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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

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Andrew C. Dzykewicz
Commissioner and Director

February 29, 2008

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Distributed Generation Working Group Report

Dear Ms. Massaro

Enclosed are ten (10) originals of the report documenting the work of the Rhode Island Distributed Generation Working Group, dated February 1, 2007.

I regret the delay in forwarding this to you. I had believed in error that it had been forwarded at the time of transmittal to the General Assembly. I regret any inconvenience the delay may have caused.

Sincerely,

Andrew C. Dzykewicz
Commissioner

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

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Andrew C. Dzykewicz

Chief Advisor To The Governor On Energy
Director, Office of Energy Resources

February 1, 2007

The Hon. Joseph A. Montalbano
President of the Senate
318 State House
Providence, RI 02903

The Hon. William J. Murphy
Speaker of the House
323 State House
Providence, RI 02903

Gentlemen:

The Rhode Island Office of Energy Resources (the OER) is pleased to submit its report on the work of the Distributed Generation Working Group (the Group). This report is submitted in fulfillment of the requirements of R.I.G.L. § 42-140.2-2. The statute directs the OER to convene such a group to discuss the issues relating to distributed generation, and report the findings to the General Assembly.

The OER thanks the members of the Group for their participation.

The report is a fair and accurate representation of the work and opinions of the Group. It does not necessarily represent the opinions of the OER.

Although the Group devoted a substantial amount of time to this effort, they were unable to accomplish one of the statutory requirements, namely § 42-140.2-2 (3),which reads as follows:

> " (3) Said study shall make findings and recommendations using methods for determining and quantifying system benefits attributable to distributed generation including costs and benefits relating to:
>
> (a) the electricity distribution system:
>
> (b) the electricity transmission system;
>
> (c) the electricity generating system and the cost and availability of capital needed to construct or maintain generation capacity;
>
> (d) system losses;

(e) congestion and reliability;

(f) ancillary services including voltage stability and reactive power;

(g) fuel availability and pricing, and costs of electricity supply;

(h) environmental impacts."

While the legitimate reasons for the Group's inability to accomplish this are well-documented in the report, the OER cautions the legislature to view the Group's recommendations in light of the Group's inability to quantify either costs or benefits adequately.

Because of the constitution of the Group, a number of the opinions expressed therein are driven by self-interest. The OER further cautions the legislature to consider the recommendations in light of the sources. Where, in the opinion of the OER, the supportive information in the report is either incorrect or misleading, this cover letter will serve to present alternate information. This information follows:

Distributed Generation Defined (Page 4)

The group adopted a definition of Distributed Generation that reads, "Distributed Generation is generation located at or near the load, designed primarily for the benefit of the local users"

In the pre-restructuring era, distributed generation was utility installed generation intended to correct shortcomings in the electrical distribution or transmission system. Such generation would be considered large DG in the context of the Group's discussion. It was, by nature cost-effective. Generation installed *primarily for the benefit of the local users* may or may not be cost effective, and, depending on location and local system consideration, may prove detrimental to the electric system. Consideration should be given to examining large DG projects on a case-by-case basis, rather than attempting to generalize costs and benefits.

"Clean/Efficient Generation" (Throughout Document)

The term, "clean generation" or "efficient generation" is used throughout the narrative. The Group never defined this term with respect to CHP systems.

Large-scale natural gas fired electric plants have efficiencies of approximately 50%. Gas turbine based CHP plants have electrical efficiencies of approximately 25% to 40%. These plants gain efficiency by reducing the need for separate heating systems, eliminating the need to burn additional gas. Well-designed CHP units with a good thermal to electrical load fit can have efficiencies of greater than 60%.

The OER believes that, in the context of the discussions, the intent of this term was to describe CHP units that burn less fuel than conventional base-load gas-fired power plants. This would mean an efficiency of 60% or greater for the "clean" CHP unit. The OER therefore recommends that any actions taken in benefit of clean CHP use this efficiency as a qualifier.

Emergency Generation Available for Demand Response (Page 6)

Emergency generation does not actually fit the definition of distributed generation used herein. Emergency generation does not operate on a full-time basis. Its use to alleviate high demand periods within the grid is a significant benefit. High electric prices are to a degree a function of the necessity to have generation assets to fulfill peak load requirements, many for less than 100 hours per year. Operation of emergency generation can alleviate some of this. In so doing, owners are eligible for demand response payments from the ISO. A concern about emergency generation is that it is most often oil fired, with associated environmental effects.

Initiatives, Policies, and Regulations Supporting DG in Rhode Island and Neighboring States (Page 13)

The Group wished to convey DG programs in other states, and suggested those contained in the report. The OER believes that the inclusion of California is inappropriate because of the lack of similarity between California and Rhode Island. In terms of size, electrical consumption and climate, they are quite different. Even New York and New Jersey are marginal in their similarities to Rhode Island.

Deferral of Distribution and Transmission System Upgrade Costs (Page 30)

The Regulatory Assistance Project's conclusions are probably correct that there are a number of opportunities for DG to offset wires and transformer system improvements. This conforms to the pre-restructuring DG approach, and confirms the location-specific nature of benefits. Because DG benefits tend to be location specific, generalizations are inappropriate and better left to PUC docket justification than a one-size-fits-all legislative solution.

Competition for the Distribution Utility (Page 31)

Unless DG owners are willing to make the investment in redundancy required to be disconnected from the grid, the notion that DG provides competition for distribution utilities is incorrect. Distribution utilities provide the wires necessary to deliver energy, and are compensated for that service. Under Rhode Island law, distribution utilities supply energy only to those customers who elect not to chose a competitive supplier, and do so without profit margin. Their vested interest is in the preservation ofd system integrity, not power sales.

Support for Renewable Energy Standard (RES) Goals (Page 32)

The Group suggests that DG support of RES goals is a benefit to society. In reality, support of DG by the RES goals is a subsidized benefit to the industry.

Ease of Siting (Page 32)

It is difficult to reconcile ease of siting as a benefit with the recommendation that NIMBY concerns be eliminated later in the report.

Job Creation and Economic Development (Page 37)

It is a leap of faith that DG reduces energy prices. There is an argument presented in the recommendations that more subsidies are required, justified by this assertion. Subsidies will tend to increase electric prices. Unless a cost/benefit analysis is performed, the veracity of this statement is in question.

Interconnection standards – "Radial" and "Network' grids (Page 38)

It is unfortunate that agreement could not be reached on this recommendation, and the OER does not understand National Grid's objection. This entails nothing more than adopting the same practices in Rhode Island as National Grid already uses in Massachusetts. The OER believes that this is a fair recommendation that can be pursued by a simple filing with the PUC.

Standby Tariffs (Page 39)

Regarding the comment that some stakeholders find PUC proceedings too expensive to participate in, it must be noted that this reason is precisely why the DG Stakeholders Group was formed. The intention for this group was that for issues where consensus could be reached, the report would represent a pre-negotiated settlement with which the PUC could go forward with a negotiated docket. The proceedings of the Group are indicative that a negotiated settlement would be difficult to reach.

The second concept is that the Assembly would instruct the PUC with respect to outcomes. Beyond separation of powers issues, such an idea negates the purpose of the PUC. It is the responsibility of the PUC to judge the merits of arguments based on facts presented.

While the OER believes that a docket should be opened regarding standby rates, it is difficult to imagine how the participants of this group could advance their cause in such a proceeding when cogent, fact-based arguments could not be advanced in the informal context afforded by the Working Group setting.

Finally, the suggestion that interveners should be state funded has implications far beyond the DG question. If this philosophy were adopted, as an issue of fundamental fairness, the state would need to fund every intervener in each of the hundreds of dockets before the PUC each year.

Monetizing Benefits To Ratepayers And Taxpayers (Page 41)

This concept is already part of Rhode Island statute. Within the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 is a provision for least-cost procurement of standard offer service that mandates funding of cost-effective DG. The statutory philosophy regarding funding of projects is one of a change from a subsidy model to a cost-effectiveness model. This was made clear to the Group through Ken Payne of the Senate Policy Office and Beth Cotter of the House Policy Office.

Unless the Assembly chooses to reverse this policy, it is unnecessary and counter to this philosophy to increase RIREF funding for this purpose, and it is further unnecessary and counter to this philosophy to create a bond fund for this purpose.

This is also the case when considering the suggestion to eliminate the restriction that the RIREF become self-sustaining.

Price Paid For Exported kW-h (Page 42)

The Group mixes two related but distinct issues here. One is net metering and the second is the ability to sell excess power.

Net metering is an issue that needs to be fully understood from a cost/benefit perspective. In essence, net metering treats excess generation differently than the generation used to supply the needs of the grid. Currently, this excess generation enjoys the same payment treatment as generation that has been competitively bid into the system, and that has an obligation to provide that generation as promised. While a large amount of excess DG does not currently exist, the excess does not provide any particular difficulties for grid operation. Encouraging large amounts of such generation will lead to the requirement for the grid to accommodate the unpredictable nature thereof, causing a need for more load-following generation.

The OER cautions the Assembly not to make judgments about net metering until the costs are well established.

The second point deals with the ability to sell power to a customer. This is in fact possible today under existing law and regulation. A generator and a user can execute a bilateral contract, and transactions can occur. Both need to comply with certain NEPOOL regulations – regulations that were put into place to maintain system reliability.

While the suggestions of the group made in this section are worth consideration, the OER believes that the costs, benefits, and system reliability considerations must be well established before proceeding.

Different State Policies For Different Clean Energy Technologies (Page 44)

Two state policies captured in statute bear consideration when evaluating the suggestions advanced for additional support for combined heat and power systems. Again, the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 contains a provision for least-cost procurement of standard offer service that mandates funding of cost-effective DG. Second, Rhode Island has placed a particular emphasis on renewable energy, and has provided specific incentives to this form of generation.

A different point is that the narrative leads one to believe that solar should be treated favorably for its impact on summer peak loads. While there is a positive impact for the100 or so hours of summer peak, one must also recognize that there are also winter peaks that occur at night, when solar PV produces no electricity, so on balance, there is probably no justification to treat solar PV differently than any other renewable resource.

General Assembly hearings re PUC settlement procedures (Page 48)

A suggestion is made that the legislature should force the PUC to accept settlements only if they are agreed to by all parties. It must be noted that this is already the case in Rhode Island. The PUC does not accept settlements where even one of the parties does not agree to the terms.

Next Steps (Page 58)

The concept embodied in the discussion of next steps is already statutorily mandated in the requirement for least cost procurement. The OER feels that the stakeholder body recommended by the Group will produce no more definitive results than this one did.

An obvious conclusion that can be drawn about the various distributed generation stakeholders is that their individual needs to advance their technologies require different support mechanisms. The support mechanisms requested by this group are, in the absence of quantifiable benefits, additional subsidies above those already available.

A second conclusion is that the advocates were unaware of the provisions of existing statute that will serve their purposes.

The Office of Energy Resources strongly recommends that the Assembly allow the new, existing least-cost procurement process to go forward before implementing any changes thereto.

Sincerely,

Andrew C. Dzykewicz
Chief Advisor to the Governor on Energy

cc: The Hon. William A. Walaska - Chairman, Senate Corporations Committee
The Hon. Brian Patrick Kennedy - Chairman, House Corporations Committee
F. Kenneth Payne – Senate Policy Office
Beth Cotter – House Policy Office
Julie Capobianco - OER
DG Working Group Participants

REPORT OF THE RHODE ISLAND OFFICE OF ENERGY RESOURCES

TO THE RHODE ISLAND GENERAL ASSEMBLY

ON THE

DISTRIBUTED GENERATION STAKEHOLDERS WORKING GROUP

FEBRUARY 1, 2007

PURSUANT TO

THE COMPREHENSIVE ENERGY CONSERVATION, EFFICIENCY AND AFFORDABILITY ACT OF 2006

Disclaimer

The contents of this report do not necessarily reflect the views of the Rhode Island Office of Energy Resources (the OER).

The OER was charged by statute, specifically R.I.G.L. § 42-140.2-2, with supporting and facilitating a stakeholder led study of issues relating to distributed generation. This report is a fair and accurate representation of the results of that process only.

EXECUTIVE SUMMARY

The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 directs the Commissioner of Energy Resources to facilitate a stakeholder-led study of issues and barriers pertaining to implementation of distributed generation ("DG"). The Commissioner is to report the findings and recommendations of the stakeholders with regard to changes necessary to reduce barriers to implementation of DG to the General Assembly by February 1, 2007. This report is issued in fulfillment of that requirement.

STAKEHOLDER PROCESS

In the spring and fall of 2006, the Rhode Island Office of Energy Resources convened a series of meeting of stakeholders interested in state policies regarding distributed generation. Participants included state government officials, consumer groups, environmental and renewable energy advocates, municipal government representatives, distributed generation equipment marketers and manufacturers, residential consumers, large institutional and industrial consumers, and National Grid electric and gas company representatives.

GENERAL POSITIONS

The Stakeholder group was diverse, but fell into a number of factions: environmental groups, renewable advocates, CHP advocates, National Grid, customer groups, and the DPU. In the Recommendations section of the report, the individual positions of the individual Stakeholders are recorded. In the general discussion, where individual positions were not recorded, the Stakeholders generally advocated the following: environmental groups, renewable advocates and CHP advocates took an expansive view of the benefits of DG and advocated for greater financial support for DG. National Grid and the DPU took a more skeptical view of many of the benefits and expressed concern regarding the cost to the ratepayer of such support. Customer groups were divided depending on the issue. Where the term "some Stakeholders" is used in this report, the context of the narrative is indicative of which of the above factions advocated the positions described.

BENEFITS OF DISTRIBUTED GENERATION

The Stakeholders discussed the benefits of distributed generation. The Assembly is already aware that DG can create a number of benefits to system owners including financial benefits that affect return on investment, reduced operating risk, and (potentially) increased good will of customers, employees, and communities. In addition, some Stakeholders identified a number of benefits that DG has some potential to create to some degree for other ratepayers and society. These benefits claimed by these Stakeholders include: reduced electricity prices, reduced natural gas prices, reduced transmission and distribution line losses, higher security and reliability, a reduced reserve requirement, deferral of distribution and transmission system upgrade costs, increased competition for the distribution utility, ancillary services benefits, increased fuel diversity, support for Renewable Energy Standard (RES) goals, ease of siting new generation, reduced environmental degradation, a reduction in adverse health effects associated with emissions from older central generation, and local job creation and economic development. It is important to note that not every benefit was believed to exist by every Stakeholder and all Stakeholders recognized that not every DG installation would produce all of the benefits. The benefits of DG are highly technology- and location-specific.

The Act directs the Stakeholders to quantify the benefits of DG. The Stakeholders engaged in extensive discussion of the need for quantification and reviewed quantification efforts undertaken in other states. In the end, the Stakeholders determined that it was not possible for them to perform quantification given a number of factors, including the technology- and location-specific nature of the costs and benefits of DG, the inherent difficulty in quantifying societal benefits such as pollution reduction, and the nature of the group, the organizations involved, and the time available. Instead, they draw upon the extensive literature on this topic from quantification efforts elsewhere, providing brief descriptions of those findings with citations. In addition, the Stakeholders developed a proposed approach and set of next steps for performing quantification.

BARRIERS TO DISTRIBUTED GENERATION

The Stakeholder Group identified a number of barriers to DG. These barriers include: interconnection standards; stand-by charges; the difficulty for DG owners of capturing all of the benefits that their investments create; the price paid for kilowatt-hours that DG owners export to the grid; variations in state policies for different clean DG technologies; and permitting and siting challenges.

STRATEGIES AND RECOMMENDATIONS TO ADDRESS DG BARRIERS

Stakeholders identified strategies to address these barriers and attempted to reach consensus on recommendations to the General Assembly. In the end, consensus was not possible due to differences in the interests and perspectives of the participants. This report describes the full range of strategies identified by the various participants, and indicates which Stakeholders support and which oppose the various strategies.

NEXT STEPS

The Stakeholders view their findings to date regarding distributed generation as the beginning of a process that may result in action by the General Assembly and the Public Utilities Commission.

To inform future action, the Stakeholders have outlined a plan for a rigorous study of the costs and benefits of a future distributed generation portfolio. The Stakeholders recommend that the General Assembly provide funding to the Office of Energy Resources to conduct such a study.

INTRODUCTION

The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 ("The Act") R.IG.L § 42-140.2-1, finds as follows:

> Distributed generation can if well implemented, contribute to electric system reliability and efficiency and have system benefits including, but not limited to, reduced congestion, improved management of system peak demands through demand response, and added capacity that mitigates the need for additional central generating capacity in the region;
>
> Distributed generation from renewable resources diversifies the power sources for electric generation, and having multiple, reliable sources of power for electrical generation reduces risks and can temper price volatility;
>
> Distributed generation from renewable resources and from combined heat and power systems can reduce the environmental impacts, including greenhouse gas emissions, of electrical generation"
>
> The system benefits of distributed generation are a function of the location of the distributed generation capacity, the reliability and the efficiency of distributed generation facilities individually or collectively, and the time of operation;
>
> The value of distributed generation can vary with changes in the wholesale and retail markets for electricity;
>
> Properly designed regulatory and financing programs for distributed generation can have both system benefits and economic benefits for entities.
>
> The independent system operator of New England has stated that mitigating peak demand should be a central strategy in reducing wholesale electricity and has established a demand response to accomplish this purpose.
>
> Established tariffs and embedded principles for rate setting and cost allocation may present substantial barriers to realizing the full potential of distributed generation in Rhode Island. [1]

Further, the Act recognizes that cost-effective distributed generation may contribute significantly to least-cost procurement of standard offer service, and is mandated to be considered as part of the least cost procurement plan.

> **39-1-27.7. System reliability and least-cost procurement. –** Least-cost procurement shall comprise system reliability and energy efficiency and conservation procurement as provided for in this section and supply procurement as provided for in section 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible.

[1] RI Gen. Laws, § 42-140.2-1.

> (a) The commission shall establish not later than June 1, 2008, standards for system reliability and energy efficiency and conservation procurement, which shall include standards and guidelines for:
>
> (1) System reliability procurement, including but not limited to: (i) Procurement of energy supply from diverse sources, including, but not limited to, renewable energy resources as defined in chapter 39-26; (ii) Distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems, which is reliable and is cost-effective, with measurable, net system benefits . . .[2]

The Act directs the Office of Energy Resources (OER) to facilitate a stakeholder led study of issues pertaining to distributed generation and "barriers that impede the implementation of distributed generation and the realization of social benefits thereof." The study shall consider definitions provided for and implications of "[b]ackup power rates," "[c]ombined heat and power system," and "[n]et-metering" on the "effective and fair implementation of distributed generation."

The Act directs OER to report the findings and recommendation of the stakeholder group with regard to statutory changes necessary to reduce barriers to implementation of distributed generation to the General Assembly by February 1, 2007. The Act further directs OER to issue a stakeholder group report to the Public Utilities Commission by June 1, 2007.

To that end, in the spring of 2006, the Office of Energy Resources brought together interested Stakeholders to examine issues relating to distributed generation and to formulate recommendations. This report sets forth the opinions and recommendations of that Stakeholder Group.

[2] RI Gen. Laws, § 39-1-27.7.

DISTRIBUTED GENERATION WORKING GROUP

The Office of Energy Resources convened interested Stakeholders in a collaborative Distributed Generation Working Group in Spring 2006 to begin discussions on distributed generation. Beginning in Fall 2006, the group met bi-weekly to discuss issues and opportunities, assess benefits and barriers, and develop recommendations.

WORKING GROUP PARTICIPANTS

The Stakeholder Working Group was a voluntary, ad-hoc gathering of parties interested in Rhode Island's policies and regulations that affect distributed generation. It included individuals and organizations with interests in a variety of specific generation technologies, among them wind turbines, solar photovoltaics, micro-turbines, and combined heat and power systems. It also included individual customers and interest groups representing classes of customers, Rhode Island government agencies, and electric and gas utility companies. The group was made up primarily of advocates for distributed generation. A list of participants in the Distributed Generation Stakeholder Working Group and their affiliations is included in this report as Attachment A.

