Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies

DG Business Models
Task #2

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ABSTRACT

This is the second in a series of four task reports and a final report prepared by Pace Energy and Climate Center and Synapse Energy Economics (Project Team) for NYSERDA under the terms of NYSERDA Contract #10472. This report develops the operational and programmatic elements for three business models designed to encourage the deployment of Distributed Generation / Combined Heat and Power (DG/CHP) by distribution utility deployment considering the utilization of DG assets as an alternative to traditional distribution capital expenditures. The models specified in the Scope of Work are: (i) the Utility Ownership Model, (ii) the DG Development Zone Model, and (iii) the Refined Request For Proposal (RFP) Approach.[1]

In addition to providing the operational and programmatic elements of each model, this report describes associated implementation issues as well as the potential risks and benefits from each model. This task report presents case studies illustrating how the various elements contained in the three models have been put into operation in the field and to reveal best utility and regulatory practices.

There is very limited practical experience with DG/CHP as a substitute for utility distribution system investment, rendering conclusions about best utility and regulatory practice premature. In this task report the Project Team developed the general structure of three possible business models. To the extent possible we have incorporated the limited existing base of case study experience; the case studies are intended to help anticipate the most problematic issues that are likely to arise with each model type, and to help illustrate the distinct benefits that each type might offer.

This task report should be read in tandem with the Task #3 Report: Comparative Analysis of DG Implementation Models, which supplements this section with a comparative analysis of the most critical issues associated with each of these three approaches. In particular, Task #3 assesses the following issues for each of the three models:

- Regulatory Burden And Management Complexity
- Project And Program Cost
- Ease Of DG Integration
- DG Relocation Flexibility, Deployment Lead Time
- DG Interconnection
- Reliability
- DG Market Development
- Meeting Utility Renewable Portfolio Standards (RPS)
- Resource Integration

[1] The authors wish to acknowledge research support from Thomas Kelly and editing assistance from Todd Olinsky-Paul.

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KEY FINDINGS

1. DG/CHP can serve as a substitute for distribution capital investment – when sited in the right locations, operating at the right times and offering the required level of reliability.
2. The paramount concern of the utility is safe and reliable operation of the distribution system whereas the DG /CHP owners are primarily interested in economic operation at their site. This can create some complications in program design, but is not an insurmountable obstacle.
3. Where the objectives of the utility (reliability) and private owner (economics) are not entirely compatible, they can be harmonized with some mix of physical and operational controls, contractual arrangements and incentives or penalties.
4. Distribution system capital cost savings benefits of DG are typically not captured in existing markets. Utilities may internalize the benefit by owning the DG asset themselves, or create a market (via RFP process or incentive payments) that compensates private sites for this otherwise non-market benefit.
5. The utility owned solution internalizes the benefits of the DG asset, while maintaining a high level of utility control and without the additional time and resource costs of creating a market, executing contracts and marketing programs.
6. Still, the utility owned solution raises questions of market power and perceptions of unfair competitive advantage.
7. Creating private market solutions may require more time and costs, but may yield innovative solutions that otherwise would not have been conceived.
8. The existing distribution planning process in large measure does not contemplate DG solutions. Consequently:
    a. modeling tools that would identify DG investments as cost-effective solutions are not well developed,
    b. forecasting methodologies that predict high-value DG deployment opportunities based on network loading, equipment ratings and demand projections are typically not employed, and
    c. program budgets that would identify DG alternatives are not in place.
9. The types of capital investments potentially addressable by DG projects has not been inventoried and prioritized in a manner facilitating comparative analysis of DG deferral relative to traditional solutions (e.g. load growth related investments, strategic business operations related, replacement of antiquated equipment and processes with new methods).
10. Where utility capital budgets are growing and putting increasing pressure on rates over time, utilities may consider private investment in the form of customer owned-DG assets as a substitute for traditional utility solutions.

SUMMARY

This task report develops three business models that enable utilities to consider the use of DG assets as an alternative to traditional distribution capital expenditures. These three models represent general approaches that would allow utilities to incorporate DG into their distribution planning process as an alternative to traditional distribution system capital expenditures.

In Section 1, the Project Team critically reviews the economics and legal issues for the existing state policy regarding utility ownership of power generation in light of current market and regulatory realities. The Project Team also analyzes the impact of utility ownership of DG on the wholesale energy market, power businesses and the DG industry. This involves an exploration of market power issues associated with the utility's ability to leverage its control of the distribution network to unfairly benefit its DG businesses. It also involves an investigation of utilities' perceived unfair advantage over other wholesale energy providers resulting from the utilities' guaranteed recovery of prudently incurred capital investments.[2] These models are supported by a number of case studies included in Appendix 1.

Section 2 presents two models that facilitate the development of customer-owned DG resources as an alternative to distribution system upgrades. In each of these models, utilities play an enabling role in encouraging customer-ownership of DG. The structure of each model is described individually, followed by an examination of critical issues relevant to both models. These models are supported by a number of case studies included in Appendix 2.

In the High Value DG Development Zone Model, the Project Team critically reviews the elements of a business model under which the utility would offer a posted incentive price for new DG deployment in geographically targeted development zones. It considers the practical elements of implementing this approach, such as defining the zone, setting incentive levels, and ensuring that incentives are paid only upon a threshold level of DG penetration sufficient to defer or avoid the capital project.

In the Refined RFP model, the Project Team proposes a refined version of the RFP process for eliciting a market response to distribution system needs identified by the utility. The analysis includes options to mitigate or resolve problems identified through a pilot program, initiated by the New York State Public Service Commission (NYSPSC) that explored the use of an RFP process to secure DG resources as an alternative to utility distribution investment.[3] The value of distribution system investment deferral ranges in some areas from $200 kW/year to $800 kW/year. In order to capture some of the savings for the utility and its ratepayers, the DG assets would probably be acquired at a price resulting in some measure of shared savings between the company and the entity receiving the incentive. At the upper end of this value distribution, utilities could offer very attractive incentives and, at the same time, realize significant ratepayer or shareholder benefits.

Note that DG/CHP asset development typically requires a long-term planning horizon. Therefore, the subset of projects that can potentially be deferred is likely to consist of those that do not need near term attention, rather can be in place in 36 months or more without sacrificing local reliability. Projects with the longer term time frames for implementation by their nature are probably not at the extreme high end of the distribution of avoided cost savings.

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[2] In Task 3, the Team investigates regulatory burdens and management complexity associated with utility owned DG projects for numerous issues such as cost recovery, project development, DG monitoring and operation, sales of energy and capacity from DG, and customer contracting. Project and program costs of utility owned DG are compared to a scenario where private companies install DG for T&D support.

[3] In NY PSC Opinion No. 01-5 2001, the New York Public Service Commission directed New York's investor-owned distribution companies to implement a three-year pilot program designed to test whether distributed generation could cost-effectively defer the need for significant investment in distribution system infrastructure.

1 UTILITY OWNERSHIP MODEL

1.1 MODEL OVERVIEW

The utility owned DG business model is one where a distribution or vertically integrated utility, in its distribution planning process, actively seeks opportunities for deployment by the utility itself, of cost-effective DG solutions, to alleviate grid congestion and to defer or avoid the construction or upgrade of distribution system equipment. The model also assumes utilities receive a regulated return on their DG investment, which is critical for a model to make economic sense. The model may take any of the following three forms:

- A utility owns and operates DG on the distribution system or other utility owned property attached to a distribution circuit or at a substation, but on the utility's side of the retail meter; or
- A utility owns and operates DG on a customer site on either side of the retail meter; or
- A utility owns DG control and monitor equipment, such as inverter and meter, at a customer site.

Detroit Edison operates an example of the first type of program. The company owns, deploys and operates mobile DG units (e.g., 1–2 MW trailer-mounted diesel or natural gas motor-generator sets) along its distribution system to alleviate local transmission and distribution (T&D) system congestion and in some cases to defer or cancel the need to build or upgrade distribution system equipment. Likewise, in Denning NY, Central Hudson Gas and Electric owns and operates a 1 MV_A generator connected at the distribution level. The generator provides a reliability benefit to the 550 residents (65 residential, 1 commercial customer) in an area prone to frequent local outages. Central Hudson selected the DG solution after investigating the cost of building a new distribution feeder and tapping into another utility's distribution system.

Austin Energy in Texas operates an example of the second approach; it owns and operates combustion turbines at two sites, one a hospital and the other an industrial park. In addition, a number of utilities including National Grid in Massachusetts, Pepco in Maryland, and Southern California Edison recently proposed to own and operate distributed PV units. These also fall under the second form of the model. Finally, a few utilities have proposed to own DG related equipment, including Public Service of New Hampshire and Chelan Public Utility District (SEPA, 2008). Some of these cases are discussed in greater detail in the Case Studies section below.

Under any of the three versions of this business model, utilities may need to begin by hiring or expanding internal staff to work on DG projects. Such internal staff will need to be familiar not just with DG interconnection, but also with overall DG technologies, installation, and operation and maintenance. A utility might employ in-house staff to perform project engineering, design, installation, operation and maintenance, but could also contract out these tasks. Utilities would then identify, far in advance of potential distribution projects, the potential for DG projects along the distribution system or at customer sites where DG could defer distribution projects. In an alternative scenario, if a utility finds that proposed distribution upgrades are not going forward as planned due to community opposition, budget constraints, or other reasons, the utility could deploy DG under its ownership to buy time for distribution projects.

Occasionally, utility-owned DG can be sited on utility-owned land, such as on property where a substation is located. Nevertheless, when seeking to use non-utility land or a customer site for DG, utilities will need to address zoning and other local regulation, engage in community and customer outreach and, possibly, negotiate lease agreements with local governments or customers. Where noise and pollution are a public concern, utilities will need to take steps to mitigate these and obtain the required permits.

Finally, utilities may need to file regulatory documents to seek siting approval for DG installation (although in some jurisdictions mobile units or other kinds of DG may not require such approvals), and go through the process of seeking rate recovery for the costs of DG in general rate cases or special proceedings. There, they will likely need to demonstrate that their investment was prudent, in the public interest, just and reasonable in order to obtain rate recovery, including return of and on the DG investment.

1.2 THE PROHIBITION AGAINST UTILITY OWNERSHIP OF DG IN NEW YORK: PAST, PRESENT AND FUTURE

1.2.1 Utility Ownership of DG in New York

In 1996, the NYSPSC initiated a proceeding that restructured the electric utility industry in New York State, fundamentally changing the market and opening the industry to competition (NYSPSC, 1996). The NYSPSC proceeding did not specifically prohibit a distribution utility from owning generation resources, but directed the investor owned utilities to divest their existing generation in order to create a competitive generation market. As a result, utilities generally divested their generation resources, with the exception of some small hydro generation, Con Edison's steam generators, and certain nuclear power plants (which were subsequently divested).

The question of utility ownership of generation has resurfaced in subsequent proceedings, with decisions on utility ownership determined on a case-by-case basis. The principles applied in those cases provide some useful insight for examining the circumstances under which utilities can own DG for the purpose of distribution system planning.

The most relevant principle for the ownership of DG by utilities is stated in the Vertical Market Power Policy (VMPP) Statement of 1998, where the NYSPSC stated its policy position on a T&D utility affiliate owning generation.[4] While the VMPP statement provided that generation divesture is "a key means of achieving an environment where the incentives to abuse market power are minimized," it also stated that the ownership of generation by a T&D company is allowed if there is a demonstration of "substantial ratepayer benefits, together with [market power] mitigation measures" (NYSPSC Case 96-E-0990, 1998). The VMPP has been relied upon to examine the appropriateness of generation divesture and ownership in past cases. Recent examples include the National Grid acquisition of KeySpan in 2007 and the Iberdrola acquisition of NYSEG and RG&E in 2008.

In contrast, there are only a handful cases since restructuring that involved utility ownership of DG. While the VMPP statement was not cited in those cases, its spirit was reflected. Brief overviews of two such cases are provided below:

- In Opinion No. 01-5, the NYSPSC directed New York's investor-owned distribution companies to implement a three-year pilot program designed to test whether distributed generation could cost-effectively defer the need for significant investment in distribution system infrastructure (NYSPSC Case No. 00-E-0005, 2001). The pilot focused on customer owned DG projects, but allowed utilities and utility affiliates to bid utility owned DG projects. It appears that this reflects NYSPSC's recognition that utility ownership of DG may provide some public benefits. Still, NYSPSC did not comment on utility ownership of DG in Opinion No. 01-5, and the recommendation report that NYSPSC endorsed in the opinion did not discuss utility ownership of DG resources in detail (other than the mention of one stakeholder who claimed that utility ownership allows for realization of the full benefits of DG). The recommendation report, however, did clearly state that utility affiliates are allowed to participate in the pilot provided that "utility does not extend preferences to its affiliates in violation of code of conduct requirements" (PSC Case No. 00-E-0005, Appendix B, 2001).
- In the April 2, 2010 Renewable Portfolio Standard (RPS) Final Order, NYSPSC, along with various stakeholders, reviewed the RPS customer-sited tier program to address the geographic imbalance between the regions of the state from which System Benefits Charge (SBC) money is collected, and the regions where renewable energy projects are installed with SBC funds (RPS Order, Case 03-E-0133, 2010). The order also examined utility ownership of PV as a possible eligible renewable energy resource option for the proposed customer-sited program in downstate New York. In the order, the NYSPSC stated that "the retail distributed solar photovoltaic market is demonstrably competitive and utility involvement in the market, at this time, does not appear necessary to address any deficiencies" (RPS Order, 2010). Still, NYSPSC also stated that "there may be merit in allowing utilities to participate further in this program, at a later date, if it were to be found that private investment is not available or sufficient in areas where utility ownership may

[4] The issues associated with vertical market power will be discussed in greater detail below.

be better targeted, more cost-effective and beneficial" (RPS Order, Case 03-E-0133, 2010). The order also emphasizes that utility ownership "will require careful consideration to ensure that such a structure is in the best interest of the ratepayer and that utilities are not able to monopolize any market segment" (RPS Order, 2010).

