery allocated among participating and non-participating customers according to benefits received. This will involve allocations among customer classes as well among customers (in the form of charges paid by the customers receiving the premium services).*
- *Rate recovery of any expenses incurred to deliver benefits to non-participating ratepayers.*
- *Other incentives.* A small adder to the rate of return on investments used to provide these services could be applied, if regulators conclude that an added inducement is still needed.

Category B: Deploying DER Assets and Infrastructure

ROLE 3: INVEST IN DER EQUIPMENT AT CUSTOMER SITES, WITHOUT PROVIDING SERVICES

The utility acquires and deploys demand response and/or generating equipment at the customer's site and charges a lease fee to the customer, but may or may not install, operate or maintain the equipment (possibly leaving those services to a third party). Vendors of demand response equipment could operate it on the utility's behalf, receive capacity and energy payments from the utility or the ISO, and allow the utility to use it for local reliability purposes at certain times.

This role involves utility investment in assets and possibly operations on individual customer sites (as distinct from investments in equipment embedded in its distribution system that clearly benefits multiple customers). As such, it introduces at least the following questions:

1. Can distribution companies in the state own equipment sited on customer property? On the customer side of the meter? How should regulators allocate costs and benefits among customers with and without DER installations?
2. If the state has restructured its electricity industry, can distribution companies own generation equipment? Should restructured regimes equate central generation (now wholly or partially divested) with local DG, which arguably serves quite different functions and objectives?

Does it make a difference if some entity other than the utility controls or operates the equipment? If the equipment serves only the site load? If it functions more as demand response than as wholesale supply?

3. Does utility ownership of equipment on customer premises present anticompetitive and/ or antitrust concerns? Does it make a difference if non-utility (i.e., competitive) third parties assume responsibility for operating the equipment and/or providing services?

Complementary Regulatory Policies:

- *Rate-base treatment of all prudent investments in utility-owned DER facilities on either side of the meter.* Allow the utility an opportunity to earn a fair return on its equipment investment, whether on its side of the meter or the customer's.

Utilities have long experience with similar arrangements for electric water heater and other lease programs, but many of those do not involve generation. In some restructured states, laws prohibit utility ownership of generating facilities to safeguard competition in markets where the utility retains its monopoly in the wires business. In other states, courts and commissions may resist such arrangements under state anticompetitive laws or possibly federal antitrust law.⁶⁷

⁶⁷ For a comprehensive discussion, see Nimmons, J., J.D., *et al.*, *Legal, Regulatory & Institutional Issues Facing Distributed Resources Development* (Chapter 4) National Renewable Laboratory, 1996; NTIS/GPO DE96014321, SR-460-21791; also, Nimmons, J., *Legal & Institutional Issues for Distributed Resources Development*, EPRI Technical Assessment Guide, 1996.

In either situation, proponents of this approach will need to establish that these arrangements are not anticompetitive or that they warrant exemption from otherwise applicable policies, or will need to consider alternative arrangements such as customer or third-party ownership.

- *Recovery of related expenses.* See Role 1.
- *Revenue decoupling.* See Role 1.
- *Rates.* See Role 1.

ROLE 4: INVEST IN ADVANCED GRID INFRASTRUCTURE

The utility invests in advanced distribution infrastructure to take full advantage of diverse DER values. It affords customers and DER providers open access to this infrastructure, but does not participate with them in other DER activities or services (such as ownership, installation or O&M).

This model, involving utility investment in assets and operations that are arguably integral to its monopoly distribution function, is quite compatible with prevailing cost-based, rate-of-return regulation. It does not require major changes in traditional regulatory approaches, but does raise at least the following questions for regulators interested in integrating DER:

1. How cost-effective is this significant infrastructure investment, and how should costs and benefits be allocated among stakeholders, including DER participants and non-participants?
2. How are any benefits flowing from the investment related to time-of-use pricing?
3. If they are strongly related, should customer participation be voluntary or mandatory?

Complementary Regulatory Policies:

- *Rate-base treatment of all prudent investments in advanced infrastructure.* Allow the utility an opportunity to earn a fair return on its investment, as it would have for any other prudent investment in assets that serve the public good. Note that this need not be a voluntary utility initiative: regulatory commissions may affirmatively find that the public interest will be served by these investments, and direct their utilities to make them.

Credit the income produced by advanced infrastructure assets against the utility's revenue requirement (cost-of-service).

- *Recovery of related expenses.* See Role 1.
- *Revenue decoupling.* See Role 1.
- *Open Access.* Regulatory policies should foster open access at commercially viable prices.

Category C: Using DER to Reduce Costs and/or Improve Grid Reliability

ROLE 5: INVEST IN DER TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, &/OR TO IMPROVE GRID PERFORMANCE

The utility owns (or leases) and operates DG equipment on either side of the meter, supplying the grid in order to reduce its own power acquisition costs and dispatching the DG whenever its marginal operating cost is less than wholesale power costs. Alternatively, the utility uses its own DG to defer distribution investment and/or improve local grid reliability more economically.

This role is similar to Role 4 in that it involves utility investment in assets and operations that effectively become part of its distribution system, and presumably benefit multiple customers. It raises some other questions as well:

1. If the utility leases equipment from others, should it be treated the same as owned equipment?
2. What mechanisms are available to link distribution returns to improved utilization factors?
3. If the state has restructured its electricity industry, can distribution companies own generation equipment at all, even on the utility side of the meter? Should regulators equate central generation (now wholly or partially divested) whose basic function is wholesale supply, with DG used to defer distribution investment or for local grid support?

Complementary Regulatory Policies:

- *Rate-base treatment of all prudent investments in utility DG equipment* deployed to reduce power acquisition costs, defer distribution investment or enhance system reliability.
- *Other Incentives.* For a vertically integrated utility without a fuel-adjustment clause, the economics of dispatching distributed resources to avoid higher cost grid-supplied power should be enough inducement to take the action. If additional incentives are needed in other situations, share system savings through ratemaking (revenue setting). Savings will accrue when DER costs are below those the utility would otherwise incur for wholesale power, grid expansion or improved reliability.⁶⁸

ROLE 6: OFFER DER CUSTOMERS INCENTIVES TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, &/OR IMPROVE GRID PERFORMANCE

Rather than owning its own DG assets, the utility offers customers incentives to reduce their demand from the grid (using customer DG or curtailing load) when called by the utility or ISO, enabling the utility to reduce its highest-cost wholesale purchases and, with appropriate assurances, to improve reliability and defer or avoid distribution investment.