Through a competitive solicitation process, the Office of Energy Resources engaged Peregrine Energy Group, Inc. ("Peregrine") to facilitate, support, and manage this stakeholder process and help draft the Working Group's report.

GROUP PROCESS

The Stakeholder Working Group drew heavily on the considerable perspectives of the group's diverse participants, homework assignments prepared by group members, and research conducted by Peregrine Energy Group and participants using the extensive literature and public record that exists on the topic of distributed generation.

Among the topics covered in the groups meetings were:

- Establishing a definition for Distributed Generation to guide participants in discussions
- Confirming issues that should be considered in evaluating distributed generation, including expanding on issues identified in The Act based on Stakeholder experience and perspectives
- Identifying the benefits of distributed generation and assigning them to the beneficiaries that get them, differentiating between the host / developer on one hand and other consumers and society at large on the other
- Creating a shared understanding of current Standby Rate Tariffs used by National Grid for customers with distributed generation and how those rates are applied
- The need for and value of quantifying benefits and how to best do this to create meaningful information that would advance the decision making process
- Identifying market, regulatory, and other barriers that impede the expansion of distributed generation in Rhode Island
- Developing recommendations for strategies that will mitigate barriers and encourage distributed generation in Rhode Island

ESTABLISHING A CONTEXT FOR STAKEHOLDER DISCUSSIONS

DISTRIBUTED GENERATION DEFINED

The Stakeholder Group adopted the following definition of distributed generation for the purposes of its discussions and this report:

> Distributed Generation is generation located at or near the load, designed primarily for the benefit of the local users

CURRENT AND PROJECTED RHODE ISLAND ELECTRICITY USE

Rhode Island's peak load demand is approximately 1,800 MW with annual electricity use of approximately 8,000,000 MW-hours.

Rhode Island's load-serving entities purchase power through the New England-wide wholesale electricity market. In its 2006 *Regional System Plan*, ISO New England describe the growth in that market and the effect of that growth on the need for additional resources:

> The growth in demand drives the need to upgrade New England's electric power infrastructure. New England's summer-peak demand is projected to grow at a compound annual growth rate (CAGR) of 1.5% from 2005 to 2007 and 1.9%, or 500 MW to 600 MW per year, in the long run. These growth rates are, in part, a function of the price of electric energy . . . In addition, the region's increased use of air conditioning is decreasing the annual load factor (i.e., the ratio of the average hourly load during a year to peak hourly load). This means that the peak hourly load has been increasing relative to average load levels. The annual load factor is expected to continue to decline to 54% by 2015, further indicating the need to add peaking capacity and demand response in the region.[3]

The most recent National Grid Disclosure Label (covering the period 4/1/05 - 3/31/06) for Standard Offer Service describes the resource mix for its Standard Offer customers.

[3] ISO-NE Regional System Plan 2006, October 26, 2006, p. 3. The 2006 Regional System Plan – Public Version is available at: http://www.iso-ne.com/trans/rsp/index.html

Table 1. National Grid Standard Offer Resource Mix

Power Source	Resource Mix
Natural Gas	36.3%
Nuclear	28.0%
Coal	12.7%
System mix	8.8%
Oil	6.1%
Hydroelectric	2.5%
Diesel	2.3%
Jet	1.5%
Trash to energy	1.4%
Wood	0.3%
Biomass	0.1%

For the period in question, 0% of the resource mix comes from solar photovoltaics, wind, digester gas, fuel cells, municipal solid waste, or landfill gas. While this percentage might imply that none of the generation is from theses sources, the reality is that they do exist, but to such a small percentage that round-off shows 0%.

DISTRIBUTED GENERATION IN RHODE ISLAND TODAY

Combined Heat and Power

Using information supplied by National Grid and also drawn from a Combined Heat and Power (CHP) Database maintained by the U.S. Department of Energy (USDOE), Stakeholders reviewed current levels of distributed generation in the state. Some statistics:

- The USDOE database identified 15 sites in Rhode Island with CHP generation. The majority of these sites are fueled with natural gas (11) and the remainder use oil.
- The oldest distributed generation system is the 4,500 kW central power plant at the State of Rhode Island's MHRH facility in Cranston. Originally installed in 1932, this system was expanded in 2005. The facility has a total of 11,000 kW of on-site generation, including back-up systems that provide redundancy.
- The newest CHP installation is the 240 kW natural gas-fired microturbine installed in 2005 at Butler Hospital in Providence, though two additional sites with capacities of 360 and 480 kW respectively will be on-line by mid-2007.
- There are a number of small (22 kW) reciprocating engine installations fired by natural gas and located in apartment buildings and nursing homes.
- While there are two industrial hosts in the USDOE database (classified by SIC as textiles, food processing, and chemicals), most of the CHP applications are in hospitals and healthcare facilities, nursing homes, or institutional settings (i.e. colleges/universities).

Table 2 below provides a summary of combined heat and power installations in the state.

Table 2: Rhode Island Combined Heat and Power Installations.

City	Organization Name	Facility Name	Application	SIC4	Op Year	Capacity (kW)
Central Falls	Micro Cogenic Systems, Inc.	Cartie Nursing Home	Nursing Homes	8051	1989	22
Cranston	State Of Rhode Island	Central Power Plant	Hospitals/ Healthcare	8062	1932/ 2005	4,700
East Greenwich	The Season Assisted Living	The Season Assisted Living	Nursing Homes	8051	2003	60
East Providence	Micro Cogenic Systems, Inc.	Orchard View Manor	Nursing Homes	8051	1988	22
Kingstown	DG Energy Solutions / Quonset Point Cogeneration Facility	Toray Plastics America	Chemicals	2821	2003	7,520
Lincoln	Amity Associates	25 Lincoln Center Blvd. - Office Bldg	Office Buildings	6512	1990	960

City	Organization Name	Facility Name	Application	SIC4	Op Year	Capacity (kW)
North Smithfield	Alliant Energy / EUA/Highland Energy Partners, L.P.	Landmark Medical Center-Fogarty Unit	Hospitals/Healthcare	8062	1987	60
Pawtucket	Pawtucket Power Associates, Inc.	Colfax, Inc.	Food Processing	2079	1991	68,000
Providence	Rhode Island Hospital	Rhode Island Hospital	Hospitals/ Healthcare	8062	1974	10,400
Providence	Providence Veterans Affairs Medical Center	Providence VA Medical Center	Hospitals/ Healthcare	8062	2002	52
Providence	Brown University	Brown University Central Heating Plant	Colleges/Univ.	8221	1982	3,200
Providence	Rhode Island College	Rhode Island College	Colleges/Univ.	8221	1990	450
Providence	Butler Hospital	Butler Hospital	Hospitals/ Healthcare	8062	2004	240
Warwick	Micro Cogenic Systems, Inc.	Shalom Apartments	Apartments	6513	1989	22
Undisclosed	Undisclosed by National Grid	Undisclosed	Manufacturing		2006	360

Sources: U.S. DOE CHP Database; Northeast CHP Application Center, UMass-Amherst; National Grid

Renewable Generation

Looking at renewable power sources in Rhode Island,

- The largest on-site wind generation built to date is the 660 kW plant at Portsmouth Abbey that came on line in 2006.
- There are two small PV installations of 58 kW (on-line in 1999) and 50 kW (2006).
- There are a number of additional smaller PV and small wind generators in operation around the state.
- Total PV installations in Rhode Island number 92, equivalent to a nameplate capacity of 0.6 MW, and there are 9 wind projects with a nameplate capacity of 0.69 MW, for a total installed capacity of 1.3 MW. Windpower has an effective capacity of

approximately 0.33 and solar of about 0.12, thus actual electrical output from these two sources is approximately 0.3 MW combined.[4]

Emergency Generation Available for Demand Response

According to an inventory conducted by NESCAUM in 2002, there are 72 permitted emergency generators in RI. All of these machines meet the 100 kW minimum size requirement for participating in ISO New England's Demand Response program, and 72% of them are above 500 kW. Assuming a minimum of 500 kW is available from each machine over 500 kW, the total potential available kW would be at least 34MWs. Across New England, NESCAUM identified 3,900 permitted machines with (under the same assumption) total available capacity of over 850 MW. See table in Appendix B.

CURRENT POLICIES AFFECTING DG IN RHODE ISLAND

The following rules and initiatives affect distributed generation in Rhode Island.

- **Interconnection standards**

- National Grid has developed interconnection standards for distributed generation which were approved by the PUC in 2002. In addition, informally, National Grid has developed a streamlined one-page interconnection application / agreement form for small net-metered systems, based on the procedure available to customers in Massachusetts.

- **Net-Metering**

- Commercial, industrial, and residential customers are eligible to net-meter renewable on-site systems up to 25 kW. The total net-metered capacity is limited to 1 MW state-wide.
- Net excess generation is credited at the retail rate to a customer's next bill; any residual excess is granted to the utility at the end of the 12 month billing cycle, which National Grid sets as the calendar year.

- **Portfolio Standards**

- Rhode Island's Renewable Energy Standard (RES), enacted in June 2004, requires the state's retail electricity providers to supply 16% of their retail electricity sales from renewable resources by the end of 2019. The requirement begins at 3% in 2007 with 2% allowed from existing sources and 1% from new sources, new source generation escalates by 0.5% per year through 2010, then by 1% per year from 2011 through 2014, and finally by an additional 1.5% per year from 2015 through 2019. In 2020, and each year thereafter, the minimum renewable energy standard established in 2019 must be maintained unless the Rhode Island Public Utilities Commission (PUC) determines that the standard is no longer necessary.
- Eligible renewable energy resources include: direct solar radiation, wind, movement or the latent heat of the ocean, the heat of the earth, small hydro facilities, biomass facilities using eligible biomass fuels and maintaining compliance with current air permits, and fuel cells using renewable resources.

[4] Source: Rhode Island Office of Energy Resources Renewable Energy Inventory

- National Grid has made a filing with the Rhode Island Public Utilities Commission, Docket No. 3765, indicating an RES compliance cost for Standard Offer and Last Resort Service customers of $0.00062 per kWh.[5]

▪ **Utility Back-up (Standby) Rates**

- National Grid has *Back-up Service Rates* for customers with grid-interconnected DG. The rates establish monthly charges based on the highest coincident peak output of the generation meter plus the demand on the customer's service meter. DG with a nameplate rating of 30 kW or under is exempt from the backup rates. Renewable DG is also exempt, up to an aggregate total of 3 MW system-wide.

▪ **Natural Gas Tariffs for Efficiency**

- Effective January 1, 2007, Rhode Island's gas-distribution utilities must collect a public benefits surcharge of up to $0.15 per decatherm delivered, which will support DSM programs administered by utilities, including programs promoting CHP.
- Gas used for distributed generation and in certain other applications is exempt from the DSM surcharge.

▪ **Rhode Island Renewable Energy Fund**

- The Rhode Island Renewable Energy Fund (RIREF) is funded at approximately $2 million per year through a charge on utility rates of $0.0003 per kWh. Incentives are available from the Fund constrained by available funds to customers seeking to install cost-effective on-site renewable distributed generation, and must include payback to the RIREF.

▪ **Rhode Island Renewable Energy Development Fund**

- Starting in 2008, a Renewable Energy Development Fund (REDF) administered by the RI Economic Development Corporation will receive funding through Alternative Compliance Payments (ACP) made by electricity suppliers to satisfy their obligations under the RES. Suppliers may meet the RES obligations either by procuring renewable energy supplies or by paying the ACP, set at $50/MW-h in 2003 dollars and adjusted by the CPI. It is expected that REDF rules for incentives will be consistent with those for the RIREF.

▪ **Tax Treatment**

- For purposes of local municipal property tax assessment, renewable energy systems cannot be assessed at more than the value of conventional energy production capacity that otherwise could be installed in a building. Qualifying technologies include photovoltaics (PV) systems.
- Certain renewable energy equipment is exempt from the state's sales-and-use tax. Eligible products include solar-electric systems, inverters for solar-electric systems, solar-thermal systems, manufactured mounting racks and ballast pans for solar collectors, and wind turbines and towers.

[5] http://www.ripuc.org/eventsactions/docket/3765page.html

- **ISO New England Demand Response Programs**

- Customers with distributed generation can participate in ISO New England's Demand Response programs which compensate DG owners for reducing consumption when demand is high and system reliability is at risk.

- **ISO New England Forward Capacity Market**

- DG can be designed to participate in ISO New England's Forward Capacity Market. New (installed after June 16, 2006) DG system owners can bid their capacity into that market, and will realize revenue in the form of capacity payments if their bids are successful. ISO New England expects capacity payments of $7.50 to $10.00 per kW capacity per month. The additional cost to ratepayers is as yet unknown.

- Participation in this market will require developing bid strategies, installing specialized metering, and conducting measurement and verification. Minimum size requirements for bids/offers is 100 kW which would enable aggregation of multiple small units.

- **Federal Production Tax Credits**

- Developers of certain renewable and other generation can qualify for production tax credits (called "PTCs") under The Renewable Electricity Production Credit (REPC) originally enacted as part of the Energy Policy Act of 1992 and extended in March 2002 as part of the Job Creation and Worker Assistance Act of 2002.[6] In December 2006, the credit was extended for yet another year (through December 31, 2008) by Section 207 of the Tax Relief and Health Care Act of 2006.

- The REPC provides a tax credit of 1.5 cents/kWh, adjusted annually for inflation, for wind, closed-loop biomass and geothermal. The adjusted credit amount for projects in 2005 was 1.9 cents/kWh. Electricity from open-loop biomass, small irrigation hydroelectric, landfill gas, municipal solid waste resources, and hydropower receive half that rate, currently 1.0 cent/kWh. The duration of the credit is 10 years.

[6] The credit expired at the end of 2003 and was not renewed until October 4, 2004, as part of the Working Families Tax Relief Act of 2004, which extended the credit through December 31, 2005. The Energy Policy Act of 2005 modified the credit and extended it through December 31, 2007.

DG INITIATIVES ACROSS THE US AND IN NEIGHBORING STATES

There has been growing interest across the United States in the role that distributed generation can play in addressing such issues as future electricity supply needs, congestion relief for transmission constrained locations, and the environmental impacts of power generation.

NATIONAL DG INITIATIVES

At the federal level, the Environmental Protection Agency and the Department of Energy are both actively encouraging states to explore the benefits of and address the barriers to demand resources and DG technologies such as combined heat and power systems (CHP), photovoltaics, and behind the meter wind generated power.

Further, the federal Energy Policy Act of 2005 ("EPACT")[7] directed states to consider the potential role for demand response in resource planning, including using demand resources such as on-site generation. To that end, the Rhode Island Public Utilities Commission opened Docket 3759 in July 2006, to implement the requirements of EPACT and those sections of the omnibus state energy act, the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006, that correspond to those requirements of EPACT.

EPACT also contains many provisions related to distributed generation, including the following.

- **Distributed Energy and Electric Energy Systems – Sec. 921**. Requires the Secretary to carry out programs on research, demonstrations, commercial development, etc. to, among other things, integrate them into the grid.

- **Micro-Cogeneration Energy Technology – Sec. 923**. Creation of grants to encourage development of such technology.

- **Distributed Energy Technology Programs – Sec 924**. Secretary shall encourage development of DG technologies, including CHP.

- **Electric Transmission & Distribution Programs – Sec. 925**. Secretary shall establish programs to, among other things, development and demonstrate technologies that contribute significantly to load reduction and the integration of CHP and micro-CHP, (subsection a3, a7 and a8).

- **Renewable Energy – Sec. 931**. Secretary shall, among many things, promote diversity of energy supply.

- **Study on the Benefits of Economic Dispatch – Sec. 1234**. Secretary shall review the benefits of and determine how to improve ability of non-utility generators to offer their output into the market.

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[7] H.R. 6 is available at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf

STATE DG INITIATIVES

Across the country, a number of states have taken steps to assist distributed generation. Efforts have included establishment of streamlined interconnection standards and expansion of net metering rules.

Table 3 below compares Rhode Island's policies with those in the other New England states. **Table 4** compares Rhode Island's policies with those in New York, New Jersey, and California.

Table 3. Initiatives, Policies, and Regulations Supporting DG in the New England States

	Rhode Island	Connecticut	Massachusetts	Vermont	New Hampshire	Maine
Recent DG Initiatives by States	▪ *Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006*	▪ *An Act Concerning Energy Independence* (2005) and subsequent DPUC orders	▪ DTE Proceeding investigating distributed generation (D.T.E. 02-38)			
Interconnection Standards	▪ NGrid revised its rules in 2002 ▪ NGrid uses a streamlined process for net metered systems, based on MA practices	▪ Formal interconnection rules and procedures for DG up to 25 MW	▪ Statewide standards for interconnection for all DG ▪ Simplified procedure for units up 10 kW	▪ Statewide standards for small renewable and DG ▪ No capacity limit and overall enrollment limit for non-net metered ▪ $300 fee and standard application	▪ Standard application with no external disconnect required for systems <10 kW	
Net Metering	▪ Renewables up to 25 kW ▪ Aggregate net metered capacity cap of 1 MW ▪ NEG credited to next bill at retail rate for 12 months; excess granted to utility after 12 mos.	▪ Renewables up to 500 kW (2006) ▪ Fossil DG up to 50 kW ▪ No cap on total net metered capacity ▪ NEG purchased monthly by utility at spot market rate	▪ Renewables and CHP up to 60 kW ▪ No cap on total net metered capacity ▪ NEG credited to next bill at average monthly market rate	▪ Renewable capacity limited to 15 kW, except 150 kW or more for farm systems ▪ NEG must be used in 12 months or is granted to utility at no compensation to customer	▪ Available to wind, solar or hydro systems up to 25 kW ▪ Credit given to customer for NEG in a billing period ▪ Limited to 0.05% of peak demand of each utility	▪ All public and private utilities must offer ▪ Available to qualified cogen and small power producers up to 100 kW ▪ No limit on aggregated net metered generation ▪ NEG credited for 12 mo. and then is granted to utility

	Rhode Island	**Connecticut**	**Massachusetts**	**Vermont**	**New Hampshire**	**Maine**
Portfolio Standards	▪ RES requires 16% of sales from renewables by 2019.ACP adjusted annually ($55.13/MWh for 2006).	▪ RPS for renewables divided as Class I or II ▪ CHP and efficiency added as Class III in 2005 with 4% target for 2010	▪ RPS goal is 4% by 2009 with 1% annual increase thereafter. ACP adjusted annually ($55.13/MWh for 2006).	▪ Utilities must meet growth in demand from 2005 – 2012 with efficiency and renewables ▪ Renewables to be capped at 10% of 2005 sales		▪ 30% of retail sales must be from renewables (1997) ▪ As of 2006, amount of new renewable generation must increase by 10% by 2017
Back-up and Standby Rates	▪ On-site renewable DG up to 3 MW aggregate is exempt; net-metered customers not counted toward this cap ▪ All DG with nameplate of 30 kW or less is exempt ▪ NGrid Back-up rates include Monthly Service charge, Back-up Service charge, and Supplemental Service charge ▪ kW Demand for calculating charges includes generator meter demand plus service meter demand	▪ All <u>new</u> DG after Apr. '06 exempt from Back-up Power Demand Charge (defined as 'ratchet demand charge' on customer bills) ▪ Demand calculation is based on actual demand in each billing cycle	NSTAR settlement: ▪ All renewable DG is exempt from standby rates ▪ All DG of 250kW or less is exempt ▪ All DG between 250kW and 1000kW that normally satisfies 30% of customer load is exempt.		▪ For C&I customers with on-site generation that will require occasional back-up service ▪ Optional for installations before 1985	

	Rhode Island	Connecticut	Massachusetts	Vermont	New Hampshire	Maine
CHP Gas Rates	▪ Gas used for CHP is exempt from DSM surcharge	▪ Gas used for CHP is exempt from DSM surcharge	▪ None identified			
Grants	▪ Limited renewable project support from RIREF	▪ CT Clean Energy Fund offers grants up to $2 million for on-site DG of 10 kW or more ▪ CT DPUC will provide grants for DG projects up to 65 MW. Base load DG gets $450/kW	▪ MA Renewable Energy Trust provides grants on a competitive basis for renewable projects over 10kW for feasibility, design and construction ▪ Grants of up to $50000 are available for renewable DG <10kW	▪ Clean Energy Development Fund (CEDF) established in 2005 to promote development of cost-effective electric-power, primarily renewable energy and combined heat and power (CHP) ▪ $6 – 7.2 million per year for efficiency and renewables		▪ Voluntary fund for customer contribution to renewable projects at non-profits
Loans	▪ Limited renewable project support available from RIREF	▪ CT DPUC arranges low-interest long-term loans for DG 50kW or larger	▪ None available			
Emissions		▪ DG less than 15 MW eligible for credits toward compliance			▪ Generators that use CHP may take credit for the heat recovered from the exhaust of the combustion unit to meet the emission standards	

	Rhode Island	Connecticut	Massachusetts	Vermont	New Hampshire	Maine
Tax treatment	▪ Law limits local property tax on PV ▪ PV exempt from sales-and-use tax	▪ Municipalities have that option to offer property tax exemptions for renewables and CHP	▪ Businesses can deduct solar and wind system costs from net income for excise tax purposes ▪ 15% credit against state income tax for a renewable system on a primary residence ▪ Solar and wind devices used for primary or auxiliary power qualify for property tax exemption for 20 years	▪ Sales tax exemption for net-metered renewable systems and residential and commercial systems not connected to grid.	▪ Local option residential property tax exemption ▪ 56 towns have elected to offer for solar, wind, or central wood heat	
Forward Capacity Market (FCM) payments	▪ ISO New England has established a mechanism whereby payments will be made to generators, including DG, that bid into the FCM and commit generating capacity to meet the region's peak demand.	▪ ISO New England has established a mechanism whereby payments will be made to generators, including DG, that bid into the FCM and commit generating capacity to meet the region's peak demand.	▪ ISO New England has established a mechanism whereby payments will be made to generators, including DG, that bid into the FCM and commit generating capacity to meet the region's peak demand.	▪ ISO New England has established a mechanism whereby payments will be made to generators, including DG, that bid into the FCM and commit generating capacity to meet the region's peak demand.	▪ ISO New England has established a mechanism whereby payments will be made to generators, including DG, that bid into the FCM and commit generating capacity to meet the region's peak demand.	▪ ISO New England has established a mechanism whereby payments will be made to generators, including DG, that bid into the FCM and commit generating capacity to meet the region's peak demand.