Opinion No. 01-5 was not explicit concerning the circumstances under which utility ownership of DG is appropriate. Nevertheless, the April 2010 RPS Final Order is more clear. The case concluded that while utility ownership of DG is not prohibited or illegal, it would be challenging for NYSPSC to approve "at this time." As stated in the April 2010 order and the VMPP statement, a utility needs to demonstrate that utility ownership of DG provides a substantial public benefit, does not harm competition and provides measures to mitigate market power. The order states that though not impossible, demonstrating the benefits of utility ownership relative to customer owned projects would be a challenge, particularly because there are few customer projects developed in the downstate area. Still, where utilities own DG-related equipment such as meters, inverters and controls, with the customer owning the DG resource itself (as the third form of the utility DG ownership proposed here), the benefits of DG can be recognized without requiring such a demonstration.

1.2.2 Market Power and Unfair Competitive Advantage

Two major issues arise when utilities own DG assets that do not arise when utilities own only DG-related equipment such as meters, inverters, and DG control units. The first issue relates to vertical market power briefly discussed above in relation to the VMPP Statement. The second issue relates to a perceived unfair advantage over other wholesale energy providers and other solar PV providers, in that a distribution company's DG business may enjoy advantages not available to other market participants.

Vertical Market Power. Vertical market power occurs when an entity that has market power in one stage of the production process (e.g., distribution and transmission) leverages that power to gain advantage in a different stage of production process (e.g., generation) (PSC, 1998). In a case where utilities own DG assets, vertical market power would occur where the utilities (e.g., New York IOUs) take advantage of their monopoly in T&D in their territories (or have the ability to do so) in order to unfairly benefit their DG businesses. The following examples are helpful to understand the exercise of market power by T&D utilities:

- "[A] T&D company has an incentive to make entry by generators into its own territory difficult, and therefore, expensive for a new entrant by either delaying or imposing unrealistic interconnection requirements…" (PSC, 1998).
- "The affiliate's generator is on the high cost side of a transmission constraint and the T&D company has the ability to influence the transmission constraint. The T&D company has the incentive to retain the constraint to keep the market price high on the high cost side of the constraint" (PSC, 1998).

The vertical market power issue can be alleviated through appropriate rules and standards established by the NYISO, FERC and NYSPSC; however, such rules and standards might not completely eliminate the possibility of market power. The impact of DG on the distribution system is not fully understood even by utilities, and the lengthy process of examining the impacts of DG on the grid has historically caused significant delay in the interconnection of DG to the distribution system. Still, it is important to recognize that if utilities are allowed to own DG, it will provide an opportunity to better understand the impact of DG on the distribution system. This may result in a more standardized and efficient interconnection process, and a more precise assessment of DG benefits.

The issue discussed in the second example, where a utility maintains, creates, or increases a transmission constraint (e.g., by building less transmission capacity than is optimal), may be of even greater concern than vertical market power. In this situation, the transmission constraint will (or could) raise the wholesale market price of energy and capacity available to its generation resource. Nevertheless, it seems likely that this problem is insignificant for smaller scale DG/CHP and renewable generation for the following reasons:

(1) Because the primary goal of DG is to meet on-site or local demand (in the case of stationary DG units) or alleviate T&D constraints (by mobile and other types of DG) in the utility DG ownership model, the company may have little incentive to exercise market power to influence wholesale market price by retaining transmission constraints.

(2) DG/CHP resources are small in capacity relative to the size of the wholesale markets. While the total collective DG capacity could become material eventually, limiting the purpose of DG ownership to T&D support would limit the collective size of fleets owned by the utility.

It is important to note that the 1998 Vertical Market Power Policy Statement allowed the combined vertical ownership of generation by T&D utilities where there is a demonstration of substantial ratepayer benefits and measures to mitigate vertical market power risk. Limiting the total size of DG ownership, as mentioned above, is one approach to mitigate vertical market power. In addition, when utilities own and use DG for T&D support, it is likely to provide benefits to the ratepayers and renewable energy industries in the form of lower distribution related cost and lower DG cost. Lower distribution costs can be achieved because utilities are best situated to support T&D and to defer T&D investment. Significant DG cost reduction may be possible because of utilities' bulk purchasing power and long-term financing.[5]

Unfair Competitive Advantage? The Impact of Utility Owned DG on DG Markets. The second major issue arising from utility DG ownership, the perceived unfair advantage over other wholesale energy providers, stems from the utilities' rates typically being set to permit recovery of and on investments through the rate base (subject to prudence and used and useful standards). This policy, it is sometimes asserted, appears to give an unfair advantage of the utility over private companies because private companies' business is not similarly protected. Private companies can be divided into two distinct groups, the first of which is wholesale generators such as independent power producers (IPP), and the second of which is private DG project developers.

Wholesale generators or IPPs are typically private companies without cost recovery from captive ratepayers via regulated rates. In the deregulated energy and capacity markets in New York, wholesale generators are likely to object to generation ownership by utilities. Still, if the size and purpose of utility-owned generation is limited, such as when utilities seek to support T&D or promote renewable generation, then the concerns of competitive wholesale generators may be mitigated. Nevertheless, if DG developers or aggregators of DG become more active in the wholesale markets, the presence of utilities means a smaller share of business activity available to the private market. Utilities would then need to demonstrate that their ownership creates ratepayer benefits in excess of that available from private providers, and that utility ownership will be subject to market power oversight and mitigation measures.[6]

The threat of competition is a major issue affecting DG project developers that can be mitigated to a great extent by limiting DG ownership to a maximum capacity and location and providing market players with ample business opportunities.[7] One model would have utilities using their own property to site DG projects, while contracting out engineering, procurement, and construction (EPC), as well as maintenance work to private companies.[8]

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[5] See examples of utility PV programs by NGRID and Southern California Edison in the Case Studies Section.

[6] The utility contribution to the development of DG markets may be beneficial to private companies if it reduces the price of DG equipment in the long term by increasing the size of the DG market. Also, if a utility becomes more familiar with DG interconnection, that will help others interconnect to the grid more easily.

[7] As recommended by the Solar Alliance, 2009. Also note that Massachusetts allows utility ownership of PV, limited to a maximum capacity of 50 MW per company.

[8] Without an initiative by a utility to own DG, it is unlikely that DG will be installed on the utility's property.

2 CUSTOMER OWNED—UTILITY FACILITATED MODELS

The Refined Request For Proposal (RRFP) model provides a mechanism for utilities to promote deployment of customer-owned DG resources in high deferral value locations. The RRFP model is an adaptation of a 2002 New York pilot program for integration of DG in utility system planning.

Key Elements of the RRFP Model:

- Independent third party and utility responsible for selection process
- RRFP limited to areas where optimal DG/CHP economics exist
- Utility or customer provided with operational influence or control over the resource
- Other energy resources allowed to be bid with DG/CHP

2.1 RRFP MODEL DEPLOYED IN 2002 PILOT PROGRAM

In October 2001, NYSPSC ordered New York's investor-owned electric distribution companies (EDCs) to implement a three-year DG pilot program designed to test whether DG could cost-effectively defer the need for distribution system infrastructure investment (PSC Opinion No. 01-5, 2001). Each EDC was ordered to issue Requests for Proposals (RFPs) in the areas of greatest need. Between 2002 and 2004, there were a total of 22 RFPs issued; however, none were selected by the respective utilities as the least cost option. Over 75% of the RFPs that were issued did not receive a bid.

In 2006, the Project Team performed an independent evaluation of New York State's DG Pilot Program, described in a report entitled "*A Comprehensive Process Evaluation of Early Experiences Under New York's Pilot Program for Integration of Distributed Generation in Utility System Planning*" (2006 Report). The RRFP model presented here incorporates lessons learned from the 2006 Report to develop a refined approach that is more responsive to market conditions. The 2006 Report offered the following eleven recommendations to the PSC on ways to improve the existing program or a future program:

1. Limit mandatory use of RFPs to utility service areas with attractive DG economics
2. Consider a greater role for distribution utilities in project development
3. Initiate collaborative process with stakeholders for development of best practices
4. Experiment with cooperative management of bid review process with third party
5. Allow DG to be bid in combination with other distributed energy resources
6. Explicitly allow commitments for load shedding in lieu of redundant DG capacity
7. Provide greater transparency of the value of deferral to the distribution utility
8. Encourage aggressive utility co-marketing of DG program to large customers
9. Utilities should not automatically foreclose post-bid negotiations
10. Explore synergies between local utilities and NYISO in relieving grid congestion
11. Provide parties with greater guidance on the evaluation of reliability

The following sections incorporate these recommendations to structure an enhanced business model available to NYSPSC, should it decide to re-evaluate an RFP program as expressed by the page numbers in parentheses above. In particular, the RRFP proposes mechanisms that establish better congruence between distribution needs and sites where DG makes the most economic and technical sense; allows adequate lead time for preparing bids and securing host sites; provides greater transparency of 'price to beat' for wires solutions; reduces transaction costs; sets appropriate standards for required DG reliability; and addresses perceptions of utility bias in favor of its own "bid." An updated RFP program may find greater acceptance in the DG market than a new program with different rules and incentives. Implementing the RRFP model with the prescribed enhancements could benefit both the utility and developers entering into contracts to defer T&D infrastructure.

2.2 RRFP MODEL

2.2.1 Definition

The RRFP will operate as a statewide business model targeted towards radial, hub-spoke and network distribution systems with the greatest deferral values. Achieving these targets will maximize the societal benefits described in Task #1, which accrue not only to utilities but also to the DG market, end use customers and all ratepayers. Amongst the key societal benefits are increased T&D system reliability, lower T&D capital costs and potential reductions in the wholesale market clearing price.

Unlike the prior pilot RFP approach, the RRFP model will be used with greater frequency in NYCA Zone J (Con Edison's service territory), as Zone J has the greatest electric capacity constraints at both the transmission and distribution levels. Nevertheless, the RRFP model would apply to all utility service territories in the state where DG/CHP would be economically and technically feasible. The RRFP model contemplates one or more of following modifications to program design:

- Solicit bids and award contracts using auction or reverse-auction process
- Allow vendors to bid portfolio of standardized Demand Side Management (DSM) and DG measures
- Standardize delivery contracts for DSM and DG measures
- Define delivery terms up front, specify quantities and timing as needed
- Bid out load reduction deliveries as they arise; place orders for low bids
- Expand eligibility to wide range of measures – e.g., DSM, DG, storage, etc.

2.2.2 Address Perception of Utility Bias

The 2006 report also identified a perceived concern that utilities controlled too much of the process. This concern is addressed in the RRFP model in two ways:

1. Establishing stakeholder working group meetings to increase transparency and improve program design. In 2006, an EPRI report prepared as part of the Massachusetts Technology Collaborative, studying the New York Integration of DG Pilot Program, revealed that stakeholder meetings can improve the likelihood for successes with DG projects (EPRI, 2006). The EPRI report also analyzed Southern California Edison's (SCE) stakeholder collaborative approach and found it to provide creative solutions that addressed all stakeholder concerns. The Massachusetts DG Collaborative specifically incorporated a collaborative approach for projects. The collaborative made it possible to:
    a. Identify criteria and screen congested areas
    b. Propose feasible locations
    c. Design methods to evaluate and assure reliability, and
    d. Develop successful contract terms and payment structures.

2. Using an independent third party to process the bids received. Evaluation of proposals by an independent third party further enhances the success of the RFP approach. As described in the 2006 EPRI report, a <u>Technical Evaluation Panel</u> (TEP) consisting of internal utility personnel and external experts would:
    a. Review the potential bids and projects (EPRI, 2006)
    b. Compare the utility cost estimate to the bidder's estimate, and
    c. Collaboratively rank the projects to decide upon the best solution.

Selection process for the TEP would require that there be no special interest on behalf of its members.

In the 2006 Report, one developer bid within 10% of the utility's projected avoided cost. Nevertheless, the utility chose not to work with the developer. The ninth recommendation suggests that utilities should work with developers when the bid is close, rather than automatically rejecting the bid. The TEP and the utility could work with the developer to see if the cost of the bid could be lowered. If the TEP and utility could not reach agreement, each would select their respective best projects and submit to the PSC for a ruling.

There are costs to parties for participation in an RFP process. These costs must be weighed against the expected return, should a bid be successful. Potential bidders will be reluctant to participate if they perceive that meritorious bids have little or no chance of acceptance. Inclusion of an independent third party will provide assurances to developers that their bids will receive fair consideration.