⁶⁸ This approach to the combined dispatch of multi-utility generating resources long characterized the operations of tight power pools (e.g., the New England, New York, and PJM power pools before restructuring).

This role does not require utility investment in assets or operations, except possibly metering and communications and control equipment to limit customer load under contractually agreed conditions. It does entail utility planning and regulatory approval of a process to inform, solicit, select and contract with participating customers; expenses to establish, implement and administer the program; and incentive payments (or billing credits) for customer performance meeting agreed contract conditions.

Complementary Regulatory Policies:

- *Rate recovery of administrative and program expenses.*
- *Rate recovery of incentive payments or bill credits.*
- *Rates.* See Role 1.
- *Revenue decoupling.* See Role 1.
- *Other Incentives.* Allow shared savings on wholesale power purchases. Reward measurable reliability improvements and cost-effective investment deferrals above specified thresholds. Consider whether it is necessary or desirable to adjust utility revenue requirements to account for slower growth or returns on ‘foregone capital investment’ of potential concern to utility shareholders.

REGULATORY-DRIVEN APPROACHES: RESOURCE PLANNING DIRECTIVES & PORTFOLIO STANDARDS

Requirements in some states that utilities plan for and acquire energy efficiency, demand response, renewables and clean distributed generation in a designated priority or ‘loading’ order before conventional resources or major infrastructure additions. Also, requirements that utilities (and sometimes competitive electricity suppliers) annually increase the percentage of preferred (usually renewable) resources in their portfolios, often targeting some required percentage by a specified year.

Complementary Regulatory Policies:

- *Rate-base treatment of all prudent investments in assets associated with priority resources.*
- *Recovery of all expenses the utility incurs to plan for and acquire such resources.*
- *Revenue decoupling* for customer-side energy efficiency, renewables and clean DG.
- *Other incentives.* Since regulatory directives have the force of law, compliance with a ‘loading order’ mandate does not necessarily require special incentives. However, molasses catches more flies than vinegar, and regulators may conclude that success is more likely if utilities are rewarded for expediting priority resources or exceeding minimum kW or kWh targets. Offering higher returns on specific investments or payments for achieving target output levels from preferred resources could help, as could expanding the set of resources covered by portfolio standards to include efficiency, demand response, and/or CCHP, as for example Vermont and Pennsylvania have done.

RELATED ISSUES

Rate Design: Rate design will be an important source of incentives or disincentives for most of the models described here. It is a large and complex topic, better suited to the smaller, more focused working groups that will be assigned to flesh out the business models favored by collaborative participants in the upcoming workshop. However, a few general comments here may be helpful.

Perhaps the biggest benefits of advanced metering and communications equipment (AMI) come in the form of operational savings to the distribution utility – customer service, outage identification and

reporting, improved management of distribution network in real time, and more accurate load data. Another significant system benefit flows from customer response (enabled by AMI and perhaps DG) to time-sensitive and dynamic prices – e.g., time-of-use, critical peak, or real-time pricing. In light of the new capability, regulators will want to consider questions of rate design generally, as well as specifically in relation to DER – whether and how rates should be designed to encourage cost-effective deployment of DER. DER-specific rate design goes directly to the question of rates for stand-by, or back-up, service.

Traditional regulation was set up to identify, allocate, and recover (through prices) *costs* incurred to provide service. With DER, rate design also requires an eye to any system *benefits* that rate-paying customers provide. Regulators’ experience with common load management programs – rewards and penalties for specified performance – provides a methodological foundation, but the uncertainty (great or small) surrounding DER operations adds complexity with which system operators may be more comfortable than rate designers. Some simple guidelines for ratemaking in this area might be useful:

- Rates should be designed to reflect actual costs, net of any offsetting benefits. Absent reliable information, don’t assume that the costs of stand-by service differ materially from those of full requirements service.
- Design rates to encourage desired outcomes. Policy favoring clean customer-sited resources should not be undone by a retail rate design that renders deployment falsely uneconomic. Where benefits are significant, quantifiable, and immediate, credits to retail rates may be offered to assure that DER is deployed where it will be most valuable.⁶⁹
- Avoid ratchets and other rate elements that create unavoidable charges. Consider setting demand charges on an “as-used” basis (daily or, at most, monthly), or energy charges loaded to recover the costs of occasionally-used capacity.
- Offer a variety of optional stand-by services, such as non-firm, physical assurance, or other services customized to customer needs. Allow customers to choose the level of standby they need and are willing to pay for, without imposing rigid utility obligations to serve that may not reflect what customer need or want.
- Minimize or eliminate demand charges for services that require no investment in incremental capacity, such as scheduled maintenance and off-peak stand-by service.

Incentives Related to Environmental Performance: Revenue-setting policies can be designed to reward utilities for bringing on line DER that meet specific emissions standards (or other environmental criteria, as appropriate). In the past five years, Texas, California, Connecticut, Maine, Massachusetts, and Delaware have all adopted DER emissions standards. A developer or owner that can demonstrate (usually through manufacturer certification) that its facilities will satisfy the standards will enjoy a streamlined environmental permitting process. To complement such approaches, regulators should consider adopting ratemaking policies as simple as a cash bonus in the company’s allowed cost-of service if the utility surpasses minimum thresholds of clean DER energy output.

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⁶⁹ See Moskovitz, D., *Profits and Progress through Distributed Resources*, RAP, February 2000, at www.raponline.org.

GLOSSARY

Note: This glossary was prepared for stakeholders participating in collaborative workshops as part of a STAC project to ‘Create And Demonstrate Incentives For Electricity Providers To Integrate DER’ more fully into U.S. electricity markets. Participants are expected from a number of States, and regulatory nomenclature varies from state to state. Stakeholder representatives also come from a variety of disciplines, some less familiar with utility and regulatory terminology than others. Although many participants will be familiar with many of the terms defined here, this glossary may be useful for those who are not, and may help participants communicate in a common language.

Advanced infrastructure: As used here, this refers to the installation of intelligent devices that can sense and respond to changes in the supply, demand and characteristics of electricity on the utility’s distribution system, as well as advanced metering devices that provide pricing and other information that customers need to modify their consumption behavior and control their equipment.