Table 4. Initiatives, Policies, and Regulations Supporting DG in RI and Select Industrial States

	Rhode Island	New York	New Jersey	California
Recent DG Initiatives by States	▪ *Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006*	▪ Case No. 04-E-0572 (Mar 2005) a Con Edison Base Rate Case launched a 300 MW/$250 M initiative with DG, EE, and LM from 2005-2008.		
Interconnection Standards	▪ NGrid revised its rules in 2002 ▪ NGrid uses a streamlined process for net metered systems, based on MA practices	▪ Statewide standards for interconnection of DG to 2 MW ▪ Simplified rules for systems to 10 kW ▪ All DG is eligible ▪ Case 04-E-0572 launched a Fault Current Study of all Networks re DG	▪ Statewide standards for interconnection of DG to 2 MW ▪ Simplified rules for small systems up to 10 kW	▪ Statewide standards for interconnection of DG to 10 MW ▪ Net metered systems exempt from many interconnection fees ▪ Simplified rules for renewables <10kW
Net Metering	▪ Renewables up to 25 kW ▪ Aggregate net metered capacity cap of 1 MW ▪ NEG credited to next bill at retail rate for 12 months; excess granted to utility after 12 mos.	▪ 10 kW for solar; 25 kW for residential wind; 125 kW for farm-based wind; 400 kW farm waste ▪ Caps vary by technology ▪ NEG credited to next bill at retail rate for 12 mo.; utility buys excess at avoided cost rate at end of 12 months	▪ Renewables up to 2 MW limit for commercial and residential ▪ No cap ▪ NEG credited rate to next bill at retail rate; utility purchases excess at avoided cost rate at end of 12 months	▪ Renewables up to 1 MW ▪ Aggregate cap of 2.5% of utility peak demand ▪ NEG credited to next bill at retail rate for 12 months; excess granted to utility after 12 mos.

	Rhode Island	New York	New Jersey	California
Portfolio Standards	▪ RES requires 16% of sales from renewables by 2019.ACP adjusted annually ($55.13/MWh for 2006).	▪ 25% of supply from renewables by 2013 (this will require 3700 MW of new generation)	▪ 22.5% of supply from renewables by 2021 ▪ Minimum of 2.12% of total sales must be generated by solar by 2021	▪ Requires 20% renewables by 2010 and 33% by 2020
Back-up and Standby Rates	▪ On-site renewable DG up to 3 MW aggregate is exempt; net-metered customers not counted toward this cap ▪ All DG with nameplate of 30 kW or less is exempt ▪ NGrid Back-up rates include Monthly Service charge, Back-up Service charge, and Supplemental Service charge ▪ kW Demand for calculating charges includes generator meter demand plus service meter demand	▪ Small CHP <1 MW and environmentally beneficial technologies are eligible for standby exemption to 5/31/09 ▪ Exempts DG with nameplate no greater than 15% of customer's max. demand ▪ Customers installing "Designated Technologies" after 5/31/06 are eligible for "otherwise applicable rates" plus phased-in "bill differential" based on operational date		▪ Exempts DG, 5 MW or smaller, that meets fuel and environmental criteria from stand-by charges ▪ Exempts solar DG up to 1 MW that does not export to the grid from add'l charges

	Rhode Island	New York	New Jersey	California
CHP Gas Rates	▪ Gas used for CHP is exempt from DSM surcharge	▪ Special gas delivery rates for gas-fired DG, including residential DG		
Grants	▪ Limited renewable project support from RIREF	▪ NYSERDA offers a changing menu of grants / incentives supporting CHP and renewables	▪ NJ CHP Program offers incentives for eligible systems up to 1 MW, varying by technology, through gas utilities ▪ The Customer On-site Renewable Energy (CORE) program provides rebates to projects ▪ 20% grant for eligible solar, wind and biomass > 1MW	▪ The Self Generation Incentive Program (SGIP) provides incentives for DG systems using renewable and non-renewable fuels. Maximum eligible system size is 5 MW. Incentives range from $0.60/W to $4.50/W based on technology and fuel
Loans	▪ Limited renewable project support available from RIREF			

	Rhode Island	New York	New Jersey	California
Tax treatment	▪ Law limits local property tax on PV ▪ PV exempt from sales-and-use tax	▪ 15 year real property tax exemption at the discretion of county and local authorities ▪ Residential solar systems exempt from sales taxes	▪ Full exemption from sales tax for all solar and wind systems	▪ CA Revenue and Tax Code allows a property tax exemption for certain types of solar systems
Forward Capacity Market (FCM) payments	▪ ISO New England has established a mechanism whereby payments will be made to generators, including DG, that bid into the FCM and commit generating capacity to meet the region’s peak demand.			

In New England, the clean energy funds in both Massachusetts and Connecticut (the Massachusetts Renewable Energy Trust and the Connecticut Clean Energy Fund) have made long term commitments to offering financial incentives for renewable distributed generation and are working to mitigate a variety of barriers that discourage investment in these technologies. The northern New England states (Maine, New Hampshire and Vermont) have been less active than Southern New England in implementing initiatives to encourage and support renewables and distributed generation, though individual states have renewable incentives (i.e. Vermont) and strong net metering provisions (i.e. Maine).

Massachusetts

In Massachusetts, a Distributed Generation Collaborative, supported by the Massachusetts Renewable Energy Trust, has been working from 2003 through 2006 on issues related to distributed generation.[8] Also, the Massachusetts Department of Telecommunications and Energy (DTE) has an ongoing docket on distributed generation, MA DTE 02-38. Thus far, these efforts have resulted in DTE-mandated interconnection standards and practices adopted by all distribution utilities, as well as research on the economic benefits of distributed generation.

Connecticut

Connecticut has undertaken several initiatives to promote distributed generation, driven in large part by the transmission capacity constraints in Southwest Connecticut. Several of these initiatives are described in detail in a document prepared by a working group member, The E Cubed Company, which is attached to this report as Appendix C.[9]

The Connecticut Legislature made a significant commitment to distributed generation in June 2005 with the passage of ***An Act Concerning Energy Independence*** which was targeted at ten percent peak load reduction and mitigating the risk of the onset of higher costs for capacity within in the State and across New England. Among other provisions, the act:

- establishes a new tier (“Tier 3”) in the Renewable Portfolio Standard for DG;
- provides for capacity-based incentive payments to qualifying customer-side distributed generators;
- mandates creation of a DPUC sponsored a loan program for customer-side DG;
- eliminates backup charges for new distributed generation implemented after July 1, 2006, while allowing distribution utilities to recover their costs of service;
- waives the retail delivery charge for transporting natural gas to customer-side DG; and
- allows distribution companies to invest in limited “grid-side distributed generation.”

[8] Information about the Massachusetts DG Collaborative, including a wealth of resource documents, is available on the Massachusetts Renewable Energy Trust website at: http://www.masstech.org/renewableenergy/public_policy/DG/collab_overview.htm

[9] Due to time constraints, the other members of the working group were not able to review this Appendix prior to the issuance of this report.

Connecticut also recently increased net-metering levels to 500 kW for renewable generation systems.

Maine

In 2003, Maine's Public Utilities Commission (PUC) reported on issues related to DG in Maine at the request of the Legislature's Utilities and Energy Committee.[10] The PUC focused on two issues: the regulatory structure for retail sales by DG owners and interconnection. The PUC recommended against legislative change on either issue.

New Hampshire

No significant policy initiative has emerged in New Hampshire regarding distributed generation and the state has taken little action to encourage such generation, either renewable or fossil fuel fired. There is no renewable portfolio standard, no clean energy fund, and limited net metering. Towns have the option to offer property tax abatements for residential renewable systems and over 50 have done so. The state also has adopted interconnection standards that differentiate small and larger system requirements.

Vermont

In September 1999, the Vermont Public Service Board (PSB) opened Docket 6290, concerning distributed utility planning. As part of this docket, in 2003, the PSB approved a memorandum of understanding under which electric utilities would include energy efficiency and distributed generation as part of a least-cost approach to resolving transmission and distribution constraints.[11] In September 2006, the Vermont Public Service Board adopted statewide interconnection standards.[12]

[10] See http://www.maine.gov/mpuc/staying_informed/legislative/2004legislation/DG-Rpt.pdf
[11] Information is available at http://publicservice.vermont.gov/energy-efficiency/ee_distributilplanning.html
[12] Available at http://www.state.vt.us/psb/rules/OfficialAdoptedRules/5500_Electric_Generation_Interconnection_Procedures.pdf.

BENEFITS OF DISTRIBUTED GENERATION

The General Assembly finds in the Act that "properly designed regulatory and financing programs for distributed generation can have both system benefits and economic benefits." It finds further that system benefits of DG are a function of the location of the capacity, the reliability and efficiency of the DG facilities individually or collectively, and the time of operation.[13]

The Act identifies a number of potential benefits attributable to "well implemented distributed generation," including electric system reliability and efficiency, reduced congestion, and added capacity "to mitigate the need for additional central generating capacity in the region." In addition, renewable distributed generation is said to diversify power sources and potentially temper price volatility.[14]

This section presents benefits of distributed generation discussed and analyzed by the Stakeholders. The benefits have been divided into two categories: benefits that accrue to the DG host/owner and benefits that accrue to other customers and society at large. This distinction is important because only benefits and costs that accrue to the system host/owner are factored into decisions regarding whether or not to install DG. If societal benefits created by DG systems are not monetized and made available to customers considering such investments, they may be forced to forgo these investments by unacceptably long paybacks and competition for capital.

QUANTIFYING BENEFITS

The Act directs the Stakeholders to make "findings and recommendations using methods for determining and quantifying system benefits attributable to distributed generation."[15] The Stakeholders had extensive discussion about the best way to approach this quantification task, given the voluntary nature of the working group process, the capabilities and availability of the participants, and the time available to complete the analysis. They also reviewed the efforts of other jurisdictions to quantify the benefits of distributed generation.

The quantification of DG benefits has challenged jurisdictions that have attempted it, for a number of reasons. First, any analysis of the costs and benefits is highly dependent upon a set of assumptions, including projections of future electricity and natural gas prices and estimates of DG market penetration levels, timelines for that penetration, mix of DG technologies installed, etc. Second, both the costs and benefits of DG are highly technology- host- and location specific. The costs and benefits of a CHP system vary from those of a PV system, which vary from those of a small wind turbine, which vary from those of a fuel cell. Even within a single technology, the costs and benefits vary depending on the host. For example, the costs and benefits of a CHP system are different at hospitals, schools, manufacturing facilities, in office buildings, and in private residences. Costs and benefits also vary depending on exactly where the system is sited, including whether it is in an area where the local distribution system is due for an

[13] R.I. Gen. Laws, § 42-140.2-1.
[14] Id
[15] RI Gen. Laws, § 42-140.2-2(3)

upgrade and, if so, when, why, and at what cost. Third, many of the societal benefits of DG are very difficult to quantify in monetary terms. This sub-category of benefits includes such "goods" as fuel diversity, market price elasticity, reduced risk to the grid, ease of siting, and local economic impacts and job creation.

Some jurisdictions have concluded that quantification with any certitude of the total benefits or typical benefits associated with DG installations is not feasible. They choose instead to limit themselves to calculating the benefits and costs of specific, sample DG installations, rather than calculating the overall costs and benefits of DG for a state.

For example, the lengthy analysis prepared by Navigant Consulting for the Massachusetts DG Collaborative,[16] cited in some detail below, calculates benefits from eight sample installations of certain sizes that use particular technologies in particular applications in specified locations served by particular electric distribution companies. Even then, Navigant was able to quantify only a subset of the total benefits they believe are created, leaving calculation of the remaining benefits for later analysis.

Other jurisdictions have attempted holistic analyses, looking at system-wide impacts of various generic, but alternative DG futures. For example, the US Combined Heat and Power Association (USCHPA) points to a recent effort led by Greenpeace with the World Alliance for Decentralized Energy (WADE) to examine the economic and environmental policies consequences of policies that encourage the more rapid uptake of DG technologies. [17] However, such analyses necessarily require access to system data and significant costs for data acquisition and analyses, and are particularly challenging for volunteer, collaborative processes such as this one.

In light of the above, the Stakeholder Group determined that it would not be possible for it to quantify the overall benefits of DG for Rhode Island within the time available to submit this report. Instead, the Group describes the benefits qualitatively below, with citations to some of the quantification efforts attempted by others. In the final section of this report, the Group outlines a set of next steps that would enable it to quantify the costs and benefits.

BENEFITS TO THE DG HOST/OWNER

Distributed generation, located behind the customer's electric meter, is distinct from central generation in that it requires a decision by the customer whose core business is not electricity production to take on the costs, risks, and the responsibilities for building and owning an electricity generation facility. Distributed generation will compete with other potential investments for available capital. Some investors will require that the investment be recovered out of positive cash flows created. Others will insist that the DG investment meet a specific rate of return requirement.

Installation of distributed generation is dependent on a prospective system owner making a determination that the benefits created by the system for the owner will exceed the cost of installation. Owners can realize a number of different types of benefits from installing distributed generation: financial benefits that affect their return on investment, reduced

[16] Navigant Consulting, Distribution and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative, January 2006
[17] http://www.localpower.org/documents_pub/reporto_greenpeace_modelrun.pdf

operating risk, and (potentially) increased good will of customers, employees, and communities. Specifically,

Electricity Bill Savings

The DG system owner avoids electric utility charges on electricity the customer generates on-site that replaces electricity that the customer would otherwise buy over the grid. These savings are reduced or offset, however, for customers that are subject to utility standby charges and/or high demand changes for service delivery.

Fuel Savings

A customer with DG can reduce its overall fuel cost if the DG uses renewable fuels or uses fuel more efficiently by replacing a stand alone boiler with a combined heat and power system.

Energy Sales Revenue

If the DG customer generates more electricity than it consumes on-site, the customer realizes revenue from the sale of the excess generation. The price the customer realizes for that generation is a key issue in project economics, as is discussed in the Barriers section below.

Increased Reliability

DG systems can be designed to increase the reliability of the owner's electricity supply by providing ongoing power for operations during utility supply outages.

Green Branding

An investment in renewable generation or other clean distributed generation is viewed by many owners as a statement to their employees, customers, and community that they are sensitive to the dangers of global warming. Clean DG owners may choose to publicize their commitment to clean electricity generation for public relations purposes.

Existing Subsidies

<u>Emission Credit Revenue</u>

Clean DG may be eligible for emission credits and be able to realize revenue from the sale of those credits.

<u>Renewable Energy Certificate Sales Revenue</u>

Renewable DG qualifies for renewable energy certificates (RECs) and can realize revenue from the sales of those certificates either in Rhode Island or in other states where there is a REC market.

<u>Tax Benefits</u>

A system owner, depending on his tax status and the DG technology employed, may qualify for investment tax credits or depreciation credits to help offset the capital costs for a system and for other advantageous tax treatment.

Capacity Sales Revenue

DG can be designed to participate in ISO New England's Forward Capacity Market. New (installed after June 16, 2006) DG system owners can bid their capacity into that market, and will realize revenue in the form of capacity payments if their bids are successful. Participation in this market will require developing bid strategies, installing specialized metering, and conducting measurement and verification. Minimum size requirements for bids/offers may require aggregation of multiple units.

Demand Response Program Revenue

Customers with distributed generation can participate in ISO New England's Demand Response programs which compensate DG owners for reducing consumption when demand is high and system reliability is at risk.

BENEFITS TO OTHER ENERGY USERS AND SOCIETY

In addition to the benefits to the host/owner, DG has the potential to create benefits for other energy users and for society as a whole. As noted above, if these benefits can be monetized and allocated to DG owners, they will support additional investments in DG. However, as also noted above, quantification of these benefits is difficult.

The potential benefits of DG identified by the various Stakeholders are discussed below, with citations to some of the studies that have attempted to quantify these benefits. Not every benefit was recognized by every Stakeholder and all Stakeholders recognized that not every DG installation would produce all of the benefits. As noted above, the benefits are highly technology- and location-specific.

Reduced Electricity Costs

By reducing demand, DG can reduce the market price of electricity. Many recent studies have identified this effect as a key benefit of DG and other demand-side resources.

Discussion

Navigant Consulting Inc., in its extensive economic analysis of DG benefits in support of the Massachusetts DG Collaborative, performed a literature review of more than 20 documents addressing the effect of DG on electricity prices.[18] Navigant concludes:

1) Many studies support the notion that increased adoption of DG generally leads to reduced electricity market prices and increased price elasticity, and

2) Although several attempts have been made to quantify these benefits, there are no widely adopted numerical values supporting this understanding.

These benefits stem from all forms of demand response, including but not limited to DG. A February 2003 report from Lawrence Berkeley National Laboratory describes the

[18] Memorandum to Fran Cummings, Massachusetts Technology Collaborative, from Navigant Consulting Inc., *An Elaboration of Navigant Consulting Inc.'s Final Report 'Distribution and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative'*, June 22, 2006, pp.6-7

benefits of distributed resources DG as including the "enhanced electricity price elasticity" and its tendency to "lower prices to the benefit of all consumers" due to the reduced market power of large generators.[19] A U.S. Department of Energy report states that the financial benefits of demand resources include, "lower wholesale market prices that result because demand response averts the need to use the most costly-to-run power plants during periods of otherwise high demand, driving production costs and prices down for all wholesale electricity purchasers." [20]

Focusing on reports that explicitly refer to this benefit arising from DG, Navigant observes that, in its general policies and principals for evaluating DG facilities, the California Public Utilities Commission (CPUC) determined that "the impacts of DG on market prices" should be included as a societal benefit." [21] Further, a Congressional Budget Office (CBO) paper titled *Prospects for Distributed Electricity Generation* reports that:

> If retail customers had the capability to adjust their net demand for utility-supplied power through distributed generation … then wholesale prices would be less volatile and lower, on average. In particular, wider use of distributed generation would tend to reduce the size and frequency of extreme short-term price spikes. [22]

According to the CBO, these short-term price responses will lead to lower prices long term because large generators will ultimately come to "accept lower prices in long-term contracts." [23]

Some have attempted to quantify these benefits. For example, a report published by the Center for Energy Efficiency and Renewable Energy and the University of Massachusetts calculates as much as a 13.75% reduction in locational margin pricing for a given day as a result of combined heat and power (CHP) facilities." [24]

Recognizing the challenges of quantification, Navigant concludes that:

> DG is generally acknowledged to present a societal benefit in terms of electricity market price reductions and increased price elasticity, but quantifying these benefits poses numerous challenges. These challenges

[19] Gumerman, E.; Bharvikar, R.; LaCommare, K.; Marnay, C. Evaluation Framework and Tools for Distributed Energy Resources, February 2003, Ernesto Orlando Lawrence Berkeley National Laboratory, p. 24.