2.2.3 Greater Transparency of the Value of Deferral in Particular Locations

One approach to the RFP process is for the utility to internally screen a pool of potential projects (sites) and from that pool select one or a few sites to offer in a solicitation for bids. Opportunities may be lost if this process is conducted internal to the utility, without customer input regarding the location of potentially favorable DG projects. For example, a deferrable project may rank just outside the utilities screen for selection yet, unknown to the utility there may be a particularly attractive DG application that would make DG deferral an economic alternative. The bid selection process should be informed to some extent by outside knowledge (external to the utility) regarding feasible DG/CHP development sites that would support the DG alternative. Having greater cost transparency and more complete information on both the utility and the developer side would drive bid prices down, since bidders with better knowledge about the project economics could offer lower cost solutions.

2.2.4 Reduced Transaction Costs

There are advantages and disadvantages to the RFP process. The exercise of a greater degree of control and the chance to procure resources adequate to meeting the requirement at a lower total cost via an RFP are reasons the approach might be favored. On the other hand, bid preparation costs are associated with an RRFP but not with a standard offer. RFPs are issued on an infrequent basis whereas a standard offer is open as long as the conditions underlying the resource need are met. The bid preparation, review and selection process is likely to be more costly in time and dollar terms than a standard offer approach. Therefore care should be taken to reduce transaction costs in the bid process to the extent possible while still retaining adequate controls and oversight. The process of bid preparation should be streamlined. Forms should be clear and bid requirements plainly described. Online forms requiring exactly what is necessary in an easy to complete format should drive the design. Bidders should have confidence in the timelines that are set, as they must conform their project development and financing schedules to the RFP process.

2.2.5 Enhanced Congruence between Distribution Needs and Optimal DG Sites

The first recommendation from the 2006 report was to offer the program where DG/CHP was economically and technically feasible. In the initial RFP offering in 2002, each utility was required to issue essentially the same number of RFPs. Still, it's likely that some NY utilities have far better opportunities for cost-saving DG deferral projects than. Utilities with less favorable economics should not be held to the same standard as those with more favorable economics.

The RRFP Model would be implemented by a fixed price specific to a particular location, which would remain constant through the life of the contract. It would be formulated by the utility, as a function of the utility deferral value as approved by the NYSPSC.

The model should include a set of performance conditions designed to address the disincentives that address utilities concerns about the reliability and performance aspects of customer owned resources, and likewise foster a more streamlined, efficient and economically attractive opportunity for DG/CHP developers. These performance conditions may include:

(a) Sizing the project to the location
(b) Certain performance requirements
(c) Potential utility control over the resource
(d) Agreement terms such as the timing commitment for construction completion

(e) Length of term for the payment commitment, and
(f) Requirements for compliance with permitting and regulations.

The development of a price signal begins with a review of the utility distribution capital investment plan to identify areas of constraint and in need of upgrade over the planning horizon, with a screen for DG feasibility as a measure that could defer or eliminate the need for utility T&D capital expenditure.[9] Based on the deferral value of a T&D project identified in the review process, the utility will provide a fixed monetary incentive based upon the deferral value for the life of the contract for installed customer owned DG/CHP resources. The cost of the incentive could be recoverable through a number of ways: through monthly adjustments from the utility's revenue decoupling mechanism, through system benefit type charges, or through rates. Once the DG/CHP capacity has been valued and is installed and deemed operational by the utility, the winning bidder would receive the value of the deferral over the life of the contract.

2.2.6 Adequate Contract Terms

One of the roadblocks identified in the 2006 report was the short duration of the contract period. Utilities would provide contract periods of only three to five years, which represented the deferral period of the distribution system upgrade, but was considered too short a contract period by developers. As a possible solution, The RRFP model could extend the contract length but at a lower value. The lower value would benefit the ratepayers and the utility. It would also benefit the DG developer by guaranteeing a revenue stream over a longer period. Some developers were willing to accept marginal projects provided the contract period was at least 15 years (2006 Report). Developers felt that longer contracts would provide a guaranteed, steady revenue stream to support other projects.

2.2.7 Reliability and Redundancy Issues

Utilities typically prefer to control the operation of DG units that are relied upon for distribution system support rather than engage resources for distribution support that are controlled by the customer. Operational control offers the utility assurance that the resource will be available to meet local requirements. Customers find it costly to provide the redundancy that a utility may demand. If a utility over-enrolls the program by requiring redundancy from every DG customer, it will ultimately result in a lower contract price between the customer and the utility, and render the project not cost-effective (MTC Annual Report, 2005). Reliability and redundancy issues are critical terms of an RRFP. Utilities should investigate lowering requirements where the directives do not lead to an appreciable gain for local area reliability, yet exact a cost to the potential bidder. For example, physical assurance requirements might better relate to hours when the resource will be required, rather than a blanket requirement of 8,760 hours per year. Likewise, the utility should consider a diversity factor to adjust payments for resources that recognize the probabilistic nature of performance of a set of resources serving a site, or a local area of need. The bidder on the other hand is going to have to accept some measure of operational controls, financial penalties or both, that will reduce the performance risk that the utility is ceding by turning over reliability responsibilities to a third party. Ultimately the utility is responsible for the safe and reliable operation of the distribution system and in the absence of direct control the utility will have to set protocols to assure that the outside party meets the proper standards.

2.2.8 Penalties and Operational Concerns

In theory the degree of control could be structured along a continuum ranging from full utility control, to utility control at peak times or emergency contingencies, to customers having full control. DG redundancy and diverse DG resources may help (MTC Annual Report, 2005; Hedman, 2004). Customers who chose to control their units could be subject to a schedule of penalties for non-performance. The penalty could be consistent with the New York Independent System Operator's (NYISO) Real Time Locational Based Marginal Price (LBMP) for that zone plus an

[9] The screening process should also consider factors related to environmental justice, network reliability, mitigation requirements in terms of timing and size load relief.

additional adder. The Real Time LBMP consists of the marginal cost of energy plus the marginal cost of losses plus the marginal cost of congestion. The penalty could be assessed if the DG/CHP resource was not compliant when requested by the utility. The generation capacity shortfall penalty could be determined by the shortfall in capacity the DG resource provided when called upon to perform during the system peak. Penalties should be set at a level that encourages the correct reliability response from the end user. When set too high, penalties might defer participation in a bid program, but if set too low, may result in reliability costs in the local area served.

2.2.9 Benefits

There are three main benefits to this updated model. The first benefit, an existing familiarity with the RFP approach, results because the fundamental structure of the RFP model will remain unchanged. Developers, regulators, and utilities are experienced with the essentials of this model. The second benefit, a better integration of the key stakeholders, will allow for a more successful program that could include the following action items:

1. Forming a collaborative in order to provide greater transparency to all stakeholders.
    - Utilities could direct developers to optimal sites in their service territory
    - Utilities could advise their customers about the program, and
    - Developers could discuss with utilities and customers obstacles they are facing during the process, as opposed to after the process is over.
2. Selecting an independent third party to work with the utility. The third party would:
    - Review the bids, providing objective analysis
    - Rank the projects according to predefined value standards, and
    - Select the most appropriate projects.

The third benefit, an integration of other demand side resources into the bid process, would provide greater opportunities for the development of responsive DG bids by project developers. This was not the case under the prior RFP process. Evidence from numerous other studies points to the benefit of a multi-resource approach that aggregates a variety of resources, including measures such as energy efficiency retrofits, and demand response.

2.2.10 Risks

An RFP process has certain advantages and disadvantages relative to a standard offer, or posted price approach, such as the High Value DG model, described later in this section. The RRFP approach gives the utilities (and regulators) more control over the final outcome. The RFP can be written in a way that provides a very exacting level of detail as to what constitutes an acceptable project. The RFP represents a price discovery method that relies on the developer/end-user to announce its bid to serve a requirement, rather than the utility announcing what it is willing to pay. The utility may get a better bargain, but this could be offset by generally higher transaction costs of developing and administering an RFP process.

2.2.11 The Role of Utility Buy In

Whether or not the utility embraces the RRFP process is likely to play a pivotal role in its ultimate success. Utilities possess the information on which areas are potentially the best candidates for T&D deferral utilizing customer sited assets. They are in the best position to assess the cost of a traditional utility distribution capital solution. A suggested refinement of the prior RFP was a recommendation to more productively use the existing utility-customer relationship. Utilities are in a strong position to promote each of these models through a range of marketing tools already in place, such as the company website, bill inserts, meetings with potential customers, vendor networks, and so on. Utilities should be required to meet with prospective customers in their service territories where the viability of DG shows promise. Utilities should explain not only the benefits of DG to the system but to the customer as well.

Obstacles to Utility Buy-In

1. Physical assurance requirements imposed by utilities
2. Difficulties in matching lead times in planning projects
3. Contractual issues between utilities and customers
4. Control issues (if a RRFP were to be issued, the utility would most likely require central dispatch due to the need to activate the resource at the precise time when needed due to reliability expectations; it is unlikely that the utility would allow the customer to activate the resource) (Armstrong, 2010)
5. Most DG developers do not integrate utility reliability expectations into their bids. As one developer stated at an April 2010 Northeast CHP Initiative meeting, "it only takes 85 percent availability to make a DG project cost effective" (Armstrong, 2010)
6. Customer resistance (it is already a difficult proposition to sell customers on the advantages of DG in today's economic conditions. It may be even more difficult to convince customers to enroll in the RRFP because most businesses are risk averse, especially when the business does not understand all of the issues involved. Thus, if a program were offered, the customer and developer would be driven more by the incentive and the "bottom line" than reliability brought to the system)

Based on evidence from the Project Team's research and outreach, a greater role for distribution utilities is recommended in project development. Most developers who partook in the original RFP process would have welcomed utility intervention for several reasons:

1. Considerable labor and overhead could have been averted in submitting bids if bidders knew the utility provided support for the project. Most customers did not understand the complexity involved with participating in the process.
2. Though some developers did not submit bids, they did incur costs reviewing the solicitation and requirements. These costs could have been allocated to other opportunities.
3. Developers would have preferred a greater reliance on a turn-key approach because of the security and bonding requirements associated with the program (Demaskos, 2009). With more active involvement in the project development phase, bid costs could have been lowered. One developer believes that Con Edison could not provide a turnkey approach today. Since the RFP program ended, this developer believes that obtaining approvals and coordination for CHP plants has become more complicated, because the utility has had too many personnel changes, including staff that is not familiar with CHP regulations, and is slow to respond to requests for information (Cristofaro, 2010).

Con Edison is using energy efficiency and demand reduction as tools for reducing distribution capital costs. Stakeholders perceive that customer-owned DG is not accorded the same value as a potential T&D asset. There are legitimate, yet potentially solvable issues that are precluding adoption of programs that would fundamentally include DG CHP in a suite of measures for reducing distribution system capital costs.

Nevertheless, there are a few recent examples where both the utility and customer have benefitted from a DG project as an alternative to a distribution system upgrade. For example, in 2005, the Aviator Sports and Recreation complex in Brooklyn redeveloped four hangars at Floyd Bennett Field (Armstrong, 2010). This required an upgrade to 4,000 Amp 208 volt service, which would have cost $2-3 million in reconductoring charges by the utility. The project was able to go forward without reconductoring when a CHP system was installed. Though this project was not a result of a RRFP program, it shows that quantifiable financial savings exist and can be realized when the utility, customer, and developer work together.

Table 1 below summarizes the major utility and developer issues regarding user-owned and controlled DG CHP as a distribution system asset:

Subject Matter	Utility Concerns	Developer/Customer Concerns
Reliability	99.9% availability with no fault current onto system. DG can trip from voltage disturbances during storms.	Project economics are satisfactory when the DG resource operates at a minimum of 85% availability.
Control	Utilities generally require control.	Developers usually unopposed. Physical assurance an issue for customer.
Deferral Value	Would not prefer to provide value for fear of gaming the system.	Would like an idea of value of deferral to gauge whether worthwhile to bid.
Other Distributed Resources	Most utilities value EE and demand response, but not DG.	No objections.
Contract Term	Utilities prefer short term at value of deferral. Less time equals less contractual commitment.	Developers prefer longer terms for guaranteed revenue streams.

Table 1: Utility/Developer DG Concerns

In the end, a Refined RFP process (RRFP) is just a mechanism for striking a bargain between two parties -- the utility and the host site -- to use a customer-side facility as a distribution system asset. There are legitimate issues on both sides of this potential bargain. Yet, there are likely to be real opportunities for utilities (and ratepayers) to reduce overall system costs by encouraging the development of customer projects that create measurable local distribution benefits. A large fraction of the capital equipment currently operating is quite aged and in need of repair. The investment costs for meeting this need is substantial. As the growth in utility rates becomes ever more driven by capital investment needs, there is going to be significant pressure to find alternatives. Using customer sited DG /CHP resources to meet distribution requirements may be increasingly seen as a desirable mechanism to leverage private investment to meet this ever-growing need.

