Massachusetts Distributed Generation Collaborative

2005 Annual Report Attachment C: A Framework for Developing Win-Win Strategies for Distributed Energy Resources in Massachusetts

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Attachment C

A Framework for Developing Win-Win Strategies for Distributed Energy Resources in Massachusetts

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Table of Contents

EXECUTIVE SUMMARY

The Massachusetts Distributed Generation Collaborative (DG Collaborative) was formed in October 2002 pursuant to Massachusetts Department of Telecommunications and Energy D.T.E. 02-38-B, and its work was extended for 2 years and expanded by the DTE in an Order in February 2004.[1] The DG Collaborative formed a Distribution Planning Working Group ("Working Group") to address the questions the Department raised on the role of DG in distribution planning. This Working Group and its activity to date are discussed in Chapter 3 of the accompanying 2005 Annual Report of the DG Collaborative.

The DG Collaborative has been supported in several ways by the Massachusetts Technology Collaborative (MTC). The MTC also engaged EPRI in February of 2005 to participate in meetings of the DG Collaborative and meetings with interested Massachusetts distribution companies to discuss MTC's current initiative to establish Congestion Relief Pilot Projects. This document presents EPRI's recommendations to the MTC and to the DG Collaborative for ways to develop win-win strategies for renewables and other DG to add value to Massachusetts electricity markets. This value could include some combination of reduced costs for utilities and their customers; expanded options and increased flexibility for utility distribution planners; lower energy costs for users who install DG at their own facilities; and greater energy diversity, security and environmental improvements for other utility customers and the public.

EPRI and its predecessor, the Electricity Innovation Institute, has been working over the last two years with a number of companies, public interest groups, state electricity regulators and utilities to identify the current status of distributed energy resources (DER) and to create a framework for initiation of public/private partnerships that can break through many of the market and regulatory barriers that exist today. The framework identifies pathways for establishing pilot programs to develop and test win/win/win scenarios for utilities, participating customers, DER developers and ratepayers as a whole. The framework provides an *integrated* approach to simultaneously meeting the needs of customers, society, and utilities and other ratepayers. EPRI has recently facilitated such a collaborative process in California and was asked by MTC to suggest ways that a similar process could be adapted to the unique circumstances in Massachusetts.

The framework presented here is a derivative of the EPRI previous work and was reviewed by the DG Collaborative in its April 27, 2005 Plenary Meeting. The DG Collaborative agreed to use this framework as guidance for next steps to develop win-win strategies for DER in Massachusetts.

[1] Full documentation on the Massachusetts DG Collaborative and its 2005 Annual Report, including this EPRI report, is available at: http://www.masstech.org/policy/dgcollab

Broadening the Inquiry

The DG Collaborative has so far focused on incorporating DG into the utility distribution planning process, an important step in recognizing where DG offers value at the distribution level. EPRI recommends expanding that focus to consider DG as part of a broader strategy to integrate efficient customer-side resources with resources traditionally provided by the utilities, where those customer resources can help reinforce, diversify and 'green' the State's electricity supply. DG on the utility side of the meter may also support policy goals of the State.

This strategy considers distributed generation as one type of distributed energy resource (DER) – a broader category which also includes combined heat and power (CHP), demand response, energy efficiency and energy storage, whose use in various combinations can often further leverage the benefits available from any one of them. This approach also recognizes that DER, including customer-initiated DG, can sometimes impact system planning, operations, and economics in ways not usually considered part of distribution planning or operations.

We recommend that Massachusetts policy makers articulate a vision for the role that DER can play in the State's energy market by certain dates, say 2015 or 2020. This vision can set the stage for assessing DER market potential, and the market assessment results in turn can guide policy makers in refining DER goals that are ambitious but realistic. EPRI recommends developing opportunities in Massachusetts for a "soft start" of DER, as described in this report, to encourage DER integration where it bring value to multiple stakeholders and to enable enough integration of DER to better understand its value. In fact, the highest value of DER will be achieved when it is fully integrated into the regional and state energy markets and delivery systems. DER should be thought of as one of many options which include renewables, efficiency, new central station plants as well as optimization of existing plants and the transmission and distribution systems.

Steps for Assessing DER Value to Massachusetts

As stakeholders and regulators broaden their shared understandings of the State's current environment for DER, they should seek win-win approaches as outlined in Chapter 1. The stakeholders should embark on a series of steps to determine whether DER in general or DG in particular can bring significant value to Massachusetts. EPRI recommends that the DG Collaborative take the following steps to realize and quantify the value of DER to Massachusetts.

These steps follow the EPRI win-win flow chart in Chapter 1 and are described in more detail in the chapters of this document. The first 3 steps can be undertaken through the DG Collaborative as it continues its work in the coming year.

1. Systematically examine the true benefits and costs of DER for all stakeholders (Chapter 2). Gather data from existing and new projects in Massachusetts and other states.
2. Evaluate opportunities to reallocate costs and benefits for mutual advantage through DER value leveraging and efficient incentives, including alternative business and regulatory models (Chapter 1).
3. Evaluate leveraging the value of DER in distribution planning. Use experiences from the Massachusetts projects and others as input. Consider the challenges and opportunities for integrating DER into utility planning and operations (Chapter 3).
4. In parallel, implement *real DER projects* through Utility Congestion Relief Pilot (UCRP) Projects that each involves a utility and the MTC. Key stakeholders should participate through the DG Collaborative, including customers, DER providers, state agencies and public interest organizations (Chapter 4). Data and analysis should flow both ways between these UCRP pilots and the work of the DG Collaborative.
5. Using actual project experience along with inputs from steps 1, 2, and 3, develop recommendations for the DTE to consider in establishing well-grounded DER regulatory policy in Massachusetts.

These five steps tie to the objectives of the DG Collaborative for the period June 2005 through June 2006 for DG and Distribution Planning as follows:

1. Identify and quantify costs and benefits of DG to test the general hypothesis that DG contributes value to distribution planning and meets customer needs, by further analyzing the eight distribution planning opportunities and by collecting data from existing, pilot or other DG installations.
   - EPRI's step 1, examine costs and benefits, Chapter 2 of this attachment)
   - EPRI's step 4, implement real projects through the Utility Congestion Relief Pilots to provide data for quantification of costs and benefits. (Chapter 4)

2. If the above hypothesis appears to be valid, develop and propose a framework for business and regulatory models that would be needed to provide distribution value and meet customer needs, and to achieve a societal win/win/win outcome with net benefits greater than costs for all stakeholders.
   - EPRI's step 2, evaluate opportunities to reallocate costs and benefits for mutual advantage through value leveraging and incentives. This approach provides a framework for developing business and regulatory models to achieve a societal win-win. (Chapter 1)

- EPRI's step 3, evaluate leveraging the value of DER in distribution planning. (Chapter 3)
- EPRI's step 5, develop recommendations for the Massachusetts DTE to consider in establishing well-grounded DER policy in Massachusetts.

The Win-Win DER Framework

Tools to of the win-win framework are already at hand developed over several years by EPRI's DER Public/Private Partnership, and described in Chapter 1. The EPRI report A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders: Report of the E2I Distributed Energy Resources Public/Private Partnership[2], describes the win-win methodology and how to bring stakeholders together to achieve win-win outcomes. The EPRI *Framework* catalogs existing programs that can point the way toward other innovative approaches, and it presents alternative regulatory constructs and useful guidance on ways that willing stakeholders can collaborate to develop new pilot programs using these tools. The EPRI *Framework* also features a spreadsheet tool to track DG costs and benefits (Chapter 2) for multiple stakeholders based on a range of specific technical, economic and regulatory variables. The spreadsheet tool can also be used to view the impacts of reallocating particular costs or benefits to optimize stakeholder outcomes.

Benefits and Costs of DER

To achieve a successful win-win outcome, the benefits and costs of DER must be understood, agreed upon, and quantified. Chapter 2 describes benefits and costs of DER and discusses tools that can be used to compute the costs and benefits and analyze how to allocate them to achieve win-win results. It is important to recognize that in a regulated market, a benefit to one stakeholder may be a cost to another, and to distinguish among different stakeholder perspectives. Here the key perspectives are those of the DER host customer; other ('non-participating') utility customers; utility shareholders; and the public interests of society at large. The reason to consider all of these perspectives is to find solutions that can benefit multiple stakeholders.

DER comprise many technologies with many distinct attributes and applications, and with different benefits and costs for different stakeholder groups. Expected benefits of different distributed resources and configurations should be defined and enumerated so stakeholders can consider the best ways to extract value from each of them. Some benefits (e.g., customer cost reductions) are tangible and

[2] Details on the Framework and its cost/benefit model can be found in the E2I/EPRI publication, A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders: Report of the E2I Distributed Energy Resources Public/Private Partnership, E2I, Palo Alto, CA: 2004. 1011026. Website: http://www.epri.com/der-ppp/index.html . MTC was one of the funders of the work initially undertaken by E2I (then an EPRI affiliate, since merged into EPRI). EPRI and its DER team are consulting with MTC and have prepared this Attachment. In addition to EPRI personnel, the EPRI/E2I Framework project team included John Nimmons and Associates, Madison Energy Consultants, Energy and Environmental Economics, Inc. and the Regulatory Assistance Project.

relatively easy to quantify, but others (e.g., supply diversity and security) are less tangible and more difficult to value. DER benefits can accrue to individual utility customers with onsite resources, to ratepayers in general, to utility shareholders, and/or to society as a whole. They can impact local distribution systems, the transmission grid, and/or the wholesale market. Some benefits accrue to multiple systems and stakeholders, and some to a discrete part of the system or a single party.

DER costs and risks should also be identified, and ways of addressing them catalogued. For example, DER may reduce operating costs for customers that install them, but often do not yield equivalent reductions in the utility's costs to build, operate and maintain the grid.

Risks from DER may arise, for example, from the fact that the electric grid was designed as a one-way, centrally-controlled system. If system operators do not develop effective ways to manage power flowing into the system from many distributed generators, reliability for all customers might actually decrease rather than increase. Ultimately, determining who benefits and who pays is essential to make win-win DER work.

Allocating Costs & Benefits through Leveraging & Incentives

Leveraging DER value refers to approaches that capture and allocate among stakeholders multiple value streams that can flow from DER selected, sited, sized and operated to create value for more than one group of stakeholders. Successful DER projects are usually those that can leverage some combination of customer values (reduced energy costs, enhanced reliability), value to the bulk power market (ISO-New England; e.g., mitigation of transmission and generation prices), value to the local distribution utility (e.g., grid congestion relief and construction avoidance) and benefits to society in general (e.g., environmental benefits from non-combustion technologies).

Introducing efficient incentives refers to initiatives that send price signals to utilities, end-users and DER providers that better reflect the true costs and benefits of DER solutions in specific situations.

Alternative business and regulatory models may provide mechanisms to leverage DER values among stakeholders and provide incentives to encourage proactive DER integration. Chapter 1 provides a number of concepts that the DG Collaborative may explore.

Leveraging DER Value: Distribution Planning

Chapter 3 describes the initial focus of the DG Collaborative—leveraging the value of DER in distribution planning. One potential DG value is its use to defer or avoid utility construction, particularly on the distribution level. For example, a utility may be able to defer a substation addition for three years if customers in a target area agree to curtail 300 kW of load for 100 hours per year (under negotiated availability and reliability criteria). In such a case, savings from deferring capital investment would accrue to the utility and its customers, who can then benefit if the savings exceed any incentive payment to load-limiting customers.

If a utility can save money for its ratepayers by convincing some customers to limit their loads during certain hours, it may be appropriate to pay those customers for that benefit. Setting the right incentive level depends on determining the value of investment deferral for various periods of time, for each distribution project potentially subject to deferral. Chapter 3 describes several approaches to this task, ranging from fairly simplistic to reasonably sophisticated. It offers an illustrative project and a sample calculation that shows how deferral value can be estimated, and how that value varies with the length of the customer contract.