Aggregator: An entity that assembles generators or customer loads to achieve economies of scale and diversity among the generators or loads being combined, or to facilitate the sale and purchase of electric energy, transmission, and other services on behalf of those it serves.

Anticompetitive behavior: Behavior that protects a firm’s market power or position, such as predatory pricing or monopoly leveraging.

Antitrust: Laws and regulations (primarily Federal, but also adopted by many States) designed to protect trade and commerce from unfair business practices, including predatory actions to achieve, maintain or extend monopoly power, price-fixing conspiracies, and corporate mergers likely to reduce competition in particular markets.

Balancing Account: A utility account used to match the collection of actual revenues against actual costs after an adjustment for unanticipated changes in expenditures; fuel costs of major plant additions are often put into balancing accounts.

Below-the-Line: All income statement items of revenue and expense *not* included in determining utility net operating income; considered as shareholder-related rather than customer-related costs.

Business Model: A description of how a company intends to create value in the marketplace through a combination of products, services, delivery mechanisms, and positioning relative to other market participants, and how it intends to make money over time by capturing a share of the value it creates.

Capacity Charge: See ‘*Demand Charge*’.

Capital Investment: Here, refers to utility investment in long-term physical assets such as land or equipment and machinery that must be depreciated or amortized, and on which regulators allow the utility to recover its capital and a fair rate of return; distinguished from *expenses* incurred for ongoing operations, which are typically recovered through rates, but are not included in the utility’s ratebase and do not earn a return for utility shareholders.

Cost Allocation: The apportionment of utility system costs to customer rate classes.

Cost-Based Service: A pricing approach that assigns utility costs and revenues to the particular customer classes that cause them, and charges those classes accordingly.

Cost of Capital: The rate of return available on securities of equivalent risk in the capital market. Investors typically require compensation that reflects the level of risk: the higher the investment risk, the higher the cost of capital. If a utility is financed by both debt and equity, its cost of capital is a weighted average of the costs from both sources.

Cost-of-Service Regulation: The traditional form of U.S. utility regulation which determines prices (rates) based on the costs of serving different customers and producing different services, and which links a utility’s rate of return to those costs. A cost of service study measures a utility’s costs incurred in serving each customer class, including a reasonable return on investment. Critics argue that COS regulation provides little incentive to contain costs.

Cost-Shifting: More properly described as shifting *revenue burdens* from one group of utility customers to another; usually used in a negative sense to imply that one group is unfairly compelled to subsidize another. In fact, utility regulators have long permitted or required such shifts to advance important public policies, and ratemaking often involves cost-sharing and policy trade-offs (see, e.g. ‘*universal service*’).

Cross-Subsidy: Pricing below incremental costs in one market and covering those losses out of the positive cash flows from another market. (Differential markups above incremental costs are not necessarily cross-subsidies, because they may reflect different demand elasticities, and both customer types may contribute to joint costs.)

Critical Peak Pricing (CPP): CPP enables medium and large customers to lower their electric bills and operating costs by shifting or reducing electricity usage during “critical peak” times when the utility determines that overall power demand, extreme system conditions, or wholesale electricity prices are approaching acute levels (for most utilities, on hot summer afternoons). Customers who have the flexibility to shift their usage – e.g., from the noon-to-6 p.m. peak period during up to some specified number of summer events – might receive a discount on all their part-peak and on-peak usage on all other summer days.

Curtailment Service Provider, or ‘CSP’: Entities that handle retail offerings of ISO demand-response programs; may include vertically integrated utilities, regulated transmission or distribution utilities, competitive electricity suppliers or other default service providers in restructured markets, or a stand-alone entity. The ISO typically notifies the CSP when interruptions are needed, and the CSP notifies the customer. The ISO pays the CSP, and the CSP pays the consumer for load reductions delivered.

Deadband (or collar): Often part of performance-based ratemaking schemes that include targeted incentives. An example would be a deadband established around a target rate of return, with earnings inside the deadband accruing solely to shareholders, and earnings outside of it being shared between ratepayers and shareholders. This sharing may be symmetric or asymmetric.

Decoupling (or ‘Revenue Decoupling’): A regulatory process that sets utility rates so that a utility’s *earnings* do not depend on its level of *sales*. Traditional ratemaking sets *rates* based on the utility’s costs, and allows *revenues* to vary as sales volumes change (until rates are reset in the next rate case): if sales decline, earnings decline; if sales rise, earnings rise. In contrast, decoupling sets *revenues* based on the utility’s costs, and lets *rates* float up if sales decline, or down if sales rise (again, until the next rate case). As described by utility economist Jim Lazar at NARUC’s August 2006 workshop on utility incentives, decoupling ‘is a mechanism to ensure that utilities have a reasonable opportunity to earn the same revenues that they would under conventional regulation, independent of changes in sales volume *for which the regulator wants to hold them harmless* – i.e., not necessarily independent of *all* changes in sales volumes (such as those due to weather, business cycles or other factors the utility cannot influence).

Demand Charge: Also referred to as a ‘capacity charge’, this charge is designed to reflect the customer’s contribution to the peak demand on the utility. Based on the maximum amount of electricity used at a given time, the demand charge is assessed according to the peak demand and can be one factor in a two-part pricing method used for utility cost recovery (the energy charge being the other). When metering does not identify the time of the *system* peak, the *customer’s own peak* kW demand is sometimes used for billing purposes.

Demand (or Load) Response: Reducing electricity use from the grid during peak periods to increase reliability and moderate the energy-clearing price during system-wide peak demand; reducing electric load or using onsite generators on the customer side of the meter.

Distribution-Only Utility: In states that have restructured – i.e., divested the generation function from vertically integrated utilities historically responsible for both generation and delivery (transmission and distribution) – the ‘distribution-only’ utility is the regulated entity responsible for owning, operating, maintaining, improving and expanding the distribution system as necessary to provide adequate service to customers. This term does not have the same meaning in every state because in some, the utility entity responsible for distribution also retains some of its historical generation and resource planning functions.