3 High Value Development Zone Model

3.1 MODEL OVERVIEW

The High Value Development Zone DG (HVDG) model uses a zonal, location based approach to offer an incentive for the procurement of DG resources. The model is designed to identify the most valuable deferral opportunities in order to direct DG/CHP development to the areas on the distribution system where it is likely to create the greatest system benefits. Presently DG/CHP development takes place absent information about the most desirable siting decisions from the perspective of the utility. Consider two potential projects of equal economic value to the two end users operating on a distribution utility system. If location at one site is on a severely constrained network it likely has far greater value to the utility and the ratepayers than does an identical project in an area with plenty of excess distribution system capacity.

This model uses a price signal that in theory spurs deployment of DG towards distribution-constrained areas of the network, where the value in deferring a traditional distribution system upgrade is high and the value to ratepayers greater. The intent is to encourage, to the extent possible, the installation of customer owned DG/CHP that complements utility operations. The model seeks to share achievable benefits between DG developers, utility shareholders and ratepayers at large, providing a win-win solution, such that the needs, interests and profitability of all parties could be synchronized to the benefit of all.

The HVDG model uses a pay for performance incentive mechanism, where the distribution utility offers a payment commitment to a DG resource owner for an agreed upon term, conditional on certain operational requirements, as well as penalty measures for under-performance. The first-come, first-served nature of the model provides a mechanism for the distribution utility to exercise control over the economic value of the transaction not obligating the utility to overpay for DG capacity, or to commit to payments where the DG resources are not sufficient to defer a wires investment. There is an option for a minimum threshold capacity to address situations where only partial satisfaction of the constraint has no demonstrable value for the utility.

The utility's highest priority is reliability of service, whereas the end-user's concern is the optimum economic operation at the facility. When the asset is outside the direct control of the utility there is a risk that the site owner's operational decisions are not in synch with the utility reliability requirement. In order to foster more congruence between the utility and the DG/CHP developer, the HVDG model provides utilities with certain means for exercising operational control, or operational influence (through the incentive and penalty approach) over the DG/CHP resource.

Key Elements of the HVDG Model:

- Publicly announced standard offer price, differentiated by distribution zones
- Pay for performance incentive/penalty for under-performance
- Simpler administration
- Utility provided with operational influence or control over the resource

3.1.1 Zone Definition

This HVDG model is perhaps most appropriate for New York City, or NYISO Zone J, where the highest wholesale energy and capacity costs, and the greatest rate of peak load growth occurs in the state, however it could also be applied in other territories (PSC Case 09-E-0115, 2009). The New York Control Area (NYCA), which includes all of New York State divided into NYISO's Load Control Zones, is subject to Resource Adequacy Guidelines established by the Northeast Power Coordinating Council. Because most of the reliability risk in the state occurs in NYISO Zone J, the guidelines specifically require that 80% of New York City's peak-load capacity be generated at facilities within the zone. To do so, Zone J relies on numerous peaking generation units, some of which operate inefficiently and produce high emissions. Con Edison, the distribution utility that serves Zones H, I and J, operates a massive distribution system, with 94,000 miles of cable, 2,204 primary feeders and 61 area substations, serving over three million customers (Con Edison website).

In 2009, costs for upgrading the distribution system in Zone J were quantified by the NYSPSC (PSC, Case No. 08-E-1003, 2009). NYSPSC staff used figures from recent Con Edison projects to estimate that the value of marginal avoided distribution costs for the utility ranged broadly anywhere from as little as $22 per kW-year up to $609 per kW-year. Though the Team knows the minimum and maximum marginal avoided costs, the shape of the distribution of costs was not made public. Needless to say, for utilities where upgrade costs are in general more expensive (where there is a concentration of costs in the upper portion of the distribution curve), there are greater opportunities for finding mutually beneficial DG/CHP deferral opportunities.

Under the HVDG model, Con Edison would identify a set of areas where the most attractive deferral value opportunities lie, and publicly post individually designed incentives for each of those locations to invite customer-side deferral projects. The incentive would be priced as a function of the deferral value in each location and available to DG/CHP/DER resources that singly or in aggregate are sized appropriately to achieve deferral. To receive the incentive, the performance of the participating DG/CHP facility would have to satisfy certain contractual obligations that would provide assurance and reliability to the utility, as described below.

3.1.2 Pricing Strategy

The HVDG Model would be implemented by a publicly posted payment specific to a particular location, formulated by the utility, and set as a function of the utility deferral value. The development of a price signal begins with a review of the utility distribution capital investment plan to identify areas of constraint and in need of upgrade over the planning horizon, with a screen for DG feasibility as a measure that could defer or eliminate the need for utility capital expenditure. The screening process should also consider factors related to environmental justice, network reliability, mitigation requirements in terms of timing and size load relief requirements, and whether there are existing targeted demand or supply side resource acquisition activities capable of reducing peak demands at the area of constraint.[10]

[10] Con Edison recently proposed a model for zonal price signals for solar development entitled "Transforming the Solar Marketplace: A Proposed Con Edison-NYSERDA Solar Program," Comments of Con Edison and Orange and Rockland Utilities, in PSC Case 03-E-0166.

3.1.3 Program Mechanics

- *Setting the Payment*: The incentive can be offered as a monthly or quarterly payment as a dollar amount per kW/year that is calculated relative to the deferral value in the posted location. The duration of the payments is relative to the length of time that a DG resource is expected to defer a traditional upgrade. For example, if a location is identified by Con Edison to be in need of 3000 kW of certain DG resources in order to defer a certain distribution upgrade for a period of five years, then a price for performance based on a kW/year would be announced in that spot, to last for five years.

- *Performance Conditions*: The HVDG model requires a set of performance conditions designed to address the disincentives that drive utilities away from customer owned resources, and likewise foster a more streamlined, efficient and economically attractive opportunity for DG/CHP developers. These performance conditions include setting the appropriate size of project specific to the location, performance requirements, control over the resource, and other agreement terms such as the timing commitment for construction completion, length of term for the payment commitment, and requirements for compliance with permitting and regulations.

- *Location*: The highest cost locations (e.g. at the top ten or twenty percent of the deferral value range) on the distribution system that are targeted for medium to longer-term upgrades in the distribution capital investment plan form the initial pool. These may include upgrades required for forecast load growth or for reliability constraints. Once those locations are identified, they must be confirmed further to be feasible for DG/CHP.

- *Resource Size*: For a DG/CHP resource to participate in the incentive, it must be sized appropriately for the need in each particular location, individually or in the aggregate. The spot incentive particular to a location could be designed to be a step function (all or nothing) or smooth (incremental) depending on the nature of the value created by deferral. For example, if anything from 0 kW to 1,000 kW creates no measurable value relative to the need, whereas at 1,000 kW the need is fully satisfied, the preferred approach would be a step function of all-or-nothing. (Alternatively, all awards for that location could be conditional on receipt of a total of 1000 kW of qualified proposals.) In such a location Con Edison would announce that they will pay full price for a minimum resource of 1,000 kW, and after 1,000 kW the need will be satisfied and the value of the payment will be $0. In the alternative, if the need is partially satisfied when 500 kW of DG resource is available then partial payment will be made at that point, and perhaps another payment when the combined DG resources are at 750 kW, and again at 1,000 kW.

- *Resource Control*: In order to accept a DG/CHP resource as an alternative to a distribution system upgrade, the utility will desire influence over the operational control of the customer owned DG/CHP resource, for reliability purposes. This can be accomplished either through indirect means by certain terms and conditions of operation for payment to be received, or by direct physical control over the resource (e.g. automatic controls). The indirect approach to influencing the operation of the resource will not enable the utility to fully determine the operating schedule of a DG resource under ownership and control of a third party, but it can use an incentive and penalty scheme that influences the operational choices of the DG owner/operator. For example, a DG resource may be uneconomic for the site to run at a time when the utility requires its operation to meet a local peak need. Program terms must ensure that the DG/CHP resource is available, at a minimum, to meet the utility's requirement and not operating on a schedule that only optimizes the site's economic return. An indirect method of control would condition payments on performance and set penalties for non-performance at stipulated times. With a direct control approach, under appropriate circumstances and upon mutual agreement, the utility would be provided with physical control over the resource, to guarantee that the resource would operate during peak periods.

- *Program Flexibility*: The model can be designed to allow adjustments to the incentive prices that correlate market conditions and deferral values; however it is desirable from the DG/CHP owners' perspective to have fixed prices and time periods over which the payment will remain constant. The associated uncertainty of adjustable pricing creates a level of risk to the developer. Such uncertainty has proved problematic in other settings. For example, sites have a difficult time monetizing the present value of a stream of payments from Renewable Energy Credits (RECs), because the future value of RECs is highly uncertain. With perfect information a site could capitalize the future value of a known and certain stream of future payments. If adjustments to the incentive are permitted, they would be made at the discretion of the utility based upon a pre-determined protocol that sets forth the conditions. Should the model be implemented with price flexibility, the utility commission should be engaged in weighing the concerns of both parties and the risk before allowing such adjustments.

- *Equipment Lead Time and DG Ramp-Up Rates*: Typical equipment and construction lead time for distribution upgrades can range from six months to two years for feeders, two and five years for substations and between three and eight years for transmission upgrades (Salamone, 2007). Lead times impose a hard constraint on the DG/CHP resources. It is imperative that the resources be available, in sufficient quantity, when needed. The program must anticipate realistic DG ramp-up rates. In interviews with utility staff, the Team was told that they would have to begin planning an alternative option, if an adequate sized DG resource was not ready by a certain cut-off date (well in advance of the need date). Risk from delays can be captured by setting a higher discount factor, or by a write down of the DG deferral value as costs are incurred to plan for an alternate wires solution. The posted incentive for each location will need to be formulated with consideration of the appropriate timing to construct and begin operation of the DG resource.

- *Unforeseen Contingencies*: Similar to the issue above, there is a significant risk of delay from any number of unforeseen factors, such as siting, permitting, regulatory compliance, or previously secured commitments failing to go forward. When opting for a DG alternative, if the utility also plans for a wires upgrade as a backstop, the cost associated with such a plan lowers the deferral value that can be credited to the DG project.

3.2 ISSUES

Previous attempts at utility facilitated, customer owned DG development have demonstrated little success, in large part because the over-riding concern expressed by the utility is distribution system reliability while the interests of DG hosts sites are quite heterogeneous. At some level of utility payment the incongruence of interests could be bridged, with the DG host site accepting the utility's pre-conditions in return for financial compensation. If that level of payment can be made at a net gain to the ratepayers, at the same time that reliability standards are maintained then a mutually beneficial end has been reached.

Privately developed DG is sited based on the suitability for the host customer, without consideration of potential distribution upgrade deferral benefits for ratepayers and society as a whole. DG operating at sufficient scale, at periods coincident with the local system in congested areas does provide, and uncompensated benefit. If sites were paid for this value, the economic return at such locations would be enhanced, resulting in more DG projects being constructed. Since these hosts are not compensated when they do produce this broad based benefit, the investment in end-user DG/CHP resources in congested areas will be under-provided from society's perspective. Sites where DG has a significant congestion mitigation value has a greater social return than a similar project at a site with no congestion relief value. Capital expenditures for distribution system upgrades can represent a considerable share of a utilities cost of service. Therefore, if more cost effective means of satisfying local congestion can be found, all ratepayers benefit.

The following section includes discussion on the following key issues: the complications and difficulty in measuring deferral values and the asymmetry of deferral value information; grid reliability issues; management complexity; administrative and transactional costs; and the impact on markets.

3.2.1 Measuring and Disseminating the Deferral Value

As discussed above, DG can provide an opportunity for considerable cost avoidance when used as a substitute for distribution system investments, particularly in locations where the marginal avoided capital investment cost is high. Whether employing the Utility Owned model, an RRFP model or a posted price (HVDG) approach, the initial step is identification of areas of the distribution system in need of upgrade that are suitable for utilizing DG as a close or perfect substitute for distribution capital investment. This is the technical feasibility assessment stage.

> *For a utility whose capital spending is centered around antiquated infrastructure rather than anticipated load growth, the set of viable DG solutions is markedly diminished. National Grid reports that of the total capital spent on investments, only 20% or so is load growth related, while the other 80% replaces old equipment or funds upgrades required from contingency events (Roughan interview, 2010).*

The next stage is ascertaining the economic viability of the DG/CHP solution. The information required to accurately measure the value of the distribution deferral potential is in the sole possession of the distribution utility. Under the utility ownership model the company can conduct its economic analysis internally and judge its economic viability.

With the customer owned models the situation is far more complex. Developers have no access to information identifying areas of high marginal distribution cost. More importantly, they have no economic incentive to choose those locations over any other feasible locations to site a project.

Access to deferral value information can assist developers in evaluating their bids in an RFP process and the information conveyed by posted prices for areas requiring upgrades directs development to the highest cost areas in a standard offer process. The 2006 Pace/Synapse Report identified the lack of deferral value information as a major stumbling block for developers. In the 2006 Report, one developer commented that if the utilities needs were more transparent, it would have saved both the utility and the developer time and money. By understanding the needs of the utility, a developer can concentrate on those projects for which it could provide a competitive solution. Competition is enhanced when all market participants have access to the same information as multiple parties vie to provide a least cost solution in an RFP type process.

