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

Comparative Analysis of DG Implementation Models
Task #3

Prepared for the

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NOTICE

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SUMMARY

This report provides a narrative summary of Task 3, which is a comparative analysis of the risks and benefits associated with the three DG deployment models described in Task 2. The complete comparative analysis exists in a matrix in the form of an excel spreadsheet, which provides a clear form for comparison. The issues considered in the comparison matrix include the following overarching issues, with both risks and benefits described with respect to each implementation model:

- 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 RPS Requirement
- Resource Integration
- Utility Ownership Of DG

The sections of the narrative below correspond to each of these overarching issues. Unless otherwise specified, the parenthetical page number references refer to the corresponding pages of the Task 2 report, "Deployment Of Distributed Generation For Grid Support And Distribution System Infrastructure: Alternative Utility DG Deployment Strategies." The Project Team would like to acknowledge the assistance of Todd Olinsky-Paul and Thomas Kelly in the preparation of this Final Task Report.

1 REGULATORY BURDEN AND MANAGEMENT COMPLEXITY

The overarching issues related to regulatory burden and management complexity include several sub-categories. These include the issues of cost recovery, program management, project development, monitoring and operation, customer screening, customer contracting, emissions, sales of energy and capacity, and noise and space.

1.1 Cost Recovery

Cost recovery is a critical issue and depends on standards imposed by regulators, which stems from the regulatory requirement that utility investments be in the public interest, prudent and just and reasonable. For each of the implementation models, all utility program costs or investments contributing to a DG/CHP project must be justifiable as cost effective and in the public interest in order to receive cost recovery. Lost net revenue may be an issue for either type of model, but is at least partially offset by return on equity under utility ownership models.

With utility-owned DG investments, in order to qualify for regulated rate treatment, including return of and on the investment, utilities need to spend time and resources to ensure that CHP/DG projects are in the public interest and the costs of such projects are prudent and just and reasonable. They may also need to spend time and resources demonstrating that such standards have been met if recovery is challenged in a rate case, but the recovery framework is the same as for other utility costs. In general, the successful use of the RFP model historically by utilities has been preceded by adoption of measures that ensure cost recovery. For that purpose, the RRFP model incorporates separate checks and balances to ensure cost effectiveness, such as the involvement of the Technical Evaluation Panel (TEP) to evaluate proposals. In the HVDG model, the program design presumes that the utility already received regulatory cost recovery guarantees before posting the prices.

1.2 Program Management

All three models require utility time and resources to manage the programs. The Utility model would be managed like any other utility program, benefitting from existing expertise and efficiency of other utility managed programs. When utilities decide to develop, design, and construct DG on their own, utility-owned DG projects/programs become more complex, but, to the extent that utility-owned resources are installed by third party contractors, the same efficiencies would accrue as utilities routinely manage construction work by others. Still, depending on the volume of work, utilities may need to create a new department or assign/hire dedicated staff who can work on utility-owned DG projects. The RRFP model would be co-managed by the utility and the technical evaluation panel (TEP). This collaborative management approach would set the incentive, market the program, and administer the application and eligibility review processes. The acquisition of the resource would be conditional upon approval by the New York State Public Service Commission (NYSPSC). The HVDG model would be managed by the local distribution utility, who would publicly post and adjust spot incentives, administer the application and eligibility review process, oversee performance payments, and submit costs to the NYSPSC for adjustment through the appropriate mechanism.

1.3 Monitoring and Operation

Monitoring and operation of the DG resource is an important attribute for each of the models. In order for DG/CHP projects to be effective as distribution resources, the units will likely need to be controlled by the utility either directly or indirectly through programmatic elements. In the utility-owned model, monitoring and operation are performed by the utility; however with the customer-owned models, programmatic elements will be necessary to manage the monitoring and operation of the resource to the satisfaction of the utility. This added level of complexity associated with the customer-owned models will likely involve additional time and expense to manage.