Diversity Benefits: Benefits expected to accrue to the utility system at such time as substantial numbers of DER and substantial DER capacity (relative to the utility’s total load or its load on particular circuits) are deployed. For example, one or a few onsite generators may not allow a utility to defer or avoid new capacity (since existing capacity may be needed to serve host customers if the generators fail); however, multiple onsite generators along the same circuit may permit deferral or avoidance (since the chances that all of them will go down at the same peak moment are small).

Embedded (or ‘Sunk’) Cost: A cost that has already been incurred and so cannot be avoided by any strategy going forward – e.g., a cost that cannot be avoided by reducing output because the cost was incurred previously, such as the original cost of an asset (less depreciation, but including operating and maintenance expenses and taxes).

Energy Charge: The portion of the charge for electric service based on electric energy, in kWh, consumed or billed.

Energy Efficiency: Using less energy/electricity to perform the same function; *doing the same with less*. (The term ‘energy conservation’ sometimes connotes *doing less with less* – i.e., going without in order to save energy – is less popular these days.)

Expense: Utility expenditures made for ongoing operations, which are typically recovered through rates, but not included in the utility’s ratebase on which its rate of return is established; distinguished from *capital investment* in long-term physical assets such as

land, equipment and machinery that must be depreciated or amortized, and on which regulators allow utility recovery of capital plus a fair rate of return.

Distributed Energy Resources, or DER: Here, DER includes both demand-reducing and supply-enhancing resources – that is, energy efficiency and demand response resources, as well as distributed generation technologies – located at or near the load they serve. Examples include solar photovoltaics, small wind turbines, reciprocating engines, microturbines and fuel cells, and especially those operating on renewable fuels or yielding particularly high overall efficiencies (usually through combined heating, cooling and power [CCHP]).

Distributed Generation, or DG: A subset of DER that includes parallel or stand-alone electric generation or CCHP units generally located within the electric distribution system at or near the point of consumption; usually ranging in size from a few kilowatts to as much as 10-20 MW capacity. See ‘DER’ examples.

Dynamic Pricing: Dynamic pricing or rates allow ‘dispatchable’ prices that can be initiated on short notice to reflect real-time system or market conditions: these better reflect wholesale electricity costs, and provide stronger incentives for customers to modify their usage in ways that serve regulatory goals. In contrast, most utilities charge fixed average prices for electricity. Some rate designs of this type, such as inverted-tier rates, provide incentives to lower total monthly usage by charging higher prices as usage increases. Others, including time-of-use rates for larger commercial and industrial customers, are fixed rates designed to mimic the utility’s daily cost variations. Although they do provide some incentives for efficiency, fixed rate forms cannot reflect weather-related cost variations or unanticipated price spikes.

Fixed Costs: Utility costs to provide service that remain constant *in the short run*, regardless of the level of output or amount of service provided. Examples include administrative overhead or loan repayments. Often contrasted with *variable costs*, which increase as output or production increases. *In the long run*, all costs are variable (e.g., as increasing demand on the system requires construction or replacement of substations, poles and wires).

Fuel adjustment clause: A term in a utility rate schedule that provides for periodic (e.g., monthly or quarterly) adjustment of the retail electric rate to account for changes in fuel and related costs. The adjustment typically reflects variations from a specified base cost per unit determined when rates are approved, and can be either a debit or a credit.

Incentive: Used here to mean any positive motivational influence, inducement or reward for a specific behavior that is designed to encourage that behavior. Not necessarily financial, and not equivalent to a subsidy (although subsidies are one form of inducement).

Incentive Ratemaking: Using performance-based ratemaking mechanisms (such as revenue or price caps) instead of traditional cost-plus ratemaking, to incentivize the utility toward efficiency by letting it retain a larger share of any savings it creates. See ‘*Performance-Based Regulation*’; contrast ‘*Cost-of-Service Regulation*’.

Integrated Resource Planning, or ‘IRP’: A resource planning process to evaluate the optimal mix of utility resources and options to achieve specified economic, environmental and social goals. IRP considers both demand-side measures to reduce electricity usage and supply-side options to redistribute generation among fuel types, locations, etc.

Independent System Operator, or ‘ISO’: A Federally regulated entity that coordinates regional transmission in a neutral, non-discriminatory manner, independent of other market participants, by monitoring and controlling in real-time the dispatch of flexible plants to ensure that loads match resources available to the system. The ISO is responsible for maintaining instantaneous balance of the grid system, and for ensuring its safety and reliability.

Loading Order: A legislative or regulatory requirement that utilities and/or other load-serving entities plan for and acquire resources in a certain preferred order. California’s loading order, for example, requires utilities to seek cost-effective energy efficiency, demand response, renewables and clean distributed generation *in that order*, and before acquiring or developing conventional power plants and major infrastructure additions.

Lost Revenues: See ‘*net lost revenues*’.

Lost Profit: Sometimes used to refer to profits (i.e., total utility revenue minus utility operating costs) expected under the utility’s ‘business as usual’ case, but potentially unrealized due to customer reductions in grid-supplied electricity resulting from DER activities on the customer side of the meter.

Marginal Cost Pricing: Setting prices (or rates) to equal the incremental cost of producing the last unit (e.g., kilowatt-hour).

Mini-Grid: Distribution equipment located within a limited geography such as an industrial or business park, college campus or new housing development, which is independent from the local utility network; sometimes connected with the grid through a single interconnection point.

Mobile generators: Usually refers to small, skid- or trailer-mounted generators that can be moved by truck from one location to another, and readily connected to a utility's distribution system for emergency or other use.

Natural Monopoly: A situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms. Natural monopolies occur in industries which exhibit decreasing average long-run costs due to size (economies of scale). According to economic theory, a public monopoly governed by regulation is justified when an industry exhibits natural monopoly characteristics.

Net Revenue or Net Margin: Revenues *less* related commodity costs and revenue taxes as derived for individual rates or classes of service.

Net Income (or 'profit'): In accounting, total revenue minus operating costs (including depreciation); from the income statement.

Net Lost Revenues: Gross revenue losses associated with selling less electricity as a result of DER programs, *minus* any production or purchased power costs avoided because of the reduced sales.

Net Lost Revenue Adjustment: A regulatory mechanism to compensate utilities for the portion of net revenue covering fixed costs that the utility did not collect due to cost-effective investment in demand reduction on the customer side of the meter. Compensates the utility for reduced sales, but does not remove the financial incentive to increase sales; usually focuses on energy efficiency but not other load-reducing initiatives.