The HVDG Model addresses information asymmetry by allowing the distribution utilities to post a price they are willing to pay for an incentive to develop DG in a location that best suits their current load forecast and associated system constraint needs. The posted price need not directly reveal the underlying deferral value itself. Because the posted incentive is only a function of the underlying deferral value, the utilities can maintain their desired confidentiality over proprietary information, if the Commission finds that warranted. The function of the posted price is to provide savings to the utility (and ultimately to the ratepayers and society) from using a DG resource as a distribution upgrade alternative.

According to NYSPSC staff, in recent proceedings staff has accepted some confidential Con Edison deferral values that were significantly higher than the standard Long Range Avoided Costs (LRAC) for Location Based Marginal Prices (LBMP) in the top 60 hours/yr, and for shaving peak on constrained distribution networks (Tress, 2010). The information on the locations and times of high marginal distribution costs are typically compiled as part of the distribution resource planning process. The deferral values should be measured by NYSPSC approved avoided cost methodology, as a component of Total Resource Cost methodology (as described in the NYSPSC Energy Efficiency Portfolio Standard (EEPS) Case) or by some other NYSPSC approved approach.

Con Edison service territory as a test case

There are many aspects of the current operating environment in the Con Edison service territory that make it an attractive test case for systematically and formally incorporating DG into the distribution planning process.

According to Company testimony, of the $854 million Con Edison sought in the 2008 rate case, the largest single driver is “infrastructure investment,” which accounts for $170 million or about one-fifth of the request (Rasmussen Direct Testimony, p. 11). Given the role of T&D infrastructure investment in driving up Con Edison’s cost of service, it is prudent to explore systematic and formal mechanisms by which Con Edison could analyze using additional investment in DG, whether utility-owned or customer-owned, as a means of avoiding or delaying investment in T&D infrastructure.

Con Edison has experience using demand side resources to defer capital investment. In testimony before the Infrastructure Investment Panel for the recent Con Edison rate case, Con Edison stated that in its 2008—2017 Forecast it is planning for demand side resources to defer eight new substations and the installation of four feeders, resulting in deferral of $1.2 billion of capital investment. Con Edison’s Ten year Independent Load Forecast of March 2009 defers two more substations (Westside and Hudson Yards) beyond the current 2009—2013 capital plan, resulting in $260 million of additional deferral for 2010-2012.

Con Edison uses an annual internal budget planning cycle, which starts in draft form April and is adjusted after the summer events to result in a formal internal budget by the end of the calendar year. Con Edison also develops a five year plan each year as an extension of the one year plan. The five year plan deals with longer term projects, such as substations that have a lead time of two to three years.

Con Edison develops capital plans that are consistent with their internal budgeting, and submits those plans to the NYSPSC for audit. Budgeting for investments involves a system load analysis, with both top down and bottom up approaches to loads to determine where the system needs reinforcement. These are 10-year resource plans and are submitted to the NYSPSC, which audits the 10 year plan for consistency with the company capital plans. These plans are not routinely made public. The most recent three-year plan is a comprehensive Joint Settlement of the most recent rate case.

3.2.2 Grid Reliability and the Capital Planning & Acquisition Process

The current NYSPSC reliability standard has been in effect since October 12, 2004, as described in Cases Nos. 02-E-1240 and 02-E-0701. The standard sets forth the following four reliability objectives:

1. Each utility must improve its reliability cost effectively and continue to do so over time.
2. Each utility must analyze at least five percent of its circuits each year and develop and maintain a program to correct its least reliable circuits.
3. When feasible, each utility must make every attempt to minimize service interruptions when working on its lines and/or equipment.
4. Each utility’s System Average Interruption Frequency Index must be calculated each year.

Planning for T&D upgrades in New York City is a particularly challenging prospect. The dense urban environment typically presents strong opposition to new peaking generating facilities within Zone J. Health concerns about EMF from high tension lines sends new transmission lines underground, which in turn drives up distribution system upgrade costs. DG can provide numerous benefits that offer solutions to these challenges, including the potential to strengthen grid reliability by mitigating load pocket constraint. In a 2001 report, Keyspan Energy recognized DG "as a valued component in a customer-oriented strategy to manage local electric load growth, and a good platform for growth in a deregulated market" (Berry, 2001). EPRI reports that while specific distribution upgrade deferrals can be supplied with certain customer owned applications, there is likely to be enhanced and systemic grid reliability improvements from the diversity supplied by integrating multiple DG/CHP resources into the resource planning process (EPRI, 2005).

3.2.3 DG for Distribution Capital Deferral: The Impact of Reliability Concerns

As noted on several occasions in this report, there is a large literature indicating the DG and other distributed energy resource (DER) assets such as demand response and energy efficiency can be used as to defer or perhaps avoid utility distribution capital investment. The actual record of employing DG/DER for that purpose is quite limited. The 2006 Pace/Synapse report concluded that certain utilities appeared to deny projects because the DG project's reliability standard could not match the same reliability of the utility's whole distribution system. National Grid (formerly known as NIMO) rejected one project because it could only provide 98% reliability compared to 99.9% off the utility's feeder (Leuthauser, 2004). The 2006 Report recommended that utilities should not measure the value of DG in isolation, but instead integrate its value into the whole system.

In the most recent rate case, Con Edison advised it "would consider supporting new incentives for encouraging reliable and timely facilitation of clean DG interconnections" (NYSPSC Case No. 09-E-0428, 2009). Still, to date, Con Edison has not selected any third-party DG providers to participate in its Targeted DSM Program. One major reason for this result is that the parameters of the TDSM program appear too restrictive, which was confirmed by Navigant Consulting independent review of Con Edison's program. An independent study of the targeted DSM program, performed under PSC Order, was completed by Navigant Consulting and filed with the PSC on May 8, 2009. Navigant concluded that DG is not used due to Con Edison's requirement of physical assurance. Navigant expressed in its report that "[p]physical assurance involves use of communication and control systems that would interrupt customer load in amounts equal to contracted firm DG delivery if the generator was unavailable when needed to reduce load" which is claimed to be necessary "to assure certainty of load reduction at the time of the load area peak" (Navigant, 2009).

> *In order to more commonly employ DG as a means for deferring distribution capital investment, a consensus must be reached on reliability issues. For example, parties must reconcile concerns about DG sites providing 100% physical assurance. The distribution utilities should employ standards that measure reliability in a consistent manner whether applied to their own existing resources or new DG/CHP.*

In 2009, testifying in NYSPSC Case No. 09-E-0428, Paul Chernick of Resource Insight described how Con Edison's physical assurance requirements reveal a double standard. He testified that three of Con Edison's gas turbine generators ranging from 12 to 20 MW each — one located on W. 59th St and two located on W. 74th St, built over forty years ago—were treated as load relief resources for nearby substations and feeders despite the fact that those generators are larger in scale than most customer owned DG, which carries with it a greater reliability risk than most customer owned DG (Chernick, 2009, discussed in detail in Task 1 report). Chernick further stated that if these same generators were proposed for Con Edison's targeted program, they would be deemed ineligible to participate according to Con Edison's program requirements.

The utility argument is that reliance on a non-wires solution to defer a T&D upgrade will require total confidence in the reliability of the resource, suggesting that the DG alternative must operate at 99.9% availability. Many DG projects operate at 95% to 97% availability. What the utility really requires is a guarantee of availability at the time of resource need. If there are multiple DG resources available to supply the need at the constrained location, then the unit availability is not the right measure—the availability of the fleet of operating DG/DER assets is the correct metric.

For the CHP developer, optimal economic performance occurs with base-loaded generation and high thermal utilization; however, the utility has no interest in thermal dispatch. This does not necessarily represent conflicting interests. In fact, if the CHP site is designed to run as often as possible, then the customer's objective function (run all the time) and the utility's primary interest (be running on and near local system peaks) are entirely in synch. While many CHP projects will fare best when operating base-load, this is not the only economically viable mode of operation. There is a significant set of potentially viable CHP projects that have negligible thermal and electric requirements for large numbers of hours of the year. Such projects may be successful if they run intensively during the highest cost (peak) hours and are able to fully use the thermal energy generated at the same time. As long as there is a high correlation between the economically advantageous times for the site to be running its generators and the occurrence of the local distribution area peak, there is no divergence of interests. It would only be the case that utility and CHP interests diverged if the days and hours when the utility needed the generator running, were days and times that were un-economical for onsite generation.

The reliability of DG operation can be affected by voltage disturbances or downed circuits from storms, accidents, or other contingency events. The operational mechanisms to control these situations are much more difficult, often occurring with no predictability. In contingency events, the utility is concerned about the impact on the grid if the unit goes down when the loads on the system are at peak demand. Such a contingency could occur with little or no notice. This issue could be resolved with some sort of automated control, such as a recloser or fuse between the utility and the customer.

Utilities may oppose DG as a means of deferring distribution upgrades based on the following claims that relate to adequate reliability, lead time, incongruence of interests and other contractual issues. These claims can be addressed as described in the text box below.

Utility opposition issues

Reliability
The utility may claim that reliability is compromised if the DG resource fails to produce the desired output, and the customer requires power to continue operations.

Diversity
Multiple DG/DER assets serving the local requirement have a reduced joint probability of failure. If a single DG resource is providing the necessary reserve, then the reliability on that network is a function of the reliability of that asset. The rebuttal to this concern is that multiple DG/DER serving the local requirement have a miniscule joint probability of failure (i.e. that all resources fail simultaneously). This is especially true if the assets satisfying the need are configured so that no one resource accounts for an overwhelming share of the requirement.

Lead Time
Most utilities need 12 to 18 months lead times to plan and implement traditional solutions to capacity constrained areas and claim that relying on its customers to meet its requirements would leave the grid in jeopardy. Most developers who were interviewed also require this amount of time due to delays with customers and securing adequate financing for the project.

Incongruence of Interests
The customer's primary objective is cost minimization, and the utility's primary objective is to meet the reliability needs of local distribution. Analysis can empirically determine whether the two objectives are in conflict, they may not be.

Contractual Issues
The utility is concerned with the assumption of contractual obligations by any future owners of the DG resource for the entire term of the contract. Appropriate contract terms regarding assumption could be negotiated with third party design/build owner/operators. Host sites can be prioritized on the basis of this type of risk.

Standby Service
Utilities suggest that virtually all customers with installed DG also require standby service, meaning that the utility would still have to plan on meeting its systems need in the event that the DG was not operational.

Sizing Constraints
In Con Edison's proposed M29 Transmission Line Project in 2006 to the NYSPSC, they advised that typical DG projects ranged from two to 10 MW which would mean several DG projects would need to be installed in order to defer this project. Con Edison references Pace's 2002 *Combined Heat and Power Market Potential for New York State* (Pace, 2002 Report) which said even though there were 26,000 sites in New York that have the technical potential for CHP representing 8,500 MW, close to 74 percent of these sites were from plants that would produce less than 5 MW.

3.2.4 Reliability Solutions

The customer-owned business models are tailored to address the needs of utilities and developers. The models provide reliability assurances for utilities and incentives to offer the assurance to the DG developer. These approaches may involve technical measures to provide operational control or commitment, as well as policy mechanisms that elicit specific behavioral responses.

Even if physical assurance is needed to maintain reliability, the degree to which it has been required is onerous to the DG developer (Yap, 2004). Accordingly, Con Edison is contemplating reducing its physical assurance requirement to peak load hours for the distribution system (Gazze, personal communication).

An alternate means to ensure reliability that may be more effective than requiring physical assurance would be to assess penalties for non-performance. Penalties for not meeting the reserve requirements can also incent behavior. For example, participation for current ISO market participants would require fulfillment of a required schedule or payment of a penalty for the cost of replacement. Customers who install DG provide a resource, however if the unit is not available, customers could be assessed a penalty, for example, equal to real-time LBMP plus an additional incremental monetary penalty assigned and determined by the utility. Since DG (especially CHP) has proven to be a reliable resource, participating CHP customers would be exposed to minimal risk.

DG developers have also suggested the use of internal controls up to the thermal load point (for CHP); and an external centralized override that increases the electrical output above thermal loading, with the use of thermal dumping when necessary (Armstrong, 2010). A suggested incentive would compensate the resource for dispatch above thermal load, where there is a positive "spark spread."[11] If a positive spark spread does not exist, it needs to be induced.

Reliability can also be enhanced by diversifying the DG resources deployed in a particular location. According to a study performed by Energy & Environmental Analysis (EEA), when a group of DG units operate as a system, reliability is increased. As was noted in the study, if one DG unit, independent of others, has a reliability risk of, say, 3%, when two such units are used, the overall reliability risk drops to 0.1 percent (Hedman, 2004). By creating local redundancy and diversity with a combination of DG and other demand side resources, utilities can relax their assurance and load shedding requirements during contingency events. As suggested by the 2006 Report, using DG in combination with other distributed energy resources may be mutually beneficial to the utility and bidders including Southern California Edison, the Bonneville Power Administration Non Wires Solution and the ISO-NE RFP. The SCE model relied exclusively on DG. By allowing participation in demand response programs, utilities may be more amenable to using customer-owned DG as a T&D resource. In addition, this may also provide a lower cost solution than just DG alone. The ISO-NE RFP obtained over 250 MW of demand side resources including 100 MW of demand response located in the Southwest Connecticut region (Carver, 2010).