A high priority concern for utility planners is whether customer-side resources will be reliable and available when they are needed. If a utility relies on these resources to defer system upgrades and they are not available when called (e.g., because a customer does not drop load when its generator is down), the utility may not be able serve all customer demand in the area.

Chapter 3 discusses several approaches for addressing the reliability and availability questions around DER, including utility operational control, financial penalties, and resource redundancy.

Real Projects through the Utility Congestion Relief Pilots

The MTC and Massachusetts utilities are developing Utility Congestion Relief Pilot (UCRP) Projects to advance the understanding of costs, benefits, and best practices for integrating DER into the state's grid. These Pilots will be formed to design or enhance projects to facilitate cost-effective DER solutions in targeted areas with T&D constraints or other opportunities.

These Pilots will provide opportunities through *real DER projects* to gather data on DER costs and benefits, and to test business models which may be approaches for encouraging win-win DER either on the customer or the utility side of the meter. Identifying ways to achieve win-win DER should be a key objective of these Pilots. Where win-win DER may not be achieved, the parties can use these opportunities to recommend what could be changed to enable the win-win outcome.

The activities of these Pilots should be designed to provide input to reports to the DTE on costs and benefits and on recommendations for encouraging win-win DER. These projects may provide valuable input for the work of the DG Collaborative both before and after the DG Collaborative's 2006 final report.

The DG Collaborative should provide support to the Pilots and to specific projects through comments, review, analysis, evaluation, and recommendations. In parallel with the Pilot Project activities, the DG Collaborative should continue to meet in the next year to address issues common to all the utilities and other stakeholders in Massachusetts. The DG Collaborative should explore costs and benefits of DER, opportunities for leveraging DER values, and concepts for efficient incentives, including business and regulatory models that could support win-win DER. The DG Collaborative should also provide input to the development of the structure and research agenda for the Pilots, and provide support to the specific projects as needed. Chapter 4 recommends a structure for screening and prioritizing projects and determining goals and strategies of the projects.

1 THE WIN-WIN FRAMEWORK

1.1 The Situation in Massachusetts

The Massachusetts Distributed Generation Collaborative (DG Collaborative) has brought together the state's distributed generation (DG) and utility communities to determine whether DG can add value to the Massachusetts electricity market. This value could include some combination of reduced costs for utilities and their customers; expanded options and increased flexibility for utility distribution planners; enhanced reliability or power quality for users who install DG at their own facilities; and greater energy diversity, security and environmental improvements for other utility customers and the public.

The Massachusetts Technology Collaborative (MTC) has invited the Electric Power Research Institute (EPRI) to participate in the DG Collaborative's meetings in order to share EPRI's knowledge of DG technologies and development issues and its experience working with DG collaboratives elsewhere. The MTC has also invited EPRI's team to suggest ways that the State of Massachusetts can encourage the formation of pilot projects between utilities and MTC with stakeholders supporting the pilots through the DG Collaborative, to encourage increased use of customer-side resources that can make the State's electricity system more robust and more valuable to its citizens. The stakeholders include utility customers, the MTC, the Massachusetts Department of Energy Resources (DOER), the ISO New England, and DG providers.

In discussions with MTC and other DG Collaborative members, EPRI has suggested expanding the focus beyond the question of how to incorporate DG into utility distribution planning. EPRI recommends considering DG as part of a broader strategy to provide viable choices to customers while integrating efficient customer-side resources with resources traditionally provided by the utilities where they can help reinforce, diversify, and 'green' the State's electricity supply. DG on the utility side of the meter may also support the goals of the State.

This broader strategy views distributed *generation* as one type of distributed energy resource (DER), a category which also includes combined heat and power (CHP), demand response, energy efficiency, and energy storage, whose use in various combinations can often further leverage the benefits available from any one of them. This approach also recognizes that DER, including DG, can sometimes impact system planning, operations and economics in ways not usually considered as part of the distribution planning process.

For these reasons, this Attachment recommends that Massachusetts regulators frame the discussion of DG's role in utility distribution planning more broadly to include *distributed energy resources* generally, and to encompass Massachusetts energy markets as a whole.

1.2 Common Starting Points

Some common starting points will help Massachusetts move toward sensible DER policies. Adopting agreed definitions for DG, DER and related terms is a good place to start. Articulating policy reasons to include or exclude technologies or applications is an essential part of that process. Describing the State's electricity market structure and its implications for DER is also important: separate wholesale and retail markets, distribution rate caps, and the development of capacity and locational marginal pricing points, all affect the value that DER provides, and the ways that DER can provide it.

Other common understandings will also advance the process. A systematic catalog of existing state law and policy toward DER, such as standby rates for customer generators, environmental permit requirements for small generators, treatment of advanced metering infrastructure costs, incentives available for specific technologies and applications, etc., would help stakeholders develop a shared understanding of initiatives already in place and the ways they intersect. Similarly, some understanding of the size and types of potential DER markets in Massachusetts is important to develop meaningful policy recommendations, and it will help if those markets are segmented by type of application (CHP, peak energy production, onsite reliability, power quality, etc.), and type of resource (diesel, natural gas, solar, wind, biomass, etc.)

1.3 Vision

Massachusetts policy makers should articulate a vision for the role that DER can play in the State's energy market by certain dates, say 2015 or 2020. This vision can set the stage for assessing DER market potential, and the market assessment results in turn can guide policy makers in refining DER goals that are ambitious but realistic.

DER is not a stand-alone approach for addressing fringe issues of the electricity enterprise. In fact, the highest value of DER will be achieved when it is fully integrated into the regional and state energy markets and delivery systems. DER should be thought of as one of many options which include renewables, efficiency, new central station plants as well as optimization of existing plants and the T&D system.

One goal of Massachusetts policy makers should be to use the best aspects of the competitive structure that has evolved in the State and apply those principles to resource planning. For the purposes of determining how best to meet customer electricity demands, this means adopting a transparent market-based process guided by fair minded regulators. Current markets are not working to efficiently integrate the full range of options; there is a lack of objective information on cost and benefits; and resource investments are not locationally optimized. The options to be considered should include: new central station base load and peak load options; T&D needs and investments; and strategically integrated resources, including DER, renewables, efficiency, load management options, and CHP.

In order to transform this vision into reality, a stakeholder process should be initiated. Although the stakeholders will be similar to those identified in Chapter Four of this attachment for the Utility Congestion Relief Pilots (UCRP), individuals representing each stakeholder may well be different. (E.g. there may be more planning/ financial and fewer engineering/ marketing representatives). This stakeholder group should address these large resource integration and planning issues in a similar collaborative fashion as suggested for the UCRP. It is likely that some of the promising but untried approaches brought forth by the group will best be tested through a targeted pilot area case study - however, the scope will not be a single distribution planning area, but a much larger planning area.

The evaluation of DER market integration in a much larger regional planning context (embracing more scope) touches a larger strategic planning issue facing utilities, suppliers, and the ISO New England than just DER market integration alone. This report addresses the subject of how to integrate DER into distribution utility planning in some detail, but should be seen as a necessary but not sufficient part of the big picture. The real value is in the big picture – where DER becomes part of an integrated, environmentally sound electricity enterprise in Massachusetts, customers have choices and the market rules are set up to encourage least-cost, most efficient solutions for Massachusetts consumers.

1.4 The Win-Win Approach

During the next phase of DG Collaborative work, the issues and opportunities described above should be addressed comprehensively to expand understanding of the broader context of DER among interested Massachusetts stakeholders. The DTE can decide if the appropriate venue to begin these inquiries is a formal regulatory proceeding or some other setting. The alternative approach recommended here is to proceed during the next year along two parallel paths. The first is to investigate these issues under the MTC’s guidance, encouraging MTC to call on the knowledge and experience of the DG Collaborative and the MTC’s own consultants. The second path, described in more detail later, is to encourage subsets of DG Collaborative participants to support the pilots to pursue concrete projects that can test the practical implications of various approaches in collaborative, non-adversarial settings. Paralleling the MTC’s issues analysis, these projects will provide the DTE and others with empirical evidence based on actual experience to make informed policy through the regulatory process.

The next sections describe the win-win framework developed by EPRI and its partners.

1.4.1 Massachusetts Pilot Programs

MTC has suggested initiating pilot projects with utilities in Massachusetts to gather data on costs and benefits, to refine existing business models and incentive approaches, and to develop and test new ones. This is an opportunity to refine an integrated "framework" for win-win DER initially developed by EPRI with MTC support, and to adapt its processes and approach for statewide, large-scale implementation in Massachusetts in the coming years. The framework features a spreadsheet tool to model DG costs and benefits for multiple stakeholders based on a range of specific technical, economic, and regulatory variables, and to view the impacts of reallocating particular costs or benefits to optimize stakeholder outcomes. The framework also presents alternative regulatory constructs and useful guidance on ways that willing stakeholders can collaborate to develop innovative pilot programs using these tools. Such pilot programs might be on the scale of a few megawatts to a few hundred, depending on the utility system and its customers. They might involve some minimum number of customers, or some threshold level of demand reduction, curtailment or local generation. They will likely include multiple individual DER installations employing diverse technologies, which may remain in place and continue to provide benefits long after the initial pilot program ends.

In the end, the approach described in the framework can not only facilitate collaboration on limited-scale pilots, but can provide a solid foundation for more wide-ranging DER market integration efforts in Massachusetts.

The pilot programs envisioned can be much more than DER technology demonstrations. They can also demonstrate:

- The value that DER can add to the electricity enterprise and customers
- More constructive ways for DER participants to communicate and cooperate to achieve innovative departures from 'business as usual' in the DER marketplace
- Creative business models and incentives targeted specifically to encourage DER that adds value beyond conventional electricity supply
- New ways to optimize benefits for multiple stakeholders

1.4.2 Strategies for Achieving Win-Win Outcomes

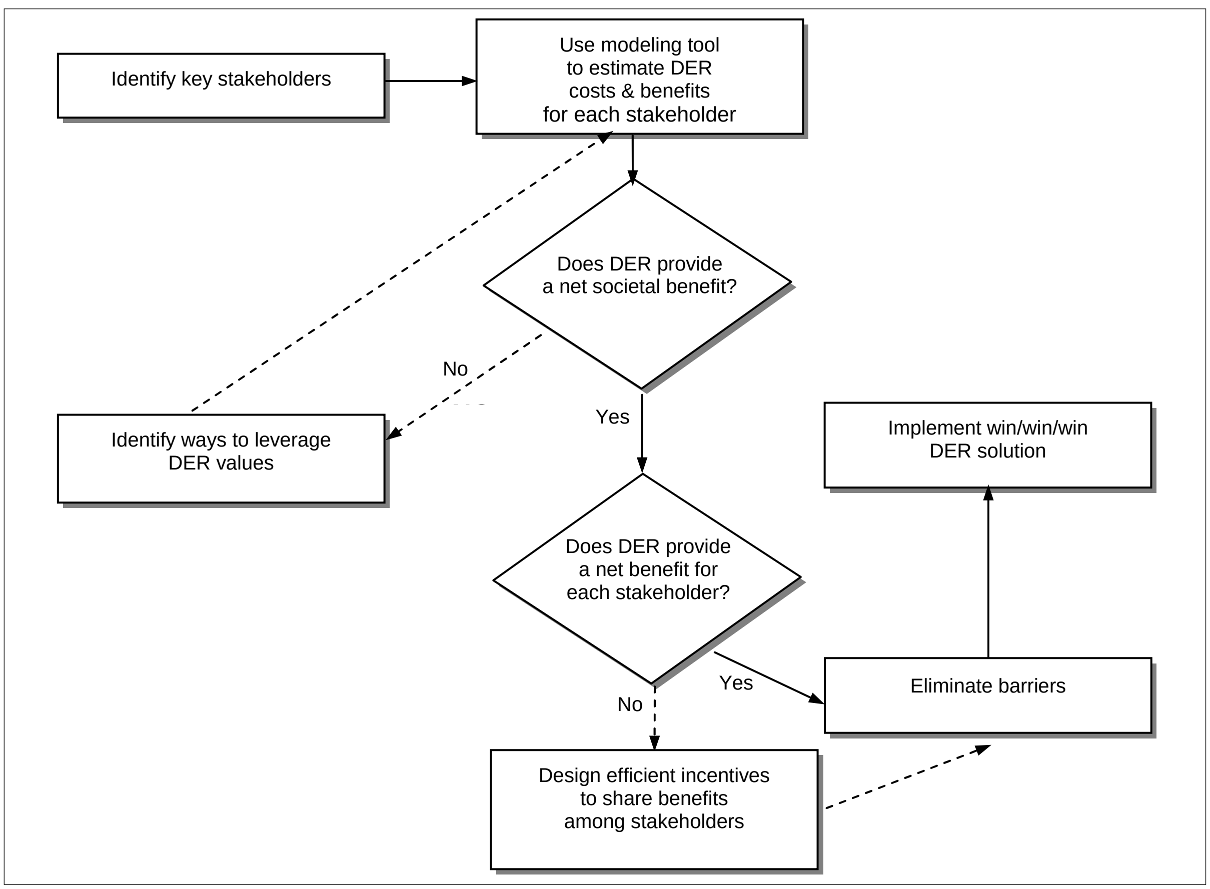
The framework suggests three basic (though not exclusive) strategies for consideration by collaborative participants. They are listed here and briefly described below:

1. *Leveraging DER value* by recognizing multiple value streams that today's markets may not;
2. *Introducing efficient incentives* to facilitate and deploy DER in those situations; and
3. *Eliminating barriers* to DER that inhibit innovation, but serve little public purpose.

These three strategies overlap at times, and are not mutually exclusive. Collaborative programs that incorporate some or all of them should make it easier for utilities to signal where DER adds value to their systems. They should also help end-users adopt DER solutions that supplement and reinforce utility service, while serving their own interests and benefiting other stakeholders.

During the next phase of DG Collaborative work, EPRI recommends that these general strategies be tailored to meet the specific needs of Massachusetts utilities, resource providers, customers, and non-participating ratepayers. The goal is to design projects that enable each of these stakeholders and society as a whole to achieve a net benefit (win-win), with no stakeholder worse off as a result of DER adoption.

The process starts by examining the costs and benefits that flow to each stakeholder from specific resource opportunities. Next, stakeholders who would derive net benefits from a project work with those who would experience net costs to see whether additional benefits can be leveraged to increase the value of the DER. Then the stakeholders consider re-allocating the costs and benefits so that each party gains something and none loses. This process to identify, leverage, and re-allocate costs and benefits is illustrated below and discussed in the following sections.



Leveraging DER Value

First an examination of the costs and benefits of DER should be conducted. This is an analysis of what is understood to be true from all stakeholders' perspectives. Chapter 2 describes this in further detail. Once costs and benefits are understood, then we can consider leveraging DER values. The costs/benefits analysis and leveraging exercise may be iterative, because some values may not have been considered prior to thinking through innovative leveraging approaches. Achieving overall societal value is the key to achieving win-win DER. The initial costs and benefits calculations may show that DER has societal value, but leveraging may be needed to achieve the societal value.

Leveraging DER value refers to approaches that capture and allocate among stakeholders multiple value streams that can flow from DER selected, sited, sized and operated to create value for more than one group of stakeholders. Successful DER projects are usually those that can leverage some combination of customer values (reduced energy costs, enhanced reliability), value to the bulk power market (here, ISO New England; e.g., wholesale price mitigation), value to the local distribution utility (e.g., grid congestion relief and construction avoidance) and benefits to society in general (e.g., environmental benefits from non-combustion technologies). Chapter 3 describes the initial focus of the DG Collaborative—leveraging the value of DER in distribution planning.

Through the use of a modeling tool (described in Chapter 2), a description of DER costs, benefits and allocation can help participants develop a common understanding of what these value streams are, what they are worth, and what it means to allocate them in different ways. These tools enable participants to tailor their assumptions and their analysis until they are comfortable with its objectivity and accuracy, and to assess a variety of impacts transparently and with some shared confidence in the results.

Potential Business Models: Relationships between Distribution Companies and Customers and DG Developers

Alternative business models may also provide mechanisms to leverage DER values with stakeholders.

Utility as Developer, Owner, and Operator of DER

Stakeholders have debated the appropriate role for Massachusetts distribution utilities in projects on the customer side of the meter. Utilities presently have little incentive to aggressively pursue customer-side projects. Even assuming that they could make up for any atypical revenue reductions attributable to DER (through a deferred account accumulator, or mechanisms to recover revenue 'lost' through efficiency measures), their business as defined today focuses on earnings from investments made to improve the grid.

If customer-side solutions are to become an integral part of developing a least-cost, robust grid, it may be good public policy to allow utilities to participate in

DER markets alongside customers and non-utility developers. The *quid pro quo* may be to provide all interested parties fair and equal access to information about locations on the grid that the utility has identified as potentially suitable for DER solutions, and to establish standard, self-executing incentive mechanisms (such as distribution capacity credits) that level the playing field for third parties to compete with utility-affiliated DG businesses, and minimize anti-competitive opportunities.

While projects on the customer side of the meter may be more likely to occur, DG on the utility side of the meter may provide solutions to least-cost grid improvements. These possibilities should be considered as well.

Utility Competitive Solicitation to Compare DER to Utility Alternatives

Utilities can issue (and some have issued) requests for proposals (RFPs) to solicit bids from customers or third parties for stated amounts of DER or load relief in specific geographic areas for defined time periods. New York and California efforts and results have been discussed in previous EPRI/E2I work.[3] The advantages of an RFP are that it can level the playing field for applicants, it is a transparent and familiar process for utility procurement personnel, it is defensible before regulators, and it should provide the lowest cost or best-fit resources. The disadvantages of an RFP are that it is often a cumbersome, time-consuming, expensive process for DER customers, developers, and the utility.

In New York, no projects have resulted to date from several rounds of RFPs. In California, San Diego Gas & Electric Co. selected 25 MW of customer-owned distributed generation aggregated and networked by a third party to provide a dispatchable DER resource.[4] Southern California Edison's (SCE) procurement plans are still in progress, and a solicitation has not yet been issued. The collaborative process to develop SCE's RFP recommended solutions for a number of problems that New York encountered, including publishing a 'market reference price' as a rough guide to the value the utility would assign to others' projects, and limiting the number of hours that customer-generators would need to be available for dispatch.[5]

Utility Develops and Offers an Area-Wide Distribution Deferral Incentive

Under this approach, a utility would identify a planning area (e.g., a bulk substation with linked 34.5 kV substations), and would develop a three- to five-year plan for the area that includes required load additions and their estimated costs by year. The utility would translate the value of deferring expenditures for

[3] EPRI Framework.

[4] R.01-10-024, Opinion Approving Motion of San Diego Gas & Electric Company (U902E) for Approval to Enter Into New Electric Resource Contracts Resulting From SDG&E's Grid Reliability Request for Proposals. Other generation resources and small, aggregated demand response resources also were selected.

[5] For more information on the project, see http://www.epri.com/der-ppp/index.html

this area construction budget into a $/kW/year incentive that it would be willing to pay for any project that defers load for the planning term while satisfying utility reliability and availability criteria. The utility could file a standard contract with the DTE as a template, and would offer a prescribed incentive to participating customers who agree to the standard terms and conditions pre-approved by DTE. Another form of this incentive (offered by Massachusetts Electric/National Grid in selected areas since 2003)[6] would be a standard $/kWh payment for load reduction or behind-the-meter generation delivered when called by the utility.

Utility Fast-Tracks Bilateral Agreements

This approach differs somewhat in that each utility would be given the flexibility to enter into bilateral contracts with customers in areas where the utility contemplates plant additions. Contract terms and conditions would be negotiable by the parties, perhaps within boundaries set by regulators, and subject to minimal initial regulatory review by DTE (as well as to after-the-fact prudency reviews).

Recent Approaches to DER Integration

Analysis of existing DER examples may provide insights into new ways of leveraging DER values. The following table from the EPRI *Framework* catalogs DER programs in several states. The *Framework* provides more details on these programs.

[6] http://www.mass.gov/dte/electric/03-53/529mecpt.pdf

TABLE 1-1. RECENT APPROACHES TO DER INTEGRATION

I. Distribution Utility Focus: enhancing distribution system reliability through cost-effective asset deployment

APPROACH	Example	Driver	Need Addressed	DER Incentive from utility	DER Incentive for utility	Distinguishing Features
A: PUCs require evaluation and acquisition of DG as grid alternative	New York	Utility Commission	Grid reinforcement	$/kW/yr $/kWh/yr	Reduced costs between rate cases	• Required by PSC • RFQ/RFP process • First solicitation had little success
	California	Legislature & Utility Commission	Grid reliability and environmental improvement	Deferral value	Reduced costs between rate cases, and ROI	• Result of multi-year proceedings • Reliance on model contracts • Utility-specific evaluation methods and procurement approaches
B: Utilities offer targeted incentives	O&R	Utility Commission	Grid reinforcement	Area-specific payment and reduced inter-connect cost	Reduced costs between rate cases	• Area-specific payments based on value to local grid • Reduced interconnection costs
	Mass Elec.	Utility		$/kWh/event		• Targeted curtailment to specific circuits to avoid identified construction project • ¢/kWh incentive easily understood and administered

APPROACH	Example	Driver	Need Addressed	DER Incentive from utility	DER Incentive for utility	Distinguishing Features
C: Utilities use customer equipment for grid reliability	PGE	Utility	Grid reinforcement and customer reliability	Generator maintenance, payment for interconnection hardware, fuel	Reduced costs between rate cases	• Utility dispatches customer generators as a utility resource. • Utility assumes O&M responsibility and non-performance risk for non-utility equipment.
	Madison G&E	Utility		Customer receives guaranteed back-up service at fixed cost.	Cost recovery thru lease payments	• Utility designs, installs and owns backup generators at customer locations • Customer charge is determined through ratemaking process • Utility bills service on customer's regular bill • Customer payment represents a value-added service revenue stream for the utility
D: Customers schedule loads for grid reliability	Green Mountain / Sugarbush Ski Area	Utility and Customer	Grid reinforcement	Avoid line extension cost/ rate discount	Customer satisfaction, continued revenue	• Strong customer interest supported a multi-party collaborative process • Customer curtails to utility load, not site load • Combined with broader utility program

II. Bulk Power Utility Focus: mitigating wholesale prices and transmission congestion						
APPROACH	**Example**	**Driver**	**Need Addressed**	**DER Incentive from utility**	**DER Incentive for utility**	**Distinguishing Features**
A: Utilities install DER for wholesale and transmission purposes	Met-Ed	Utility	Wholesale energy, grid reliability and congestion mgt.	Shared LMP savings	Reduced energy and transmission congestion costs	• DER vendor owns and dispatches units based on locational marginal prices • Equipment used for multiple purposes
	AMP-Ohio	Utility	Transmission cost savings	N/A	Reduced FTR payments	• DG used to reduce peak transmission costs • Provides alternative to firm peaking service
B: Utilities purchase DER from aggregator	Public Service New Mexico and Celerity	Utility and DER Provider	Increase wholesale energy sales	Celerity pays fuel and maintenance PNM pays Celerity for KW and kWh	PNM resells power in wholesale market	• Third-party aggregator develops customer contracts and assembles supply • Aggregator works with local AQMDs to reduce environmental impacts • 25 MW now, with potential for 75 MW
	Com-Ed	Utility and DER Provider	Reduce costs of purchasing peak power	$/MW / year	Lowered capacity costs	• Utility contracts with third-party aggregator for 50 MW demand reduction at market prices • Large-scale demand resource is tradeable
C: Utilities pay for load curtailment	BPA	Utility	Reduce costs of constructing transmission capacity	$/kW / event	Reduced peak power expenses	• Wholesale utility enlisted retail customers to help solve standard operational issues • Winter rather than summer load control • Uses demand response to avoid transmission construction
	NYISO	Utility (ISO)	Reduce costs of wholesale energy and increased grid reliability	$/kW / event	Reduced peak power expense	• ISO program • $500 / MWh minimum payment, regardless of market price
	PSE&G	Utility		Setback thermostat, customer incentives	Reduced peak power expense Recovery of administrative expense	• Utility dispatches aggregated load control as a system resource • Targets residential loads • Utility controls customer equipment