[20] U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, p. vi.

[21] Simons, G. CPUC Self-Generation Incentive Program Preliminary Cost-Effectiveness Evaluation Report, September 14, 2005, Itron, Inc., p. 1-3.

[22] Prospects for Distributed Electricity Generation, September 2003, Congress of the United States: Congressional Budget Office, p. 17. Available at: http://www.cbo.gov/ftpdoc.cfm?index=4552&type=1

[23] Prospects for Distributed Electricity Generation, September 2003, Congress of the United States: Congressional Budget Office, p. 18.

[24] Kosanovic, D., Beebe, C., System Wide Economic Benefits of Distributed Generation in the New England Energy Market, Center for Energy Efficiency and Renewable Energy (CEERE) and the University of Massachusetts, February 2005, pp. 1 and 8

> are not unique DG and its benefits, but rather are symptomatic of attempting to quantify something as abstract as societal economic values.[25]

Some Stakeholders, while recognizing the accepted principle that reductions in demand lead to reductions in price, offer two cautionary notes. First, they suggest that very small amounts of DG may not affect prices; to affect prices, there must be enough DG to affect resources at the margin. Second, there is a circumstance under which, even if DG lowers regional electricity prices, it could increase Standard Offer and Last Resort Service prices if the suppliers of those services perceive increased penetration of DG as increasing their level of risk.[26]

Reduced Natural Gas Prices

Some Stakeholders suggest that, by reducing the need to burn natural gas in central power plants, DG could reduce market demand for natural gas and thus upward price pressure on limited supplies. This can be true even for natural-gas-fired DG (as long as it is efficient), if it displaces older, less efficient, gas-fired central generation. Similarly, Micro-CHP using natural gas that otherwise would have been solely used for heating gets extra electricity benefits from the same fuel use. However, other Stakeholders suggest that, given that natural gas prices are set in a national market, the reduction in natural gas demand due to DG in Rhode Island would be too small to affect prices.

<u>Discussion</u>

The American Council for an Energy Efficiency Economy found that:

> if policy initiatives to increase investment in energy efficiency and renewable energy were implemented, gas prices would fall about 20 percent within five years, saving over $100 billion…Findings were in-line with the recommendations of the National Petroleum Council's major report on the future of natural gas in the United States.[27]

Energy and Environmental Analysis, Inc., in an October 2003 report to the USCHPA,[28] found that increasing CHP capacity by 50 percent over existing levels could reduce natural gas consumption by 4.2% in the Northeast. They observed that small changes in demand can have large effects on gas price because the gas market today is at a very inelastic point on the price curve. They also suggest that increased use of CHP moves electric generation from the potentially volatile central grid market to more base loaded CHP facilities and that provides more constant gas use and can reduce volatility in gas markets.

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[25] Navigant Memo to Fran Cummings.
[26] Standard Offer and Last Resort Service are load following services, meaning that the supplier is obligated to serve the customers' load, no matter what it is. If suppliers perceive DG as increasing their volume risk, they may increase their price. However, any such increase could be partially offset by any dampening effect DG has on wholesale market prices.
[27] American Council for an Energy Efficiency Economy, <u>Impacts of energy Efficiency and Renewable Energy on Natural Gas Markets: Updated and Expanded Analysis</u>, Report Number E052, April 2005. Available at: http://www.aceee.org/pubs/e052full.pdf
[28] http://uschpa.admgt.com/chp_gasoct03.pdf

However, some Stakeholders point out that, since natural gas prices are set in a national market, it is unlikely that any reduction in natural gas use caused by DG in Rhode Island will be large enough to affect prices. Other Stakeholders counter that, by this logic, the small state or Rhode Island would not pursue any policy through which it might make a small contribution to solving a large problem, for example reducing emissions of greenhouse gases.

Reduced Transmission and Distribution Line Losses

Because it is sited at the customer load, DG avoids the line losses that occur when electricity generated in central stations travels to customers through the transmission and distribution system. With average system losses of 8%, this means that 100 MW of central generation can be replaced by just 92 MW of DG. This effect enhances the environmental, fuel efficiency, and other benefits of DG.

In its analysis for the Massachusetts DG Collaborative, Navigant Consulting identifies avoided electric system losses as a benefit to other rate payers and to society as a whole. This is because reductions in load through DG create greater than average reductions in losses. As Navigant explains:

> Heat losses increase as the square of load. Therefore a load reduction – for example, from running DG – will reduce line/winding losses (per kW of DG running) more than the average loss per kW of total load. In other words, loss reductions at the margin are greater than average losses. For typical substation and feeder load profiles reduced on the order of 5% by DG, the savings (per kW of DG) will be roughly 1.9 times the pre-DG line/winding loss per kW of load on the feeder.[29]

For the eight specific CHP project opportunities it analyzed, Navigant calculated a $NPV/kW benefit ranging from $600 to $1,250.[30] Their methodology assumes that, "the electric generation supplier is responsible for the transmission and distribution losses when it generates electricity, which then impacts total emissions from central power plants [and] cost of electricity to other ratepayers."

Higher Security and Reliability

Some Stakeholders suggest that there are inherent reliability and security benefits associated with replacing few nodes with many nodes, as is implicit in a more DG-dependent grid.

<u>Discussion</u>

The security benefit of DG is listed as a "potentially important" but un-quantified benefit in Navigant Consulting's analysis for the Massachusetts DG Collaborative:

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[29] Navigant Consulting, <u>Distribution and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative</u>, January 2006, p. 129. Navigant's analysis is based on typical feeder load factors. Navigant assumes that the average electrical losses in the transmission and distribution system are 2% and 6% respectively, and that distribution system losses are composed of fixed no-load losses (2%) and line/winding losses (4%) to total the 6%.
[30] Id, p. 35

> The dispersal of generators makes the energy supply and delivery system less susceptible to a coordinated attack on a few points. DG could also harden individual facilities; especially critical governmental, industrial, or commercial facilities in need of secure, reliable, rapidly available, high-quality power.[31]

The Congressional Budget Office also discussed this benefit.

> Security benefits of distributed generation relate to the current vulnerability of the nation's electricity infrastructure to terrorist attacks. Most of the nation's electricity comes from large central generation plants and moves over an extensive network of transmission lines, which would be difficult to defend against a physical attack. The operation of that system relies on telecommunications and computers to relay instructions to dispatch generating units and route power supplies. Those controls are increasingly tied to the online operation of regional wholesale markets that balance supply and demand and set prices. If more of the nation's electricity supply originated in the homes and businesses where it was consumed, the adverse consequences of any attack that disrupted the network would be diminished.[32]

Also, some Stakeholders suggest that reliability is enhanced by DG because, for equally designed and constructed units, it is more likely that one 100 MW unit will fail than that 100 1 MW units will fail simultaneously. Others suggest that this implies that DG units would utilize utility grade components with the necessary redundancy in balance-of-plant equipment as do utility-grade plants.

In addition, some Stakeholders DG that operates at system peaks reduces demand on the grid when it is under the greatest stress.

Reduced Reserve Requirement

By reducing losses and improving reliability as discussed above, DG reduces the necessary reserve requirement at any given time.

Deferral of Distribution and Transmission System Upgrade Costs

By slowing the rate of load growth, DG can defer or even avoid distribution and transmission system upgrade costs. There were a number of points of view within the stakeholder group on this point. All recognized this benefit in theory, but some Stakeholders expressed the view that it would be realized only when DG reaches a high level of penetration. Also, the Stakeholders recognized that this benefit is highly location-specific, that there are some locations where siting DG would reduce distribution costs and other locations where siting DG could potentially increase distribution costs.

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[31] Navigant Consulting.

[32] Prospects for Distributed Electricity Generation, September 2003, Congress of the United States: Congressional Budget Office, p. 19.

Discussion

Navigant's project specific analyses completed for the Massachusetts DG Collaborative identified a benefit of $60 to $140 NPV/kW[33, 34]associated with deferred distribution system investment associated with DG projects. Navigant analyzed eight specific project opportunities identified by Massachusetts Distribution Companies.[35] This enabled them to account for the specifics of particular installation effects for their analyses.[36]

The Regulatory Assistance Project has also analyzed the opportunities that distributed resources can offer to defer distribution system upgrades in their 2001 report *Distribution System Cost Methodologies for Distributed Generation*,[37] concluding that that there are many opportunities to implement distributed resources in lieu of traditional wires and transformers solutions.

New York's regulated utilities conducted pilot programs regarding incorporating DG into distribution utility planning for three years from 2001-2004. The results of these pilot programs were evaluated in 2006 by the Pace Energy Project and Synapse Economics. [38] Two areas of recommendations were offered, with one area involving improvements to the RFP process while the other set involved alternatives to an RFP process for integration of DG in distribution planning.

The New York Public Service Commission has approved a three-year rate plan for Consolidated Edison that includes a 150 MW targeted transmission and distribution deferral component. This has led to Rounds Two (43 MW awarded to three providers announced in January 2007) and Three (bids for up to 109 MW due by February 5, 2007). In addition, a system wide program of 150 MW of distributed generation, energy efficiency, and load management was also set up to be administered by NYSERDA. Both programs need to average no more than $750/kW. It is also important to note that both Con Edison and NYSERDA are allowed 7.5% to manage and evaluate their respective

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[33] Navigant Consulting, Distribution and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative, January 2006, p. 35

[34] Navigant's net present value (NPV) calculation uses a 20 year time period and discount rates ranging from 3% to 9%depending on the entity that realizes the benefit.

[35] Utility Distribution Planning Situations Analysis, March 9, 2005. Available at: http://www.masstech.org/renewableenergy/public_policy/DG/resources/Collab_2005Collab05_03_09_DP_UtilityList.xls

[36] Navigant's methodology assumes that "there is sufficient distributed energy resource in the opportunity to enable a deferral of the asset for three years. The contribution of this deferral asset to the distribution system deferral is on a kW basis and is independent of the type of DG. A factor of 1.5 is used to approximate the actual capacity of DG to ensure sufficient reliability to meet distribution system needs.[36] There is a net positive societal impact because the budget that would have been spent on deferral is spent to upgrade another part of the distribution system. Navigant Consulting, Distribution and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative, January 2006, p.124

[37] http://raponline.org/Pubs/DRSeries/DistCost.PDF

[38] Pace University Energy Project and Synapse Economics, A Comprehensive Process Evaluation Of Early Experience Under New York's Pilot Program For Integration Of Distributed Generation In Utility System Planning Final Report 06-11, August 2006 New York State Energy Research And Development Authority. Available at: http://www.nyserda.org/publications/06-11-IntegrationofDGPilot-complete.pdf

programs. The utility obtains a $22,500/MW incentive payment for all MW acquired in the two programs.[39]

However, some Stakeholders suggest that widespread use of DG could potentially degrade reliability or necessitate costly upgrades to the distribution system. The Congressional Budget Office discussed this risk:

> Without adequate upgrades to the electricity supply network, widespread adoption of distributed generation could adversely affect regional electricity distribution systems. For example, with many customers switching their generators on and off, the quality of the power and the reliability of the systems could be degraded. Moreover, because utilities could have difficulty pinpointing the sources of the degradation, they might not be able to allocate to the owners of distributed generators the costs of preventive actions.
>
> It may be difficult to develop economically sound policies on how to pay for any required upgrades in the utility infrastructure to protect against those risks. Experts generally agree that the current risks to the distribution system from the parallel operation of small generators, representing only a small fraction of a local distribution network's capacity, are usually manageable. But the cumulative effects of many generators would be another matter. The utility network might require significant up grades and additional protective devices to manage distributed generators that could use a large fraction of the local distribution network's capacity.[40]

Competition for the Distribution Utility

Some Stakeholders suggest that DG can create competition for monopoly distribution utilities. The risk of losing customers to DG, these Stakeholders argue, will pressure utilities to become more efficient and to strive to provide better service at lower cost. Other Stakeholders counter that PUC regulation creates these pressures for utilities.

Ancillary Services Benefits

If located in areas where there is a need for power factor correction, voltage stability, phase balancing, and harmonics correction, DG creates ancillary services benefits.

<u>Background</u>

Navigant Consulting, in its Massachusetts analysis of DG benefits,[41] notes that while DG units will be unlikely or unable to participate in markets for Load Following, Operating Reserves, and Dispatch and Scheduling, synchronous DG may offer some of these

[39] Case 04-E-0572-Consolidated Edison Company of New York, Inc. – Electric Rates, <u>Order On Petitions For Modifications And Modifying Electric Rate Order</u> (December 22, 2006) and Case 04-E-0572-Consolidated Edison Company of New York, Inc. – Electric Rates, <u>Order Adopting Three-Year Rate Plan</u> (March 24, 2005)("Rate Order")

[40] <u>Prospects for Distributed Electricity Generation</u>, September 2003, Congress of the United States: Congressional Budget Office, p. 21.

[41] Navigant Consulting, <u>Distribution and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative</u>, January 2006, p.125

benefits when operating. Navigant estimates the potential value of Ancillary Services for synchronous DG to other electric ratepayers is $0.003/kWh.[42]

Increased Fuel Diversity

Renewable DG will increase fuel diversity, reducing the region's heavy reliance on natural gas to generate electricity. Even gas-fired CHP may reduce the region's reliance on gas, if it replaces older, less efficient gas-fired central generation.

Background

The benefit of increased fuel diversity is difficult to quantify, though there is general consensus that diversity is a protection against disruption of individual fuels and can influence and affect future energy price and supply.

Indeed, the General Assembly recognized this benefit in the legislation that created the Renewable Energy Standard ("RES"),[43] finding that:

> The people and energy users of Rhode Island have an interest in having electricity supplied in the state come from a diversity of energy sources including renewable resources

Support for Renewable Energy Standard (RES) Goals

Rhode Island's RES requires that the state's retail electricity providers supply 3% of their retail electricity sales from renewable resources starting in 2007, escalating to 16% by the end of 2019. Governor Carcieri has ordered the OER to secure 20% of the state's electricity from native renewable generation by 2014. Renewable DG will increase the supply of electricity to meet those requirements.

Ease of Siting

DG eases the siting of new supply, avoiding the usual conflicts over new central generation and transmission line location.

Discussion

In its *Evaluation Framework and Tools for Distributed Energy Resources*, Lawrence Berkeley National Laboratory identifies the ease of siting distributed resources (compared to central generation and transmission projects) as a societal benefit with a "[s]ignificant potential for direct policy intervention to change incentives." They note that:

> A cry goes up for new power plants whenever a power emergency hits, but once a site is chosen for a new power plant, opposition raises up from many directions…The problem is even more severe for transmission line projects, which usually succeed or fail based on local opposition. Investment in transmission has been falling in the U.S. since the 1980's.

[42] Navigant's figure is based on Energy and Environmental Economics' model of avoided costs in CA (http://www.ethree.com/cpuc_avoidedcosts.html). In that model, there is a $0.003/kWh adder to the energy component of avoided costs to account for the reliability benefits that DG provides through ancillary services. *CPUC Self-Generation Incentive Program Preliminary Cost-Effectiveness Evaluation Report*, Itron Inc. September 14, 2006. Available at: http://www.itron.com/asset.asp?path=assets/itr_001094.pdf

[43] R.I. Gen. Laws § 39-26-1 et seq.

> Nobody wants the newest and cleanest plants or power lines near their homes or schools. This seeming contradiction, that while everybody wants more power, lower prices, and no blackouts, yet nobody wants the new power plants to be built nearby, is longstanding and intractable. More [DG] should reduce the number of central station plants built near people who share NIMBY sentiment.[44]

Environmental Benefits

By displacing central generation, clean DG reduces emissions of criteria pollutants and greenhouse gases and reduces water use. Renewable DG will help avoid the many environmental problems created by mining, transportation, and conversion of conventional fuels to generate electricity. Also, by reducing the need to build new central generation, DG reduces the land use impacts. The environmental benefits created by DG systems will vary with their location, the technologies involved, and the generation displaced.

The Disclosure Label for Standard Offer Service identifies the resource mix and emissions associated with Standard Offer.

[44] Gumerman, E. et al, Evaluation Framework and Tools for Distributed Energy Resources, February 2003, LBNL-52079, p. 28. Available at: http://www.eere.energy.gov/de/pdfs/de_evaluation_framework_tools.pdf.

The Disclosure Label

Electric power suppliers are required by the Rhode Island Public Utilities Commission to provide customers with a disclosure label. The label enables consumers to look at the energy sources and air emissions of the power used to serve their needs. Consumers can compare energy labels to make the best choice based on their energy needs.

Electricity Facts

Standard Offer Service for National Grid Customers in Rhode Island

Power Sources

Demand for this electricity product in the period 4/1/05-3/31/06 was assigned generation from the following sources:

Power Source	Resource Mix
Biomass	**0.1%**
Coal	**12.7%**
Diesel	**2.3%**
Digester Gas	0.0%
Efficient Resource	0.0%
Fuel Cell	0.0%
Hydroelectric/Hydropower	**2.5%**
Jet	**1.5%**
Landfill Gas	0.0%
Municipal Solid Waste	0.0%
Natural Gas	**36.3%**
Nuclear	**28.0%**
Oil	**6.1%**
Solar Photovoltaic	0.0%
System Mix	**8.8%**
Trash-to-Energy	**1.4%**
Wind	0.0%
Wood	**0.3%**

Air Emissions

Air emissions from the electric power resources used to serve National Grid's Standard Offer Service customers in Rhode Island are compared to the New England regional average air emissions for all power resources in the period 4/1/05-3/31/06.

Air Emissions	Pounds per MWh	Air Emissions as a % of NEPOOL System Mix
Carbon Dioxide	926.420	73.9%
Carbon Monoxide	1.287	39.7%
Mercury	0.000	2.2%
Nitrogen Oxides	1.324	71.3%
Particulates	0.432	47.3%
Fine Particulates	0.338	60.0%
Sulphur Dioxides	3.321	79.7%
Organic Compounds	0.024	24.2%

NOTES

1. Electricity customers in New England are served by an integrated power grid, not particular generating units. The above information is based on the most recently available information provided by the Company's suppliers via the NEPOOL Generation Information System. National Grid procures its electricity supply for Standard Offer Service, on behalf of its customers, from system power contracts, not from specific generating units.
2. You may call National Grid at 1(800)322-3223 or the Rhode Island State Energy Office at (401)222-3370 for additional information.

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Discussion

The General Assembly recognized the environmental benefits of renewable generation in creating the Renewable Energy Standard ("RES"), R.I. Gen. Laws § 39-26-1 et seq. (2005), finding that:

> (c) Increased use of renewable energy can reduce air pollutants, including carbon dioxide emissions, that adversely affect public health and contribute to global warming;
>
> (d) It is in the interest of the people, in order to protect public health and the environment and to promote the general welfare, to establish a renewable energy standard program to increase levels of electric energy supplied in the state from renewable resources.