1.4 Customer Screening

One form of the utility-owned DG model deploys DG units along distribution systems (e.g., as in the mobile DG example from Detroit Edison discussed below), on public property such as parking lots and subway depots, and on utility property (e.g., solar PV examples from SCE and NGRID), and does not require host customer screening. For utility-owned DG that uses customer sites for DG projects and for the customer-owned DG models, there will be considerable amount of time dedicated to identifying and screening the customers who are most suitable for participation. For CHP projects, where both power and thermal needs of the customer must be considered, this process will take additional time. With the customer-owned models, the burden to identify appropriate hosts will lie with the DG developer.

1.5 Customer Contracting

With a utility ownership model, as with central station power plants, there may or may not be a counterparty for the development, ownership or operation of the generating unit. Depending on the technology and location, there may be a site landlord or a steam or heat customer to engage in a contract. The customer-owned models will need to contractually obligate the customer operating the resource to make the unit available and operating at critical times in order for DG to be used as a distribution resource. In both customer-owned models, the utility would contract with its customers for the prescribed amount of time to match the deferral value. For the RRFP model, developers would contract with the customer who would then remit to the utility for contracted payments. For the HVDG model, depending upon the deferral price, the customer would contract that amount with the utility.

1.6 Emissions

Depending upon the type of fuel used for the resource, New York State Air Resource regulations may apply to DG projects, and the appropriate permits must be acquired. The utility-owned DG model includes mobile generators that can be used to defer T&D system upgrades as demonstrated by Detroit Edison. If such mobile generators are run by diesel fuel (as is typical), and if they are not eligible to be treated as emergency generators in New York (perhaps, because they are incorporated in T&D system planning or due to projected annual run times), emissions from diesel units would not likely meet the current emission regulations in New York.[1] Adding emission control technologies such as a selective catalytic reduction (SCR) system could cut the emission enough to allow diesel engines to comply with regulations, but are very costly to install. SCR requires up to $250,000 additional capital cost for a 1 to 2 MW unit (MECA, 2009). On the other hand, natural gas engines have significantly lower emission rates and could be viable for mobile DG options. The NOx emission limit for stationary compression ignition internal combustion engines under the current air regulation is approximately 6.79 lb/MWh while the emission rate of natural gas engines range from 0.096 to 1.25 lb/MWh (NY Air Regulations, US EPA Catalog of CHP Technologies).

1.7 Sales of Electric Energy and Waste Heat

In some situations, utilities may need to sell electric energy to the wholesale market if, for example, it cannot be treated as load reduction for reliability and market purposes. Nevertheless, sales of energy may not be complicated if output does not require scheduling of energy output and pricing, i.e., if the unit is simply a price taker. This is likely the most to be the case when DG is mainly used for T&D support or when the output of renewable DG cannot be scheduled. When utilities own CHP as Austin Energy in Texas is doing (see Task 2, Appendix A), they have to sell not just energy but steam or other forms of waste heat to their customers. Selling steam is within the ordinary

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[1] According to New York Air Regulations, emergency power generating units, such as those that are currently used by utilities to support T&D system during T&D system upgrades or to buy time when system upgrades are delayed, are exempt from permitting as long as they operate less than 500 hours per year (NYCRR 201-3.2(c)(6)). Still, given that the nature of DG envisioned for distribution planning is mobile, non-emergency or both, the air regulations for non-emergency generators are likely to be more applicable for the utility DG model discussed here.

scope of business for Con Edison. which has been operating steam generators for its steam customers for many years, but it may be quite novel (or a "flashback") for other utilities.

1.8 Sales of Capacity

Dealing with capacity from DG does not appear complicated given that utilities are familiar with the capacity market in their role to meet installed capacity requirements. Also capacity from DG, if it is owned by a utility, would likely be regarded as self-supply resource by utilities (LSEs), the amount of which will be subtracted from the capacity requirement the company needs to purchase via bilateral contracts or from the installed capacity market (NYISO, 2010).

1.9 Noise and Space

Noise and space are generally not a significant concern for some DG technologies such as solar PV, fuel cells, and microturbines; however noise and space can be significant issues for engines and turbines, aside from CHP applications. (Facilities that support CHP can often provide indoor industrial space and noise control.) When engines are used outdoors for mobile DG applications to support T&D system, noise and space become a significant matter for a densely populated city like New York. Detroit Edison uses mobile DG for T&D support and usually places diesel DG around 300 feet from residential areas, at which distance the noise level is about 60 dB, equivalent of the noise level of people talking on the street (Asgerrisson, 2004). It would be challenging to find such space in New York City in a useful DG T&D support location, although utility substations, empty industrial sites, under highway overpasses, subway depots, or the like could possibly host engines and mitigate noise concerns. Natural gas gensets operate more quietly than diesel units, and would face fewer siting challenges in NYC.