III. DER Customer Focus: increasing the reliability of on-site energy supplies and expanding energy options						
APPROACH	**Example**	**Driver**	**Need Addressed**	**DER Incentive from utility**	**DER Incentive for utility**	**Distinguishing Features**
A: Utility offers time-of-use pricing	Gulf Power	Utility	Offer customers a way to control energy costs through real time pricing	Lower energy costs	Customer pays to access the technology service	• Value-added service opportunity for utility • Residential customers use TOU rates to schedule use and reduce bills
B: Customer installs on site co-generation	New Yorker Hotel	Customer	Increase on-site reliability and reduce energy costs thru CHP	On-site reliability or reduced overall energy costs	Often seen as negative due to loss of revenue	• CHP system installed in New York City, a difficult place to site local generation • DER provider owns and operates CHP facility and guarantees host energy savings
C: Customer installs on-site generator to adopt hourly pricing	Pa. Mall	Customer	Customer reliability, lower energy costs	Wholesale mkt. sales	N/A	• DG becomes a tool in the customer's energy procurement strategy • DER value in wholesale market exceeds value of avoided hourly purchases under demand response strategy

IV. Regulatory and Societal Focus: increasing energy efficiency and improving environmental quality						
APPROACH	**Example**	**Driver**	**Need Addressed**	**DER Incentive from utility**	**DER Incentive for utility**	**Distinguishing Features**
A: States offer efficiency and renewable incentives	New York	Legislature and Utility Commission or State Energy Agency	Reduce peak demand, Increase efficiency through CHP, and improve air quality through renewables	Direct customer payments, interest buy downs, etc.	N/A	• Independent state agency administers program • Focus on CHP efficiency value
	California					• CEC rebate program has stimulated renewables market, especially small PV • CPUC tiered incentive program administered by investor-owned utilities rewards ultra-clean, high-efficiency technologies • DER size limits for both programs have limited their system impacts
	Texas					• Administratively-set DER deferral value and contract length provides transparency • Distribution utilities excluded from demand response and renewable DG projects
B: State requires solar DER in state energy supply	New Jersey	Utility Commission	Improve air quality	Required solar RPS	N/A	• Solar RPS establishes a market for Renewable Energy Credits (RECs) from distributed solar • Solar RECs available for customer-sited projects, recognizing retail value as well as RPS value • Increased size limits for net metered systems enables larger seasonal users (e.g. schools) to recognize retail PV value

Introducing Efficient Incentives

Introducing efficient incentives refers to initiatives that send price signals to utilities, end-users and DER providers that better reflect the true costs and benefits of DER solutions in specific situations. MTC's presentation of these issues at the December 2004 meeting has helped the Collaborative to frame this discussion.[7] These materials were drawn from a presentation entitled, "Potential Regulatory Incentives" was presented by Stan Blazewicz of Navigant Consulting at MTC's Symposium on Regulatory Frameworks for Distributed Generation on January 26, 2004.[8]

Innovative business and regulatory models may be considered as mechanisms to introduce efficient incentives. Business models are discussed in the preceding section. Regulatory models may be considered for discussion and brainstorming among stakeholders. The following discuss some of the issues that could be addressed in such efforts and some ideas for addressing the issues.

Issues

In general, states' regulatory models, where kWh sales are the regulatory mechanism through which utilities recover their costs of running the distribution grid, typically provide disincentives to encouraging distributed generation. For example, where reducing system loads using DG could defer utility investment in system capacity and upgrades over the next few years, the reduced loads would also significantly reduce electricity throughput, and therefore, utility revenues to the extent tied to throughput. Utilities typically remark that every kWh that DG produces, reduces utility revenue by a corresponding amount. When DG reduces kWh throughput, those costs cannot be recovered until a future rate case establishes a new, smaller sales base. Utilities worry that their shareholders lose value when DG erodes utility revenues, and are not recoverable again until the next rate case reallocates the utility's revenue requirement to reflect its shrunken sales base.

From a utility perspective, another financial consequence of DG installations that defer or eliminate utility construction projects is that there are fewer dollars of utility investment that can be added to utility plant. This may reduce the opportunity to earn a return on new investments. Although there are corresponding opportunities to reduce utility expenditures between rate cases with DG, it may be more advantageous for utilities to add to capital accounts than reduce expenses.

Potential Incentives

Some have suggested decoupling utility margin from kWh sales to help remove the perceived disincentive for utilities to encourage or at least accommodate

7 http://www.masstech.org/renewableenergy/public_policy/DG/meetings/2004_december10_dp.htm

8 http://www.masstech.org/renewableenergy/public_policy/dg/meetings/2004_january26_symposium.htm

DER. Decoupling can occur in two primary ways. One approach is to make the revenues the utility receives from its customers more fixed, and less variable with changes in customer usage.[9] NStar has implemented this approach by charging commercial/industrial customers for the distribution portion of their electric bill only on their demand, not on the energy they use.

Another approach is to adopt a revenue-based performance ratemaking (PBR) mechanism.[10] Revenue-based PBR would substitute for traditional cost-of-service ratemaking an approach that sets utility rates to recover a predetermined level of revenues (usually with some allowance for customer growth). This form of PBR removes the utility incentive to promote sales, and rewards utility shareholders if the utility reduces its costs – even if that means reduced sales.[11]

As another approach, utilities could use a distributed generation tracking account to accrue shortfalls in distribution revenues caused by new distributed generation in its service area, and then recover those shortfalls (with or without a deferred return) when regulators reset distribution rates in the next general rate case. This could make utilities indifferent to DG-related revenue reductions; it would not incentivize them to participate vigorously in the DG market, but should encourage their participation where DG options can reduce utility costs between rate cases.

Another alternative is to provide utilities an incentive to encourage cost reductions through the use of DG. The disincentive that exists now comes from the cost-based regulation that provides shareholders a return on capital investments. Therefore, reducing capital investments reduces shareholder return. One approach to removing this disincentive would be to allow utilities to capitalize incentive payments and other costs of DG solutions and include them in rate base. This would allow shareholders to earn a return on the DG costs, which in part would offset the lost return on the deferred or eliminated capital project.

[9] See e.g. rate designs proposed by Southern California Edison in Application No. 00-01-009, Ex. SCE-5, January 2000.

[10] Adapted from the E2I Framework- A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders: Report of the E2I Distributed Energy Resources Public/Private Partnership, E2I, Palo Alto, CA: 2004. 1011026 p. 3-10, 3-11

[11] DER proponents, as well as customers and conservation and efficiency advocates, more often favor the PBR approach because of its strong incentives for efficiency. It represents a change from traditional ratemaking, with implications for many aspects of utility operations beyond those related specifically to DER. Although well-designed PBR mechanisms could help level the playing field, many observers would acknowledge that a wholesale shift to PBR to encourage DER at this stage of its development could be the tail wagging the dog.

Another approach is to calculate what the return would have been on the traditional utility project, and provide a shareholder incentive based on the savings achieved by deferral or elimination of the T&D capital project. Used in conjunction with the DG tracking account that offsets revenue loss through lower throughput, a shareholder incentive policy could help encourage utility support of cost-effective DG projects.

Eliminating Barriers

Eliminating barriers here refers to eliminating or reducing obstacles to DER siting, installation, operation, and value recognition in the market. It includes minimizing transactions costs for all participants, from project inception to completion. An example includes the work being done in Massachusetts to address detailed implementation issues for the recently adopted Interconnection Standards.

2 BENEFITS AND COSTS OF DER

To achieve a successful win-win outcome, the costs and benefits of DER must be understood, agreed upon, and quantified. This chapter describes costs and benefits of DER and discusses tools that can be used to compute the costs and benefits and analyze how to allocate them to achieve win-win results.

2.1 DER Benefits

DER comprise many technologies with many distinct attributes and applications, and with different benefits and costs for different stakeholder groups. To begin with, expected benefits of different distributed resources and configurations should be defined and enumerated, so stakeholders can consider the best ways to extract value from each of them. Some benefits (e.g., customer cost reductions) are tangible and relatively easy to quantify, but others (e.g., supply diversity and security) are less tangible and more difficult to value. DER benefits can accrue to individual utility customers with onsite resources, to ratepayers in general, to utility shareholders, and/or to society as a whole. They can impact local distribution systems, the transmission grid, and/or the wholesale market. Some benefits accrue to multiple systems and stakeholders, and some to a discrete part of the system or a single party. Ultimately, determining who benefits and who pays is essential to make DER business models work.

2.2 DER Costs and Risks

DER costs and risks should also be identified, and ways of addressing them catalogued. For example, DER may reduce operating costs for customers that install them, but often do not yield equivalent reductions in the utility's costs to build, operate and maintain the grid. Other utility customers must continue to bear those costs, and may see their electric bills rise as more DER customers reduce or cease their own contributions to system costs. In such cases, the DER may or may not yield societal benefits, but arguably will shift costs from a few customers to many others.

Risks from DER may arise, for example, from the fact that the electric grid was designed as a one-way, centrally-controlled system. If system operators find it difficult to manage power flowing into the system from many distributed generators, reliability for all customers might actually decrease rather than increase. By definition DER are dispersed, small and often customer-controlled. With current technology and institutional arrangements, some of these resources cannot necessarily be counted on to deliver power on the scale or with the reliability needed to meet utility and DTE standards. Additionally, depending on the resource, operating large numbers of small, local customer-side generators (especially diesel-fueled ones) could harm local air quality.

Most of these issues can be addressed through informed State policy that encourages specific types and applications of DER whose benefits can be shown to outweigh their costs to Massachusetts citizens.

2.3 Determining Costs and Benefits of DER

The DG Collaborative considers it important for all parties to agree on a standardized model and process for determining costs and benefits for customers, utilities and society in general. The Excel spreadsheet model developed for E2I/EPRI has been presented to the DG Collaborative,[12] and illustrates an analytical approach that can be adapted to Massachusetts.

2.3.1 Stakeholder Perspectives and Cost-Effectiveness Tests

The starting point is to recognize that a benefit to one stakeholder may be a cost to another, and to distinguish among different stakeholder perspectives. Here the key perspectives are those of the DER host customer; other ('non-participating') utility customers; utility shareholders; and the public interests of society at large.[13] The reason to consider all of these perspectives is to find solutions that can benefit multiple stakeholders.

Regulators often gauge benefit through 'cost-effectiveness'[14] tests. They use different cost-effectiveness tests to determine the value of various activities from different stakeholder perspectives. These tests include:

- *Participant Cost Test (PCT)* – reveals whether it is worth it to the *customer* to install DER
- *Ratepayer Impact Measure (RIM)* – assesses DER's impact on utility earnings or rates
- *Total Resource Cost Test (TRC)* – measures the net tangible benefit available to be reallocated in order to produce a 'win-win' solution
- *Societal Cost Test (SCT)* – identifies any additional societal costs and benefits available from the DER, including externalities such as reduced pollutant emissions.