Navigant Consulting's analysis of DG benefits for the Massachusetts DG Collaborative, calculates the value to environmental stakeholders (and society as a whole) of reduced emissions associated with combined heat and power.[45] For the eight opportunities analyzed, the $NPV/kW benefit ranged between $400 and $900. A 250 kW natural gas engine CHP project at a nursing care facility in Framingham, Massachusetts in the NSTAR Electric and NSTAR Gas service territory would create $230,000 in reduced emissions on a net present value basis.[46] Navigant notes that for PV systems which tend to operate during the highest load hours, the avoided emission rates may be higher than for other technologies, since less efficient power plants are utilized during these periods.[47]

Health Benefits

By reducing emissions and air pollutants, clean DG can reduce the adverse health impacts and increased mortality associated with reduced air quality when clean or cleaner energy

[45] Navigant Consulting, Distribution and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative, January 2006, p.128

[46] The emissions value of DG is determined by calculating total emissions and by valuing each pollutant. Emission rates are based on 2003 ISO-NE annual average marginal emission rates. Navigant assumes that a DG owner's boiler burns natural gas as its primary fuel and if the DG is CHP, it will offset natural gas consumed by the DG owner's boiler. Boiler emission rates are based on historic emission levels and assume a sulfur content limit on natural gas. Navigant then determines the emissions benefit using the values cited below in the following calculation. The value of CO2 emissions is based on ICF Consulting projections in the "Very High Emissions" scenario and that an unlimited number of offsets are available for $6.50/ton, effectively providing a backstop to the CO2 allowance price.[46] The value of NOx emissions is its commodity value in the EPA SIP NOx Trading Program. For November 2005 the average monthly price was about $2,500 per ton. The value of SOx emissions is its commodity value in the cap and trade market for the EPA's Acid Rain Program. For November 2005 the average monthly price was $1,300 per ton.

- *Emissions Benefit ($)* = Σ [(Pollutant$_i$ After DG (tons) × Pollutant$_i$ Value ($/ton)) – (Pollutant$_i$ Before (tons) × Pollutant$_i$ Value ($/ton))] where i = CO2, NOx and SOx.
- Pollutant (tons) = Electric Generator Emissions + Boiler Emissions + DG Emissions
- Electric Generator Emissions = DG Owner Annual Electricity (kWh) × Emission Rate (lb/kWh)
- Boiler Emissions = Fuel Input (MMBtu) × Emission Rate (lb/MMBtu)
- DG Emissions = Fuel Input (MMBtu) × Emission Rate (lb/MMBtu)

[47] Connors, S. et al. *National* Assessment of Emissions Reduction of Photovoltaic (PV) Power Systems. 2004. Available at: http://www.masstech.org/renewableenergy/public_policy/DG/resources/EconomicsofDG-Renewables.htm

sources replace or offset the need to run older plants with harmful emissions. The health benefits created by DG systems will vary with their location, the technologies involved, and the generation displaced.

Discussion

The General Assembly recognized the health benefits of renewable generation in creating the Renewable Energy Standard ("RES"), R.I. Gen. Laws § 39-26-1 et seq. (2005), finding that:

> (c) Increased use of renewable energy can reduce air pollutants, including carbon dioxide emissions, that adversely affect public health and contribute to global warming;
>
> (d) It is in the interest of the people, in order to protect public health and the environment and to promote the general welfare, to establish a renewable energy standard program to increase levels of electric energy supplied in the state from renewable resources.

The Clean Air Task Force commissioned Abt Associates to quantify the health impacts of emissions from power plants. Their findings include[48]:

- Fine particle pollution from U.S. power plants cuts short the lives of nearly 24,000 people each year, including 2800 from lung cancer.
- The average number of years lost by individuals dying prematurely from exposure to particulate matter is 14 years.
- Hundreds of thousands of Americans suffer each year from asthma attacks, cardiac problems, and respiratory problems associated with fine particles from power plants. These illnesses result in tens of thousands of emergency room visits, hospitalizations, and lost workdays each year.
- Power plant pollution is responsible for 38,200 non-fatal heart attacks per year.
- The elderly, children, and those with respiratory disease are most severely affected by fine particle pollution from power plants.

Sulfur dioxide and nitrogen oxides emissions cause acid rain and urban soot and smog, which leads to premature death and asthma attacks. According to the Rhode Island Department of Health's report *Asthma in Rhode Island* (July 2004), there are approximately 71,250 Rhode Islanders who suffer from asthma.[49]

In a May 2000 report, the Harvard School of Public Health analyzed the health impacts associated with emissions from two power plants in Massachusetts. The analysis quantifies health impacts including: premature deaths, emergency room visits, asthma attacks, and incidents of upper respiratory symptoms.[50]

[48] Clean Energy Task Force, Dirty Air, Dirty Power: Mortality and Health Damage Due to Air Pollution from Power Plants, June 2004. Available at http://www.catf.us/publications/view/24
[49] http://www.health.ri.gov/disease/asthma/asthma-burden2004.pdf, p. 25
[50] Harvard University School of Public Health for the Clean Air Task Force, Estimated Public Health Impacts of Criteria Pollutant Air Emissions from the Salem Harbor and Brayton Point Power Plants, May 2000. Pp. 4-5. Available at http://www.pewtrusts.com/pdf/env_estimated_public_health.pdf

Job Creation and Economic Development

Some Stakeholders suggest that DG fosters economic development by reducing energy costs, both for customers that host DG systems and for all customers through DG's impact on energy prices. Reduced energy prices lower operating costs and improve the competitiveness of Rhode Island businesses, resulting in job protection and creation. In addition, DG installation creates jobs for design engineers and contractors. DG installation jobs are more likely to go to local workers than are jobs building large, central generation stations. However, it is very difficult to quantify or even state the magnitude of this benefit.

Summary of Potential Benefits

The potential benefits of DG claimed by the various Stakeholders are listed in a summary table below. As noted above, not every benefit was recognized by every Stakeholder and all Stakeholders recognized that not every DG installation would produce all of the benefits. The benefits are highly technology- and location-specific.

SUMMARY OF POTENTIAL BENEFITS
Customer, Host, Developer
▪ Electricity bill savings
▪ Fuel savings
▪ Energy sales revenue
▪ Capacity sales revenue
▪ Tax benefits from investment and depreciation
▪ Renewable energy certificate sales revenue
▪ Emission credits revenue
▪ "Green" branding
▪ Increased on-site reliability
Other Energy Users and Societal
▪ Reduced electricity prices
▪ Reduced natural gas prices
▪ Reduced transmission and distribution line losses
▪ Higher reliability and security
▪ Reduced reserve requirements
▪ Deferral of distribution and transmission system upgrade costs
▪ Competition for distribution utility
▪ Increased fuel diversity
▪ Ancillary services benefits
▪ Support for Renewable Energy Standard goals
▪ Ease of siting
▪ Environmental benefits
▪ Health benefits from reduced environmental impacts
▪ Job creation and economic development

BARRIERS TO DISTRIBUTED GENERATION IN RHODE ISLAND AND POTENTIAL STRATEGIES TO ADDRESS THEM

The Stakeholder Group identified a number of barriers to DG and potential strategies to minimize them. Stakeholders attempted to achieve consensus on a set of strategies, but this was not possible due to diverging interests and perspectives. The report describes the strategies that were identified and, in a summary section below, indicates which Stakeholders supported and opposed each strategy.

INTERCONNECTION STANDARDS – "RADIAL" GRIDS

NATIONAL GRID'S INTERCONNECTION STANDARDS REQUIRE UPDATING TO BE BROUGHT IN LINE WITH CURRENT "BEST PRACTICES" THAT HAVE BEEN ADOPTED BY MANY OTHER STATES.

Utility interconnection standards set forth the requirements for DG interconnection to the utility grid. National Grid has an interconnection standard in place that applies to customers in radial grid areas. This standard was approved by the PUC in 2002. National Grid also has adopted an informal, expedited interconnection process for inverter-based systems that are smaller than 10 kW.

National Grid presently uses different interconnection standards in Rhode Island and Massachusetts. The standards National Grid employs in Massachusetts are more recent and are based on a statewide model approved by the Massachusetts Department of Telecommunications and Energy that, in turn, is based on national standards and best practices.

To the extent Rhode Island interconnection standards employed by National Grid can be streamlined and made consistent with standards in neighboring states and national "best practices," cost and delay for DG developers can be reduced.

Potential Strategy

- Rhode Island should adopt the interconnection standards developed by the Massachusetts DG Collaborative,[51] modified as necessary to be compatible with Rhode Island law.

INTERCONNECTION STANDARDS – "NETWORK" GRIDS

NATIONAL GRID HAS NO FORMAL INTERCONNECTION STANDARDS FOR "NETWORK" AREAS.

0.25 % of customers of National Grid (i.e. 1200 customers) are located in networked portions of the grid (in Providence) where current interconnection rules do not apply. These customers account for 2% of National Grid's total load (or about 35 MW of the total 1800 MW on the system). While interconnection standards for distributed

[51] The Collaborative developed a revision in June 2006 to the Model Interconnection Standard that was first proposed to and adopted by the Massachusetts DTE. This revision has been recommended for adoption by the DTE can be found at http://www.masstech.org/DG/02-38-C_Attachment-B_Tariff-Recs_Clean_June-30-2006.pdf

generation have been approved by the PUC for National Grid's radial grid locations, no formal standards exist for DG in the network area. Instead, proposed interconnections are considered on a case-by-case basis

The interconnection standards for network grids vary significantly from state to state. Two states have standards allowing for interconnection of large DG systems in networked areas: New York (2 MW) and New Jersey (500 kW). By contrast, Massachusetts only allows network interconnection of systems under 10 kW.[52]

A national working group, the IEEE P1547.6 Working Group is currently developing standards for network grid interconnection. However, it is unclear when this national standard will be finished; it took 6 years to develop the 1547 standard. Also, this working group will address only technical requirements for interconnection, but not commercial requirements.

Potential Strategies

- Rhode Island should adopt the interconnection standard for network grids developed by the Massachusetts DG Collaborative[53], allowing interconnection of inverter-based distributed generation less than 15 kW.
- Rhode Island should continue to follow deliberations on IEEE 1547.6

STAND-BY TARIFFS

ON-SITE GENERATORS ARE ASSESSED A MONTHLY STAND-BY CHARGE BY NATIONAL GRID.

National Grid has *Back-up Service Rates* for customers with DG that sets monthly charges based on the highest coincident peak output of the generation meter plus the demand on the customer's service meter. The current Back-up Service Rates were approved in 2005 as part of a settlement process.

The National Grid standby tariff exempts customers with DG below 30 kW and exempts all renewable DG up to an aggregate total of 3 MW. There are already over 1 MW of renewable DG installations and Rhode Island seeks to significantly increase the amount of wind DG.

Some of the Stakeholders say that Standby Rates are designed to recover the fixed costs of the distribution system. Without standby rates, customers with DG will pay less and therefore either the utility will collect less revenue or other customers will need to pay more to maintain the distribution system.

Other Stakeholders suggest that Standby Rates are excessive or discriminatory (because other customers with loads similar to DG customers are not required to pay standby rates), are not based on the costs that DG customers impose on the system, and do not account for the benefits that DG creates.

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[52] The Massachusetts DG Collaborative has recommended increasing this limit to 15 kW.
[53] http://www.masstech.org/DG/02-38-C_Attachment-B_Tariff-Recs_Clean_June-30-2006.pdf

Some Stakeholders also suggest that PUC proceedings are a difficult forum for DG interests because the time, cost and expertise required to participate in PUC rate cases often exceeds that which the DG community is able to provide (especially in a small state like Rhode Island, where DG companies are unlikely to preferentially deploy intervention resources including legal and technical expertise). The result, these Stakeholders suggest, is often a settlement process driven by resource considerations. Other Stakeholders disagree very strongly with this perspective.

Potential Strategies

Three suggested strategies emerged from the Stakeholder discussions of Standby Rates. The first, endorsed by some Stakeholders, is that Standby Rates should be examined by the Public Utilities Commission. The second, endorsed by another subset, is that the General Assembly should direct the PUC to examine Standby Rates and should provide specific direction as to the issues and outcomes to be considered. Further, some Stakeholders suggest that the General Assembly should consider alternatives to the current PUC settlement process.

1. PUC Rate Case

- The PUC should conduct a rate case to examine the standby rates, specifically taking into account:
  - Costs that customers with DG impose on the distribution system as compared to costs imposed by other customers.[54]
  - The PUC should consider all costs and benefits created by DG in any proceeding concerning standby rates or any other rates that affect DG system owners
  - Benefits that DG creates for the utility and other customers, including but not limited to the marginal electricity losses that can be avoided by dispersed generation and reserve requirements that can be reduced.
  - The load profile of actual DG customers in the state as compared to other similarly situated customers
  - Based on the outcome of the rate case identified above, the PUC should set standby rates, considering all possible outcomes, including but not limited to:
    - Adjusting or eliminating the 3 MW aggregate cap on the standby rate exemption for renewables
    - Setting a different standby rate and/or rate structure
    - Eliminating all standby rates
    - Providing net credits (e.g., a negative standby rate) to customers who install DG

[54] Some stakeholders specified that this analysis should be independent of utility revenue requirements. They did not suggest that revenues should be compromised, but rather that standby rate examination must start from a consideration of costs, not from a presumption of revenue maintenance.

- This proceeding should be completed in time to allow any changes in standby rates to take effect concurrently with the other rate changes that will go into effect at the conclusion of the current rate plan in 2009.

2. General Assembly directive re PUC rate case

- The General Assembly should direct the PUC to undertake the investigation described above, should specify the issues and potential outcomes to be considered, and should direct that the proceeding be fully-litigated and not resolved by settlement.

3. General Assembly hearings re PUC settlement procedures

- The General Assembly should convene hearings to examine the potential for inequity in PUC proceedings resolved by settlement, and direct the PUC to craft new rules based on the outcome of those hearings. Among the alternative methodologies that can be considered by Rhode Island (together or separately) include:
  - A model such as that employed in California, whereby intervenors in rate cases can petition to have their legal expenses covered by the state, so as to level the playing field between all participants.
  - A model such as that employed in Illinois, whereby a settlement is only accepted by the PUC if it is joined by all intervening parties. Such a rule can help to ensure that all perspectives are factored into future settlements, although it does not specifically address the inherent costs of rate case participation.

MONETIZING BENEFITS TO RATEPAYERS AND TAXPAYERS

As described above, some stakeholders as enumerated above believe that DG can create benefits that accrue to someone other than the system owner. These benefits may include: reduced electricity prices, reduced transmission and distribution line losses, improved reliability and security, reduced environmental impacts, and increased jobs and economic development. Some Stakeholders suggest that, until these benefits can be monetized and provided to the system owner, Rhode Island will under-invest in distributed generation.

RIREF can address this barrier for renewable DG, but its funding is limited and its charge is broad. Starting in 2008, however, renewable energy development will receive additional funding through ACP funds paid by electricity suppliers as a means of compliance with the RES.

Potential Strategies

1. RI REF funding increase

- Increase funding for the Rhode Island Renewable Energy Fund to underwrite more investment in renewable DG.

2. State bond program

- Establish a state bond program to help finance local renewable generation projects and assist with the large first costs of these systems.

3. RI REF requirement

- Eliminate the requirement that Renewable Energy Fund be "self-sustaining" (R.I. Gen. Laws, § 39-2-1.2)

4. Tax benefits

- Extend to all clean DG systems the tax benefits that are currently available to renewable DG, in so far as these systems produce benefits for Rhode Island.

PRICE PAID FOR EXPORTED KWH

MOST DISTRIBUTED GENERATION SYSTEM OWNERS ARE NOT ABLE TO CAPTURE THE FULL RETAIL VALUE OF THE KILOWATT-HOURS THEY EXPORT TO THE GRID.

At times, some distributed generation systems produce more electricity than the owner / host is consuming on-site. This excess generation is exported into the grid. With the exception of systems eligible for net-metering (discussed below), the DG owner's only option is to sell these exported kW-h to the utility at a wholesale price.

The DG owner is not permitted to use the utility grid to transmit and sell the exported kW-h to a neighbor. Nor is the DG owner permitted to run his own wire to a neighbor to transmit and sell the exported kW-h. (This restriction applies only if the wire would cross a public way. It is permissible to run private wires that do not cross public ways, e.g., within industrial parks). Also, a customer cannot use the electricity he produces with DG to offset usage at other facilities owned by the customer, even if those facilities are in the same neighborhood or town; however, a customer can request National Grid to transfer any credits accrued on his account to any other account with the permission of the other account owner.

While net-metering does enable some renewable generators to capture the retail value of exported kW-h by crediting those kW-h against future usage, net-metering is limited:

- Net-metering in Rhode Island is restricted to renewable generators 25 kW or smaller, with the maximum connected net-metered capacity system-wide capped at 1 MW. Many other states allow net metering of larger systems and do not have a system-wide capacity limit.
- While net excess generation (NEG) rolls over month-to-month at the full retail rate to offset purchases from the grid, after 12 months any net excess generation is absorbed by the utility without payment to the DG customer.
- National Grid sets the 12-month period as the calendar year, though this may not be the most beneficial 12-month period for the generator, given natural seasonal variations in generation for certain resources (e.g. solar).
- Certain potential DG systems have little or no on-site usage to offset because the resource is not on-site, e.g., a town-owned wind turbine on a hill.

Some members of the group suggested that full retail net metering has the economic effect of "over-compensating" the project for kilowatt-hours put out into the grid because it allows the user to cancel out charges that are designed to cover the costs of maintaining and operating the distribution wires system upon which the project relies for service. Thus, Stakeholders also discussed an alternative approach to pricing DG-exported kW-h's. Under this approach, termed "Commodity Net," the DG system owner would receive the Standard Offer price for any net generation. This is more than the wholesale supply price (currently paid for non-net-metered kW-h) and less than full retail prices (currently effectively paid for net-metered kW-h). [55]

Potential Strategies

1. Commodity net

- For systems not covered by the net metering statute, adopt a "Commodity Net" approach to pricing DG-exported kW-h's.
- Do not modify the existing net metering statute.

2. Commodity net plus net metering expansion

- For systems not covered by the net metering statute, adopt a "Commodity Net" approach to pricing DG-exported kW-h's.
- AND, modify the net metering statute as follows:
    - Increase the cap on eligible system size to 1 MW
    - Remove the overall cap or increase it to 1% of the utility peak load
    - Allow Net Excess Generation (NEG) to roll forward indefinitely
    - Extend net metering to all clean DG, including clean CHP

3. Sliding scale net metering

- Modify the net metering statute as follows:
    - Provide full retail net metering for all DG systems under 5 kW
    - Allow customers with systems over 5 kW to net meter, but require that they pay an annual service charge to the utility. The charge would increase with the size of the system.

4. Transfer of credits between accounts

- Formalize procedures to enable net metering customers to transfer dollars credited for net positive kW-h.

5. Wheeling of power – building lines

- Allow a customer with DG to deliver power to another customer by building a line to that customer.

[55] Some suggested that a determination may be needed regarding the Schedule C tax implications, FERC implications, and gross receipts tax implications of customer sales of NEG to other customers or to the distribution utility.

6. *Wheeling of power – utility lines*

- Allow customers with DG to deliver power to other customers by using the utility lines and paying a wheeling rate.

DIFFERENT STATE POLICIES FOR DIFFERENT CLEAN ENERGY TECHNOLOGIES

STATE POLICIES DO NOT SUPPORT AND REWARD SOME DG TECHNOLOGIES IN PROPORTION TO THE BENEFITS THEY CREATE. (E.G. CHP CREATES SOME OF THE SAME BENEFITS AS RENEWABLES, BUT IS NOT ELIGIBLE FOR MUCH OF THE SUPPORT THAT IS AVAILABLE TO RENEWABLES.)

Many of the provisions that support distributed generation reward specific generation technologies rather than their contribution toward achieving state goals. Policies take a black and white approach (i.e. a technology is either in or it's out) and do not recognize the many variations in performance and contributions of different generation sources.

Efficient combined heat and power ("CHP") is an example of a technology that creates environmental benefits but whose benefits are not recognized by the policy framework. CHP is a low emission resource. It is not a zero emission resource like renewables, but, it nonetheless creates an environmental benefit where it is cleaner than then central generation it displaces. However, the policy framework that supports renewables excludes CHP. CHP is excluded from:

- The Renewable Energy Standard
- Net-metering
- The exemption from standby rates for renewable systems above 30 kW (CHP does qualify for the standby rate exemption for all systems 30 kW and smaller).