In Con Edison's service territory, fault current issues have also limited the amount of synchronous generation that can be added to the grid in various load-constrained areas. Con Edison contends that the fault current interferes with protection systems and creates power quality issues such as harmonic distortion and voltage flicker (Jolly, 2010). These issues have resulted in a range of proposed technical solutions. For example, Washington D.C.-based Pareto Energy has developed the so-called "GridLink" technology to address this problem. When installed at the customer's site, GridLink interconnects power from multiple sources and switches power from AC to DC using converters, and then switches it back to AC in order to enhance power quality. GridLink varies the amount of power supplied by sources, down to zero, within milliseconds. The grid views GridLink as an on-site generator reducing its load rather than as a power source.

3.2.5 Regulatory Compliance and Complementary Policies

The HVDG model puts the burden of satisfying regulatory requirements on the DG resource owner.[12] In New York, the approvals and permitting necessary to develop DG/CHP resources are administered by the New York State Department of Environmental Conservation (NYSDEC) Air Pollution Control Permitting Program.[13] In New York City, additional regulations further impact the development of DG resources.[14] Depending on the DG/CHP resource

[11] Spark spread can be defined as the cost of buying electric power from the grid relative to the cost of natural gas.

[12] Pace published a comprehensive guide for prospective DG/CHP project developers, owners, and planning/code officials that explains all applicable regulations governing smaller-scale (from .1 MW to 10 MW) on-site generation projects (Bourgeois, 2003).

[13] Authorized under the New York State Environmental Conservation Law, Articles 19 (Air Pollution Control) and 70 (Uniform Procedures), and DEC amended regulations 6NYCRR Parts 200, 201, 621 and 231. Available at http://www.dec.ny.gov/permits/6069.html

[14] New York City regulates air permits, boiler registrations, fuel gas supply, piping, venting and stack height, and material & equipment under a number of city codes including the building, electrical and fire codes, involving the New York City Department of Environmental Protection, the New York City Department of Buildings and the Fire Department.

technology,[15] a project must receive one of three types of state air permits, which are based primarily on a comparison of the facility's potential to emit (PTE) using federally-defined major source thresholds. The entire downstate region (encompassing Zone J) is within New York's Severe Non-Attainment Area, which could subject some projects to New Source Review.[16]

In early 2005, the NYSPSC initiated a proceeding to consider Demand Response Initiatives (NYSPSC Case No. 09-E-0115, 2009). As part of the DR proceeding, working groups are actively considering how to reduce the operation of combustion generating units in environmental justice and Severe Non-Attainment Areas. The outcome of these proceedings will have implications for the development of DG resources in those locations.

Both local and state policymakers have recognized the importance and potential of DG. For instance, in PlaNYC, Mayor Bloomberg has set aside a goal to install 800 MW of clean DG by 2030 (PlaNYC, Energy Initiative 9, 2009). The 2009 New York State Energy Plan recognizes that DG/CHP increase energy efficiency, reduces costs and improves reliability.

The DG interconnection process has been a major obstacle to DG development. In 2000, a NREL study showed that only seven of sixty-five DG projects were interconnected in a timely manner (NREL, 2008). The remaining projects were delayed due to three types of barriers: technical, business practice and regulatory. Some of the technical barriers included power quality issues, safety and reliability. Business practice barriers included contractual and operational requirements. Finally, regulatory barriers included standby tariff issues, ISO requirements and exit fees. This led to the development of IEEE 1547 in 2005, which sought to provide a national interconnection policy (LBNL, 2008). According to the Database of State Incentives for Renewables and Efficiency, there are presently 40 states in the U.S. that have interconnection standards, and in February of 2009, New York standardized the processes for all applications that run parallel to the grid up to 2 MW.

Though the IEEE has made substantial progress in standardizing interconnection policy in its Standard 1547, subtle nuances do exist across the country. Interconnection policy should be streamlined across the country to provide clarity and consistency for project developers who may want to do business in other states. Presently, projects require external disconnect switches and size limits are capped at 2 MW. Increasing the cap up to 20 MW would provide additional incentive for large businesses to invest in DG technologies (Network for New Energy Choices, 2009). Another approach would be to standardize and streamline the interconnection process, which would lower costs and provide certainty for project developers. Costs vary depending upon whether the system will be connected to transmission or distribution system and these costs would be the responsibility of the customer.

3.2.6 Impacts on Markets

Customers consider several factors when they decide to install DG/CHP. These factors include energy and economic savings, enhanced power quality/reliability, reduced emissions and hedging against price volatility. The success of customer owned models will depend on the effective marketing of the model to those who recommend, bid, develop and own/operate DG/CHP systems. The incentive will be ineffective unless it contributes meaningfully to a project's economic fundamentals (IRR or payback).[17] To the extent possible, incentive levels should mirror the deferral value of an investment.

On the other hand, customer owned DG models will in general give more competitive impetus to developing the market for DG service providers (turnkey operators, installers, engineers, maintenance companies, etc.) because private companies participating in DG projects are facing fierce competition and are making every effort to find and

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[15] Technologies governed by the permitting process in New York include natural gas reciprocating engines, diesel reciprocating engines, micro-turbines, combustion turbines, fuel cells and renewables.

[16] The New Source Review permitting program was originally promulgated under the 1977 Amendments to the Clean Air Act. Nonattainment NSR permits are required for new major sources or major sources making a major modification in an area not in attainment with the National Ambient Air Quality Standards (NAAQS). In New York State, the NYSDEC administers NSR permits for all of New York, except for PM2.5 non attainment, which is administered by US EPA, Region 2.

[17] Although payback periods are considered to be an inferior measure of economic return, many businesses report using the metric and in some cases a "years to payback threshold" may be set as a screening out mechanism for any projects that do not fall within the period.

offer cost-effective DG/CHP solutions for their customers in all aspects of DG development and operation including engineering, designing, procuring equipment and fuel for, building and maintaining and operating DG projects on their own or using other private companies.

For example, Fran Cummings, Policy Director for the Renewable Energy Trust, Massachusetts Technology Collaborative (MTC) noted with regard to the lessons learned from MTC customer sited DG pilot projects that the programs would also benefit from collaboration with an energy services company that provides services related to DR since these third party service companies are frequently very effective at finding demand side opportunities and marketing (See the MTC case study section below). Further, one participant in SCE's 500 MW PV program proceeding (discussed in the utility DG model section) mentioned that "competitive markets drive developers to seek new technologies, to negotiate better prices, to find highest value sites, and/or to accept lower return to gain market shares" (CPUC, 2009, page 25).

Still, the utility owned DG model can also use competitive market forces to some extent. As noted in the utility owned DG model section, to the extent these services are contracted out to private companies, the utility owned DG model can also be competitive to their parties. Lastly note that the competitive advantage does not necessarily apply to upstream markets that provide DG equipment because utilities will also purchase equipment from private companies. Upstream markets are likely to be more sensitive to scale than to the whether the buyers are utilities or competitive DG service providers.

3.2.7 Management Complexity, Administrative, Transactional Costs

The HVDG Development Zone program would be managed by local distribution companies, which would publicly post and adjust spot incentives, administer the application and eligibility review process, oversee performance conditional payments, disburse payments, and submit costs to the PSC for adjustment through the appropriate mechanism.

On the other hand, the operational burden of individual DG/CHP resources, including regulatory compliance, construction oversight, and so forth, fall to the DG/CHP resource owner. In the event utilities retained some form of control over DG operations, they would assume any associated operational burdens under the HVDG model.

Compared to an RFP model, the HVDG model is designed to keep program costs low, for both applicants and utilities. The HVDG model is conceptualized around least cost solutions, by synchronizing the needs of developers and the utility in a way that allows both to achieve cost savings. A simple proposal process allows for low application and proposal costs to the resource owner, and a first come first served review process with pre-established standard conditions simplifies and reduces costs to the utility to administer the selection process. The development of a standard form agreement between Con Edison and DG/CHP developers will lower legal costs.

The management of the RRFP Model would be the responsibility of the utilities and the Technical Evaluation Panel TEP. Management includes setting the incentive; marketing the program, administering the application and eligibility review process; oversight of the DG resource performance conditional to payment, administering payments, and submitting all costs to the PSC for decoupling mechanism approval.

The eighth recommendation from the 2006 Report suggests that utilities should be more involved in the process including marketing of an RFP approach. At a minimum the report stated, the utility should notify large customers about the potential benefits of the program and provide these customers with contact information of potential DG developers.

Once a customer has been selected, the onus would be on the customer to follow through with the necessary permits to install the system. If the customer chose the full ownership model, it would have to sign a contract with the utility that in the event of an emergency and load was not curtailed, that it would be responsible for penalties. The penalty provision would be made part of the participating customer's tariff with the utility. If the customer allowed the utility to operate the system during peak times, it would not be subject to the penalty provision.

Administrative costs can be seen from the perspective of the utility or alternatively from the perspective of the DG developer and host. With traditional wires approaches, utility administrative costs can vary quite considerably. The

Massachusetts DG Collaborative revealed that utilities claimed that administration accounted for 20% of the carrying charge for implementing a DG program (MTC minutes, 2005). The administrative costs for utilities include the planning and permitting process and the time and resources spent in creating and executing the RFP process. In Massachusetts DG Collaborative, key stakeholders questioned the 20% administration charge asserting by the utilities, and instead suggested that administrative costs would likely decrease once the program has been implemented and standardized. Two alternative approaches were proposed, one that would limit administrative charges for projects under a certain size, and another that would assess a fixed fee based on the number of employees needed to run the utility program. The RRFP collaborative group could consider administrative costs in a similar way to MTC, by determining the most effective strategies for administration and lowering transaction costs.

DG developers have their own set of administrative and transaction costs to consider in responding to an RFP. DG developers require adequate time to prepare their bids and find financing for the project and time to implement the project. Transaction costs for developers are increased when utilities do not provide ample time for developers to secure a customer site for the program. Extending the time required for the project could allow for developers to seek lower cost bids from subcontractors for engineering services. As a result, the RRFP model may be more effective if utilities promptly identified reliability concerns associated with proposed locations. In addition, utilities could provide developers with adequate notice of the location of congested areas so that developers could plan in advance to respond to the RRFP by identifying appropriate host customers and incrementally scoping a project.[18] The same issue is also applicable to the HVDG model, but to a lesser degree.

3.2.8 Financing Costs

Financing costs are heavily influenced by risk. Lenders are wary of a variety of issues, such as risk of default and complicated and varied contract forms. With a streamlined or standard form contract, lender risk premiums will go down, and financing costs will be reduced. Longer lead times would also allow developers to secure more attractive financing, which could enhance the economic benefits for all the parties involved. The lack of transparency for the deferral value forced developers to estimate approximate values for the project; greater transparency would have lowered the costs involved because competitors would have bid costs to secure the contract. This knowledge also would lessen the financing costs for the utilities, because not all bidders would have bid on these projects had they known how the utility valued the asset.

Developers have argued that if the utilities knew the value of the project then they should be provided the same information. The NYSPSC, however, agreed with the utilities stating that developers would be able to game the system by submitting bids at or just below the utility's cost (Rieder, 2005). Some utilities did provide additional information about the project that should have allowed the developer to estimate the value of the project within +/-10% (Hamilton, 2005).

[18] If, for example, the utility provided two years' notice that an award would be issued in a particular location, developers who could guarantee a project to be online within a shorter time period may be eligible to receive an incremental incentive. The detailed design of an incremental incentive could be left up to the collaborative discussion process, or the TEP and utilities.

4 DISCUSSION

In this task report the Project Team identifies certain circumstances where DG has been used as a distribution system asset by utilities. Such circumstances have been quite limited. Utilities occasionally employ DG assets that they own and control as a short term measure to address a local distribution investment need. In New York State the Project Team reports on the experiences of Con Edison in using mobile DG on its system. Con Edison uses the mobile generators as an emergency or "backstop measure." They are not employed to defer distribution system investment; rather, they are used to buy time while the distribution upgrade is being completed. This strategy is compared to that of Detroit Edison, a company that has elected to incorporate mobile (and stationary) DG applications into its distribution planning and capital budgeting process. Detroit Edison's strategy is one of the most robust examples of the utility ownership approach.

Other examples of utility ownership in New York include a case of a C-323 1 MVa diesel engine generator installed in the town of Denning, NY in lieu of investing in a new distribution feeder. The town was experiencing an average of 10 outages per year, and Central Hudson was exploring different scenarios to improve reliability in this location. The cost of installing a new distribution feeder was approximately $1 million, while the capital cost of the generator was $700,000.[19] Peak demand in the village is about 500 kW. Load growth in the area is < 1% per year. Therefore, this generator should be sufficient for meeting local reliability requirements for several years.

Utility programs that facilitate the deployment of distributed scale photovoltaic (PV) for distribution grid support appear more popular than DG/CHP programs. These are considered in two examples from outside New York State. National Grid has a plan to own and operate 25 MW of utility owned and operated PV in Massachusetts, in five 5MW projects; and Southern California Edison has a plan to install 500 MW of PV on commercial rooftops in 1-2 MW size projects, 250 MW to be utility owned and operated, and 250MW to be customer owned and operated.

