A Comprehensive Process Evaluation of Early Experience Under New York's Pilot Program for Integration of Distributed Generation in Utility System Planning

Final Report 06-11
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Final Report

Prepared for the

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Energy Research and
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EXECUTIVE SUMMARY

This report describes the results from an independent evaluation of New York State's Distributed Generation (DG) Pilot Program (DG Pilot Program). The Pace Law School Energy Project (Pace) and Synapse Energy Economics, Inc. (Synapse) were commissioned by the New York State Energy Research and Development Authority (NYSERDA) to document the results of the three-year pilot program, assess the program's effectiveness in meeting pilot program objectives, and to identify and evaluate alternative approaches for procuring DG as a distribution system resource.

In Opinion No. 01-5, 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. Each distribution utility was ordered to identify distribution systems in need of major reinforcement and to issue a target number of Requests for Proposals (RFPs) in order to elicit competitive responses for DG capacity to be located in these high value areas.

Between 2002 and 2004, the six[1] participating distribution utilities issued a total of twenty-two (22) RFPs encompassing a wide range of system needs and contexts. The level of DG developer participation in the program was generally quite low, with over three-quarters of the RFPs eliciting no bids for DG resources. The highest number of bids submitted in response to any single RFP was four (4). Of the DG bids offered, none were chosen by the distribution utility as the least-cost option. Table ES-1 presents a breakdown of the results. Further detail on the scope and results of the utility solicitations is provided in Section 2.

[1] Consolidated Edison Company of New York; Orange and Rockland Utilities; Central Hudson Gas and Electric; Niagara Mohawk (now National Grid); New York State Gas and Electric; and Rochester Gas and Electric. NYSEG and RGE consummated a merger in the midst of the DG Pilot Program and jointly conducted some activities.

Table ES-1. Summary of Results of DG Pilot Program

Utility	CHGE	NYSEG	RGE	NIMO	CECO	ORU	TOTAL
RFP's Issued	4	2	3	4	5	4	22
Bids Received	5	0	0	7	1	1	14
Bids Accepted	0	0	0	0	0	0	0

In order to assess the factors contributing to these results, the study team conducted a series of interviews with developers (both participants and non-participants), utility distribution system planners, Public Service Commission staff and others. A number of factors were determined to limit the submission of DG bids in the first instance, and for the failure of the DG Pilot Program to elicit any successful projects. These include:

Incongruence between the utility distribution system need and DG "best fit". There were instances where RFP project areas were selected that lacked one or more key attributes for viable DG (e.g., proximity to natural gas supply or other fuel sources; opportunities for low cost interconnection; potential host sites for CHP).

Limited time available for proposal development. Developers identified the short lead-time available to them to package a project as a barrier to participation.

Inability to secure developable site. One of the more significant barriers to participation identified by DG project developers was the difficulty in securing a developable site with the degree of site control and in the time frame required by utilities.

Non-disclosure of the cost of the utility build option. From the vantage point of the developers, a major risk factor was the lack of transparency as to the cost of the wires solution, and thus the value to the utility of the DG alternative. Without this information, developers contended they were handicapped in their ability to determine whether DG might provide a viable alternative, and thus whether the RFP warranted their investment of time and resources.

High transaction costs to participate. Parties acknowledged the high cost of preparing a detailed bid as a barrier to entry.

Economics did not often support project development. Parties generally concurred that it was hard to make the economic case for a DG project on the basis of pilot program revenues alone or in significant part. At best, the DG Pilot Program afforded the developer and site owner a modest supplemental revenue stream to support already economically viable projects.

Short contract period. Utilities offered contract periods of 3-5 years, corresponding with the deferral period of the distribution system improvement. This was generally perceived as unattractive by DG developers.

Risk of incurring significant financial penalties for non-performance. Developers cited both the level of financial surety requirements and the risk of financial penalties for non-performance as major factors influencing their participation in the DG Pilot Program.

Reliability/redundancy requirements. In instituting the DG Pilot Program, the Commission imposed a binding constraint that the integration of the DG resource may not compromise the reliability of the system. There was concern that in implementing this mandate, some utilities held DG to a more exacting standard forcing greater system redundancy and escalating bid costs.

As directed by the Public Service Commission, a number of study objectives guided the implementation and development of the DG Pilot Program. This report analyzed the extent to which these objectives had been achieved.