Connecticut provides these forms of support to CHP:

- Established a separate portfolio standard (Tier III) for all distributed resources (including CHP) with a minimum percentage that reaches 4% by 2010.
- Allows net-metering for fossil fueled CHP up to 50 kW.

Massachusetts allows net-metering up for CHP up to 60 kW.

CHP in Rhode Island is eligible for some forms of support. CHP is eligible for payments from ISO New England's Forward Capacity Market (FCM). The FCM makes payments to generators, including DG, insofar as they commit generating capacity to meet the region's peak demand. A CHP system can receive larger payments through the FCM than a solar or wind system of the same size because the contribution of solar and wind resources is discounted because they are intermittent. The FCM is a bid-based market; only the lowest priced set of resources needed to meet the demand will receive payments. Also, the natural gas energy efficiency programs proposed by National Grid and under review by the Public Utilities Commission would provide incentives for CHP.[56]

[56] Further information is available at: http://www.ripuc.org/eventsactions/docket/3790page.html

Some Stakeholders believe that it would be appropriate for all clean distributed generation to receive the policy support that is available for renewables, in proportion to the benefits that generation creates. They suggest that is possible that doing so could lower the cost of achieving the state's clean air goals by encouraging the deployment of low-cost, clean resources. However, some of those Stakeholders assert that any support for technologies such as CHP should be additional to the support currently available to renewables, and should not reduce that support.

There is also variation in the benefits created by different renewable technologies that could be reflected in policy provisions. Currently, all renewable energy technologies are treated the same under Rhode Island's RES, even though they vary significantly in terms of reliability, predictability and value, and cost. For example, solar DG has particular value in that it produces the majority of its output during sunny summer afternoons, coincident with system peaks.

Potential Strategies

1. Create complementary incentives for specific technologies to recognize their benefits, for example:

- Establish a separate portfolio standard to encourage distributed generation development that does not compete with the RES, as in the Tier 3 for DG resources established in CT
- Allow net metering for clean, non-renewable DG
- Establish a RES carve-out for PV with its own alternative compliance payment (ACP) level
- Modify the Renewable Energy Fund enabling legislation to eliminate the requirement that the Fund be self-sustaining.
- Establish time-of-use rates to enable PV systems to capture the full value of on-peak generation

2. Adopt a technology-neutral approach, providing incentives to all clean energy technologies based on progress toward state goals, for example:

- Re-cast the RES in terms of its goals, and then provide incentives to projects based on the degree to which they achieve those goals

PERMITTING CHALLENGES FOR DG

DISTRIBUTED GENERATION IS UNFAMILIAR TO LOCAL CODE ENFORCEMENT OFFICERS. THIS CAN RESULT IN PERMITTING DELAYS AND UNNECESSARY DEVELOPER EXPENSE AS DEVELOPERS ADDRESS INDIVIDUAL CONCERNS OF INEXPERIENCED INSPECTORS. ALSO, AIR PERMITTING PROCEDURES AND REQUIREMENTS MAY HAVE BEEN DESIGNED WITH OLDER SYSTEMS IN MIND AND MAY NOT REFLECT THE INHERENTLY CLEANER OPERATING CHARACTERISTICS OF NEWER SYSTEMS.

Local permitting approvals for distributed generation (e.g. electrical, building, and fire communication) are unevenly administered by municipalities and local code officials.

The Department of Environmental Management, Office of Air Resources has undertaken initiatives to streamline permitting for distributed generation. The Stakeholders support these initiatives. Further, they agree that, while certain DG Permitting could benefit from "streamlining", it should never be "expedited" at the sacrifice and to the detriment of public health and safety.

Recommendation for the General Assembly

- Provide resources to the Office of Energy Resources to support training and education regarding DG to local permitting officials.

SITING CHALLENGES FOR DG

THE COST AND TIME ASSOCIATED WITH SECURING PERMITS TO SITE SOME NEW DISTRIBUTED PROJECTS CAN BE A SIGNIFICANT MARKET BARRIER. NIMBYISM AND EXTENSIVE LOCAL, STATE, AND FEDERAL SITING APPROVAL PROCESSES ALL SLOW DOWN PROJECTS AND CONSUME DEVELOPERS' RESOURCES. THIS IS PARTICULARLY, THOUGH NOT EXCLUSIVELY, AN ISSUE FOR WIND PROJECT DEVELOPMENT.

Rhode Island can facilitate development of distributed generation by addressing the costs associated with site approvals, perhaps through the creation of generic siting guidelines that projects can design against. A new initiative being undertaken by the State Planning Program of the Department of Administration at the direction of the General Assembly will result in a State Guide Plan for renewables.

Stakeholders support the efforts of the State Planning Program to develop standardized or model siting or permitting guidelines, procedures, and zoning by-laws for distributed resources, including mapping of areas that are optimally suited for renewable energy development

Recommendation

1. State Planning Program

- Continue to use the State Planning Program to develop standardized or model siting or permitting guidelines, procedures, and zoning by-laws for distributed resources, including mapping of areas that are optimally suited for renewable energy development.

2. Technical support

Rhode Island should provide technical support to address concerns about proposed DG projects.

SUMMARY OF POTENTIAL STRATEGIES

Stakeholders developed the following summary list of Potential Strategies to address the identified above. The positions of the Stakeholders on those strategies are recorded below.[57] Some Stakeholders chose neither to endorse nor oppose individual strategies. Certain strategies might be incompatible with others; where a Stakeholder has endorsed incompatible approaches, it indicates his willingness to support either approach individually.

RECOMMENDATIONS AND STRATEGIES	POSITIONS OF THE PARTIES
INTERCONNECTION STANDARDS – "RADIAL" GRIDS	
▪ Rhode Island should adopt the interconnection standards developed by the Massachusetts DG Collaborative, modified as necessary to be compatible with Rhode Island law.	***Endorsed by all parties that voted***
INTERCONNECTION STANDARDS – "NETWORK" GRIDS	
▪ Rhode Island should adopt the interconnection standard for network grids developed by the Massachusetts DG Collaborative, allowing interconnection of inverter-based distributed generation less than 15 kW.	***Endorsed by all parties that voted***
▪ Rhode Island should continue to follow deliberations on IEEE 1547.6	

[57] National Grid's position on the recommendations is set out in a note that follows this section.

STANDBY TARIFFS

1. PUC Rate Case

- The PUC should conduct a rate case to examine the standby rates, specifically taking into account:
  - o Costs that customers with DG impose on the grid as compared to costs imposed by other customers.[58]
  - o Benefits that DG creates for the utility and other customers, including but not limited to the marginal electricity losses that can be avoided by dispersed generation and reserve requirements that can be reduced.
  - o The load profile of actual DG customers in the state as compared to other similarly situated customers
- Based on the outcome of the rate case identified above, the PUC should set National Grid's standby rates, considering all possible outcomes, including but not limited to:
  - o Adjusting or eliminating the 3 MW aggregate cap on the standby rate exemption for renewables
  - o Setting a different standby rate and/or rate structure
  - o Eliminating all standby rates
  - o Providing net credits (e.g., a negative standby rate) to customers who install DG
- This proceeding should be completed in time to allow any changes in standby rates to take effect concurrently with the other rate changes that will go into effect at the conclusion of the current rate plan in 2009.

Endorsed by:

- Peoples Power and Light
- SolarWrights
- Naval Station Newport
- TEC-RI
- Lorax Energy
- E Cubed LLC
- CoEnergy America, Inc.
- USCHPA
- Clean Water Action

2. General Assembly directive re PUC rate case

- The General Assembly should direct the PUC to undertake the investigation described above, should specify the issues and potential outcomes to be considered, and should direct that the proceeding be fully-litigated and not resolved by settlement.

Endorsed by:

- Lorax Energy
- E Cubed LLC
- CoEnergy America, Inc.
- Portsmouth Sustainable Energy

[58] Some stakeholders specified that this analysis should be independent of utility revenue requirements. They did not suggest that revenues should be compromised, but rather that standby rate examination must start from a consideration of costs, not from a presumption of revenue maintenance.

3. General Assembly hearings re PUC settlement procedures

- The General Assembly should convene hearings to examine the potential for inequity in PUC proceedings resolved by settlement, and direct the PUC to craft new rules based on the outcome of those hearings. Among the alternative methodologies that can be considered by Rhode Island (together or separately) include:
    - A model such as that employed in California, whereby intervenors in rate cases can petition to have their legal expenses covered by the state, so as to level the playing field between all participants.
    - A model such as that employed in Illinois, whereby a settlement is only accepted by the PUC if it is joined by all intervening parties. Such a rule can help to ensure that all perspectives are factored into future settlements, although it does not specifically address the inherent costs of rate case participation.

Endorsed by:

- Peoples Power and Light
- SolarWrights
- Lorax Energy
- E Cubed LLC
- CoEnergy America, Inc.
- Climate Energy
- USCHPA
- Clean Water Action

ADDITIONAL SUBSIDIES

3. RI REF funding increase ▪ Increase funding for the Rhode Island Renewable Energy Fund to underwrite more investment in renewable DG.	***Endorsed by:*** ▪ Peoples Power and Light ▪ SolarWrights ▪ Naval Station ▪ Lorax Energy ▪ E Cubed LLC ▪ CoEnergy America, Inc. ▪ Climate Energy ▪ Portsmouth Sustainable Energy ▪ A. Storms ▪ Clean Water Action
4. State bond program ▪ Establish a state bond program to help finance local renewable generation projects and assist with the large first costs of these systems.	***Endorsed by:*** ▪ Peoples Power and Light ▪ SolarWrights ▪ Lorax Energy ▪ E Cubed LLC ▪ CoEnergy America, Inc. ▪ Climate Energy ▪ Portsmouth Sustainable Energy ▪ Clean Water Action
5. RI REF requirement ▪ Eliminate the requirement that Renewable Energy Fund be "self-sustaining" (R.I. Gen. Laws, § 39-2-1.2)	***Endorsed by:*** ▪ SolarWrights ▪ Naval Station ▪ Lorax Energy ▪ E Cubed LLC ▪ CoEnergy America, Inc. ▪ Climate Energy ▪ Portsmouth Sustainable Energy ▪ Clean Water Action

6. Tax benefits ▪ Extend to all clean DG systems the tax benefits that are currently available to renewable DG, in so far as these systems produce benefits for Rhode Island.	***Endorsed by:*** ▪ ▪ Lorax Energy ▪ E Cubed LLC ▪ CoEnergy America, Inc. ▪ Climate Energy ▪ Clean Water Action ▪ USCHPA ***Opposed by:*** ▪ SolarWrights

MONETIZING BENEFITS TO RATEPAYERS AND TAXPAYERS

1. PUC proceedings ▪ The PUC should consider all costs and benefits created by DG in any proceeding concerning standby rates or any other rates that affect DG system owners.	***Endorsed by:*** ▪ Peoples Power and Light ▪ SolarWrights ▪ Lorax Energy ▪ E Cubed LLC ▪ CoEnergy America, Inc. ▪ Climate Energy ▪ USCHPA ▪ Clean Water Action ▪ Portsmouth Sustainable Energy

PRICE PAID TO DG OWNERS FOR EXPORTED KILOWATT-HOURS

1. *Commodity net*

- For systems not covered by the net metering statute, adopt a "Commodity Net" approach to pricing DG-exported kW-h's.
- Do not modify the existing net metering statute.

Endorsed by:
- USCHPA
- Portsmouth Sustainable Energy
-

Opposed by:
- Climate Energy
- CoEnergy America, Inc.
- E Cubed LLC
- Lorax Energy
- SolarWrights
- Clean Water Action

2. *Commodity net plus net metering expansion*

- For systems not covered by the net metering statute, adopt a "Commodity Net" approach to pricing DG-exported kW-h's.
- AND, modify the net metering statute as follows:
    - Increase the cap on eligible system size to 1 MW
    - Remove the overall cap or increase it to 1% of the utility peak load
    - Allow NEG to roll forward indefinitely
    - Extend net metering to all clean DG, including clean CHP

Endorsed by:
- Peoples Power and Light
- SolarWrights
- Lorax Energy
- Climate Energy
- CoEnergy America, Inc.
- E Cubed LLC
- USCHPA
- Clean Water Action

Opposed by:

3. *Sliding scale net metering*

- Modify the net metering statute as follows:
    - Provide full retail net metering for all DG systems under 5 kW
    - Customers with systems over 5 kW pay an annual service charge to the utility. The charge would increase with the size of the system.

Endorsed by:
- SolarWrights

Opposed by:
- Lorax Energy
- E Cubed LLC
- CoEnergy America, Inc.

4. Transfer of credits between accounts ▪ Permit transfer of credited dollars between customer accounts, formalizing procedures to enable net metering customers to transfer dollars credited for net positive kWh.	***Endorsed by:*** ▪ Portsmouth Sustainable Energy ▪ Climate Energy ▪ CoEnergy America, Inc. ▪ E Cubed LLC ▪ Lorax Energy ▪ Naval Station Newport ▪ SolarWrights ▪ Clean Water Action ▪ Peoples Power and Light
5. Wheeling of power – building lines ▪ Allow a customer with DG to deliver power to another customer by building a line to that customer.	***Endorsed by:*** ▪ Naval Station Newport ▪ E Cubed LLC ▪ Climate Energy ▪ CoEnergy America, Inc ▪ USCHPA ***Opposed by:*** ▪ SolarWrights
6. Wheeling of power – utility lines ▪ Allow customers with DG to deliver power to other customers by using the utility lines and paying a wheeling rate.	***Endorsed by:*** ▪ Climate Energy ▪ CoEnergy America, Inc. ▪ E Cubed LLC ▪ Lorax Energy ▪ Clean Water Action ▪ Naval Station Newport ***Opposed by:*** ▪ SolarWrights

DIFFERENT STATE POLICIES FOR DIFFERENT CLEAN TECHNOLOGIES

1. Create complementary incentives for specific technologies to recognize their benefits, for example: ▪ Establish a separate portfolio standard to encourage distributed generation development that does not compete with the RES, as in the Tier 3 for DG resources established in CT ▪ Allow net metering for clean, non-renewable DG ▪ Establish a RES carve-out for PV with its own alternative compliance payment (ACP) level ▪ Modify the Renewable Energy Fund enabling legislation to eliminate the requirement that the Fund be self-sustaining. ▪ Establish time-of-use rates to enable PV systems to capture the full value of on-peak generation	***Endorsed by:*** ▪ Peoples Power and Light ▪ SolarWrights ▪ Naval Station Newport ▪ Climate Energy ▪ CoEnergy America, Inc. ▪ E Cubed LLC ***Opposed by:*** ▪ Lorax Energy
2. Adopt a technology-neutral approach, providing incentives to all clean energy technologies based on progress toward state goals, for example: ▪ Re-cast the RES in terms of its goals, and then provide incentives to projects based on the degree to which they achieve those goals	***Endorsed by:*** ▪ USCHPA ▪ Climate Energy ▪ CoEnergy America, Inc. ▪ E Cubed LLC ▪ TEC-RI ▪ Naval Station Newport ***Opposed by:*** ▪ SolarWrights

PERMITTING CHALLENGES FOR DISTRIBUTED GENERATION

▪ Provide resources to the Office of Energy Resources to support training and education regarding DG to local permitting officials.	***Endorsed by:*** ▪ Peoples Power and Light ▪ Naval Station Newport ▪ Lorax Energy ▪ TEC-RI ▪ E Cubed LLC ▪ CoEnergy America, Inc. ▪ Climate Energy ▪ USCHPA ▪ Clean Water Action ▪ Portsmouth Sustainable Energy ***Opposed by:*** ▪ SolarWrights

SITING CHALLENGES FOR DISTRIBUTED GENERATION

1. State Planning Program ▪ Continue to use the State Planning Program to develop standardized or model siting or permitting guidelines, procedures, and zoning by-laws for distributed resources, including mapping of areas that are optimally suited for renewable energy development.	***Endorsed by:*** ▪ Peoples Power and Light ▪ Naval Station Newport ▪ Lorax Energy ▪ TEC-RI ▪ E Cubed LLC ▪ CoEnergy America, Inc. ▪ Climate Energy ▪ Clean Water Action ▪ Portsmouth Sustainable Energy ***Opposed by:*** ▪ SolarWrights
2. Technical support ▪ Rhode Island should provide technical support to address concerns about proposed DG projects.	***Endorsed by:*** ▪ Peoples Power and Light ▪ Naval Station Newport ▪ E Cubed LLC ▪ CoEnergy America, Inc. ▪ Climate Energy ▪ Portsmouth Sustainable Energy ***Opposed by:*** ▪ SolarWrights

<u>Note from National Grid</u>:

National Grid tried to work closely with the group in order to develop some consensus recommendations regarding distributed generation. However, the majority of the participants at the meeting turned out to be advocates for distributed generation. Thus, from National Grid's perspective, it was difficult for the group, as a whole, to engage in an objective dialogue on the issues. One major obstacle to success was the inability to quantify any costs or benefits. There were many practical reasons for the group not being able to develop the analysis and it is not National Grid's intention to blame anyone or suggest that anyone was deliberately obstructing an analysis. To the contrary, sincere attempts were made by many to try to reach common ground. But, without quantitative analysis, the report essentially relies on broad opinions about "benefits." While National Grid supports renewables development and believes that there are circumstances in which targeted distributed generation can bring quantifiable benefits to customers, National Grid strongly believes that the benefits and costs need to be quantified before more funding is provided for distributed generation development through mechanisms such as full retail net metering, lower stand-by rates for fossil-fueled DG projects (without regard to location or operating characteristics), and other special funding programs. Because this key ingredient is missing from the report, National Grid does not join in the general conclusions and recommendations contained in this document, other than recommending that a cost/benefit analysis be performed for each of the proposed types of DG technologies.

NEXT STEPS

At this time, the group has been unable to reach consensus on a set of recommendations on the subject of DG that is supported by a cost effectiveness analysis. While the group, to varying degrees, believes that there are potential benefits to be realized from increasing the amount of CHP and renewable distributed generation in the state, there was not enough time to perform a rigorous study to quantify and confirm the value of the benefits that might accrue to all citizens and/or all ratepayers. Before any significant undertaking occurs, such an analysis would be critical to perform.

For example, if there is a package of investments that will result in a portfolio of DG that generates $200 million in benefits to RI ratepayers, and the cost for RI ratepayers is $50 million, that certainly seems like a promising direction to take. On the other hand, if that $50 million only buys $20 million in benefits, that package is a clear loser. So quantities matter.

A SUGGESTED APPROACH FOR ADDITIONAL QUANTIFICATION

Quantification requires that we establish a cost-effectiveness framework and run the analyses. The Cost-Effectiveness analysis will require three key components to result in the quality of information needed for policy development and decision making:

(1) Cost Effectiveness Framework or Model

An existing, reliable, well-accepted cost-effectiveness framework or model that captures the major economic variables and relationships concerning DG installations and the electric supply system, and examines cost-effectiveness from the vital perspectives: the project sponsor, Rhode Islanders as a group, non-participating ratepayers, and the utility (or , in cost-effectiveness jargon: the Participant Test, the Total Resource Cost/Societal Test, the Ratepayer Impact Measure, and the Utility Test).

(2) Quantified Portfolio(s) of DG

For purposes of analysis, a subject DG portfolio should be developed, including the following data points:

- Resource mix, with amounts added, by year, of wind, solar, hydro, CHP and so forth in certain locations (broadly stated; i.e., coastal, urban, suburban ring) in Rhode Island.
- Quantify the amount of generation that is realistically available from the various technologies.
- Cost and performance specs for each resource in the mix, including:
  - First cost
  - Operating costs
  - Time differentiated energy production
  - Environmental attributes

- Energy security (i.e., resilience from natural disaster, fuel supply disruptions, and attack).
- Benefits attributable to each resource in the mix

(3) ***Specifications of the Electricity Grid Supply System***

These specifications should include monetized externality cost ranges and should quantify all elements of the system, particularly those that were enumerated in the legislation. Assumptions and values for all elements (for example, reserve margins and electricity losses) must be transparent. Particular care must be taken to accurately model temporal and locational factors, including (but not limited to) reserve margins and electricity losses.