Obligation to Serve: A utility's legal requirement to provide service to anyone in its service territory willing to pay its established rates. Utilities have traditionally assumed this obligation in exchange for an exclusive monopoly franchise.

Open Access: FERC Order No. 888 requires utilities to allow others to use their transmission and distribution facilities, to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee. Some states have also established their own open access requirements for portions of their distribution systems not subject to FERC jurisdiction.

Opportunity Fuels: Any of a number of fuels that is not widely used, but has the potential to be an economically viable source of power generation. Usually derived from waste or as a byproduct of agricultural, industrial or municipal activities, these fuels typically exhibit lower heating values or more difficult combustion than conventional fuels, but are far less subject to market volatility. Examples include anaerobic digester gas, biomass-produced gas, crop residues, landfill gas, wood waste, municipal solid waste, refuse-derived fuel, food processing waste and textile waste.

Performance-Based Regulation or 'PBR': Any of many different rate-setting mechanisms which link rewards (generally profits) directly to desired results or targets. Unlike traditional regulation, PBR sets rates, or components of rates, for a period of time based on external indices rather than a utility's cost-of-service. Usually takes the form of a 'revenue cap' or a 'price cap', and may include 'targeted incentives' to encourage behaviors that meet or exceed specific performance measures, such as prices relative to those of similar utilities, customer service quality, employee safety, etc. Generally believed to provide utilities with better incentives to reduce their costs than does cost-of-service regulation.

Portfolio Standard: A legislative or regulatory requirement that electricity providers obtain a minimum percentage of their power from renewable or other preferred energy resources by a certain date; also, the specified percentage of electricity generated by eligible resources that a retail seller is required to procure. May be achieved through market approaches that use tradable credits to achieve compliance at the lowest cost, similar to the Clean Air Act credit-trading system (which permits lower-cost, market-based compliance with air pollution regulations). About twenty states (representing over 42% of US electricity sales) have adopted portfolio policies, and others have nonbinding goals in lieu of a mandatory standard.

Price cap: Price cap regulation seeks to control a utility's rates by linking future prices to inflation and productivity, rather than to utility capital investment. A typical price cap formula is 'RPI minus X', meaning that the price automatically adjusts for the previous year's retail price inflation (RPI) and for expected productivity or efficiency improvements (X) over the period when the formula is in place. Price caps generally encourage utilities to minimize costs and maximize sales, although they may moderate these tendencies by including performance measures and targeted incentives to encourage improved reliability and employee safety, DSM activities, etc

Profit: See 'net income'.

Purchased Power Adjustment: A clause in a rate schedule that provides for automatic adjustments to customer bills when energy from another electric system is acquired and it varies from a specified unit base amount; intended to pass through to utility customers changes in wholesale power costs.

Rate: The authorized charges per unit or level of consumption for a specified time period for any of the classes of utility services provided to a customer.

Rate Base: The base investment on which regulators permit a utility to earn a specified rate of return, generally representing the amount of property ‘used and useful’ in public service. The rate base may be based on fair value, prudent investment, reproduction cost, or original cost. Depending on the jurisdiction, it can be adjusted to take into account accumulated depreciation, and may provide for working capital, materials and supplies, and deductions for accumulated depreciation, contributions in aid of construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Rate Design: The type of prices used to signal consumers and recover costs. Examples include *block pricing*, *multipart prices*, *seasonal rates*, *time of use rates*, and *bundled services*. Rate design follows cost allocation (which determines how much revenue to collect from each rate class), and governs the relative level of rate charges such as customer charges, energy and demand charges, block structure, seasonal and time-of-use charges, etc., to be included in tariffs.

Rate of Return: The ratio (percentage) of profits (or earnings) compared to capital or assets; the percentage applied to the rate base to determine the net operating income that a utility is allowed to earn.

Rate-of-Return Regulation A regulatory method that provides the utility with the opportunity to recover prudently incurred costs, including a fair return on investment. *Revenue requirements* equal operating costs plus the *allowed rate of return* times the *rate base*. This mechanism limits the profit (and loss) a company can earn on its investment. See ‘*cost of service regulation*.’

Real-Time Pricing: The instantaneous pricing of electricity based on its cost at the time the customer uses it. RTP rates can be highly variable, and are typically very high when system demand peaks (e.g., on a hot summer weekday afternoon). Real-time rates differ from time-of-use (TOU) rates in that they are based on actual (not forecasted) prices that can fluctuate frequently during a day, and they vary with weather and other immediate influences rather than on a predetermined schedule.

Regulated Utility: A utility, usually investor-owned, that is subject to State and/or Federal commission regulation to achieve social or political objectives (such as controlling monopoly power or benefiting disadvantaged customer groups). Regulated utilities are expected to charge fair, nondiscriminatory rates and to render safe, reliable service to the public on demand. In return, they are generally free from substantial direct competition and permitted (although not guaranteed) to earn a fair return on investment.

Return on equity: The rate of earnings realized by a utility on its shareholders' assets, calculated by dividing the earnings available for dividends by the equity portion of the rate base.

Revenue: The total amount of money received by a utility from sales of its products and services, gains from asset sales or exchange, interest and dividends earned on investments, and other increases in shareholder equity except those arising from capital adjustments.

Revenue Cap: A revenue cap limits the growth in a utility's overall revenues, rather than directly limiting its prices. Revenue caps generally encourage utilities to minimize both costs and sales. They can encourage utilities to maximize prices, so in practice they often include performance measures, and are calculated based on *revenue per customer*. Utilities and regulators often prefer revenue to price caps because they need not affect current allocations of the revenue requirement among customer classes, or actually set retail prices (whereas price caps may constrain the ability to shift costs among or within customer classes, if the cap is applied to individual rather than average rates.) Revenue cap formulas are similar to those for price caps: they establish a base revenue requirement, and then index it for inflation, productivity, trends in customer or sales growth, etc.

Revenue Decoupling: Typically a multi-year ratemaking arrangement that severs the link between a utility's sales and its revenues. Removes both the ‘throughput’ incentive to increase sales to maintain earnings, and the disincentive for conservation, and insulates utility earnings from sales shortfalls.