Whether DG can be a least cost strategy to satisfy distribution system needs. At current state of technological development and cost, the universe of distribution system projects amenable to a DG solution is a relatively small part of the New York utilities' capital expansion programs. However, DG *can* provide a least cost means of satisfying certain distribution system needs *if* favorable conditions exist. Efforts to formally and systematically review potential opportunities for deferring distribution system investment with DG should continue.

Develop case specific information on DG costs, benefits and impacts across a range of conditions. It is clear that the DG Pilot Program fell short of its objective of testing DG in real-world situations. In order to gain this experience, the DG Pilot Program could be reoriented more towards traditional research and demonstration projects, and away from its overriding emphasis on deploying least-cost solutions through a competitive solicitation.

Refine utility in-house capability to evaluate customer-owned DG. In carrying out their responsibilities under the DG Pilot Program, New York's distribution utilities have unquestionably developed a greater capacity to integrate DG in conjunction with their traditional distribution system planning practices. This has taken many forms. It is equally clear, however, that the lack of winning DG bids to emerge from the competitive solicitations translated into a foregone opportunity for utility distribution system planners to test, and perhaps ultimately become more comfortable with, the performance of DG as distribution system assets.

The Project Team developed two sets of recommendations. The first set of recommendations pertains to reforms of the RFP-based approach utilized as the primary procurement methodology in the DG Pilot Program.[2] The second set of recommendations present alternative procurement approaches. These recommendations are supported by an independent evaluation of the DG Pilot Program experience, as well as by a national review of like efforts to integrate DG in transmission and distribution system planning.

Recommendations for Improving the RFP Approach for Procuring DG as a Wires Solution

We would recommend that the Commission Staff convene a working group to continue to explore the lessons learned from the three-year pilot program and evaluate process reforms and alternative program constructs for integrating DG that are potentially more effective at identifying and securing cost-effective resources. At a minimum, the following process reforms should be considered:

[2] The authors express no opinion as to whether the RFP-based approach should be continued, and the recommendations offered herein should not be construed as an endorsement of this approach.

1. To reduce the number of nonproductive RFP processes, the Commission should consider constraining the mandatory use of RFP's to utility service territories with more attractive DG/CHP economics in conjunction with high avoided T&D costs.

2. To manage development risk, the Commission should consider authorizing or requiring the utility to assume a greater role in DG project specification, including the option that the utility deployment of DG be under a turnkey arrangement with the DG project developer. Alternatively, utilities may wish to take an equity position in DG, retaining ownership for at least as long as these assets provide deferral value.

3. To address the perception of utility bias in favor of traditional wires options, for future DG procurement processes, the Commission may wish to experiment with the cooperative management of the bid review process with an independent third party such as NYSERDA.

4. To identify least-cost deferral projects, for future solicitations the Commission may wish to consider expanding eligibility to a broader array of demand- and supply-side resources.

5. To meet reliability requirements without the need for redundant distributed generation, the Commission should explicitly allow contractual commitments to shed load, or through the deployment of other physical assurance alternatives on the customer site.

6. Utilities should be required to provide prospective DG bidders with greater transparency of the value of deferral, such as a "market reference price", that would not compromise the integrity of the bidding process.

7. New York utilities are well positioned to facilitate communication between large customers and third party DG developers and demand response service providers in order to identify more opportunities for such resources to support the grid. Those utilities that have not already adopted this practice should consider doing so.

8. In close cases, utilities should enter into negotiations with project developers submitting proposals for resources at bid prices marginally above the build option; the categorical refusal to enter into negotiations may result in lost opportunities for cost-effective DG deployment.

9. New York's investor owned utilities should explore synergies between their own efforts to relieve distribution constraints and NY ISO's efforts to relieve transmission constraints. It is also worth exploring ways to use existing utility and public benefit programs in New York to mitigate distribution, transmission, and capacity constraints and ways to ensure that DG and other non-wires projects are compensated for all the benefits they provide.

10. The Public Service Commission should clarify its intentions regarding the requisite standard of reliability for DG as a distribution system asset. We recommend that the Commission adopt the following principles:
    - The deployment of DG should not lead to a material degradation of the reliability of the circuit as a whole. DG projects need not meet an availability target of the comparable "wires" solution standing in isolation.
    - Any review of the reliability impacts associated with DG should, to the maximum extent possible, identify and quantify any DG reliability benefits (including but not limited to local voltage or reactive power support and the ability to provide continuous service to downstream customers on radially configured networks).