Viewing DER from different stakeholder perspectives also aids in program design. For example, one way to allocate costs and benefits is to establish an incentive (say, a locational credit) that the utility pays to the DG provider – i.e., a cost to the utility and a benefit to the DG provider. A 'win-win' program design in this case would set the incentive payment at a level that would make both the

[12] See 3/9/05 report of DG Collaborative Distribution Planning subcommittee at http://www.masstech.org/renewableenergy/public_policy/DG/meetings/2005_march9_dp.htm.

[13] In the E2I/EPRI model whose output is illustrated below, non-participating customers and utility shareholders are grouped together for analytical purposes. This is because costs and benefits available to these stakeholders come out of the same utility source of funds, and their allocation between these groups is determined by regulators in rate cases.

[14] 'Cost-effectiveness' as used here need not be limited to tangible monetary costs and benefits, but can include intangible ones as well (as the Societal Cost Test described in the text does).

utility's ratepayers and the program participant better off. Stated in terms of the cost-effectiveness tests used by regulators, both the RIM and the PCT benefit/cost ratios are greater than one. Mechanisms that strike such a balance will warrant further consideration.

2.3.2 Identifying and Quantifying Costs and Benefits

Specific types of costs and benefits, both direct and indirect, can be (and have been) identified for each stakeholder group. For example, costs and benefits to the DG customer could include various combinations of the following:

	Benefits	Costs
Direct	Annual electricity bill savings Annual avoided fuel costs (thermal) Wholesale energy sales Renewable energy credits (sales of)	DG capital, maintenance & fuel costs (including siting & permitting) Interconnection study, equipment, & system upgrade cost Emissions offset purchases Utility backup charges Insurance Other utility infrastructure & operational costs
Indirect	Customer reliability	

The EPRI/E2I Framework presents similar benefit/cost tables from the perspectives of other stakeholders (the utility, society, etc.), as well as more detailed descriptions of each cost
and benefit category relevant to each stakeholder.

A more inclusive set of potential DER benefits is shown below:[15]

<u>Customer Perspective</u>

- Annual electricity bill savings
- Annual avoided fuel savings (CHP)
- Wholesale energy sales, demand response incentives
- Renewable energy credits
- Increased reliability
- Control of energy costs and volatility

<u>Utility Perspective</u>

- Avoided T&D expansion
- Increased utilization efficiency of T&D system
- Other T&D system benefits including:

[15] EPRI/E2I Framework. Pp. 2-5… 2-7. and California Energy Commission Public Interest Energy Research Program: DG WORKING GROUP: DG DEFINITION AND COST-BENEFIT ANALYSIS – POLICY INVENTORY Report (July 9, 2004)

    - Reduced line losses
    - Voltage support
    - Voltage regulation
    - Reactive power support
    - Equipment life extension
    - Reduced facility maintenance
- System reliability

Total Resource and Societal Perspective

- Avoided energy purchases
- Wholesale market price mitigation
- Market power mitigation of generation suppliers
- Support of RPS goals
- Reduced security risk to electric grid
- NIMBY opposition to central power plants & transmission lines
- Reduced land use effects
- Energy system efficiency improvements

Once a qualitative set of costs and benefits is identified from each stakeholder's perspective, the next steps are to quantify them, and then to determine whether various combinations of them can yield net benefits that might be re-allocated among the stakeholders to achieve outcomes that benefit all or most of them, without harming others. The inputs needed to realistically quantify values that a DER project or program can generate for groups of stakeholders include, among others, utility-specific tariff structures; DG technology- and application-specific costs, operating and emissions characteristics; the type, duration and costs of financing; etc.[16]

2.3.3 Modeling Costs, Benefits and Allocation Impacts

The current version of the EPRI cost-benefit model is customized with input data for California and its three major investor-owned utilities: it uses actual rate structures and tariffs in effect or proposed for each utility, and California-specific

[16] Determining these values and their potential for tradeoffs among stakeholders is a different exercise than estimating the value of a specific DER project to an individual DER customer, site host or owner/operator. EPRI and others have developed models for that purpose, and their objectives and functions are different from those described here.

regulatory incentives in place in 2003 (see Figure 1, below)... For other inputs, such as generation and T&D avoided costs, interconnection costs, emissions control costs, and any applicable 'generation multiplier', the model allows users to enter ranges of value (e.g., low, medium or high, each corresponding to a specified dollar amount or numeric multiplier). It also uses published cost and performance data on a range of DG technologies and applications, which can be updated with the most current information for use in Massachusetts.

The model structure lets users vary numerous inputs relevant to DER projects to see how they affect the costs and benefits flowing to each stakeholder group. Its output reveals which stakeholders profit and which ones pay for different combinations of DER technologies under differing assumptions concerning energy prices, T&D deferral, 'generation multiplier' value, emissions profiles, financing terms, operational characteristics, available incentives, etc. On the following page is a sample of the model's output summary (on the left side), and also shows the kinds of input settings available to users (on the right side).

Where a model run reveals substantial net benefits for one stakeholder group and net costs for another under relevant cost-effectiveness tests, it suggests that re-allocating some of the costs and benefits generated in that scenario might result in net benefits to all parties and net costs to none
(or lower costs to some). In doing so, it identifies scenarios that may be subject to constructive collaboration among stakeholders to benefit all of them. Although it may seem counterintuitive, shifting some benefits from advantaged stakeholders to disadvantaged ones may make sense for the former as well as the latter. This is because programs that would benefit one stakeholder group at significant expense to others often succumb to opposition, benefiting no one; their proponents may prefer part of a loaf to none at all.

For regulators and policymakers, utility revenue setting and rate design are the critical points where DER intersects with the utilities they regulate. The rates that end-users pay for grid-supplied electricity largely drive DER economics, and the ways that utilities are compensated for supplying that electricity can determine their receptivity to DER development. This means that utility revenue setting and rate design (discussed later) offer important tools to shape DER incentives, and thus help or hinder DER integration into emerging electricity markets.

Figure 1: Output of California Based Analysis Showing Costs and Benefits to Customer, Utility, and Society (completed in 2004 by E2I / EPRI Team)

Costs and Benefits

Units: Levelized $ — Analysis Horizon Years (20 Years Max): 10

DER Customer
Participant Cost Test: Is it worth it to the DER customer to install the DER?

Annual Electricity Bill Savings	352,547.30	Annual Capital Cost	115,766.11
Annual Avoided Fuel Savings (Thermal)	141,592.01	DER Maintenance Cost	69,374.77
Wholesale Energy Sales	-	DER Fuel Cost	330,216.16
Sales of Renewable Energy Credits	-	Emissions Offset Purchases	9,891.91
CEC Buydown / CPUC Self-gen Program	32,157.25	Interconnection Study Cost	275.98
Incentive / Credit from Other Ratepayers	-	Insurance	-
Incentive from Public Funds / Tax Credit	-	Other Utility Upfront Costs	-
		Other Utility Operational Costs	-
Total Benefits	526,296.55	Total Costs	525,524.93
		Net Benefit	771.63

Utility Shareholders and Other Ratepayers
RIM Test: How much will the impact be on earnings or rates?

Avoided Wholesale Energy Purchases	411,893.43	Revenue Reductions Due to DER (e)	352,547.30
Avoided Generation Capacity	-	System Upgrades	-
Avoided T&D Capacity	25,489.36	Interconnection Study Cost	275.98
Customer Payment for Interconnection Study	275.98	Credit to DER Customer (b)	-
Credit from Public Funds / Tax Incentive (c)	-		
Total Benefits	437,658.77	Total Cost	352,823.28
		Net Benefit	84,835.49

Combined DER Customer, Shareholders, Other Ratepayers
Total Resource Cost Test: What is the net tangible benefit that can be reallocated to produce a 'win-win'?
Sum of DER Customer, Shareholder, and Other Ratepayer Perspectives

Net Benefit: 85,607.12

Incremental Societal Value
Societal Cost Test: What are the additional net intangible benefits?

Reduced Central Generation Emissions	13,612.35	DER Emissions	60,400.77
		CEC Buydown / CPUC Self-gen Program (d)	32,157.25
		Public Funds / Tax Credit to Utility (c)	-
		Public Funds / Tax Credit to Customer (a)	-
Additional Benefits	13,612.35	Additional Costs	92,558.02
		Incremental Societal Net Benefit	(78,945.67)
		Net Societal Benefit (TRC+Societal)	6,661.45

Notes:
(a) transfer assumes there is no incremental change in rates, otherwise this would appear in RIM test
(b) transfer assumes the credit leads to a change in rates to non-participants, otherwise this would appear in the societal cost test
(c) transfer assumes the credit would not increase costs to shareholder or non-participants
(d) we assume that the CEC / CPUC programs will not increase the level of the current Public Goods Charge
(e) Net of Standby Charges (if not a DER technology) and Exit Fees

Input Settings

Avoided Costs	
Wholesale Energy Forecast	SP15 9/8/2003
Generation Multiplier	Medium - 3X
Residual Net Short Position	Medium - 5%
Generation Capacity Avoided	Zero Cost
T&D Avoided Cost	Average (50%)
Customer Characteristics	
Utility	SCE
Customer Rate	SCE: GS-2 Proposed
DER Type (Qualify for DER Rate?)	Non-DER (Does not qualify)
Customer Size (kW)	Enter --> 1500 kW
Customer Load Factor	90% Load Factor
DER Technology Type and Financing	
DER Type	Caterpillar G3516 LE - 800kW w/C
DER Operation	High Cap - 2 Outages
DER Financing	10-Years
Natural Gas Rate (If Nat. Gas)	Cogen Discount Customer
Diesel Cost (If Diesel)	Industrial
Interconnection Cost	Medium - $2000
Customer Payment for Interconnection	High - 100%
Other Inputs	
Rebates	California CPUC
Emissions Costs	Low
Attainment Area	Non-Attainment
REC Credits	None - $0/MWh

2.3.4 Customizing the EPRI Cost-Benefit Model for Massachusetts

EPRI's cost/benefit model is an example of a tool that Massachusetts can use to help answer the DTE's question whether widespread adoption of DG, demand response, and energy efficiency will significantly benefit the State's citizens. Any generic model will require customization. Costs must reflect regional or local electric, gas and other fuel prices, permitting costs, equipment costs, air emission limits, etc. Stakeholder costs and benefits depend heavily on utility rates for various customer classes, demand charges and ratchets, backup charges (in the case of NStar), as well as the demand profile of the facility and the specific technology selected. They also depend on state regulatory rules governing rate basing, allowed rates of return, etc. Societal costs and benefits reflect environmental conditions, compliance costs, etc.

Massachusetts' electricity market structure presents other important issues. Benefits accrue directly to the state's utilities only where DER reduces distribution construction, maintenance and/or operational costs. Generation savings benefit the state's energy consumers (through lower energy and capacity prices), but not its distribution utilities. Monetizing generation savings that result from DER projects is an important task for the Pilots, but distribution utilities should not be expected to pay for those benefits unless they receive the value directly or indirectly.

In Figure 2, below, we have revised the model structure to more closely reflect Massachusetts stakeholders' appropriate costs and benefits. However, the numbers still reflect California assumptions. In this example, we have analyzed the effect of introducing a T&D capacity payment for a small combined heat and power application. In Figure 3, below, we show the corresponding tabular results of this example analysis in levelized cents per kWh as output by the new analysis tool.