In performing this Cost Effectiveness Analysis, it will be important to be consistent with other like analysis in the use of assumptions. For example, the avoided cost forecast that National Grid provides from its DSM analysis has imbedded in it a projection for natural gas prices. That same projection should be used to calculate the operating costs of CHP units that are driven by natural gas.

Next Steps

The Stakeholders recommend that the General Assembly provide funding for an Office of Energy Resources-led study to perform the cost effectiveness analysis and quantification that the General Assembly has requested in the Act. They recommend that the convened Study Team consist of no more than eight parties, in order to keep the group at an efficient and manageable number. The team would be constituted to represent each of the stakeholder interest group sectors, including CHP developer, renewable developer, municipal sector, commercial and industrial sector, residential sector, environmental, utility, and government/regulatory.

The Study Team will manage the study under the auspices and direction of the Office of Energy Resources. The following guidelines and procedures are suggested:

(1) The OER and/or its consultant would perform the analysis, with input from the study team

(2) National Grid would provide rate impact analysis, consistent with study assumptions established by the team

(3) Members of the study team can provide data, review data submitted by others, suggest scenarios to run, and review the results

(4) The team can take a common sense, conservative approach to save time and money, and avoid arguments

(5) The study could borrow liberally from existing and approved data. For example: we can get “approved” numbers for avoided energy, capacity, and T&D costs from National Grid’s DSM cost-effectiveness model

(6) Where substantial disagreement persists concerning the “right” number, develop a range (low to high) and run scenarios using the low and the high

(7) The cost-effectiveness framework can also be used to score individual DG projects as part of a utility or state program. Locational elements will be set up so that subsequent analyses and more detailed planning can bore down to more local situations.

APPENDIX A:
DG STAKEHOLDER WORKING GROUP PARTICIPANTS

Organization / Individual	Interest	Represented by
A.E.S.C, Westerly RI	Municipal wind project advocate	Greg Nedwetzky
Bristol Wind Power	Municipal wind project advocate	Merritt K. Meyer
Bristol Wind Power	Municipal wind project advocate	Paul M. Sanroma
Clean Water Action	Environmental advocacy	Denise Parrillo
Climate Energy	Micro-turbine industry	Rui Afonso
Conservation Law Foundation	Public interest environmental law	Ian Gray
Conservation Law Foundation	Public interest environmental law	Jerry Elmer
E Cubed Company	Consultants specializing in DER	Ruben Brown
CoEnergy America	Cogeneration industry	Arthur Pearson
National Grid	Natural gas utility	Mark DiPetrillo
National Grid	Electric utility	Ron Gerawatowski
National Grid	Electric utility	Tim Roughan
Naval Station Newport	Federal government consumer	John Reichert
People's Power and Light/ECANE	Consumer advocates focusing on clean energy resources	Karina Lutz
Portsmouth Sustainable Energy	Municipal wind project advocate	Gary Gump
Roger Williams University	Large institutional consumer	Lefteris Pavlides
Sierra Club	Environmental advocate	Chris Wilhite
SolarWrights/Ocean State Wind	Solar and wind energy industry	Bob Chew
South County ConCom/RI Wind Alliance	Municipal wind project advocate	W. Murray Gates
Toray Plastics	Industrial distributed generator	Shigeru Osada
U.S. Combined Heat and Power Association	CHP industry advocate	Sean Casten

<u>Additional Observer/Advisors</u>

House Majority Leader's Office	Beth Cotter
RI Attorney General's Office	Paul Roberti
RI DEM Air Resources	Steve Majkut
RI DPUC	Dave Stearns
RI House Policy	Gary Ciminero
RI Office of Energy Resources	Andrew Dzykewicz
RI Office of Energy Resources	Julie Capobianco
RI PUC	Doug Hartley
RI DPUC	Steve Scialabba
RI State Representative	Rep. Eileen Naughton
RI Statewide Planning	Bruce Vild
Massachusetts Tech Collaborative	Francis Cummings
Environment Northeast	Sam Krasnow

APPENDIX B

BASIC DATA ON DIESEL EMERGENCY GENERATORS IN RHODE ISLAND AND OTHER ISO-NE STATES

Number of Permitted Engines in the Northeast States   2002 Year of Data

	CT	ME	MA	NH	RI	VT	Total	Percent of total in all states
25-50 KW	112	2	11	1	0	0	126	3%
50-100 KW	208	78	13	2	0	9	310	8%
100-250 KW	411	184	278	65	4	18	960	25%
250-500 KW	321	158	156	123	1	17	776	20%
500-750 KW	273	64	138	71	20	7	573	15%
750-1000 KW	144	28	73	39	11	2	297	8%
1000-1500 KW	153	36	160	47	11	10	417	11%
1500 + KW	99	28	275	9	25	3	439	11%
TOTAL	1721	578	1104	357	72	66	3898	100.0%
% above 500 KW	39%	27%	58%	46%	93%	33%	44%	
% above 100 KW *	81%	86%	98%	99%	100	86%	89%	

* 100 KW is the minimum size eligible to participate in demand response programs.

CALC NO. MACHINES >500 KW	669	156	646	166	67	22	1726	
TOTAL MW AVAILABLE IF ASSUME ONLY 500 KW AVAILABLE AT ALL MACHINES >500KW	335	78	323	83	34	11	863	MW TOTAL POTENTIAL AT PERMITTED MACHINES

SOURCE TABLE ES-3
has had the NJ and NY facilities deleted for this presentation.
ALL NUMBERS OF MACHINES ARE TAKEN STRAIGHT FROM THE SOURCE
Data Source Source data in pink cells
NESCAUM, Stationary Diesel Engines in the Northeast, June 2003

APPENDIX C:
DG INITIATIVES IN CONNECTICUT

APPENDIX D:
EXAMPLES OF NAVIGANT CONSULTING ANALYSIS FOR MASSACHUSETTS DG COLLABORATIVE

APPENDIX E:
LETTER FROM DIVISION OF PUBLIC UTILITIES AND CARRIERS

BASIC DATA ON DIESEL EMERGENCY GENERATORS IN RHODE ISLAND AND OTHER ISO-NE STATES

Number of Permitted Engines in the Northeast States **2002 Year of Data**

	CT	ME	MA	NH	RI	VT	Total	Percent of total in all states
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100-250 KW	411	184	278	65	**4**	18	960	25%
250-500 KW	321	158	156	123	**1**	17	776	20%
500-750 KW	273	64	138	71	**20**	7	573	15%
750-1000 KW	144	28	73	39	**11**	2	297	8%
1000-1500 KW	153	36	160	47	**11**	10	417	11%
1500 + KW	99	28	275	9	**25**	3	439	11%
TOTAL	1721	578	1104	357	**72**	66	3898	100.0%
% above 500 KW	**39%**	**27%**	**59%**	**46%**	**93%**	**33%**	**44%**	
% above 100 KW *	**81%**	**86%**	**98%**	**99%**	**100%**	**86%**	**89%**	

*** 100 KW is the minimum size eligible to participate in demand response programs.**

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CALC NO. MACHINES >500 KW	**669**	**156**	**646**	**166**	**67**	**22**	**1726**	
TOTAL MW AVAILABLE IF ASSUME ONLY 500 KW AVAILABLE AT ALL MACHINES >500KW	**335**	**78**	**323**	**83**	**34**	**11**	**863**	**MW TOTAL POTENTIAL AT PERMITTED MACHINES**

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has had the NJ and NY facilities deleted for this presentation.
ALL NUMBERS OF MACHINES ARE TAKEN STRAIGHT FROM THE SOURCE
Data Source Source data in pink cells
NESCAUM, Stationary Diesel Engines in the Northeast, June 2003

A Discussion Prepared by The E Cubed Company, LLC
For the Rhode Island DG Stakeholders Workgroup's Report to the Energy Advisor to the Governor For Possible Use In Reporting to the General Assembly Pursuant The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006, RI Gen. Laws

SUMMARY

There are a number of lessons learned for Rhode Island from the State of Connecticut's recent experiences at enhancing opportunities for distributed resources in Connecticut. The E Cubed Company, LLC participated in multiple dockets from 2005-2007 in designing and implementing several of the programs involving distributed generators, including base load, emergency generators, and renewables.

In each policy situation, the benefits deemed significant by the policymakers are directly driven by the goals of the review. The costs and benefits to be evaluated in Rhode Island may not be construed to be the same or even similar to those in Connecticut.

For example, in implementing the guidance of the Connecticut Legislature in the Energy Independence Act of 2005, the Department of Public Utility Control (DPUC) opened a regulatory docket (05-07-17), took stakeholder workgroup inputs and determined the benefits of CHP and Demand Response Emergency Generators are sufficient to justify awards of $200/kW to emergency generators and $450/kW to combined heat and power units. Furthermore, an additional $50/kW would be available if the project were situated in the right place where the need was greatest (one of the 54 towns in Southwest Connecticut). These were compared to projected capacity costs in the new ISO-NE Forward Capacity Market at the "cost of new entry" (CONE), estimated to be $90/kW/Year.

The benefits and costs of base load distributed generation and demand response generators were evaluated in the several Connecticut Dockets in workgroups in litigated proceedings, but ultimately were determined by the DPUC itself. As noted, the assumptions and results may vary from those that might be employed in further cost-benefit evaluations applied to Rhode Island. <u>The CT DPUC focused on ratepayer costs and benefits and ignored all other costs in order to justify monetary awards within the band authorized by the Legislature.</u>

Details are summarized below and demonstrated in cost-Benefit Exhibits 1 and 2 to the March 27, 2006 Decision in Docket 05-07-17 authorizing monetary awards for demand response generators and base-load generators within the parameters set by the Legislature ($200-$500) are attached. Actual experience with 64 applications that have been submitted to the CT DPUC through January 12, 2007 is also examined.

The E Cubed Company, LLC also participated in design negotiations for the new ISO-NE Demand Resource Program in 2006-7 on behalf of several of the entities represented in the RI DG Work Group process, notably Climate Energy, LLC and CoEnergy America, Inc., and other entities, including several Demand Response Providers.

The ISO-NE program design anticipates that the values in the transitional and the Forward Capacity Markets may be sufficient to draw out Distributed Generation and DG under 5 MW or the connected load whichever is higher can be treated as a Demand Resource and can be paid upon having a measurement and verification plan approved by the ISO-NE. Every effort is being made so that M&V plans for State sponsored EE and DG programs and the ISO's requirements are compatible.

The interplay between the evolving State Programs and the evolving ISO-NE Demand Resource programs is substantial.

BACKGROUND ON DG PROCUREMENT/MOBILIZATION IN CONNECTICUT.

Aside from grants from Clean Energy Funds and the like which are not addressed here, CT's policymakers have assisted the ISO-NE in mobilizing distributed generation sources in an all source 2002-3 RFP process to mobilize resources in SWCT, in the two major initiatives with monetary awards discussed here, and in all source Connecticut RFP 2006. Each will be discussed briefly.

GAP RFP – All Sources Procurement in 2002.

In 2002, facing transmission congestion problems, with the encouragement of the State of Connecticut the ISO-NE issued an all sources RFP for capacity resources situated in South West Connecticut.[1] Twenty-six bids come in and Demand Resource Generators were the clear winner. DR was less than two percent (2%) of Connecticut's peak. Large generators and demand resources, including Demand Resource Generators, competed head-to-head with the solution being more that 450 MW of least cost demand resources were awarded contracts that expire in February 2008. In 2006 DR comprises six percent of Connecticut's peak.

2005 - An Act Concerning Energy Independence

The Legislature made a significant commitment to distributed generation in June 2005 with the passage of ***An Act Concerning Energy Independence*** which was targeted at ten percent (10 %) peak load reduction and mitigating the risk of the onset of higher costs for capacity within in the State and across New England.

As a result of the Energy Independence Act Connecticut established a series of short-term awards[2] and provided another long-term all-source RFP opportunity[3]. Both are

[1] ISO-New England, A REQUEST FOR PROPOSAL (RFP), 2002 Load Response Program, Southwest Connecticut Emergency Capability Supplement, (LRP SWCT ECS), Issued February 27, 2002

[2] Docket 05-07-14 Phase 1, implemented by a series of dockets, including Dockets 05-07-15 through 05-07-21 Decisions began December 28, 2005 and were mostly completed by June 2006.

[3] Docket 05-07-14 Phase 2, Decision, September xx, 2006.

underway. They are discussed below. Methodological Cost-Benefit Items will be provided below.

AWARDS FOR DG/CHP[4]

BASE LOAD GENERATORS

Simulated in part by award levels as indicated in the States Table in the Main Report ($450/kW plus $50/kW if in SW Connecticut), base-load distributed generators that operate within set hours during four summer months and two winter months are eligible to receive awards. They have to participate as Demand Resources in the ISO-NE transitional and Forward Capacity Market. Capacity revenues are owned by the contractual counterparty on behalf of the ratepayers for fifteen years. The local distribution company is the counterparty.

Between April 1, 2006 and January 12, 2007 a total of twenty-four (24) applicants have appeared seeking a total of 137 MW of support, including two projects with a total of 98 MW. To date, 15 awards for 25,624 kW have been approved by the DPUC at an average cost of $414/kW. The awarded facilities are installing 31,600 kW of capacity. Two-thirds of the awarded projects are outside SW Ct. Projects must post a bond, meet the utility interconnection standards, and operate the required hours.

DEMAND RESPONSE GENERATORS

Simulated in part by award levels as indicated in the States Table in the Main Report ($200/kW plus $50/kW if in SW Connecticut), forty (40) demand response generator applications have been submitted to the DPUC between April 1, 2005 and January 12, 2006.[5]

A separate table analyzing this data has been prepared by The E Cubed Company, LLC and is attached. To date, 18 awards for 12,828 kW (average size 800 kW) have been approved by the DPUC at an average award $241/kW up to the size of the on-site load.

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[4] Docket No. 05-07-17, DPUC Review of the Development of a Program to Provide Monetary Grants for Capital Costs of Customer-side Distributed Resources, Decision, March 27, 2007, pp. 19-23, and Exhibits 1 – Cost Benefit Analysis for Emergency Generation and Exhibit 2 Cost Benefit Analysis for Base Load DG.

[5] Summary Data sheet available from the DPUC at: http://www.dpuc.state.ct.us/Electric.nsf/bb23886a033a7ef28525713c000031d4/f694842efe5f30ff852572680058f0fb?OpenDocument

These have been mostly in SW Ct. These are leveraging total investments averaging $562/kW. This 2 to 1 leverage. Projects must post a bond, meet the utility interconnection standards, and participate in the ISO-NE Demand Response program. Capacity revenues received by the awardees are owned by the project. Awards are paid by the local distribution company.

To date, 40 applications have been submitted for 30,956 kW of on-site load displaced although the total installed capacity would be 33,398 kW. The average size of to be installed projects is 838 kW. Twenty-six of the applicants are in SW CT. These are leveraging total investments averaging $675/kW which suggests that later applicants have higher costs.

RFP 2006 – ALL SOURCE PROCUREMENT FOR UP TO 600-2300 MW (15 YEARS)

The Long-term contracts mandated by the Energy Independence Act were designed in Docket 05-07-14 Phase 2 which launched RFP 2006 (bidding closed November 13, 2006) which is an all source RFP leveraged around the revenue streams of the ISO-NE's transitional capacity (2007-May 2010) and Forward Capacity Market (FCM) thereafter.

The regulated utilities are the counterparties to the contracts to be awarded and provide a means of advancing funding to accelerate project development whether by awarded Demand or Supply Resources. Ideally, if the bids were forecast at exactly the levels that will be received from the transitional and FCM capacity markets, there would be no incremental cost to ratepayers of Connecticut.

While not publicly circulated the potential bidders all had to register at the DPUC and that was posted in Docket 05-07-14 Phase 2. The expressions of interest were summarized publicly by the RFP Manager as involving more than 40 entities interested in providing more than 6,000 MW of resources to meet Connecticut's needs for 600-2300 MW. The list included a number of entities that might have bid DG/CHP. In the end approximately twenty organizations responded with over forty bids. The number Awards are to be determined and contracted to take effect after review in regulatory proceedings by November 2007.

METHODOLOGICAL CONSIDERATIONS

Data on costs and benefits were collected in a stakeholder process inside a litigated proceeding. Only those stakeholders that could afford to be in the room participated in approximately eight meetings in four week period. A number of factors discussed in the WG were adopted, such as recognition of reserves, losses avoided, kWh values, etc. Total Resource Costs (including customer costs were considered casually at the Work Group level, but the Regulators used the following in reaching their decisions regarding award amounts. Many factors had been considered.

The cost/benefit analyses demonstrated below in their Exhibits 1 and 2 deal with the following:

COSTS

The costs include the several kinds of incentives offered, such as gas delivery credits (CHP), incentive payments (the $200 or $450/kW), waived back-up rates in the case of CHP, discounts on load interest (2% available to awardees), and demand response payment from the ISO in the case of emergency generators.

BENEFITS

The benefits include capacity, energy and forward reserve payments if applicable.

RESULTS

In the case of base load DG the total cost per kW for 15 years was determined to be $910 (PV $610) and the benefits per kW totaled $1950 (PV $1,113) for a net benefit fo $1,040 and a net PV benefit of $503 per kW (which justified the goal – the ability to provide monetary awards at $450).

In the case of demand response EG the total cost per kW for 15 years was determined to be $1,379 (PV $811) and the benefits per kW totaled $1,770 (PV $1,010) for a net benefit fo $391 and a net PV benefit of $199 per kW (which justified the goal – the ability to provide monetary awards at $200).

A. EXHIBITS[6]

1. Exhibit No. 1 - Cost Benefit Analysis for Emergency Generation

Cost Benefit Analysis of Customer Side Distributed Generation

		Emergency Generation														
Costs	**Total Cost**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Gas Credit	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CL&P/UI Incentive	200.0	200.0														
Backup Rate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Loan Interest	22.0	4.0	3.6	3.2	2.8	2.4	2.0	1.6	1.2	0.8	0.4					
Demand Response Payment	1157.4	36.6	36.6	45.0	49.2	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Total Cost	1379.4	240.6	40.2	48.2	52.0	92.4	92.0	91.6	91.2	90.8	90.4	90.0	90.0	90.0	90.0	90.0
Present value	$811															
Benefits																
Capacity	1350.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Forward Reserves/Energy	420.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Total Benefit	1770.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0
Present Value	$1,010															
Net Benefit	$391															
Net PV Benefit	$199															

1. Gas credit estimated at 0 due to infrequent use of emergency generators.
2. Loan based on $200/Kw loan for 10 years with 2% interest rate subsidy.
3. Proposed Transitional Capacity payrments for year 1 through 4.
4. Forward reserve/energy value of $28kW/year results in present value net benefit of $209/kW.
5. Capacity value = $7.50/kW/month.

[6] Docket No. 05-0717**, Connecticut DPUC Review of The Development of A Program To Provide Monetary Grants for Capital Costs of Customer-Side Distributed Resources, Decision, March 27, 2006**, Exhibits 1 – Cost Benefit Analysis for Emergency Generation and Exhibit 2 Cost Benefit Analysis for Base Load DG, pp. 24-25.

2. Exhibit No. 2 - Cost Benefit Analysis for Base Load DG

Cost Benefit Analysis of Customer-Side Distributed Generation

Base Load DG

Costs	**Total Cost**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Gas Credit	300	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
CL&P/UI Incentive	200	200														
Backup Rate	300	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Loan Interest	110	20	18	16	14	12	10	8	6	4	2					
Demand Response Payment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Cost	910	260	58	56	54	52	50	48	46	44	42	40	40	40	40	40
Present value	$610															
Benefits																
Capacity	1350	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Energy	600	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Total Benefit	1950	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Present Value	$1,113															
Net Benefit	$1,040															
Net PV Benefit	$503															

1. Gas credit estimated by CL&P EL-9.
2. Backup Rate estimate assumes the unit operates 9 months, is off-line 3 months per year and the unit is billed no demand charges during the months of operation.
3. Loan based on $1000/kW loan for 10 years with 2% interest rate subsidy.
3. Base load units will not qualify for ISO-NE load response program.
4. Energy value of $40/kW/year results in present value net benefit of $503/kW.