2 PROJECT AND PROGRAM COST

2.1 System Installed Cost and Project Cost

When utilities install and own DG resources, there is significant potential for them to face system capital costs lower than those non-utility owners would face, depending on the type of DG technology used. Some utility-owned DG projects can be large scale either in individual unit size or collectively in capacity with numerous projects, while others such as CHP may not be much different in size regardless of who own the projects. The nature of large scale projects allow for (a) economies of scale in planning and operation, (b) bulk purchase and (c) standardization of products and installation practices, all of which reduce the project cost. This is especially true for technologies like solar PV, the cost of which still has potential to decline with widespread installations (DOE EIA 2010, Navigant 2004). For example, Southern California Edison is planning to install 250 MW of utility-owned PV on commercial rooftops over five years. The program targets an average system size of 1-to-2 MW. The cost is estimated at $875 million, resulting in a cost of $3500 per kW installed (SEPA, 2008; CPUC Solar PV Decision, 2009). (See Task 2, Appendix A for the SCE's PV example and another PV project example from NGRID.) Another example is Tucson Electric's 5 MW Springerville PV generation station, which had a system cost of about 30% less than other PV systems installed around the same time due to the incorporation of standardized products, volume purchasing and an efficient array field design and installation (Moore, 2005). According to Tucson Electric, a key to cost reduction was achieved through "an identical copy of a standardized array field configuration that uses the same hardware components, wiring topology, and structural mounting plan" (Moore, 2005).

It is also possible that an incumbent utility may have advantages in the access to information or the cost of information for pre-development activities. The most important of these would likely be information about current and future T&D relief needs. When all market participants have access to the same information on deferral value of a T&D project, multiple parties may vie to provide a least cost solution in an RFP type process, but utilities may know long in advance which circuits will need expensive upgrades, giving them a potential competitive advantage in siting DG to defer those upgrades. On the other hand, utilities often have commercial and industrial customer account representatives who would know large customers and their facilities in detail. This knowledge could allow a utility to identify good prospects for hosting a DG unit, an advantage difficult to erase in an RFP.

2.2 Cost of Capital

The cost of financing a utility-owned, rate-regulated DG project is typically lower than the cost to other types of private companies. This is due in part to a lower cost of equity and debt for regulated monopolies compared to the unregulated private market and in part to the ability of utilities to obtain financing with a larger debt ratio than other "unregulated" businesses. Together with utilities' ability to recover costs over a longer term than most unregulated entities can afford, these savings generally help lower the cost of capital for utilities compared to unregulated companies. Further, if utilities offer third party developers long-term power purchase agreements or feed-in tariffs, which guarantee long-term payments to DG projects, the cost of capital for private companies is also reduced. In either case, the lower financing costs would benefit both utilities and consumers.

Another aspect of capital cost may favor one of the models or the other, depending on the utility's circumstances and the state of capital markets. The utility-owned business model is more or less attractive to the utility depending on its appetite for, cost of and access to raising capital, as well as the relative capital cost of meeting a given need with T&D investment or DG investment. Some utilities have ready access to capital and confidence in their ability to obtain recovery for rate base additions through their Commission. Such utilities will see capital additions as a valuable activity. Others are capital constrained and would not. Such capital constrained utilities could see negative impacts on their bond ratings and cost of capital if they pursue capital additions for needs that could be met in other ways, as over-leveraging will be penalized by risk averse financial markets.