Revenue Requirement: In rate-of-return regulation, the total revenue a utility must collect to pay ongoing operating expenses and provide a fair return to investors.

Sales: The number of kilowatt-hours sold in a given period of time; usually grouped by classes of service, such as residential, commercial, industrial, and other. Other sales include public street and highway lighting, other sales to public authorities and railways, and interdepartmental sales.

Solar Utility: A company that owns solar equipment on customer property; sells solar-generated electricity to the property owner (usually discounted from the local utility's price); maintains the system in operation; and bills for and collects revenue. Customers continue to receive grid electricity from the local utility as well as solar electricity from the solar utility. Other technologies could also provide on-site power using this model.

Special Contract: Any contract that provides utility service under terms and conditions other than those listed in the utility tariff. For example, an electric utility may enter into a special contract with a large customer to provide electricity at a lower-than-tariff rate in order to dissuade the customer from taking advantage of other options (e.g., deregulated competition or onsite cogeneration) that would result in the loss of the customer's load. Regulators may review special contracts to ensure that these negotiated arrangements do not unfairly burden other customers.

Sunk (or 'Embedded') Cost: A cost that has already been incurred and so cannot be avoided by any strategy going forward – e.g., a cost that cannot be avoided by reducing output because the cost was incurred previously, such as the original cost of an asset (less depreciation, but including operating and maintenance expenses and taxes).

Targeted Incentives: Incentives adopted in association with PBR mechanisms to encourage or discourage specific utility activities and mute potentially negative effects of some PBR approaches. These incentives vary considerably, and depend largely on the regulatory goals and environment of each jurisdiction. Examples include reward/penalty mechanisms for DSM, renewable resources, purchased power savings, generation capacity factors, emissions performance, and number and duration of customer outages.

Throughput Incentive: The motivation to increase commodity sales when revenues are tied to sales.

Time-of-Use (TOU) Rates: The establishment of rates that vary by time of day or by season to reflect changes in a utility's cost of providing service. TOU rates are usually divided into three or four blocks per 24-hour period (e.g., on-peak, mid-peak, off-peak, super off-peak), and by seasons of the year (e.g., summer, fall, winter, spring). TOU rates differ from real-time rates in that they vary on a forecasted, predetermined schedule, rather than with actual prices that fluctuate many times a day and are weather-sensitive.

Universal Service: The policy adopted by most legislatures and utility commissions of making utility products and services accessible to all citizens at affordable prices. This policy typically involves subsidies from customers who are less costly to serve on a per-unit basis (such as densely packed urban users), to customers who are more costly to serve (such as rural customers at the end of a long feeder).

Utilization Factor: For a circuit, an annual utilization factor is the ratio of the average load on the circuit (in amps) divided by the maximum load carried by that circuit during the year. For the overall system, it is the ratio of average distribution loading for all circuits divided by total load at system peak.

Variable Costs: Utility costs to provide service that vary with the level of output. Examples include fuel or operating and maintenance costs. These costs increase as output increases, unlike *fixed costs*, which are unchanged when output changes.

Vertically Integrated Utility: A utility that owns and controls all components of production, sale, and delivery for its product or service (sometimes as a result of mergers with firms involved in different stages of the business). Before many states restructured their electricity industries, most U.S. investor-owned utilities were vertically integrated, with a single firm owning assets and being responsible for generation, transmission, and distribution systems, as well as for retail metering and billing activities. This arrangement still prevails in a number of states.

Volumetric Charge: A charge for using the transmission and/or distribution system that is based on the volume (in kW or kWh) of electricity delivered.

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Attachment A

Business Models: Descriptions & Regulatory Issues

#	Utility Role	Asset Ownership & Rate-Basing		Activities or Services	Utility Revenue/Savings	Customer or Third Party Role	Key Regulatory Issues
		Utility Side	Customer Side				
A: Providing DER-Related Services							
1	<u>SELL NETWORK MANAGEMENT SERVICES, WITHOUT OWNING DER ASSETS</u>			<ul style="list-style-type: none">• Manage customer demand response for ISO programs• Manage grid for VAR control or back-up services for mini-grids• Metering & billing for solar utilities	<ul style="list-style-type: none">• Management fees• Share of ISO DR prmts• Service fees for backup services, metering, billing	<ul style="list-style-type: none">• Purchase DR services, possibly through incentive sharing?• Purchase backup services• Purchase metering or billing services	<ul style="list-style-type: none">• Should account for utility lost profits or unrecovered costs embedded in lost load<ul style="list-style-type: none">– e.g., if new solar utility sells electricity to customers, allow utility opportunity to recover cost-based portion of lost revenue from solar utility customers
2	<u>INVEST IN DG AT OR NEAR CUSTOMER SITES, AND OFFER PREMIUM SERVICES</u>	<ul style="list-style-type: none">• DG systems such as engine, fuel cell, microturbine, or concentrating solar	<ul style="list-style-type: none">• DG systems such as engine, fuel cell, microturbine, or rooftop PV• If CHP, consider treatment of thermal eqpmt	<ul style="list-style-type: none">• Provide premium power quality• Provide enhanced reliability	<ul style="list-style-type: none">• Customer payment for premium or enhanced service(s)• Customer capital contribution• If in constrained area, premium or incentive from other ratepayers	<ul style="list-style-type: none">• Possibly provide site• Buy premium/enhanced services• Buy energy &/or capacity, possibly including thermal	<ul style="list-style-type: none">• ‘Generation’ ownership in restructured regimes• On customer side, antitrust or anticompetitive?• ‘Used & useful’ for ratebase purposes (if serve only selected customers)?• Ratebase treatment of thermal eqpmt?• Treatment of any revenue reduction from foregone grid charges?
B: Deploying DER Assets and Infrastructure							
3	<u>INVEST IN DER EQUIPMENT AT CUSTOMER SITES, WITHOUT PROVIDING SERVICES</u>		<ul style="list-style-type: none">• Demand response switches & other equipment• DG systems such as engines, fuel cells, or solar PV; maybe CHP	<ul style="list-style-type: none">• Invest in & install DER equipment<ul style="list-style-type: none">◦ solicit competitively, or◦ let customer select & contract with vendor or operator, or◦ install &/or operate equipment	<ul style="list-style-type: none">• Customer lease or tariff payments• Possibly:<ul style="list-style-type: none">◦ installation charges◦ vendor or operator fees	<ul style="list-style-type: none">• Customer might select equipment vendor(s) & operator(s)• Vendor or operator compensated by:<ul style="list-style-type: none">– ISO energy / capacity payments– customer payments	<ul style="list-style-type: none">• ‘Generation’ ownership in restructured regimes• Antitrust & anticompetitive issues• ‘Used & useful’ for ratebase purposes if serve only selected customers?• Ratebase treatment of thermal equipment?• Treatment of any revenue reduction from foregone grid charges?
4	<u>INVEST IN ADVANCED GRID INFRASTRUCTURE</u>	<ul style="list-style-type: none">• Intelligent control & communications devices on circuits & transformers	<ul style="list-style-type: none">• Advanced meters, communications & control equipment	<ul style="list-style-type: none">• Develop & build advanced grid infrastructure• Purchase, install, maintain & monitor advanced meters	<ul style="list-style-type: none">• ROI on ratebase investment• Rate recovery of administrative costs	<ul style="list-style-type: none">• Choose vendor or service company to control site equipment & respond to price signals• Control metering info & communication	<ul style="list-style-type: none">• Cost/benefit of utility investments• Link between benefits & dynamic pricing• If link is strong, should dynamic pricing be voluntary or mandatory?