The analysis of the reliability impacts of DG should, in the first instance, be the responsibility of the distribution utility rather than the DG developer.

Recommendations Related to Alternatives to an RFP Process for Integration of DG in Distribution System Planning

Given the results of the DG Pilot Program, alternative procurement methods and planning approaches warrant further consideration as a means of better meeting the programs' varied objectives:

1. **Localized incentives for DG in constrained areas.** Under this approach, a distribution utility would identify high cost zones of the distribution system through its annual planning exercise and offer a "bounty" to developers installing DG within these targeted zones.

2. **Annual disclosure of utility capital expansion plans to qualified DG developers.** Consideration should be given to a process in which the utility annually discloses to pre-qualified bidders its 5-year capital expansion plans. This would provide DG developers a much better opportunity to step forward with projects already in the works, or give greater guidance on future projects of high value, that may simultaneously resolve the distribution system problem.

3. **Experimentation with DG as a part of the utilities' research and development programs.** We recommend that NYSERDA and the PSC consider limited use of System Benefits Charge funds to support cooperative analysis with New York State distribution utilities of DG costs, benefits and risks as a critical component of the future grid.

4. **Explore the costs and benefits of more widespread use of utility "optioning" of DG resources.** The Con Ed DG Pilot Program revealed the potential benefits of optioning DG, particularly for areas of the distribution network where load growth is uncertain. New York should give greater consideration to optioning of portable DG units as distribution capacity. These DG units could be a quick, cost-effective DG solution to a congested area that is (a) expected to experience a modest capacity shortfall (e.g., less than 2-3 MW) and a low load growth in the

near future and (b) away from densely populated area and (c) not suitable for CHP applications.

1.0 INTRODUCTION

1.1 Purpose of Report

The Pace Law School Energy Project ("Pace") and Synapse Energy Economics ("Synapse") were commissioned by the New York State Energy Research and Development Authority ("NYSERDA") to conduct a comprehensive evaluation of the recently completed three-year Distributed Generation Pilot Program (hereafter "DG Pilot Program") for the integration of DG in utility distribution system planning processes.

Under the DG Pilot Program, the New York Public Service Commission (PSC) directed each of the states' investor owned distribution utilities to issue a specified number of Requests for Proposals ("RFPs") for deferral of planned distribution system projects meeting certain cost thresholds and technical requirements. Year 1 of the Program[3] was largely devoted to "capacity building" activities to enable the utility to, among other things: identify candidate projects potentially amenable to a DG solution, develop the internal capability to evaluate DG on terms comparable to traditional "wires" solutions, pre-qualify potential bidders and so forth. Years 2 and 3 of the program were principally devoted to utility identification of target areas, issuance of RFPs from pre-qualified bidders and the evaluation of submitted bids.

It is fair to say that the New York DG Pilot Program has been closely watched by the industry as a unique and potentially precedent setting opportunity to determine whether distribution system needs can be satisfied on a least cost basis by DG/CHP. Moreover, a great deal of effort was put into the pilot program by utility distribution engineers, DG project developers, regulators and other interested stakeholders.

[3] Note that for some utilities this was 2001, for others it was 2002.

Unfortunately, experience to date with the DG Pilot Program has been disappointing. In the end, the program has yielded no successful DG/CHP bid[4]. Post-program evaluations filed with the PSC by the subject utilities call for the discontinuance or alternatively, a significant overhaul of the program[5]. Interviews conducted by the study team with DG project developers reveal a similar lack of enthusiasm for the current program configuration.

The principal objective of this analysis is to understand why the DG pilot program did not produce any viable DG projects. Are these results attributable to structural problems with the program? Are there inherent economic and performance limitations with available DG/CHP technologies that make them poor candidates for distribution system planning purposes? Do the results reflect a utility bias in favor of a traditional "wires" solution? The lack of a solid empirical foundation and causal understanding may lead to erroneous conclusions about the future viability of DG/CHP as a means of replacing or deferring distribution system investment.

The principle goals of this research report are to:

- develop a comprehensive understanding of how utilities have implemented the DG Pilot Program within their respective service territories, and how these programs have been received by market participants;

- determine how these programs have performed to date;

- identify key factors contributing to program success/failure;

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[4] The DG Pilot Program was designed to fulfill a number of other objectives. These are described in Section 2.