One recent example of this is the history of CECONY, as set out in the 2009 Comprehensive Management Audit by Liberty Consulting. Liberty Consulting concluded that an increase of more than 100% in the Company's capital spending levels increased revenue requirements faster than revenues, leading to higher costs for new capital and serious concerns about the company's ability to raise further capital. The implication here is not that investment in DG is risky; quite the opposite if the DG option is the least cost solution for T&D constraints. Rather, the point is that for a company in such a financial situation, customer ownership models may be favored, at least while that situation continues. For a utility with problems accessing or carrying debt, non-utility ownership models for DG could make more sense for the utility and for ratepayers. Still, the balance is likely to be utility specific and change over time. It should be noted that this issue does not depend on whether DG is the least cost option for a given T&D constraint. When DG is the least cost option, it will eventually reduce the amount of capital and debt spent on dealing with T&D constraints and investments associated with them. Nevertheless, for some utilities, other aspects of their financial situations may interact with DG investments in ways that make either type of investment (T&D or DG) quite difficult. In such cases, utility-owned DG models may be untenable.

In some situations, a third capital cost issue may arise. Investment rating agencies treat the payments required of utilities under long-term power purchase contracts as a debt obligation, at least in part. Thus, utility ownership can be attractive for utilities and ratepayers inasmuch as it can avoid that type of burden on the utility balance sheet. Still, that potential benefit may be irrelevant if the utility has a weak balance sheet to start with. Conversely, if a utility is capital constrained, i.e., has difficulty obtaining additional capital or is otherwise reluctant to invest rate base, it could see the customer-owned DG models as advantageous because they do not require utility financing, but that perceived benefit (avoiding the need to raise or spend capital) may partially offset by any commitment to future power purchases from customer-owned DG, depending on rating agency treatment of purchased power obligations.

In general, financing costs, including transaction 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 utility posted price in the HVDG model may lower the cost of financing because bidders will have certainty about their bid costs in securing the contract.

2.3 Administrative and Transaction Costs

2.3.1 Utility Ownership Model

Utility administrative and transaction costs mainly occur when utilities are marketing the program, searching for potential DG and customer sites, reaching out to potential customers, arranging lease agreements with customers to install DG at customer site, and during DG interconnection and operation. In general, if utilities own DG resources, they can avoid the time and expense that otherwise would be required to deal with customer-owned DG. For instance, DG interconnection becomes easier if DG is owned by utilities because utilities do not need to process applications for numerous customers. DG monitoring and control would also be simpler and more cost effective because utility ownership does not require utility-customer agreements for monitoring and control of customer-owned DG units. With utility-owned DG resources, when utilities use their own or affiliates' properties, buildings and substations to site a DG resource, leasing costs are also eliminated. Where the utility sites a DG unit on private property, a situation unique to the utility-owned DG model, transaction costs ought to be minor, as lease agreements could be a short, standard form document.

Seeking proposals from customers willing to help the utility's T&D system with a DG proposal requires a significant amount of marketing time, dealing with inquiries by potential participants, and screening and selecting the winning participants. Identifying customers with sites appropriate for DG as a T&D solution also requires a considerable amount of time and resources, and is necessary regardless of who owns the DG units.

2.3.2 Customer-owned Models

The utility management of an RFP for customer-owned DG projects requires a significant amount of utility staff administrative time and resources (page 36). The costs associated with administering an RFP include activities undertaken in creating and executing the RFP process, marketing the program, handling inquiries from potential participants, and screening and selecting the winning participants, as well as the costs of finalizing and executing power purchase contracts. Unlike the HVDG model, the RRFP process entails more granular management of the public-procurement process. For private DG developers, bid preparation costs associated with an RFP process can be significant, but are likely to be significantly lessened with a standard offer. These costs can be significant and potentially deterring qualified firms because those bid costs are at risk if a firm bids and does not win a contract.

Nevertheless, the customer-owned implementation models both provide mechanisms to address and lower these types of costs. The RRFP collaborative group is intended to address administrative costs by determining the most effective strategies for administration and lowering transaction costs (page 36). Under the RRFP, DG developers would be provided with adequate time to prepare their bids, secure financing and 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 (page 37).

Transparency on the deferral values specific to a particular location will provide knowledge that will allow private developers to bid more accurately and discriminately, where multiple parties vie to provide a least cost solution, and thus will lessen administrative costs for the utilities (pages 13 and 26).