Figure 2: Output of Updated California Based Analysis Showing Costs and Benefits to Customer, Utility, and Society (completed in 2005 by EPRI Team)

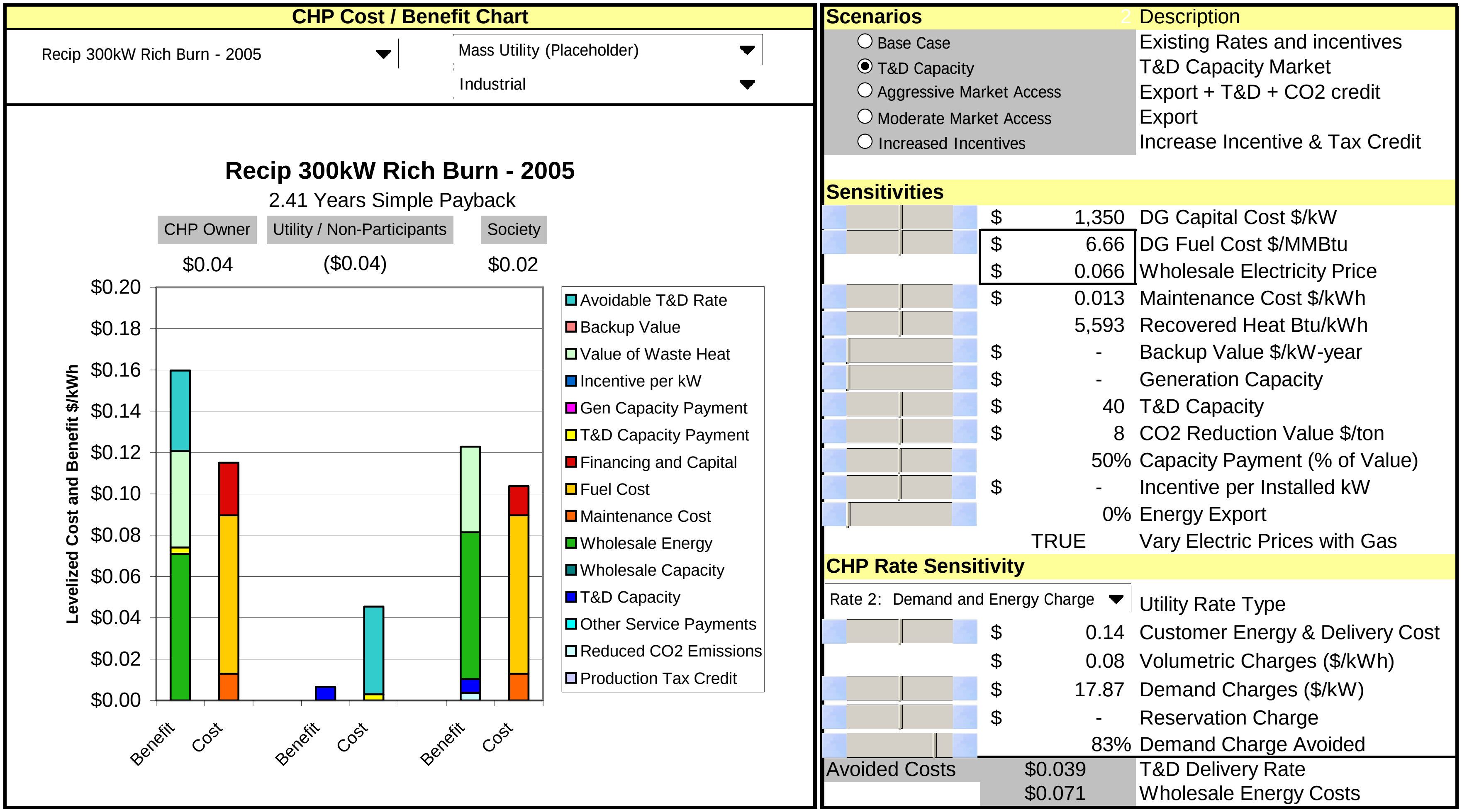


Figure 3: Tabular Results of Cost-Benefit Analysis

Tabular Results						
Recip 300kW Rich Burn - 2005						
	Customer		Utility		Society	
	Benefit	Cost	Benefit	Cost	Benefit	Cost
Financing and Capital		$0.025				$0.014
Fuel Cost		$0.077				$0.077
Maintenance Cost		$0.013				$0.013
Avoidable T&D Rate	$0.039			$ 0.042		
Value of Waste Heat	$0.047				$0.041	
Backup Value	$ -				$ -	
Incentive per kW	$ -			$ -		
Gen Capacity Payment	$ -			$ -		
T&D Capacity Payment	$0.003			$ 0.003		
Other Service Payments	$ -			$ -		
Wholesale Energy	$0.071				$0.071	
Wholesale Capacity			$ -		$ -	
T&D Capacity			$0.007		$0.007	
Reduced CO2 Emissions					$0.004	
Production Tax Credit	$ -					$ -
Total	$0.160	$0.115	$0.007	$ 0.045	$0.123	$0.104
Net Benefit		$0.04		($0.04)		$0.02

3 LEVERAGING DER VALUES: DISTRIBUTION PLANNING

This chapter focuses on one of the ways to leverage DER value – to provide services to the distribution utility, for example, by deferring distribution upgrades via peak load reduction. While EPRI recommends that the analysis of DER values and leveraging these values should be broadened to beyond distribution planning, because the DTE specifically requested the DG Collaborative to consider DER in distribution planning, this should be a key focus of the DG Collaborative. This chapter then serves as an example of leveraging DER value.

3.1 Background

One frequently cited source of additional DER benefits is the potential to defer or avoid costs the utility would otherwise incur to upgrade T&D capacity. EPRI's recent work with Southern California Edison[17] and initial reports from the Massachusetts utilities at the March 9, 2005 DG Collaborative meeting,[18] indicate that this economic value is highly area-specific: at any given time in the planning cycle, it can be very substantial in some areas of the system, but negligible or non-existent in other areas. Moreover, typical utility planning processes rarely identify, publicize, or offer benefit-sharing mechanisms to induce customers or DER providers to locate projects in high-value areas.

In order to determine where DER can provide locational benefits, Massachusetts utility and ISO New England planners must be looking for these benefits and considering DER as a potential solution. Utility planning efforts do focus on targeting system weaknesses, but do not typically consider DER as potential solutions. Rather, most planning processes identify conventional wires solutions and set out to implement them without identifying or evaluating DER alternatives. By adjusting the planning process to identify where DER can offer better solutions than conventional alternatives, utilities can identify investments that benefit their shareholders, DER host facilities, and other customers.

Some jurisdictions have begun to address this situation. Two examples are California and New York. California now requires utilities to consider DER as an alternative to distribution upgrades, and to take steps to procure it where it appears to offer a least-cost solution.[19] New York requires its utilities to evaluate

[17] http://www.masstech.org/renewableenergy/public_policy/dg/resources/Collab_2004Collab04_12_10_DP_EPRIPresentation.ppt

[18] see the report of the March 9, 2005 Distribution Planning subcommittee of the DG Collaborative at http://www.masstech.org/renewableenergy/public_policy/DG/meetings/2005_march9_dp.htm

[19] "Distribution system planning must consider distributed generation alternatives to wires upgrades as part of the normal planning process and non-utility distributed generation solutions should be actively solicited through the distribution planning process," and California utilities "shall develop model contracts for distributed generation designed to defer

DER for T&D projects whose costs exceed certain benchmarks, and is engaged in a pilot program that requires utility RFPs to procure DER where it can defer or displace needed T&D capacity.[20]

3.2 Information Needed to Prioritize Opportunities that May Yield Candidate Projects

At the March 9, 2005 DG Collaborative meeting, the Massachusetts utilities presented a series of projects that could potentially be deferred if distributed generation were able to provide equivalent reliability to the grid. In order to broaden this effort to identify such opportunities in the future, each utility will need to identify planning areas or sub-areas where its upgrade or expansion needs could be met effectively by distributed customer resources. Utilities which have not yet done so can set up a screening process for areas needing grid reinforcement within the next five-year planning cycle, designed to identify any areas where least-cost, best-fit distributed solutions compare favorably with conventional investments.

Many planning situations will not be good candidates for customer-side solutions, due to load growth characteristics or difficulties obtaining sufficient resource blocks on the utility's critical path schedule. The screening process should consider lead times for planning, development, construction and acceptance to realistically identify projects that can meet utility service requirements. A good screening process will identify the projects most likely to succeed, and will minimize time and resources spent by all stakeholders on detailed analyses of less promising candidates.

3.3 Determining the Value of Project Deferral or Cancellation

If a utility can save money by convincing customers to limit their loads during certain hours, it should be willing to pay customers for that benefit. For example, a utility may be able to defer a substation addition for three years if customers in a target area agree to curtail 300 kW of load for 100 hours per year (under negotiated availability and reliability criteria). In that case, savings from deferring capital investment will accrue to the utility and its customers, who can benefit if the savings exceed any incentive payment to load-limiting customers. Setting the right incentive level requires determining the value of investment deferral for various periods of time, for each distribution project potentially subject to deferral.

The utility first needs to estimate the cost of the project it would build to meet the system need it has identified. Then, in the most simplistic case, it would

distribution system upgrades." California Public Utilities Commission D.03-02-068 in R.99-10-025, pp. 69 and 72; February 27, 2003.

[20] Case 00-E-0005, Proceeding on Motion of the Commission to Examine Costs, Benefits and Rates Regarding Distributed Generation, Opinion and Order Approving Pilot Program for Use of Distributed Generation in the Utility Distribution System Planning Process (issued by New York State Public Service Commission October 26, 2001)

multiply the project cost by the utility's cost of capital (or carrying charge) for each year that the conventional project would be deferred. The result would be a rough estimate of the utility's avoided cost, which would set a ceiling on any annual incentive it should pay to a customer for a deferred project.

A more refined calculation might consider other factors. Massachusetts utilities have presented a formula that would net out from the previous calculation the utility's costs to administer the demand reduction program.[21] They roughly estimate this cost to be on the order of 20% of the annual project deferral value, pending more detailed analysis. The DG Collaborative members agree that an analysis of the utility cost of administering a project deferral program should be one of its goals for the coming year.

Massachusetts utilities have also proposed to reduce potential DER incentive payments by an amount equal to any revenues the utility foregoes because the customer reduces its kilowatt hour usage. They reason that without the incentive, there would be no project; with the incentive, the project will become attractive, the customer will install it, and fewer kilowatt hours will flow through utility lines and meters. The utilities suggest that any incentive for customer-generators should therefore be reduced by what they characterize as 'lost revenue' corresponding to lower kWh sales.

Massachusetts utilities differ about how to calculate 'lost revenue'. Some consider the revenue at issue to be that which is 'lost' during the hours when the utility actually calls on customer equipment for load relief. Others argue that when customers run generators as baseload units to maximize their own economic benefit, 'lost revenue' should reflect many more hours of operation than those needed to provide load relief. These two approaches yield very different numbers of hours – from perhaps 200 a year to over 3000 a year. The first results in more viable customer-side projects, while the second results in many fewer.

The E2I/EPRI approach suggests a somewhat different methodology, often called the '*present worth method*', to determine deferral value which is based on the change in present value revenue requirement. The revenue requirement (RR) is the amount of money ultimately collected from customers for an investment.[22] In this approach, direct capital costs are "grossed up" to include indirect savings of capital deferral such as reduced property tax, depreciation, insurance, avoided maintenance, and other costs.

The analysis then compares the total revenue requirement for the base case project (without DG) to the case where the customer installs and operates DG

[21] The DG Collaborative has been focused on distributed generation, not demand reduction. Since DG on the customer side of the meter will almost always be used to serve on-site loads, the net impact of DG from the utility perspective will be the same as other DER measures- namely to reduce the load on the local distribution circuit. The use of the term 'demand reduction program' thus encompasses both DG and demand response.

[22] http://www.masstech.org/renewableenergy/public_policy/DG/resources/Collab_2004Collab04_12_10_DP_EPRIPresentation.ppt

and the project is deferred. The change in revenue requirement is calculated as the present value of the base case RR less the present value of the RR of the project with DG. The incremental value of each new kva of customer-side resource is calculated by dividing the change in the revenue requirement by the amount of new load that must be displaced.