DG AWARD APPLICATIONS IN CT

DG Capital Grant Projects

BaseLoad ID No. In This Analysis	Docket No.	Type	Fuel	Size (kW)	Size (MW)	Town	SWCT	MW Approved	Grant Amount	Approved
1	06-04-12	Combined Heat & Power	Gas	2920	2.92	E. Hartford	No	2.920	$1,314,000	yes
2	06-05-11	Combined Heat & Power	Gas	5041	5.04	Killingly	No	3.772	$1,697,400	yes
3	06-05-12	Combined Heat & Power	Gas	5499	5.50	Fairfield	Yes	4.600	$2,300,000	yes
4	06-06-10	Combined Heat & Power	Gas	376	0.38	Branford	Yes	0.300	$150,000	yes
5	06-07-03	Combined Heat & Power	Gas	75	0.075	Meriden	Yes	0.074	$36,850	yes
6	06-07-06	Combined Heat & Power	Bio-D	7.5	0.0075	Stamford	Yes	0.007	$3,375	yes
7	06-07-09	Combined Heat & Power	Gas	75	0.075	Seymour	Yes	0.074	$36,950	yes
8	06-07-16	Combined Heat & Power	Gas &#2 Oil	7520	7.52	Middletown	No	7.795	$3,507,750	yes
9	06-07-22	Combined Heat & Power	Gas	250	0.25	Norwalk	Yes	0.250	$125,000	yes
10	06-08-11	Combined Heat & Power	Gas	169	0.169	Bloomfield	No	0.148	$66,452	yes
11	06-08-17	Combined Heat & Power	Gas	404	0.404	New London	No	0.575	$258,750	yes
12	06-10-12	Combined Heat & Power	Gas	240	0.24	East Hartford	No			pending
13	06-10-19	Combined Heat & Power	Gas	35,168	35.168	New Milford	Yes			pending
14	06-10-27	Combined Heat & Power	Gas	1,500	1.5	Norwalk	Yes			pending
15	06-10-29	Combined Heat & Power	Gas	227	0.227	Branford	Yes			pending
16	06-11-08	Combined Heat & Power	Gas	62,903	62.903	Ansonia	Yes			pending
17	06-12-19	Combined Heat & Power	Gas	2,800	2.8	Windsor	No			pending
18	06-12-22	Combined Heat & Power	Gas	535	0.535	New Haven	Yes			pending
19	06-12-23	Combined Heat & Power	Gas	2,365	2.365	Middletown	No			pending
20	06-04-06	Simple Cycle Natural Gas	Gas	920	0.92	Bristol	No	0.375	$105,469	yes
21	06-07-18	Reciprocating Engines	Gas	4500	4.5	Wethersfield	No	4.120	$824,000	yes
22	06-08-21	Baseload	Hydro	500	0.5	Mansfield Cente	No	0.480	$115,369	yes
23	06-09-15	Turbine	Gas	142	0.142	Simsbury	No	0.134	$60,300	yes
24	06-11-09	Baseload	Methane	3,200	3.2	East Windsor	No			pending
24				137,337	137.34			25.624	$10,601,665	
								$/kW	$ 413.74	

Summary CT DG-Emerg Gen

	B	E	G	H	I	J	K	L	M	N	O	W	X	Y
2		EmergGen	EmergGen	EmergGe n	EmergGen	EmergGen	Emerg Gen	EmergGe n	EmergGen	EmergGen	EmergGen	EmergGen	EmergGen	EmergGen
3	EG ID No. In This Analysi s	**Docket No.**	**Fuel**	**Size (kW)**	**Size (MW)**	**Town**	**SWCT**	**MW Approve d**	**Grant Amount**	**Approved**	**Peak Load last 12 mons (kW)**	**Est. Capital Costs**	**Ongoing Costs**	**Est Transition Period Benefits from Jan 2007 @ $146.05/kW**
4	1	06-04-07	Diesel	500	0.50	Saybrook	No	0.436	$87,200	yes	436	$200,000		$73,025
5	2	06-05-09	Diesel	2250	2.25	No. Haven	Yes	2.250	$562,500	yes	2477	$2,327,000		$328,613
6	3	06-05-14	Diesel	400	0.40	New Haven	Yes	0.325	$81,250	yes	325	$85,000		$58,420
7	4	06-06-07	Diesel	163	0.16	So. Windsor	No	0.100	$20,000	yes	100	$77,500	$1,000	$23,806
8	5	06-06-08	Diesel	200	0.20	Storrs	No	0.170	$34,000	yes	170	$20,000		$29,210
9	6	06-06-11	Diesel	1500	1.50	Southington	Yes	1.100	$275,000	yes	1100	$715,000		$219,075
10	7	06-06-19	Diesel	150	0.15	New Htfd	No	0.113	$16,657	yes	113	$49,000	$1,200	$21,908
11	8	06-06-20	Diesel	350	0.35	So. Windsor	No	0.170	$33,960	yes	170	$93,598	$1,000	$51,118
12	9	06-07-04	Diesel	650	0.65	Shelton	Yes	0.427	$124,250	yes	497			$94,933
13	10	06-07-12	Diesel	787	0.787	Shelton	Yes	0.787	$196,750	yes	787	$365,803	$31,480	$114,941
14	11	06-07-13	Diesel	54	0.054	So. Windsor	No	0.060	$12,000	yes	512			$7,887
15	12	06-08-07	Diesel	415	0.415	Stamford	Yes	0.415	$103,750	yes	1317	$361,400	$49,765	$60,611
16	13	06-08-13	Diesel	83	0.083	Bristol	No	0	0	denied				
17	14	06-08-15	Diesel	3200	3.2	New Haven	Yes	3.200	$800,000	yes	3200	$1,838,366	$100,000	$467,360
18	15	06-08-19	Diesel	750	0.75	Shelton	Yes	0.750	$187,500	yes	750	$383,800		$109,538
19	16	06-09-08	Diesel	1,500	1.5	Norwalk	Yes	1.000	$250,000	yes	1000	$600,000	$2,500	$219,075
20	17	06-09-09	Diesel	600	0.6	Bridgeport	Yes			pending	450	$165,000	$2,500	$87,630
21	18	06-09-10	Diesel	500	0.5	Shelton	Yes			pending	422	$170,000	$2,500	$73,025
22	19	06-10-04	Diesel	275	0.275	Waterford	No	0.275	$55,000	yes	244	$120,000	$1,000	$40,164
23	20	06-10-24	Diesel	150	0.15	Rocky Hill	No	0.150	$30,000	yes	150	$80,400	$1,600	$21,908
24	21	06-11-02	Diesel	2250	2.25	Cromwell	No			pending	2250	$1,300,000	$5,000	$328,613
25	22	06-11-03	Diesel	600	0.6	East Lyme	No			pending	600	$300,000	$1,500	$87,630
26	23	06-11-04	Diesel	1100	1.1	Dayville	No	1.100	$220,000	yes	1100	$600,000	$1,500	$160,655
27	24	06-11-11	Gas	500	0.5	Bridgeport	Yes			pending	505	$312,500		$73,025
28	25	06-12-03	Diesel	475	0.475	Seymour	Yes			pending	475	$212,965		$69,374
29	26	06-12-11	Diesel	6,000	6	Stamford	Yes			pending	3000	$4,750,000	$10,000	$876,300
30	27	06-12-15	Diesel	175	0.175	New Haven	Yes			pending		$70,000		$25,559
31	28	06-12-18	Diesel	400	0.4	Hartford	No			pending	1861	$190,000	$4,000	$58,420
32	29	06-12-20	Gas	2,800	2.8	Windsor	No			pending	3635	$4,771,000	$7,500	$408,940
33	30	06-12-25	Diesel	400	0.4	Fairfield	Yes			pending	276	$190,000	$4,000	$58,420
34	31	06-12-26	Diesel	300	0.3	Fairfield	Yes			pending	195	$140,000	$4,000	$43,815
35	32	06-12-27	Diesel	100	0.1	Norwalk	Yes			pending	100	$86,000		$14,605
36	33	06-12-28	Diesel	750	0.75	Branford	Yes			pending	449	$240,000	$4,000	$109,538
37	34	06-12-29	Diesel	450	0.45	Greenwich	Yes			pending	300	$300,000		$65,723
38	35	06-12-31	Diesel	131	0.131	Stratford	Yes			pending	131			$19,133
39	36	06-12-32	Diesel	600	0.6	New Haven	Yes			pending	522	$274,000	$1,500	$87,630
40	37	06-12-33	Diesel	175	0.175	Stratford	Yes			pending	150	$99,000	$1,000	$25,559
41	38	06-12-34	Diesel	500	0.5	Bridgeport	Yes			pending	450	$254,000	$1,500	$73,025
42	39	07-01-01	Diesel	1,100	1.1	Trumball	Yes			pending	622	$575,000	$2,000	$160,655
43	40	07-01-06	Diesel	115	0.115	Niantic	No			pending	115	$70,732		$16,796
44	**40**			**33,398**	**33.40**			**12.828**	**$3,089,817**		**30956**	**$22,387,064**	**$242,045**	**$4,865,656**
45									**Awards to Date**		**All Applics**			**thru May 31, 2010**
46								**No. of Awards**	**18**		**No of Applic**	**40**		PLUS FCM Mkts
47								**avg kW award**	**$241**		**avg $/kW**	**$670**		value as existing
48								**Avg Award per project**	**$171,657**		**At $241/kW**			resource for life of
49								**Avg kW size of awarded project**	**800**		**if for 30,520**	**$7,456,219**		machines
50								**Avg Total Inv. Of Awarded Projects**	**$449,270**	**$561.82**	**avg.size/kW**	835		
51										**/kW**				

Sample calculation of Category A Benefits and Costs for a 250 kW natural gas engine CHP project at a nursing care facility in Framingham.

	Category A Benefit/Cost	DG Owner	Electric Distribution Company	Electric Transmission Provider	Other Electric Ratepayers	Gas Distribution Company	Environmental Stakeholders	Net
Total Electric Bill	DG Owner Electricity Bill: Transfer Payments	520,000	(280,000)	(55,000)	(330,000)	-	-	(230,000)
	Reduced Central Power Plant Fuel Consumption	1,400,000	-	-	-	-	-	1,400,000
	Avoided Central Power Plant Capacity	330,000	-	-	-	-	-	330,000
Total NG Bill	DG Owner Natural Gas Bill: Transfer Payments	(130,000)	-	-	-	170,000	-	40,000
	Increased DG Owner Natural Gas Consumption	(740,000)	-	-	-	-	-	(740,000)
	State and Federal Incentives (NPV)	-	-	-	-	-	-	-
	Renewable Energy Certificates	-	-	-	-	-	-	-
	DG Equipment and Installation	(500,000)	-	-	-	-	-	(500,000)
	Annual O&M Expenses for DG	(320,000)	-	-	-	-	-	(320,000)
	Increased Reliability for DG Owner	63,000	-	-	-	-	-	63,000
	Locational Installed Capacity (LICAP) Value	-	-	-	54,000	-	-	54,000
	Deferred Distribution System Investment	-	16,000	-	-	-	-	16,000
	Ancillary Services	-	-	-	91,000	-	-	91,000
	Congestion Value	-	-	-	48,000	-	-	48,000
	Emissions - CO_2, NO_x & SO_x	-	-	-	-	-	230,000	230,000
	Avoided Electric System Losses	-	-	-	260,000	-	12,000	270,000
	Benefits Overhead	-	-	-	-	-	-	(190,000)
	Sub-Total Category A*	580,000	(260,000)	(55,000)	120,000	170,000	240,000	520,000

* Including Category B benefits/costs for CHP could provide additional net positive benefits.

Costs and benefits vary across the eight opportunities; however, the relative magnitude of the costs and benefits is fairly constant.

Range of Total Net Benefits (CHP Installations in all Eight Opportunities)				
Category A Costs/Benefits	$NPV/kW		% of Total	
	Low	High	Low	High
DG Equipment and Installation	(1,200)	(2,000)	32%	29%
Annual O&M Expenses for DG	(800)	(1,300)	21%	19%
Benefits Overhead	(400)	(800)	37%	41%
Increased DG Owner Natural Gas Consumption	(1,400)	(2,800)	11%	12%
Sub-Total Category A Costs	*(3,800)*	*(6,900)*	*100%*	*100%*
Reduced Central Power Plant Fuel Consumption	3,300	6,000	64%	57%
Avoided Central Power Plant Capacity	600	1,300	12%	12%
Increased Reliability for DG Owner	140	250	3%	2%
Locational Installed Capacity (LICAP) Value	0	200	0%	2%
Deferred Distribution System Investment	60	140	1%	2%
Ancillary Services	220	390	4%	4%
Congestion Value	-150	200	-3%	2%
Emissions - CO2, NOx & SOx	400	900	8%	8%
Avoided Electric System Losses (1)	600	1,250	12%	11%
Sub-Total Category A Benefits	*5,200*	*10,600*	*100%*	*100%*

Category B benefits/costs are all positive for PV and would likely make PV substantially more attractive for Society.

Photovoltaics – Category B Benefits							
Category B Benefit/Cost	DG Owner	Electric Distribution Company	Electric Transmission Provider	Other Electric Ratepayers	Gas Distribution Company	Environmental Stakeholders	Net
Health Impact of DG	0	0	0	0	0	+	+
Increased Emissions (CO2, NOx and SOx).	0	0	0	0	0	0	0
Noise Disturbance	0	0	0	0	0	0	0
NIMBY Opposition to DG	0	0	0	0	0	0	0
Consumer Electricity Price Protection	+++	0	0	0	0	0	+++
Power Quality (DG Owner)	0	0	0	0	0	0	0
Market Price Impacts/Elasticity	0	0	0	++	0	0	++
Fuel Diversity	0	0	0	0	0	+++	+++
Avoided Transmission Capacity	0	0	0	+	0	0	+
Reduced Security Risk to Grid	0	0	0	0	0	0	+
Fuel Delivery Challenges	0	0	0	0	0	0	0
NIMBY Opposition to Central Power Plants and Transmission Lines	0	0	0	0	0	+	+
Real Options Value of DG	0	+	0	0	0	0	+
Support of RPS Goals	0	0	0	0	0	+++	+++
Local economic impact	0	0	0	0	0	0	++

+++ Benefit: same order of magnitude as the customer's electricity bill savings
++ Benefit: one order of magnitude less than the customer's electricity bill savings
+ Benefit: two orders of magnitude less than the customer's electricity bill savings
0 No impact

- Cost: two orders of magnitude less than the customer's electricity bill savings
-- Cost: one order of magnitude less than the customer's electricity bill savings
--- Cost: same order of magnitude as the total customer's electricity bill savings

NAVIGANT CONSULTING

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

Rhode Island Division of
Public Utilities and Carriers
89 Jefferson Blvd.
Warwick RI 02888
(401) 941-4500

January 26, 2007

Mr. Paul Gromer
The Peregrine Energy Group, Inc.
151 Merrimac Street
Suite 660
Boston, MA 02114

Dear Paul:

The Division of Public Utilities and Carriers appreciates the opportunity to participate in the distributed generation stakeholder process and the hard work and input of many of the group's members. We have previously submitted comments on the draft DG report that reflected some misgivings. These were in the form of a January 16 memo from Dr. John Stutz, a consultant to the Division on energy matters. These are appended to this letter. At this point, after reviewing the "Recommendations and Potential Strategies" document, we do not think we should be taking positions on many of the elements listed. In addition to addressing our original comments, we would require that a cost / benefit analysis be performed to set an appropriate foundation for the development of a rational policy in Rhode Island. An approach that seems reasonable is one described in an attachment to an e-mail from John Farley of TEC-RI and circulated on January 23, 2007. It describes a cost / benefit quantification process that when completed, will provide the framework and foundation for further development of DG, renewables, and energy efficiency. Before that study is completed and scrutinized, it is difficult to draw conclusions and confidently make recommendations on these matters. We have appended the aforementioned January 23 document as well for your convenience. We recommend that our comments as well as comments of other stakeholders be included in the report that ultimately stems from this process.

Very truly yours,

Steph Scialabba

Stephen Scialabba

cc: Andy Dzykewicz
Thomas Ahern

w/ enclosures

MEMORANDUM

TO:	Dave Stearns, Steve Scialabba
	R.I.Division of Public Utilities
FROM:	John Stutz, Tellus Institute
TOPIC:	Comments on the Draft DG Report
DATE:	January 16, 2007

As requested, I have reviewed the Draft Report from the Distributed Generation (DG) Stakeholders Group to the RI General Assembly. The report is a first draft, with much to be added and fleshed out. However, despite its unfinished state, there are two points that merit discussion. These are the failure to address "costs" (i.e., uncertainties or risks) associated with DG, and the lack of discussion of RI-specific conditions which may materially affect the results presented in the report.

In the report I could not find a single uncertainty and risk associated with DG that was identified or discussed. Other reports have no difficulty finding and discussing them. For example, *Prospects for Distributed Electricity Generation*, a review paper prepared by the Congressional Budget Office (CBO) in late 2003, devotes a number of pages to DG-related uncertainties and risks. Among the risks the CBO raises is the possibility of adverse effects on power quality and local system reliability if there are numerous DG installations in an area. Since power quality has been an issue in RI in the past, this is a material omission. More generally, a report that does not identify or discuss uncertainties and risks may lack credibility, and so may not further the development of DG in RI.

The report has a section headed **Benefits to Other Energy Users and Society**. The first two items in the section are reduced natural gas and electricity prices, due to reduced demand. The argument is a standard one—all else equal, in a competitive market a reduction in demand leads to a reduction in price. This argument is at best incomplete. One needs DG sufficient to change the resources on the margin in order to produce the claimed benefit. Because gas is a North American market and, with imported LNG on the margin may become a world market, the argument that DG in RI will change the marginal resource will be hard to make. The fact that electricity is a regional resource makes the argument easier, but some evidence is still needed to show that the likely impact is sufficient to change the resource on the margin.

If the "Other Energy Users" are the businesses and residents of RI, a rather different set of issues emerge. For gas, one would need to look at the local gas utility carefully, to see how plausible amounts of DG would affect its costs. Since DG development may increase the amount, and shift the seasonal pattern of gas use in RI, the impact is unclear. Turning to electricity, there is reason to believe that DG development could raise average prices for Last Resort Service now and for the successor to Last Resort and Standard Offer Services after 2009. These services are what are load-following services. DG development may make it riskier and more expensive to for LRS and SO suppliers to provide such services if DG development is seen as contributing to additional load uncertainty over a suppliers contract period. If the services are provided based on fixed-price, multi-year contracts, such as 3-year laddered arrangements that are becoming typical, DG development will add risk, and so cost.

I do not want to give the impression that consideration of RI-specific conditions will invariably be adverse to DG. There are RI-specific conditions that may favor DG. For example, National Grid and Northeast Utilities recently announced agreement on a major transmission project. One part involves the construction of transmission lines in RI to address reliability problems within the state. In the section on Benefits to Other Users and Society, the report touches on transmission at a number of points, but makes no mention of this development. As the Grid/NU agreement was announced publicly (*Electric Utility Week*, Jan. 8, 2007), it must have been in the works for some time. Mention of this in-state effort would have given the report's general transmission-related arguments more weight.

Finally, let me point out a recommendation that may lead to unintended results. The report calls for a "fully litigated hearing" on standby rates. The 2004 settlement with Grid gave standby rates fairly favorable treatment. In a fully litigated case, one might end up with something less favorable. Were I seeking to foster DG, I would be more confident discussing standby rates with the Legislature as part of a development package, than going before the PUC based on costs. However, before arranging for a reduction in the scope and cost of standby service, I would expect the Legislature to want a more balanced and complete discussion of benefits and costs than the report appears likely to provide.

I hope these brief comments are useful. If you have any comments or questions, please feel free to give me a call.