National Grid's (NGRID) plan to deploy 25 MW of PV in Massachusetts involves the construction, ownership and operation of five 5 MW PV systems at five sites owned by the company or its affiliates. This plan developed as from the Congestion Relief Pilot projects in Everett and at Revere. NGRID recognizes the opportunity provided by these projects to study distribution system benefits including the effects of PV as a percent of the load carrying capacity of a distribution feeder, and the impact of DG on a substation and contingency loading issues. NGRID cited not only distribution system benefits but other factors that may be relevant to decision makers such as the ability to secure DG resources at a lower cost (in this case PV), to speed the time to deployment and to more readily study the impacts on the distribution system. This is relevant to New York insofar as Con Edison has expressed interest in using PV resources in constrained areas of the distribution system.

Southern California Edison (SCE) 500 MW Commercial Rooftop Solar PV Project involves the installation of 500 MW of solar PV on existing commercial rooftops in the SCE service territory at an average system size of 1 to 2 MW, over a five year period. SCE will own, install, operate, and maintain 250 MW of solar PV projects, which will primarily consist of one to two MW rooftop systems. The remaining 250 MW will be installed, owned, and operated by independent, non-utility solar providers selected through a competitive process. The cost is estimated at $875 million, resulting in a cost of $3500 per kW installed (SEPA, 2008; CPUC Solar PV Decision, 2009). The company requested a 10% contingency for potential additional capital cost spending before being subject to reasonableness review by the Public Utility Commission (PUC). SCE also earns a return on its PV investment.

The California PUC determined that SCE's application was in the public interest, because the economies of scale and installation efficiencies resulting from deploying MW scale, multi-year projects will provide benefits to the ratepayers, and the solar PV systems promoted under the program will be located near load and can be quickly deployed. The PUC also noted that the program offers SCE and the State an opportunity to better understand the implications of interconnecting significant amounts of distributed renewable generation to the grid, and the comparative costs and benefits of different renewable energy deployment options. SCE asserts that this program will allow it to coordinate PV with demand shifts using its existing demand reduction programs on the same circuit,

[19] Conversations with Steven Vincent, Central Hudson's Electric Standards and Utilization Engineer.

more fully utilizing distribution assets. It will also combine PV, customer demand programs, and advanced circuit design and operation into a unified system.

These two examples are relevant to New York State insofar as Con Edison has also recently offered the PSC a proposal for a multi-year program that would facilitate 25 MW of customer owned distributed PV along three networks for distribution grid support (EEPS Comments Case 03-E-0188, Jan 29, 2010). Con Edison's proposal includes the following main elements: a production based incentive, a capacity based incentive that targets networks that the company has identified as suitable for PV, and rebate funding that adds to existing NYSERDA PV rebates (with an addition for low income customers).

Con Edison's proposal included a statement about how this deployment effort will allow them to study how generation resources at the distributed scale can be integrated into resource planning for the future.[20]

An issue that the Project Team struggled with in the development of this report was the very slim historical record of the utilization of DG/CHP in distribution system planning. Experience with models utilizing customer owned utility facilitated DG/CHP assets as a substitute for distribution capital is even less well developed than the utility ownership approach.

The Project Team reviewed the Massachusetts Technology Collaborative Pilot and the Con Edison Targeted DSM program as a basis for establishing a more broadly based program that would pay an incremental incentive to projects demonstrably substituting for distribution capital investment. National Grid and NSTAR experimented with similar programs on a pilot scale in Massachusetts. The Team also studied the policy literature that discusses the outlines of potential utility programs that might implement this type of approach.

The Team did considerable outreach in support of the work in Chapter 2 of this report, conducting individual meetings, workshops, and numerous phone call interviews. The purpose was to get a thorough understanding of the issues involved in establishing a program that uses customer owned and operated assets that might substitute for utility distribution capital investments. There is a host of issues and concerns both on the utility side as well as the end user. The outreach conducted was designed to provide NYSERDA an inventory of these concerns from all perspectives. The Report goes beyond simply cataloguing parties' issues and requirements in implementing Customer Sited DG as an alternative to distribution investment, and provides specific recommendations, many of them arising from the outreach with key stakeholders.

In Chapter 2 a detailed description of HV DG Development Zone model is presented. The Project Team considered the benefits (and drawbacks) of establishing geographically targeted development zones for DG under which the utility would offer a set incentive for new DG deployment. In this chapter the Team explored the practical considerations of implementing a geographically targeted approach (e.g., defining the zone, setting incentive levels, ensuring that incentives are paid only upon a threshold of DG penetration sufficient to defer/avoid the "wires" solution).

The Scope of Work included a review of the prior RFP model that was implemented in response to NYSPSC Opinion No. 01-5 2001. This section of the report suggests several refinements to the earlier RFP process that would address problematic issues that had been identified by bidders and by the utilities that ran the bids.

The Task #3 Report will present a more thorough and detailed description of how the three models perform on various metrics that are of concern to policymakers. The reader is referred to that report for a full presentation of how each model fares on issues having to do with management complexity, transaction costs, and regulatory burden.

The utility ownership model has certain advantages particularly with respect to the utilities interest in operation and control of the asset. From the utilities' perspective there is significantly less reliability risk to relying on an asset that they own and control rather than relying on contractual arrangements and incentive payments to ensure that a third party operates the resource in a manner that insures the reliability level that the utility requires (see Table 2).

[20] Con Edison Solar Proposal, Jan 29, 2010

IMPLEMENTATION ISSUES:	UTILITY OWNED	CUSTOMER OWNED
Dispatchability	Can dispatch to meet utility, economic, and reliability needs	Contractual arrangement, utility risk
Reliability	Can operate to meet utility reliability criteria	Contractual arrangements, physical controls, utility risk
Access to site	Not problematic	Contractual arrangements

Table 2: Implementation Issues

There are certain other factors that tend to be favorable to utility ownership of DG assets. These circumstances include:

- Internalized Non-market benefits
- Operated to maximize utility's objectives
- Lowered transaction costs (e.g., contracting with third parties, lowered setting and monitoring incentive payments, running outreach programs, etc)
- Shorter implementation schedules (if utility owns land and can secure permits more quickly)

Some of these issues can be overcome. Where markets for capturing uncompensated benefits do not exist, they can be developed. That is the rationale for the HVDG Development Zone model, to provide a price signal encouraging DG siting in areas that provide a high value for the local distribution system.

Policymakers and stakeholders may be wary of the utility ownership model for some of the following reasons:

- Ability to wield market power
- Existing relationships with customers may create an unfair competitive advantage
- Utility dominance in the market may result in lower rates of product and service innovation

The customer owned models may be favored in circumstances where the utility is facing pressure to reduce the growth rate of distribution system capital investment. In some cases distribution capital expenditures are a key driver of increases in distribution utility revenue requirements (and consequently rates). A large proportion of the distribution system is quite aged and in need of imminent replacement. The costs of meeting the investment requirements are substantial. Using customer owned assets that are cost effectively serving as a local distribution system resource is a mechanism for leveraging new sources of private investment.

New capital investment should not simply be replacement of parts in kind – particularly where such a strategy fails to advance stated policy interests in accommodating greater local levels of clean DG penetration and facilitating more economic operation of systems of local resources (DG, DR, EE, storage) on the distribution system. Incorporating DG/CHP in distribution planning necessitates taking a longer run view of the productivity enhancing, future cost savings of investments that enable future integration and optimization of a suite of resources operated at the local area level in support of clean energy and distribution system operation objectives.

APPENDIX A

3.3 CASE STUDIES

Detroit Edison's Mobile DG Strategy

Background. Since 2003, Detroit Edison has been incorporating DG into its distribution planning and using DG as a temporary distribution capacity solution. Detroit Edison, a subsidiary of DTE Energy, is a regulated electric investor owned utility located in Michigan. Detroit Edison experienced electric industry deregulation in the 1990s, and divested its transmission system, but still owns and operates a large number of electric power plants. Detroit Edison started to use mobile DG back in the summer of 2002, when it used several leased mobile DG units to mitigate stressed areas on the distribution system. Since then it formally incorporated DG into its distribution planning and distribution capital budgeting process as one of the cost-effective distribution system solutions.

Detroit Edison developed and owns several mobile DG units mounted on trailers. Detroit Edison owns three 1 MW natural gas units, two 2 MW diesel units, and one 1.5 MW dual fuel unit. To date, it has deployed 16 distribution DG projects totaling 26 MW since the beginning of the program. (Asgeirsson, 2010)[21] Most of the projects are considered temporary installations, designed to operate until system upgrades have been completed (from one to five years). Detroit Edison uses mobile gen sets, internal to the distribution circuit, at a substation, and in an island mode to support maintenance work. Detroit Edison also offers a premium power program to large customers on overloaded circuits who could host generators (Jakubiak, 2004). In these cases of customer-sited DG Detroit Edison owns and operates the unit under three to seven year contracts. Customers pay a monthly fee based on the size of the unit and enjoy cost savings and increased power quality (Jakubiak, 2004).

Detroit Edison's DG Strategy. Detroit Edison sees DG as "one way of delivering just-in-time and "right-sized" capacity to resolve smaller short falls while minimizing the initial capital outlay" (Jakubiak, 2004). Detroit Edison occasionally has faced time and budget constraints in investing its distribution assets. Construction delays affected some planned projects. Limited capital budgets also constrained initiation of some distribution projects. Distribution projects oftentimes involve significant amounts of up-front investment in capacity to solve a small capacity problem expected in the near term future. Detroit Edison found DG provided an option to better match the scale of investment to the imminent distribution need, thereby saving limited budgets for other important projects.

A number of important elements Detroit Edison's mobile DG strategy are described as follows:

- **Earning a return**: Michigan Public Service Commission allows Detroit Edison to earn a return on the DG investment. Detroit Edison has noted that " purchasing of generators, rather than leasing, has turned out to be advantageous because the Michigan rate-setting commission tends to look more favorably on capital investments" (Journal for Onsite Power Solutions, 2004).
- **Project screening process**: Detroit Edison uses a load flow model called the Distribution Engineering Workstation (DEW) to identify and evaluate potential DG sites on the distribution system. The DEW identified critical distribution problems; estimated capacity shortfalls at specific sites, and evaluated potential DG solutions (including size and type of DG) and the impact of DG on the grid system. Detroit Edison then conducts economic screening tests of DG over conventional distribution projects. One of the screenings compares the installed cost of DG with the installed cost of distribution projects per kW of *capacity shortfall*. Another and more important screening is to compare the annual cost of DG projects to the annual cost of distribution capital investment.
- **Community outreach**: When siting portable DG units, Detroit Edison performs community outreach to help gain acceptance of the idea. Detroit Edison shows parties a short video, which introduces the idea of portable power for grid support. (Journal for Onsite Power Solutions, 2004) When Detroit Edison needs to lease property from other entities (e.g., city, school, and church) they structure a very simple lease

[21] According to Asgeirsson, most of the units are not used as of this writing given the depressed electricity load due to the economic recession.

agreement with the counterparties (Jakubiak, 2004). Lease payments provide a welcome revenue stream to schools, churches and other organizations.

- **DG operation**: Detroit Edison uses sophisticated monitoring and remote control devices to ensure reliable DG operation. Using a number of different media such as radio, satellite, cell phone, the Internet, the monitoring device transmits operational data including oil pressure, loading level, fuel consumption and temperature. Detroit Edison also uses an automation technology that dispatches mobile DG units automatically in response to temperature.
- **Emission and noise issues**: as noted above, Detroit Edison typically places diesel DG around 300 feet from residential areas, at which distance the noise level is about 60 dB, equivalent to the noise level of conversation. In contrast, natural gas engines emit significantly lower noise and would need just 50 feet clearance to maintain 60 dB noise. When noise level is still a concern, sound baffles are often installed to accommodate concerns from the surrounding residents.

Case Examples. The Union Lake substation conversion project was meant to relieve an emergency overload. Nevertheless, due to the delay in construction, the project was not completed before the summer overload. The Company installed a mobile DG at the substation at an annual cost of about $61,000. This project was not only significantly cheaper than the annual cost of the substation upgrade, which was estimated to be about $137,000, but also deferred the conversion project for four years (Pace, Synapse, 2006 Report; Asgeirsson, 2004; Asgeirsson and Seguin interview, 2005).

The Milford DG project is a 1 MW natural gas generator that is located at an elementary school property. It was used to help with load relief on the 13.2 kV distribution circuit MILFORD DC8103 while the substation was being upgraded. The project has been in operation for six years and has seen two renewals of the lease agreement with the school (Asgerisson, personal communication, 2010).

In 2002, a 13.2 kV radial system near Ann Arbor, Michigan, was experiencing overloading due to larger-than-expected load growth and abnormally hot weather. The Collins substation project was supposed to mitigate this problem, but constructing the Collins substation was delayed due to issues obtaining community approval to build the substation. To temporarily solve this matter Detroit Edison installed a 2-MW diesel generator at the location of the planned substation. The unit was remotely started when temperature rose above 80 degrees F. The DG project cost was roughly equivalent to annual charges for the substation project. The construction of the DG project took just five days to complete. After seeing Detroit Edison's commitment to serve its customers, the community recognized the need for the substation project and accelerated the approval process granting permission to build the project (Asgeirsson, 2002).