With the HVDG model, a simple proposal process allows for low application and proposal costs to the resource owner, and a first-come, first-serve review process with pre-established standard conditions simplifies and reduces costs to the utility to administer the selection process. These costs are expected to be lower than the costs expected with the RRFP model. For example, the development of a simple, standard form agreement between Con Edison and DG/CHP developers will lower legal costs (page 36).

2.4 Tax Credits

Federal tax credits often have a significant impact on the rate of return for DG projects. Until October 2008, utilities were not eligible for federal investment tax credits (ITCs) on renewable energy and DG projects. The solar industry claimed that the federal ITC is critical for the economics of utility-owned projects (SEPA, 2008). In October 2008, the Energy Improvement and Extension Act of 2008 (H.R. 1424) extended the ITCs for eight years and also extended eligibility to utilities. Existing law provides ITCs for solar energy, fuel cells and microturbines and that was extended to new small wind-energy systems, geothermal heat pumps, and CHP systems (DSIRE). Solar Electric Power Association states that the removal of the utility exclusion from the federal solar investment tax credit, along with other current conditions such as lower PV module prices, has made photovoltaic a viable ownership option for utilities to consider (SEPA, 2009).

3 EASE OF DG INTEGRATION

With respect to DG integration, the utility ownership model is the model best suited to integrate DG into the distribution grid with ease. This is because utilities are in the best position to identify the most beneficial sites and system sizes for their network. The NYSPSC indicated recently in the RPS proceeding, that "utilities are not only uniquely situated to identify locations within their distribution networks that are in need of significant upgrades or replacement where added distribution support may be desirable but also that utilities are in the best position to analyze system performance and the impact of any installations on their respective distribution systems" (Case 03-E-0188, RPS Order, 2010, page 35).

With the customer-owned implementation models, the utility will need to respond to a variety of project-specific proposals that involve a range of different technologies. Fielding these proposals and managing the requirements and specifications to interconnect a variety of DG technologies at different locations on the distribution grid will undoubtedly complicate the integration of DG.

The Refined RFP process is intended to integrate DG into the distribution grid with more ease, by recommending certain adjustments based on the lessons learned after the three-year DG pilot program ordered by the NYSPSC in 2001. By matching RFPs with service territories that contain more attractive DG/CHP economics, implementation in those areas will tend to be more successful. Inviting utilities into the process for a greater role in project development, and initiating a collaborative process that solicits stakeholder input and develops best practices are also actions that will ease implementation. Exploring the synergies in grid congestion between the local distribution utilities and the NYISO will help accomplish more accurate identification of locations where DG economics make sense. Finally, the provision of guidance on the evaluation of reliability will serve to save time, create efficiency in project development, and ultimately better ease DG integration.

Both the posted incentive and standard offer process outlined in the HVDG model are also intended to ease DG integration, despite the complexities associated with customer-owned models. Clear price signals resulting from accurate deferral values will improve DG economics. A streamlined process with a first-come, first-served nature selection process saves the distribution utility reviewing time over the RRFP process.

4 DG RELOCATION FLEXIBILITY, DEPLOYMENT LEAD TIME

Periodically, distribution problems emerge on the grid with so much urgency that they must be addressed rapidly. These urgent situations, often related to T&D congestion, are routinely addressed by utilities with the deployment of utility-owned DG resources. Certain DG technologies, such as mobile DG and PV, can be located and relocated to best meet the changes in distribution loading condition. With respect to alleviating T&D constraint, utility-owned DG projects, especially those located on distribution systems or utility properties, have an advantage over customer ownership forms because they save time on site and customer selection, contractual relationships with private parties, interconnection agreements, and monitoring and control of a customer-owned resource. Even utility-owned DG models located on customer sites will save time and resources on interconnection agreements, and monitoring and control of a customer-owned resource.

DG project lead time can be relatively short and can be extremely short for utility-owned mobile DG applications. These benefits are demonstrated in the cases of Detroit Edison and National Grid (pages 4 and 38). Most private developers who were interviewed require a lead time of 12 to 18 months, similar to lead times that a traditional distribution solution requires. Private developers desire these lead times primarily because of the necessary time to identify host customers and to secure adequate financing for a project (page 37). Utilities also have to plan for lead times based on project deferral timelines. With the HVDG implementation model, the location incentive would be posted with expectations on lead time, allowing for greater efficiency in planning a project and cost savings.