[5] Summary of Findings and Recommendations of Distributed Generation Requests for Proposals by Consolidated Edison Company of New York, July 1, 2005; DG Pilot Program Evaluation (letter from Scott Leuthauser, National Grid, to James Gallagher, Dept. of Public Service, dated June 27, 2005); NYSEG and RGE Pilot Program Assessment, dated July 12, 2005; DG Pilot Program Evaluation Report of Central Hudson Gas and Electric Corporation in Compliance With Order of October 26, 2001 for Distributed Generation Pilot Program, dated June 30, 2005; Summary of Findings and Recommendations of Distributed Generation Requests for Proposals by Orange and Rockland Utilities, June 30, 2005.

- identify opportunities to improve the utility DG planning processes based on an analysis of early program experience and integration of utility best practices from New York and elsewhere; and

- identify alternative DG/CHP procurement approaches and determine whether these approaches can elicit projects that are more responsive to distribution utility system needs.

1.2 Study Approach/Methodology

In carrying out this analysis, the study team considered a wide range of inputs:

- The study team solicited input from program participants through a detailed questionnaire. (Appendix A). Separate questionnaires were developed for utility distribution personnel and for DG developers. These documents were intended to elicit information on both quantitative measures of success (e.g., developer awareness; number of bidders; DG/CHP project awards) and process issues (e.g., bidder pre-qualification requirements; bid specification; utility evaluation criteria).

- Between February 2005 and June 2005, the study team conducted in-depth interviews. Participants included responsible staff for most of the participating utilities6, DG developers (including those who responded to RFPs and those who did not), and Public Service Commission staff (Appendix B).

- The study considered the post-program evaluations submitted on or about July 1, 2005 by each of the participating utilities. These studies served a useful cross-check of program parameters and results, and provided each utility's perspective on and lessons learned from the program.

[6] Consolidated Edison and Orange and Rockland Utilities declined to be interviewed but reviewed and commented on information prepared by the project team for purposes of this report.

- The study team initially considered a dozen examples from around the country of processes for formal consideration and procurement of DG. From this universe of programs, the study team selected four such programs for detailed review and analysis.

1.3 Organization of Report

This report is organized in six sections. Immediately following this introduction, Section 2 describes the study parameters and objectives of the New York DG Pilot Program. Further, Section 2 documents and synthesizes the results of the three-year implementation effort. Section 3 evaluates the causes of these results, identifying a number of program design limitations. Additionally, Section 3 evaluates the success of the New York DG Pilot Program in achieving its stated objectives. Section 4 then surveys and describes other formal programs outside of New York State to integrate DG in transmission and distribution system planning. (A more detailed program description of four such programs is provided in the appendix to this report.) Finally, the report concludes in Section 6 with a series of options for improving future RFP processes, or for implementing alternative mechanisms to secure DG resources as distribution system assets.

2.0 NY DG PILOT PROGRAM

As part of an ongoing investigation into the costs and benefits of distributed generation (DG)[7], the New York Public Service Commission initiated a three-year pilot program for the objective and timely consideration of DG as a resource in the distribution system planning processes of electric utilities (DG Pilot Program).

Under the three-year program, initiated in 2001, utilities were required to incorporate consideration of DG as part of their traditional annual distribution system planning processes. To accomplish this, utilities were expected to issue Requests For Proposals (RFPs) seeking bids for DG/CHP projects that meet specified monetary thresholds and technical requirements. As many as 22 RFPs were expected to be issued statewide over the three year pilot phase of this program.

Moreover, the pilot program proceeded from a recognition that "utility distribution system planners, DG/CHP developers and other stakeholders have limited practical experience in evaluating the impacts of customer-owned DG/CHP capacity on distribution system costs and performance and the effectiveness of such DG/CHP capacity as a substitute for distribution facilities".[8] In conjunction with the RFP process, it was envisioned that utilities would enhance their in-house capability to evaluate distributed generation as a cost-effective and reliable alternative to major "wires"-related investment, and to integrate this capability within their respective long-range (i.e., five year) system planning processes.

[7] Throughout this proposal, the Project Team uses the term "distributed generation" to apply primarily, but not exclusively, to systems configured for combined heat and power (CHP).

[8] *See* of Opinion and Order Approving Pilot Program For Use Of Distributed Generation In The Utility Distribution System Planning Process (hereinafter referred to as Order), at Appendix B (Report of the Designated-Parties Committee Regarding the Integration of Distributed Generation in Utility Planning Processes) (hereinafter referred to as Designated Parties Report), at 3.