Con Edison Emergency Generation Application

Currently Con Edison, the investor owned utility serving New York City, owns four mobile generators and a number of central power plants. The regulated central power plants owned by the company are mostly steam generators with the total capacity of 500 to 600 MW and also serve about 2,000 steam customers (Basu, personal communication, 2010). The company has been actively using emergency generators (including the four mobile generators, but the majority of the generators are leased units) to deal with distribution system maintenance and power outage events (Jolly, 2010: Jolly, personal communication, 2010). The company also occasionally used emergency generators to support its distribution system (by directly supplying a feeder or by transferring customer load to emergency generators) and to buy time when it found that it cannot build distribution circuits or substations on time. For example, the company used emergency generators to temporarily mitigate overloading system conditions while upgrading the distribution system serving the World Trade Center and upgrading the Sherman Creek substation (Jolly, personal communication, 2010).

In a way, Con Edison's practice is similar to Detroit Edison's. The major differences are that (a) Con Edison mainly uses mobile generators for distribution maintenance and power outage events, rather than to defer T&D investment, (b) when mobile gen sets are used for deferring T&D investment, the majority of such cases, if not all, are actually for buying time for T&D upgrades because the upgrades could not be completed on time, and (c) Con Edison does not incorporate mobile DG applications into its distribution planning and capital budgeting process unlike Detroit

Edison. In other words, Con Edison's use of mobile generators is exclusively a short term or emergency solution. Still, it is not clear whether and to what extent Con Edison can incorporate DG into distribution planning and consider the use of mobile DG a few years in advance of T&D upgrades. Con Edison staff noted the difficulty of taking this approach due to the fact that the majority of its distribution systems are network systems whose capacity and load growth are so large that it is challenging to find situations where a few mobile generators can reduce enough load on the system to defer T&D investment (Jack, personal communication, 2010). Mobile generators may have to be combined with other demand side resources, such as demand response and energy efficiency measures, in order to make a difference to the distribution system.

National Grid PV project in Massachusetts

Background/Overview. The New England wholesale energy and capacity markets are competitive. All Massachusetts investor owned utilities sold off their generation assets in the late 1990s when the state restructured the retail electric industry. However, more recently, the Massachusetts Green Communities Act allows utility ownership of solar PV for electric distribution companies, limited up to 50 MW per company after January 2010 (MA Green Communities Act, 2008). In response to the Act, National Grid filed a proposal on April, 2009 to construct, own, and operate a total of 5 MW solar PV facilities at 5 properties owned by the company and its affiliates. This is the first phase of the three phase programs NGRID is planning where the company will also install PV on customer sites as well as provide incentive to customer owned PV systems in the later phases. The company also requested a pre-approval of their PV cost estimates for those sites as well as the cost recovery method for the projects. The approved plan for a total of 5 MW PV capacities is expected to cost from $26.4 million to $35.7 million, with a median estimate of $31.1 million. This results in an average $6.34 per watt installed, with a range from $5.4 to $7.1 per watt for different sites, a relatively low cost per kW installed cost. The cost of the program will be determined by the annualized cost of the projects and the revenues the company would receive from selling energy and capacity as well as Solar Renewable Energy Certificates (SREC) from the PV projects into wholesale markets. The net cost will be recovered annually using the Solar Cost Adjustment Provision (SCAP) Tariff. On October 23, 2009, the MA DPU approved the company's plan (MA DPU, 2009).

Rationales for MA DPU's Approval. The MA DPU approved the company's plan for a number of reasons. First, the DPU acknowledged that the NGRID plan is consistent with the state's energy policy including (1) the state's RPS goal to meet 20% of its electric load by 2020 through new renewable energy and alternative energy; and (2) Governor Patrick's solar PV goal of 250 MW by 2017. The DPU also recognized that the plan is in the public interest and the cost-recovery method proposed by the company will result in just and reasonable rates because the company's PV proposal also bring about a number of benefits to the state. Such benefits, the DPU stated, includes "(1) producing electricity without emissions, thus avoiding future costs to electric consumers associated with the control of greenhouse gas emissions, (2) stimulating markets forces in creating additional solar generation in the Commonwealth, and (3) producing valuable information on the costs and benefits of installing solar generation facilities in Massachusetts" (MA DPU, 2009).

Benefits Claimed by National Grid. In their Application, National Grid claimed that there are a number of unique benefits that the company will bring about from their utility owned PV projects, as follows:

- Using company-owned properties for siting PV will eliminate the time required to negotiate with other parties and eliminate lease payments or fees for the use of properties owned by others. The DPU acknowledged that this will allow NGRID timely development of the PV projects (MA DPU, 2009).
- NGRID identified site specific benefits (with which MA DPU agreed). One project will be integrated with the Congestion Relief Pilot project in Everett and will allow NGRID to study the effects of PV as a percent of the load carrying capacity of a distribution feeder. Another project in Revere will allow NGRID to evaluate the impact on a substation and contingency loading issues (MA DPU, 2009).
- NGRID can buy in quantity, achieving lower prices for the system (EPRI, 2008).
- Utility owned PV projects can achieve lower net cost of service because of the ability of the utility to sell the energy and capacity to the ISO (EPRI, 2008).
- Utility owned PV projects now can take advantage of the 30% federal tax credit (EPRI, 2008).
- NGRID's PV project proposal will provide the company with "the opportunity to study the interaction of utility-scale solar generation with the distribution system under a variety of different conditions" (MA DPU, 2009).

Southern California Edison 500 MW Commercial Rooftop PV Project

Background. On March 27, 2008, Southern California Edison (SCE) filed an application with the California Public Utilities Commission (CPUC) for approval of SCE's Solar Photovoltaic Program (SPVP) to install 500 MW of solar PV on existing commercial rooftops in the SCE's territory over a 5-year period (SCE Application, 2008). Under SPVP, SCE builds, owns, and operates 250 MW of utility owned PV facilities and seeks competitive bids for power purchase agreement for electricity from the other 250 MW from independent power producers (IPPs). The targeted system size is in the 1 to 2 MW range, which has experienced limited installations in the past in the existing state's renewable energy programs. The SCE estimates the capital cost to be $875 million with the average cost of the PV facilities at about $3.5 per watt Detroit Edison requested a 10% contingency for potential additional capital cost spending before being subject to reasonableness review by the PUC. SCE also earns a return on their PV investment. On June 22, 2009, the CPUC approved the program in Decision 09-06-049 with slight modifications (CPUC, Solar Program, 2009).

Rationales for CPUC's Approval. The CPUC has a general policy to encourage utility ownership of distributed renewable energy generation. The Energy Action Plan I adopted by the Commission in 2003 states, "the state is promoting and encouraging clean and renewable customer and utility owned distributed generation as key component of its energy system" (CA Energy Action Plan, 2008).

In Decision 09-06-049, the CPUC reviewed some of the Public Utility Code Section 2775.5 and comments from stakeholders mainly as to how the utility ownership element of this adopted program will affect market competition and if the program is in the public interest. Public Utility Code Section 2775.5(b) required the CPUC to consider whether the program restricts competition in the solar industry, and it concluded that the program will solicit competitive bids from solar equipment manufacturers and will enhance the market for solar energy systems of one to two MW by creating a new market opportunities that currently do not exist. The PUC addressed IPPs concern that SCE's program eliminates competition in leasing commercial roof space for the use of solar PV, and modified the original plan in a way to allow IPPs to secure roof space on their own and require SCE to procure 50% of the program capacity from IPPs. With this modification, the PUC concluded that "because the adopted SPVP will allow for significant competition throughout the solar energy industry value chain, including competition for ownership and operation of the solar generating facilities, it will not restrict competition in solar energy industry" (CPUC, 2009).

In response to Public Utility Code section 2775.5(f), the PUC also examined whether the program is in the ratepayer's interest, and determined it is in the public interest because of the following reasons:

(1) The program would promote the development of additional renewable projects on existing rooftops;
(2) The program would help expand the one to two MW solar market, which under current policies has remained under-developed;
(3) The economies of scale and installation efficiencies resulting from deploying large MWs and multi-year projects will provide benefits to the ratepayers;
(4) The solar PV systems promoted under the program will be located near load and can be quickly deployed;
(5) The program can play a role in meeting the objectives of the state RPS and driving down the costs of renewable energy technologies;
(6) Large scale utility deployment of solar PV facilities along with the adopted competitive procurement process can put downward pressure on renewable energy prices;
(7) The program offers SCE and the state an opportunity to better understand the implications of interconnecting significant amounts of distributed renewable generation to the grid and the comparative costs and benefits of different renewable energy deployment options (CPUC, 2009).

Given that utility-owned renewable generation is a new program approach, CA PUC intends to carefully monitor the program's progress, to examine ways in which the program can be improved, and to improve the design where and when appropriate.

Benefits of Utility Owned PV Systems. SCE argues that the utility is in the best position to promote large scale PV deployment on the commercial rooftop spaces for the following reasons (SCE Application, Case 08-03-015):

(1) SCE can use established electric supply arrangements with vendors and commercial lessors who are also its longstanding customers, and who view the utility as a stable, competent, reliable business partner (whereas 'most solar PV developers have been in business for only a few years')
(2) SCE can obtain volume discounts not available to most PV developers
(3) SCE has a strong balance sheet and procurement expertise that enables it to negotiate effectively with rooftop owners and vendors
(4) SCE will refer building owners/developers to its Energy Efficiency group to identify efficiency opportunities for new structures considering PV
(5) Utility field personnel can effectively monitor and cost-effectively repair systems
(6) SCE can coordinate PV with demand shifts using its existing demand reduction programs on the same circuit, more fully utilizing distribution assets
(7) SCE is uniquely situated to cost-effectively combine PV, customer demand programs, and advanced circuit design and operation into a unified system
(8) SCE involvement substantially increases the chance that 250 MW of PV will become available to meet State RPS goals
(9) SCE will share with other entities, in California and elsewhere, its experience concerning PV interface issues, forecasting and scheduling, training and best practices for 1-2 MW facilities, and streamlining of tariff applications and local and State codes.

Austin Energy's CHP Solution at Dell Children's Hospital

Austin Energy is a publically owned municipal electric utility located in Austin, Texas. Austin Energy serves 388,000 customers in the City of Austin, Travis County, and parts of Williamson County. Also functioning as a city department, Austin Energy returns profits to the community on an annual basis. Austin Energy's generation mix includes 2,600 MW of nuclear, coal, natural gas, and renewable energy sources. The utility offers highly successful renewable energy, green energy, and energy efficiency programs to residential and commercial customers (Austin Energy Profile, 2010).

Dell Children's Medical Center, a 170-bed hospital located in Austin, first contacted Austin Energy about contracting for a CHP generator to be located on the hospital site (TAS, 2010). Dell was interested in becoming the first hospital in the world to obtain Platinum LEED® certification, and hoped the CHP installation would assist achieving this goal (TAS, 2010; Collins, 2010). Austin Energy would own and operate the unit on the hospital site, and in turn the hospital would purchase the power and chilled water from the plant at tariffed rates over a 30-year term (TAS, 2010).

Given its history of supporting renewable energy, green buildings, and energy efficiency, Austin Energy accepted the request as an opportunity to experience the advantages and disadvantages of CHP generation. Austin Energy further hoped that the CHP experience would contribute to improved customer relationships and reliability, two long-standing goals of the company (Collins, 2010).

Austin Energy contracted with Burns & McDonnell for engineering, procurement, and construction of the unit, which was completed in 10 months and initiated operation in 2006 (TAS, 2010). Burns & McDonnell was able to secure cost share funding through a grant from the U.S. Department of Energy (DOE) and the Oak Ridge National Laboratory (ORNL) (Burns, 2010). The system is comprised of a 4.3 MW Solar Mercury 50 combustion turbine with a HRSG and absorption chiller (TAS, 2010). With a 1.5 MW diesel backup generator and two grid feeds from separate substations, the system is exceptionally reliable and supplies 100% of the hospital's electricity, heating, and cooling needs (TAS, 2010).

Both Austin Energy and Dell have benefited from the CHP project. Austin Energy receives the stability of a long-term contract while the hospital enjoys a reliable power supply (Collins, 2010). Dell has also saved $7 million in capital outlay by outsourcing power, heating, and chilled water needs to Austin Energy (Bullock, 2010; Collins, 2010). In addition, the CHP unit operates with very low emissions, enabling the utility and the hospital to meet environmental goals and minimize regulatory hurdles (Collins, 2010).

Overall, Austin Energy encountered very few regulatory barriers costs in implementing the Dell CHP project.

Environmental permitting was simple due to the unit's low emissions, and Austin Energy's role as a city department simplified other regulatory matters. Coordination of the parties involved significant time and effort upfront, mostly because neither Austin Energy nor Dell had prior experience with similar projects. Connection to the grid was not difficult (Collins, 2010).

From a project management standpoint, the greatest challenges to the Dell CHP project have come from allocation of fuel and equipment between power production and non-power production and maintaining 24-hour staffing. Operating cost accounting can be complex and subject to fluctuating natural gas prices. The plant has experienced three outages early in its four-year operation. These outages were caused by problems switching to the grid power feed, and Austin Energy is working to eliminate such problems in the future (Collins, 2010).

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