5 DG INTERCONNECTION

In a 2009 study, the Solar Electric Power Association (SEPA) stated that, “the major utility obstacle for interconnection [of DG] is the utility’s desire to ‘protect’ the grid,” by requiring “highly reliable” and “continuously operat[ed]” DG resources (Sautter, 2009).

With utility ownership of DG, utilities are better suited to improve DG interconnection and technologies, although possibly not their cost or flexibility in application. The development of more simplified and standardized interconnection requirements for DG is likely to benefit utilities in the long run (Sautter, 2009). SEPA points out that when a utility decides to own and operate a DG resource, the utility also gains an opportunity to “expedite the development of simplified interconnection” and the “education to identify the lowest cost (both in hardware and process) to assure grid reliability is not affected by PV systems” (Sautter, 2009).

Both NGRID and SCE photovoltaic projects (referred to in the Task 2 case studies) demonstrate the benefit to utilities of understanding and facilitating DG interconnection. For example, MA DPU stated that 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). The CA PUC stated that the SCE’s PV 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).

In February of 2009, New York standardized the processes for all applications that run parallel to the grid up to 2 MW. Projects require external disconnect switches and size limits are capped at 2 MW (Page 34). This new standard is beneficial for the customer owned DG models, but the capacity limit is still small for many commercial scale DG projects. Network for New Energy Choices argues that 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).

6 RELIABILITY

Utilities and DG developers vehemently disagree on whether DG serves to improve or weaken grid reliability. The contradiction was explained in a 2002 article by Roger Dugan of Electrotek, who pointed out the differing perspectives of the utility versus the DG owner. "Almost all of the literature promoting DG also claims that DG improves reliability. Still, utility engineers often will not give DG any credit for reliability improvement, and in fact, they often will give reasons why it will decrease reliability" (Dugan, 2002). Utility concerns about reliability, particularly with respect to radial distribution systems, include issues related to the "multiple sectionalizing switches that allow for reconfiguration of the radial circuits during emergencies, or for balancing loads between substations during normal conditions" (Dugan, 2002).

Detroit Edison uses sophisticated monitoring and remote control devices to ensure reliable DG operation. Using a number of different media such as radio, cell phone and the Internet, the monitoring device transmits operational data including oil pressure, loading level, fuel consumption and temperature. Monitoring equipment is duplicated for safety and reliability (Pace, Synapse, 2006 Report). Also, relay protection is often installed to DG units in addition to the protection device embedded in the DG system (Pace, Synapse, 2006 Report). The company also uses an automation technology that dispatches mobile DG units automatically in response to temperature.

Utilities typically prefer to control the operation of DG units that are relied upon for distribution system support rather than engage those resources for distribution support if they operate under customer control, primarily for a desire for physical assurance that the resource will operate during system peaks. For example, Con Edison operates three small gas turbine generators (one located on W. 59th St and two located on W. 74th St.), which were built over forty years ago. These units 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.

Nevertheless, there are alternatives to 100% physical assurance that utilities typically demand for customer DG resources, such as (1) reducing physical requirement to just peak load hours for the distribution system (Con Edison is considering this option for its targeted DSM program); (2) assessing penalties for non-performance; (3) diversifying the DG resources deployed in a particular location; and (4) allowing other distributed energy resources such as EE and DR in addition to DG (page 32).

Furthermore, according to a study performed by Energy & Environmental Analysis (EEA), when a group of DG units operate as a system, reliability is increased. It 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% (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.

With both customer-owned models, compensation for energy and capacity from DG units, including performance based incentives or penalties, may be pre-defined. Relaxing physical assurance requirements to only peak periods may induce more cost-effective DG to enter the market.