The following example illustrates this approach:

SAMPLE PROJECT

- Replace/upgrade a transformer to serve new commercial & residential load
  and replace existing transformer for maintenance requirements.
- Project Capital Budget: $743,000
- Revenue Requirement Factor: 1.40[23]
- Needed Capacity Addition (Base Plan): 10 MVA
- Projected Incremental Capacity Additions: 300 kVa / year
- Hours When Capacity Is Needed: less than 100 hours / year

SAMPLE CALCULATION

Where: *.02 = inflation rate .06 = weighted avg. cost of capital*

Change in Revenue Requirements, Year One

= Cost of project x Revenue Requirement Factor x {1-(1+.02)/ (1+.06)}
= 743,000 x 1.4 x .0377
= $1,040,000 x 0.0377
= $39,208

Change in Revenue Requirements Year Two

= $39,208 x (1-.0377)
= $37,730

Change in Revenue Requirements Year Three

= $37,730 x (1-.0377)
= $36,307

EXAMPLE- 1 year contract

Value of one-year contract for demand reduction
=$39,208/ 300 kVa= $131/kva

[23] The revenue requirement factor reflects the 'grossing up' described in the text. The 1.4 factor is a representative number in the range of investor-owned utilities generally; it does not necessarily reflect any particular Massachusetts utility, which could have a higher or lower value.

EXAMPLE- 3 year contract

3 year NPV (@6%) for rev requirement reductions of $39,208, $37,730, and $36,307 = $101,000

$101,000 X (1 + .06) / 900 kVa
= $107,000 / 900 kVa
= $ 119 / kVa

This example illustrates that the utility could lower overall customer costs if it were able to sign a one-year contract for 300 kVa of demand reduction for less than $131/kVa. On a three-year contract, the utility could afford to pay up to $119/kVa for the delivery of 900 kVa of demand reduction or customer generation for the 100 hours per year needed to satisfy its peak distribution requirements.

3.4 Meeting Utility Reliability Criteria

One of the most important concerns for utility planners considering the use of customer-side resources to defer or avoid a utility construction project is whether these resources will be reliable and available when they are needed. If a utility plans for customer demand reduction and/or generation as part of its system, and those resources are not available when called (because a customer does not drop load, its generator is down for maintenance, etc.), the utility may not be able serve all customer demand in that geographic area. This possibility is an anathema to utility planners and executives responsible for providing safe, universal, and adequate service under all circumstances.

3.4.1 Control of Project Timing

System planners are concerned that if a DG project they are counting on for grid reliability fails to enroll its projected customer loads on schedule and in the right places, the utility will be left short of capacity to serve its load. Utilities typically need at least 12-18 month lead times to design system additions, procure land rights, order and install equipment, etc. Given these lead times, if a customer-side project fails to meet its obligations, the utility may not be able to pick up the slack and bring in its own project when needed. A related concern is that a customer could agree to limit its facility's load for a certain period of time, but the next owner or occupant of the facility might not have the same operational flexibility. It might need 24/7 supply from the utility – supply that is no longer available in the area.

3.4.2 Guarantees of Resource Availability

Utility planners and system operators also worry that using DER as a grid resource will endanger power reliability and availability to all customers. If customers who agree to reduce load do not, or their generators fail to operate during high usage periods, the grid becomes vulnerable to outages. To avoid this, utility operators want the same level of control over customer resources as they have over utility-owned assets.

3.4.3 Possible Solutions

Various approaches have been used or proposed to provide guarantees of DER availability. Three such approaches are listed here and discussed briefly below:

1. *Utility direct operational control of the resource*
2. *Guarantees via contracts with financial penalties*
3. *Guarantees via resource redundancy*

3.4.3.1 Utility direct operational control of the resource

This approach offers the utility the highest level of comfort. Utility operators can directly control the customer's equipment, or the utility can install a physical switch at the customer interconnection point that it can activate if the customer fails to limit its demand or meet its generation commitment. In California, the ability to limit a customer's demand is called physical assurance.

From the utility perspective, the customer's obligation, established by contract between them, will be to cap its load at an agreed amount during defined periods or under specified system conditions, relieving the local distribution circuit accordingly. Whether this occurs because the customer turns off some of its lighting or machinery, or turns on its own generator to serve those loads, is of no real interest to the utility so long as the customer's demand on the system does not exceed the agreed cap. To guarantee this, the utility will have a communication and control link between its control center and the customer electrical interconnection point with the utility, which permits it to immediately and automatically limit the customer's load under emergency conditions if the customer does not do so as agreed (even though the utility does not own the equipment or control it under normal conditions).

3.4.3.2 Guaranteeing via contracts with financial penalties

Here the utility does not have physical control over customer equipment, but does have contractual rights to impose financial penalties if the customer fails to limit its load to the agreed cap. Utilities often resist these arrangements because they remain responsible to their regulators and other customers if a DER customer makes an economic decision to pay the penalty rather than reduce its load when required. Historically, utilities have been reluctant to alienate some of their best customers who have signed curtailment contracts without fully understanding the implications. There have also been occasions when a manager who signed the customer contract subsequently left the facility, and a successor tried to void the arrangement. Unlike curtailment contracts whose value derives from generation savings, the value of distribution-based demand limitation contracts is reliability when the grid is stressed, so non-performance can have much more severe consequences.

3.4.3.3 Guaranteeing via redundancy

Two types of guarantees have been suggested:

1. In the DG Collaborative meetings, Massachusetts utilities have suggested requiring customers with generators to have a second generator available if the first one fails. While this would address the utility concern, the cost of a spare generator would likely make DG installations uneconomic.

2. Another approach would use historical patterns of response to utility-called demand reductions to estimate a contingency reserve. Although a certain number of customers will be unable or unwilling to respond to any given event, enough will respond to meet the utility's load reduction goal. For example, if the resource required is 10 megawatts, a network of 11 one-megawatt generators in the area might guarantee the reliability and availability the utility needs. Utility planners can establish criteria for first and second contingency failures for distributed resources as they do for traditional utility assets. The value of the demand resources can then be determined by the diversity required, and no single customer need shoulder the entire burden of network redundancy.

By definition this requires contracting for more demand response than the utility expects to need for any single event. This tends to reduce the incentive the utility can afford to pay per unit of load reduction, so it may be harder to enroll enough resources using this approach.

4 UTILITY CONGESTION RELIEF PILOTS

4.1 Building on the Work of the DG Collaborative

The MTC and Massachusetts utilities are developing Utility Congestion Relief Pilot (UCRP) Projects to advance the understanding of costs, benefits, and best practices for integrating DER into the state's grid. These Pilots will be formed to design or enhance projects to facilitate cost-effective DER solutions in targeted areas with T&D constraints or other opportunities.

These Pilots will provide opportunities through *real projects* to gather data on DER costs and benefits, and to test business models which may be approaches for encouraging win-win DER either on the customer or the utility side of the meter. Identifying ways to achieve win-win DER should be a key objective of these Pilots. Where win-win DER may not be achieved, the Pilot can use these opportunities to recommend what could be changed to enable the win-win outcome.

The particular DER projects undertaken through these Pilots should be designed to provide input to reports to the DTE on costs and benefits and on recommendations for encouraging win-win DER whether the projects are completed or not. These Pilots may provide valuable input for the work of the DG Collaborative both before and after the DG Collaborative's 2006 final report.

At early stages of their development, programs that make sense for society as a whole may fail the utility cost test. Just as some efficiency measures that are commonplace today might not have achieved the critical mass they needed to succeed without the early incentive programs, some DER technologies have the potential to support viable, cost-effective industries and to add real value to the electricity enterprise over time. The cost to promote this DER now can be considered the cost of an option for the future.[24]

For this reason, EPRI and others have advocated an interim approach referred to as the "DER Soft Start".[25] This would create pilot programs to test not only the use of customer-side resources as an alternative to wires and poles construction, but also business models to facilitate DER where multiple stakeholders stand to benefit. These pilot models would, for example, explore mechanisms to overcome the utilities' disincentives while accumulating information on planning and implementation costs that regulators need to understand who benefits and who pays for DER. To encourage experimentation and innovation, the

[24] E2I EPRI Framework- p. 3-11. See also MTC Activities Regarding Distribution Planning (ppt.) http://www.masstech.org/renewableenergy/public_policy/DG/meetings/2004_december10_dp.htm

[25] The phrase was coined by the late Joseph Ianucci, one of the early proponents of the distributed utility concept and a pioneer in this field until his death in 2004.

understanding should be that pilot projects will not necessarily create regulatory precedents, but will be evaluated at the end of a test period to decide whether any or all of their lessons should be recommended for consideration in developing a statewide policy.

The following are EPRI's recommendations for the Pilots and the DG Collaborative roles and goals.

MTC and utilities are developing Utility Congestion Relief Pilots. The DG Collaborative should provide support to the Pilots and to specific projects through comments, review, analysis, evaluation, and recommendations.

In parallel with the Pilot activities, the DG Collaborative should continue to meet in the next year to address issues common to all the utilities and other stakeholders in Massachusetts. The DG Collaborative should explore costs and benefits of DER, opportunities for leveraging DER values, and concepts for efficient incentives, including business and regulatory models that could support win-win DER. The DG Collaborative will also provide input to the development of the structure and research agenda for the Pilots, and provide support to the specific projects.

4.2 Screening and Prioritizing Potential Pilot Activities

To determine the highest priority DER projects, the Pilots should explore the following dimensions:

- **Business models**
- **Technology alternatives**, including the best ways to integrate CHP, demand response, energy efficiency, energy storage and clean distributed generation**.**

In each of these dimensions, the MTC and the participating distribution companies should consider three to five approaches or models that might be tried in a Pilot project, and will use a screening process[26] to identify the best projects.

Taking the business model dimension as an example, the Pilot might explore the value of testing utility ownership, deployment, maintenance and operation of DER assets. Alternatively, it might recommend an open competitive utility solicitation for a specified set of resources within a defined area. Or it might recommend that a utility define a constrained planning area on its system and offer a standard credit ($/kW or $/kWh) to any customer who provides demand-limiting resources in the target area. Chapter 1 outlines a number of business models that form a good starting point for this analysis.

A screening process should evaluate suggested business models with criteria such as:

[26] Based on work product of Navigant Consulting provided in its role as consultant to the Collaborative.

- Whether it advances the DG Collaborative's objectives
- Whether it fits within the DG Collaborative's scope (transmission vs. distribution, include demand response or only clean DG, etc.)

Each business model should be assessed to determine whether it can create 'win-win' outcomes; whether its approach can be replicated in other situations; and whether the size and importance of the market warrants that.

Finally, the practicality of each business model should be assessed, including:

- How difficult it is to implement
- Whether it will yield solutions functionally equivalent to traditional ones
- Whether regulatory hurdles are manageable.

For the other dimension –technology alternatives – a similar filtering process should be used. The result of these screening efforts will be a matrix of possible combinations across the dimensions of business models, regulatory models and technology alternatives. MTC and the distribution companies should then choose the most attractive combinations as templates to create real projects.

The DG Collaborative should monitor the progress and results of each Pilot and seek to apply early lessons and best practices as they become apparent to other Pilots. Ultimately the DG Collaborative should be asked to recommend the most successful approaches for statewide adoption and policy consideration.

Although the DG Collaborative has so far focused on issues surrounding the use of distributed generation in utility planning and operations, the Pilots should consider whether the limitation to generation – and not efficiency, demand response or energy storage – makes sense in the context of designing projects. While projects involving only DG may well be one of the alternatives screened, experience suggests that projects incorporating several DER technologies and solutions may be more viable alternatives, at least to short-term utility investment deferrals.