#	Utility Role	Asset Ownership & Rate-Basing		Activities or Services	Utility Revenue/Savings	Customer or Third Party Role	Key Regulatory Issues
		Utility Side	Customer Side				
C: Using DER to Reduce Costs and/or Improve Grid Reliability							
5	<u>INVEST IN DER TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, AND/OR TO IMPROVE SYSTEM PERFORMANCE</u>	<ul style="list-style-type: none">• DG systems such as engine, fuel cell, microturbine, or concentrating solar	<ul style="list-style-type: none">• Advanced meters, communications & control equipment• Demand response switches & other equipment• DG systems such as engine, fuel cell, microturbine, or concentrating solar	<ul style="list-style-type: none">• Plan, install, operate &/or maintain advanced meters, communications & control equipment• Dispatch DG when DG marginal operating costs < wholesale power costs• Use DG to enhance system reliability when DG costs < conventional utility construction	<ul style="list-style-type: none">• Equipment charges (DR, (meters, communication & control)• Output sales (wholesale to grid, or retail to customers?)• PBR incentives (if any) for enhanced reliability• Expansion cost savings (between rate cases)	<ul style="list-style-type: none">• Customer might provide DG site &/or buy output when grid doesn't need it	<ul style="list-style-type: none">• Generation' ownership in restructured regimes• Cost/benefit of utility equipment investments• Same incentives for owned & leased equipment?• Ratebase treatment of any thermal equipment?• Linkage of utility returns to improved utilization factor for distribution assets• Sharing of any savings between utility shareholders & ratepayers• Possible antitrust & anticompetitive issues re: customer-side investments
6	<u>OFFER DER CUSTOMERS INCENTIVES TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, AND/OR TO IMPROVE SYSTEM PERFORMANCE</u>			<ul style="list-style-type: none">• Design incentive program to inform & market to customers• For DG, prepare & administer procurements; select & contract with successful proposers• Bill & credit participants	<ul style="list-style-type: none">• Savings from deferring wires investment• PBR incentives (if any) for enhanced reliability• Shared savings with customers incented to use DER for system support	<ul style="list-style-type: none">• Install, operate & maintain onsite DER• Agree to limit demand at utility request &/or during specified periods• Receive bill reductions or payments for agreed demand limitation	<ul style="list-style-type: none">• Cost/benefit of utility payments or credits to participants• Utility recovery of program costs & any customer incentive payments• Approval of participant solicitation & selection process, & of demand limitation agreements

#	Utility Role	Values that this Role Creates			Structure of the Value Chain		Utility Position in DER Value Network
		– FOR UTILITY	– FOR PARTICIPATING CUSTOMERS	– FOR NON-PARTICIPATING CUSTOMERS	HOW VALUE'S DELIVERED	COST STRUCTURE / PROFIT POTENTIAL	
A: Providing DER-Related Services							
1	<u>SELL NETWORK MANAGEMENT SERVICES, WITHOUT OWNING DER ASSETS</u>	<ul style="list-style-type: none">Opportunity to sell new servicesOpportunity to develop new markets in service territoryEnhances grid control, flexibility, resiliency & reliabilityIncreases customer interactions & retention	<u>Customer, Aggregator &/or Mini-Utility:</u> <ul style="list-style-type: none">Facilitates market access for DR & ancillary servicesMaximizes value of owned equipment through efficient integration into the gridOutsourcing can reduce costMay substitute for capital outlays	<ul style="list-style-type: none">New service revenues and improved utility asset utilization may reduce non-participant ratesEffective DR reduces peak power costs, defers utility investment & moderates ratesEnhances reliability, utility flexibility to meet local customer needs	<ul style="list-style-type: none">Utility provides equipment & experienced personnel to work with customer, set up & monitor systemsUtility controls systems using telemetry & internet	<ul style="list-style-type: none">Fee for services delivered to customers or aggregatorsWould need to be treated as incremental service revenue, not simply as pass-through expenses	<ul style="list-style-type: none">Utility brings special knowledge & expertise re: system & customersServices aren't inherently 'utility'; general ratepayer benefit would need to be shownAffiliate may be appropriate vehicle??Strategic partnerships with customers & aggregators useful?
2	<u>INVEST IN DG AT OR NEAR CUSTOMER SITES, AND OFFER PREMIUM SERVICES</u>	<ul style="list-style-type: none">Opportunity to earn on DG investment & possibly defer system expansion costsOpportunity to sell new services (premium power, enhanced reliability)Potential revenue from sales of power, ancillary services	<ul style="list-style-type: none">Service enhancements – e.g., power quality, security, reliability &/or thermal'Insurance' against downtime for critical operationsAvoidance of capital investment; can deploy capital for core business or higher return	<ul style="list-style-type: none">New service revenues may reduce non-participant ratesMay enable utility to retain some customers it would otherwise lose, contributing to fixed costs	<ul style="list-style-type: none">Utility sites & installs mobile or other DG on either side of the meterUtility provides premium services to customers who choose themEnergy services from utility- owned & operated equipment	<ul style="list-style-type: none">Not clear that utility can ratebase customer-side investments, unless they benefit other ratepayersFee for services delivered to customers or aggregatorsWould need to be treated as incremental service revenue, not simply as pass-through expenses	<ul style="list-style-type: none">Services aren't inherently 'utility'; no clear competitive advantage; general ratepayer benefit needs to be shownMay compete with private suppliers; anticompetitive & antitrust challengeAffiliate may be appropriate vehicle, or strategic partnerships with DER vendors & developers?
B: Deploying DER Assets and Infrastructure							
3	<u>INVEST IN DER EQUIPMENT AT CUSTOMER SITES, WITHOUT PROVIDING SERVICES</u>	<ul style="list-style-type: none">Opportunity to earn on new DER investmentFuture opportunity to sell new services (installation & maint.)Enables DER for system reliability &/or environ. benefitsMitigate congestion, mkt powerIncrease customer interactions & retention	<ul style="list-style-type: none">Avoidance of capital investment for service enhancements (thermal, power quality, security &/or reliability, etc.) allowing capital to be used for core business or higher returns'Off-balance sheet' financing lowers debt costMay be able to shift some risks	<ul style="list-style-type: none">All benefit where DER is least-costEnvironmental &/or system reliability benefitsCan mitigate congestion & market power	<ul style="list-style-type: none">Brings unique system knowledgeFunds/performs feasibility studyMay bring favorable financingMay oversee installationTurnkey installations on customer premises, leased to customers for operation	<ul style="list-style-type: none">Not clear that utility can ratebase customer-side investments, unless they benefit other ratepayersBelow-the-line investment, not included in rates or subject to ROR regulation?May need to pass "competitive services" test in some states	<ul style="list-style-type: none">Utility brings special knowledge & expertise re: system & customersArguably competes with vendors & developers; subject to anticompetitive & antitrust challengesArms-length affiliate wouldn't bring all utility advantages, but might insulateMay need strategic partnerships with DER vendors &/or developers