7 DG MARKET DEVELOPMENT

Two of the barriers to the wider spread of customer-owned DG technologies are the lack of upfront capital for development and the short payback periods demanded by customers and developers. Utilities can overcome these barriers by providing incentives to customers who want to install DG units. Still, even with incentives (for ongoing performance) and rebates to purchase clean DG technologies, many customers still face a barrier in terms of lack of up-front capital. In contrast, utility ownership models, in general, do not encounter these barriers if installed DG qualifies for regulated rate recovery. Utility-owned but customer-sited technologies, such as utility installed and owned rooftop solar panels, can deliver the benefits of clean energy to customers without the necessity of a large up front financial investment by the customer. Utilities can often more readily obtain the necessary capital due to their size and access to capital, and can amortize PV investment and recover over a longer term than most customers.[2]

Another related benefit of utility ownership models is that a large scale utility DG program (e.g., SCE's 250 MW PV plan) could provide certainty in terms of actual delivery of DG installations, while a customer ownership model that aimed at the same scale of DG deployment would tend to have some uncertainty as to whether they could actually be delivered.

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 offered must be designed to contribute meaningfully to a project owner's economic fundamentals in terms that customers relate to, such as internal rate of return (IRR) or simple payback period.

Customer-owned DG models generally viewed as giving more impetus to developing the competitive market for DG service providers (turnkey operators, installers, engineers, maintenance companies, etc.) because private companies participating in DG projects presumably face fierce competition and make every effort to find and 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 (pages 34-35). However, utility ownership models can provide similar kinds of benefits if implemented via contracting between the utility and such providers, although the result may be somewhat less diversity if utilities favor consolidated master contracts for many DG projects.

[2] For example, SCE is recovering the cost of utility-owned PV assets over 20 years. See http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/116784.htm

8 MEETING UTILITY RPS REQUIREMENTS

Production of renewable energy credits (RECs) for renewable portfolio standard (RPS) compliance is a possible benefit available from DG projects that qualify as renewable energy for that purpose. Both utility ownership and customer ownership models may provide a significant benefit in the form of a vehicle for aggregating qualifying generation. This is because many REC clearinghouses (such as ISO generation information systems) issue such certificates only in minimum amounts of one MWh, a utility managed DG program can bundle the generation together for that purpose, if the clearinghouse rules permit. For a utility ownership model, this is straightforward. Under a customer ownership model, there would be a need to specify terms and conditions that govern ownership of and compensation for any RECs produced.

9 RESOURCE INTEGRATION

Active utility involvement in DG projects could allow for economies of scope and thus reduce the cost of DG projects. Economies of scope are possible when a utility having existing energy efficiency and/or demand response programs promote DG projects by utilizing the existing program infrastructure, staff, marketing methods and channels and by targeting the same customer base at the same time as promoting energy efficiency and/or demand response resources at customer site. A case in point is SCE's 250 MW utility PV program. In the case study of that project, SCE noted the following points as the benefits of its utility-owned PV program:

1. SCE can refer building owners/developers to its Energy Efficiency group to identify efficiency opportunities for new structures considering PV;
2. Utility field personnel can effectively monitor and cost-effectively repair systems;
3. SCE can coordinate PV with demand shifts using its existing demand reduction programs on the same circuit, more fully utilizing distribution assets; and
4. SCE is uniquely situated to cost-effectively combine PV, customer demand programs, and advanced circuit design and operation into a unified system.

Coordination and integration of DG with other programs and resources will be easier if DG is owned by a utility, especially for (2) and (3) mentioned above.

10 FEASIBILITY OF UTILITY OWNERSHIP OF DG

In 1996, the New York State Public Service Commission (NYSPSC) initiated a proceeding to restructure the electric utility industry, fundamentally changing the market and opening the industry to competition. (PSC, 1996) In order to create a competitive generation market, the PSC directed the investor owned utilities (that at the time owned transmission, distribution and generation) to unbundle and divest most of their existing generation, although the PSC did not specifically prohibit a distribution utility from owning generation in the future. 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 (that were subsequently divested). Since then, distribution-utility ownership of generation has been determined on a case-by-case basis when the issue arises in proceedings. 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 and operation.