There is also tremendous interest in integrating clean generation and renewable resources into the Massachusetts distribution grid. The screening process may reveal customer and societal values favoring renewables that will drive the design of some projects to make renewable generation eligible to participate in demand response programs at the distribution or ISO New England level. The challenge will be to design mechanisms that recognize and reward the continuing demand reduction value of efficiency and renewables over more than one year or one utility planning cycle. Today, for example, the value of solar electricity in reducing peak demand is recognized only for the first year after installation. In the second year, the customer baseline is reset and the PV-induced demand reduction becomes part of the customer's new load profile: although the installation will reduce that customer's grid demand for as long it operates, its incentive payments cease.

4.3 Structuring Utility Congestion Relief Pilots

The DER projects of each Pilot should be customized to address specific congestion situations identified by the utilities and/or the ISO New England. If the congestion or capacity shortage is a local distribution problem, the structure of the Pilot and those invited to participate may be quite different than if the constraint is at the transmission level. The initial assumption is that the UCRP would focus on solutions on the customer side of the meter, rather than the utility side. However, these opportunities could be considered as well.

The Massachusetts Technology Collaborative/ Renewable Energy Trust is in the process of developing UCRP Pilot Projects with each interested distribution company. MTC expects to actively participate in each UCRP to provide financial support, to represent the broader public interests of Massachusetts citizens and to help coordinate with the work of the DG Collaborative.

Each participating distribution and/or transmission utility could provide information about specific locales of concern to it, reliability projects it is considering in those locales, costs that DER projects might be able to defer, and additional costs these projects might impose. This information will help to identify projects best suited for DER solutions, to provide a starting point for allocating costs and benefits to yield win-win outcomes, and to assess any customer incentives needed to ensure demand reductions where and when the utility needs them.

The DG Collaborative's Distribution Planning Work Group provides an opportunity for other stakeholders to support these Pilots. The following describes likely roles of the parties supporting the projects:

ISO New England

ISO New England representatives familiar with demand response programs should be part of each UCRP. Experience suggests that the value of distribution deferrals is rarely enough by itself to justify customer investment in demand response or DG projects. Often, wholesale generation savings and other values from these projects must be included in the benefit stream in order to create win-win outcomes, and the ISO New England is well situated to identify these.

Customer Representatives

The customers and customer representatives participating in the DG Collaborative may also be active participants in these Pilot Projects. There will also be a role for individual customers in the areas of project focus, or for representatives from customer trade groups such as the Associated Industries of Massachusetts.

DER Suppliers and Aggregators

Utility distribution upgrade or expansion projects typically range from 1-10 MW, and transmission projects can be much larger. Since relatively few customers have loads large enough to be reduced by these amounts, utilities may want to enlist help from developers and aggregators who can work with multiple customers to assemble and coordinate this level of resources. In considering DER aggregator participation, it will be important to establish selection criteria and ground rules that address fairness to other developers and aggregators not participating in the Pilot's formative discussions, as well as confidentiality and anti-competitive issues.

Massachusetts Division of Energy Resources

DOER staff should continue to actively participate in the DG Collaborative and provide ongoing support to the Pilots as appropriate.

Massachusetts Department of Telecommunications and Energy

If possible, DTE staff should review and informally provide expert feedback on proposals from the project team regarding potential regulatory approaches to removing barriers to utility participation and encouraging demand response solutions.

Electric Power Research Institute

EPRI brings existing DER knowledge and experience from other areas of the country and other collaborative DER efforts, as well as guidance to "calibrate" results to Massachusetts geography, market structures, grid needs and regulatory conditions. EPRI can also support the exploration of business and regulatory models that could significantly expand the use of distributed CHP, demand response, energy efficiency, storage and renewable generation to relieve grid congestion. The EPRI cost/benefit model should be customized to account for Massachusetts energy costs, utility tariffs, and market structure, and will apply the model to analyze UCRP costs and benefits for customers, utilities, and society as a whole.

4.4 Determining UCRP Research Goals & Objectives

Utility Congestion Relief Pilots should design projects specifically to result in win-win outcomes for customers, DER developers, non-participating ratepayers and distribution utilities. The thesis is that projects like those outlined here, affecting multiple stakeholders with sometimes divergent interests, can best be implemented by facilitating collaboration among project teams consisting of utility representatives, customers and customer trade groups, the MTC and their consultants, and DER aggregators, developers and solution suppliers. This collaboration should be accomplished through the DG Collaborative.

Once a project team has agreed on a business model and technology plan, the next step is to establish more specific goals, objectives, and strategies for implementing individual projects. One of the first activities of collaborative members themselves will be to settle on project goals, objectives, and strategies. The following are examples of goals and strategies to focus on:

- Goal: Demonstrate ways to overcome the challenges of incorporating DER in utility planning and operations

  Possible Strategies:
  - Achieve necessary scale by aggregating resources
  - Design a project schedule with milestones that will satisfy utility date-in-service requirements

- Goal: Demonstrate a way to achieve equivalent network reliability and availability using DER resources

  Possible Strategies:
  - Use utility-controlled demand limitation devices
  - Achieve resource diversity across many customers
  - Test the reliability of individual DER configurations

- Goal: Compare total costs and benefits of DER vs. utility investment approach

  Possible Strategies:
  - Demonstrate how to monetize several DER value streams in a single project
  - Demonstrate how to fairly allocate benefits among project participants

- Goal: Secure the needed "utility grade" demand response/clean DG to defer one or more utility infrastructure investments.

  Possible Strategies:
  - Combine demand response and DG resources in the same project
  - Partner with developers/aggregators to maximize marketing channels within target area.

4.5 A Prototype Project: What Might It Look Like?

The following describes a fictional project of a Utility Congestion Relief Pilot Project to illustrate the process and content presented above. It assumes that the project takes into account the results of the screening of business models and technology alternatives. Stakeholders including at least one major customer, the ISO New England, EPRI, and technology providers/DER aggregators, will support the project via the DG Collaborative. The project will address a distribution congestion issue in a utility planning area with approximately 25 megawatts of load at issue.

4.5.1 The business model

The distribution utility serving the target area will offer an incentive to any customer who reduces its electrical usage during periods of time specified by the utility. The incentive will be based on the value delivered by those customers that allow the utility to delay one or more construction projects over some period of time. The incentive may be a combination of a capacity deferral incentive ($/kW) and/or an energy deferral incentive ($/kWh/hr). The utility may develop, own and operate the project or work with independent DER developers, customers and aggregators.

MTC would support the marketing and technical assistance needed to enroll sufficient amounts of load response to meet project goals, including funding a percentage of the costs of signing up customers. This support could include market research to find out what customers want, are willing to participate in, how they would participate, and other behaviors. If customers in the target area express an interest in a renewable energy project, MTC could provide technical assistance to the customer.

4.5.2 The Technology Alternatives

Customers can choose among technologies that facilitate demand response, self-generation or some combination. The Pilot has decided to explore how clean distributed generation (e.g., fuel cells, solar, or other non-combustion technologies) can be integrated into the demand response aspects of the project. The project will facilitate the installation of automated response capabilities at small and medium-sized customers to enable them to participate in the project.

MTC could support the demonstration of renewable resource technologies sited and operated to help relieve grid congestion. Examples might include a project to demonstrate PV with storage (to evaluate the use of PV systems to meet the second peak in the evening when PV is off line), or demand limitation strategies and technologies for controlling residential room air conditioners.

4.5.3 Key Project Objectives

- Enroll sufficient customer load within six months of project start
- Determine the form and substance of customer incentives most likely to motivate customer enrollment
- Determine if utility quality network reliability and availability can be achieved using DER on this project
- Determine the costs and benefits of automated demand response and advanced metering technologies
- Determine how clean distributed generation (e.g., solar, fuel cells or other non-combustion technology) can be integrated into demand response programs

- Implement a collaborative process that leads to win/win outcomes for participants
- Determine how to integrate storage and room air conditioner controls with PV to create demand response that addresses the residential 9:00 p.m. summer peak.
- Achieve the required demand response when called by the utility.
- Make a recommendation to the DG Collaborative regarding rate treatment of DER deferral payments
- Make a recommendation to the DG Collaborative regarding accounting treatment for any compensable revenue losses result from the project
- Design a process that can be replicated across Massachusetts

4.5.4 Key Issues:

1. What is the role of technology in the projects?
2. How will load reduction delivered vs. promised be monitored?
3. Can customers shed manually or will they be required to have automated response equipment?
4. What technology platform(s) will be used for automated response?

5, Who pays for equipment installed under the program?

6. Will customers be willing to assume responsibility for limiting their load during curtailment periods (i.e., agree to a utility load limit switch on their service)?
7. Will utilities agree to limit the hours of exposure during the year for the customer's demand response commitment?
8. How can renewable energy participate in load demand?
9. What is required to achieve the win-win for this project?

4.6 Measuring Project Success

The Pilot should base its evaluation criteria and plan on goals and objectives previously adopted, so the project team can readily measure success. Success can be measured based on a number of criteria, such as ability to achieve win-win, capacity deferred, measures developed to address utility disincentives, ability to accurately track costs and benefits, project replicability across Massachusetts, ability to integrate clean DG into utility planning. The project team should identify a person or firm to be responsible for collecting information and data needed to address the evaluation plan activities.

Each project's data collection needs will be driven by its goals and evaluation plan. Members of the DG Collaborative have already expressed interest in quantifying the costs and benefits of DER activities. To achieve this goal, all parties will need to submit cost information (with sufficient detail) that can be reviewed by a project evaluation team. Similarly, if a project goal is to defer 10 megawatts of load over a summer period, data regarding individual customer actions as well as aggregated customer responses may need to be collected.

Once measurement and evaluation criteria are listed, a program evaluation process can be developed. This process should document the development of the project, the choices and alternatives considered along the way, reactions of participants, successes and failures. The intent of the evaluation is to determine what works well and what doesn't under various circumstances, in order to refine future approaches.

The ultimate purpose of the UCRPs is to help guide the DTE concerning future State policies vis-à-vis DER. The ultimate success of the projects will be measured by the amount of helpful information about DER use in Massachusetts that flows from them. The project outcomes will be processed through the DG Collaborative and submitted to the DTE in a formal report.

4.7 Summary of Recommendations for Next Year's Program

As stakeholders and regulators broaden their shared understandings of the State's current environment for DER, they should seek win-win approaches as outlined in Chapter 1. The stakeholders should embark on a series of steps to determine whether DER in general or DG in particular can bring significant value to Massachusetts. EPRI recommends that the DG Collaborative take the following steps to realize and quantify the value of DER to Massachusetts. These steps follow the EPRI win-win flow chart in Chapter 1 and are described in more detail in the chapters of this document. The first 3 steps can be undertaken through the DG Collaborative as it continues its work in the coming year.

1. Systematically examine the true benefits and costs of DER for all stakeholders (Chapter 2). Gather data from existing and new projects in Massachusetts and other states.
2. Evaluate opportunities to reallocate costs and benefits for mutual advantage through DER value leveraging and efficient incentives, including alternative business and regulatory models (Chapter 1).
3. Evaluate leveraging the value of DER in distribution planning. Use experiences from the Massachusetts projects and others as input. Consider the challenges and opportunities for integrating DER into utility planning and operations (Chapter 3).
4. In parallel, implement *real DER projects* through Utility Congestion Relief Pilots (UCRP) that each involve a utility and the MTC. Key stakeholders should participate through the DG Collaborative, including customers, DER providers, state agencies and public interest organizations (Chapter 4). Data and analysis should flow both ways between these Pilot projects and the work of the DG Collaborative.

5. Using actual project experience along with inputs from steps 1, 2, and 3, develop recommendations for the DTE to consider in establishing well-grounded DER regulatory policy in Massachusetts.

Web Link to Report

Note: the remaining Chapters and Attachments are available at the DG Collaborative website illustrated below, through the following web address:

www.masstech.org/policy/dgcollab