#	Utility Role	Values that this Role Creates			Structure of the Value Chain		Utility Position in DER Value Network
		– FOR UTILITY	– FOR PARTICIPATING CUSTOMERS	– FOR NON-PARTICIPATING CUSTOMERS	HOW VALUE'S DELIVERED	COST STRUCTURE / PROFIT POTENTIAL	
4	<u>INVEST IN ADVANCED GRID INFRASTRUCTURE</u>	<ul style="list-style-type: none"> Opportunity to earn on significant system investment Future opportunity to sell new services (installation & maint.) Enhances grid control, flexibility, resiliency & reliability Increase customer interactions & retention 	<ul style="list-style-type: none"> Lowers initial cost of DER & TOU pricing participation Facilitates & leverages DER that offers multiple values accruing to different parties Makes some DER applications viable that wouldn't otherwise be 	<ul style="list-style-type: none"> Benefit from access to resources utility wouldn't otherwise have Enhances reliability, utility flexibility to meet local customer needs May reduce utility risk, cost of capital, rates 	<ul style="list-style-type: none"> Plan, finance, install upgrades Educate customers in value & use of enhanced features Streamline customer access to advanced grid features Deliver onsite meter upgrades & maintenance services 	<ul style="list-style-type: none"> Traditional: cost-based ROR; prudent infrastructure costs plus ROI recoverable in rates PBR or similar: could provide incentives for modernization – bonus ROR, etc. 	<ul style="list-style-type: none"> Utility is best situated to plan, install, maintain & operate 'smart grid', & to integrate & meter customer DER Equipment operation & metering is integral to delivery utility's business; arguably justifiable under regulated monopoly theory
C: Using DER to Reduce Costs and/or Improve Grid Reliability							
5	<u>INVEST IN DER TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, AND/OR TO IMPROVE SYSTEM PERFORMANCE</u>	<ul style="list-style-type: none"> Opportunity to earn on DG investment Reduce wholesale power costs Potential revenue from sales of power & ancillary services Capacity deferral savings Maintaining reliability during system peaks Enhanced flexibility for transfers & switching 	<ul style="list-style-type: none"> [No 'participant' when equipment is on the utility side of the meter] 	<ul style="list-style-type: none"> Lower peak generation costs Possible mitigation of market power &/or local congestion Deferral of more costly utility investment, moderating rates Possible environmental &/or system reliability benefits 	<ul style="list-style-type: none"> On its side of the meter, utility sites & installs mobile or other DG at substations or elsewhere Utility or third party operates DG when it's the least-cost resource, or can otherwise reduce costs or support system 	<ul style="list-style-type: none"> Traditional: cost-based ROR on prudent investment in infrastructure, & maybe customer-side controls that enhance system operations or defer investment PBR or similar: could provide incentives for least-cost solutions, bonus ROR, etc. 	<ul style="list-style-type: none"> Utility is best situated to plan, install, maintain, operate & integrate grid-side DER for customer benefit Some DER appropriate for grid side (e.g., wind, concentrating solar); some aren't (e.g., rooftop PV, CCHP) Arguably integral to delivery utility's business, justified monopoly activity
6	<u>OFFER DER CUSTOMERS INCENTIVES TO REDUCE WHOLESALE POWER OR SYSTEM EXPANSION COSTS, AND/OR TO IMPROVE SYSTEM PERFORMANCE</u>	<ul style="list-style-type: none"> Reduce wholesale power costs Savings from deferring capacity investments Enhanced flexibility for transfers & switching 	<ul style="list-style-type: none"> Incentive payments, bill credits or other rewards for limiting demand on utility's request 	<ul style="list-style-type: none"> Lower peak generation costs Possible mitigation of market power &/or local congestion Deferral of more costly utility investment, moderating rates Possible environmental &/or system reliability benefits 	<ul style="list-style-type: none"> Utility provides equipment & experienced personnel to work with customer, set up systems Utility controls customer systems using telemetry, internet, etc. 	<ul style="list-style-type: none"> PBR or similar: could provide incentives for least-cost solutions, bonus ROR, etc. Service fee to customers to establish utility interface, inspect & maintain controls, meter & bill, etc. 	<ul style="list-style-type: none"> Utility is best situated to integrate, meter & reward customer for DER benefiting system Short-run value of customer DER to grid minimal; won't yield much DER