The most relevant principle for the ownership of DG by utilities is stated in the Vertical Market Power Policy (VMPP) Statement of 1998 regarding a T&D utility affiliate owning generation. 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." (PSC 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 DG ownership by a distribution utility itself. While the VMPP Statement was not cited in those cases, the spirit of the Statement was reflected. Brief overviews of two such cases are provided below:

- In Opinion No. 01-5 issued on October 26, 2001, the PSC directed New York's investor-owned distribution companies to implement a three-year pilot program designed to test whether DG could cost-effectively defer the need for significant investment in distribution system infrastructure. (PSC Case No. 00-E-0005, 2001) The pilot focused on customer owned DG projects, but allowed utilities and utility affiliates to bid DG projects. This could reflect the PSC's recognition that utility ownership of DG may provide some public benefits. Still, neither the PSC's Opinion No. 01-5, nor the recommendation report that the PSC endorsed in the Opinion discussed utility ownership of DG resources in detail beyond mentioning 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 proceeding leading up to its April 2, 2010 Renewable Portfolio Standard (RPS) Final Order, the PSC 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 those where SBC-funded renewable energy projects are installed. (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. The PSC 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) Nevertheless, the PSC 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 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 about the logic of allowing utility-owned DG projects in the pilot. Still, almost a decade later, the April 2010 RPS Final Order is more clear concerning the circumstances under which utility ownership of DG is appropriate. The case concluded that while utility ownership of DG is not prohibited or illegal, it would be challenging for the Commission to approve "at this time." As stated in the April 2010 Order and the VMPP Statement, a utility must demonstrate that its 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. Nevertheless, 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 the demonstration of utility ownership of the resource.

10.1 Vertical Market Power and Unfair Competitive Advantage

Electric industry restructuring seeks to promote a competitive market for wholesale power, retail power, or both. To do so, market structures are developed to prevent the exercise of undue market power over the price or availability of power by any market participant. Two major issues arise when utilities own DG assets that do not arise when utilities own only DG-related equipment: vertical market power and possible unfair advantage over other wholesale energy or DG providers.

Vertical market power could exist if utilities own and operate generation or T&D assets (including DG) in a manner that could or does unfairly benefit their DG businesses. Utility good faith in design and implementation of markets is generally not sufficient to address vertical market power concerns. Regulators typically need to provide market power oversight of terms and conditions and market monitoring of implementation. Requiring competitive solicitation mitigates these issues, assuming proper design, and may be included in either utility ownership or customer ownership models.

Two examples of potential vertical market power are (1) a T&D company could hinder entry by generators into its own territory by delaying or imposing unrealistic interconnection requirements (PSC, 1998); (2) a T&D company could influence the transmission constraints that affect the operability or profitability of generation owned by others.

The first concern can be mitigated to a great extent by appropriate rules and standards established by the NYISO, FERC and the PSC. It is worth noting that utility DG ownership could provide an opportunity to better understand the impact of DG on the distribution system, resulting in a more standardized and efficient interconnection process and a more precise assessment of DG benefits. The second concern is likely insignificant for smaller scale CHP/DG and renewable generation for the following reasons:

(1) Renewable generation such as PV and wind is an intermittent resource whose availability is not under utility control. Therefore, there may be less incentive for a utility to use T&D constraints to raise prices than if the utility owned dispatchable generators.
(2) Because the primary goal of DG in the utility DG ownership model 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), the company may have little incentive to exercise market power to influence wholesale market price by retaining transmission constraints.
(3) CHP/DG resources are small 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 CHP/DG fleets owned by the utility.

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 could give an unfair advantage to the utility because private companies' business is not similarly protected. Private companies can be divided into two distinct groups – wholesale generators such as independent power producers (IPP) and 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. If the amount of generation owned by a distribution utility is small and limited to a particular public purpose, such as supporting T&D or promoting renewable generation, the concerns of competitive wholesale generators may be mitigated. When DG developers or aggregators of DG become more active in the wholesale markets, the presence of utilities in these businesses means a smaller share of private DG businesses in the wholesale market. Utilities would then need to be able to demonstrate that the ownership will benefit such private companies in addition to ratepayers and be subject to market power oversight and mitigation measures.

The threat of competition from utilities is a major issue affecting DG project developers that can be mitigated to a great extent by limiting utility DG ownership to a maximum capacity and location and providing market players with ample business opportunities. Further difficulties can be avoided if utilities use their own property to site DG projects, and contract out to private companies the work of engineering, procurement, and construction (EPC), as well as maintenance work.

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