2.1 Program Parameters

2.1.1 Objectives of the DG Pilot Program

As directed by the NYPSC, a number of study objectives guided the development and implementation of the DG Pilot Program.[9] Specifically, these included:

- to determine whether distribution system needs can be satisfied on a least cost basis by creative and competitive alternative means;
- to develop case-specific information on DG/CHP costs, benefits, and impacts across a range of distribution system conditions;
- to refine methods for evaluating customer-owned DG/CHP proposals against traditional distribution system improvement projects; and
- to determine whether a competitive solicitation process using requests for proposals ("RFPs") is a viable and optimal means of eliciting a market response to the utility's distribution system needs.

2.1.2 Key Program Elements

Much of the basic structure of the DG Pilot Program was arrived at through collaboration of utility and non-utility parties, culminating in the issuance of a "Report of the Designated Parties Committee Regarding the Integration of Distributed Generation in Utility Planning Processes."[10] The Commission endorsed the major program elements articulated in the report, and resolved outstanding issues where the participants could not reach consensus.

[9] Order at 8-9.
[10] Submitted December 21, 2000 and revised on January 24, 2001.

Criteria for Issuance of RFPs

The Commission Order established a number of criteria for utility consideration of DG proposals:

- RFPs would be issued only for system needs that require at least 18 months to satisfy from the date they are recognized.[11]

- Satisfaction of the system need by DG must be technically feasible.[12]

- DG would be considered as a means of satisfying load growth or the need for expansion or construction of a unit substation or area substation, or at the utilities' discretion, for projects on a radial distribution feeder on which load may be temporarily islanded.[13]

- DG would be considered only for projects above specified threshold costs:
    - $750,000 for Con Edison and Niagara Mohawk
    - $500,000 for NYSEG
    - $250,000 for Central Hudson, RG&E and O&R (if qualified projects are not identified at the $500,000 level).[14]

These criteria were designed to serve the mutual interests of DG developers and utilities. The criteria narrow the universe of all utility distribution system investments included in its five-year capital improvement plant to those that, from a practical, technical, and economic perspective would appear to be most amenable to a DG solution. They also are intended to give the DG developer community confidence that the distribution system

[11] Report at 7.
[12] Id.
[13] Id. at 22.
[14] Id. at 22-3.

need selected for competitive bidding would have a high likelihood of moving forward. At the same time, the utility was left with the flexibility to withdraw or modify RFPs should their needs change, and with time to proceed should the RFP process not reveal any competitive DG solution.

Number of RFPs

The Order obligated each utility to issue a minimum of 2 RFPs annually for the second and third years of the program, with the exception of Con Edison, which was directed to issue 4 RFPs in the third year.[15]

Utility Ownership of DG

The Order expressly permitted utilities to satisfy up to half of their RFP requirement through utility-owned DG.[16]

Bidder Pre-Qualification

In order to participate in the utility RFP processes, developers were required to demonstrate the requisite financial and technical capability to implement DG projects by completing a detailed questionnaire. [17] The presumption was in favor of pre-qualification. Once pre-qualified, the DG bidder would receive utility RFPs pursuant to the DG Pilot Program, and would be entitled to receive advance notice of longer-term distribution system needs that may be the subject of future RFPs.

[15] Id.at Appendix 3.
[16] Id. at 10.
[17] Id., at 11 and Appendix B.

Basis for Comparison

The utility's economic evaluation generally consists of a present-value comparison of the developer's DG bid to the cost of the utility distribution system project. The utility's avoided cost sets an upper bound on the compensation available to prospective bidders.[18]

Treatment of Lost Utility Revenues

One of the few disputed issues with respect to the DG Pilot Program was the appropriateness of utility consideration of lost revenues in bid review. Utilities and large customers argued that the potential for lost revenues should be considered insofar as the utilities' costs would ultimately be borne by other customers. DG proponents on the other hand, argued that imputation of lost revenues biases the comparison against DG.
The Commission ultimately concluded that:

> [l]ost revenues are a proper factor to consider in a bidding process, as they would create additional cost burdens on other ratepayers…[W]e expect the RFP pilot project to involve far fewer, if any, lost revenues. In developing methods for comparing the economics and reliability aspects of distribution upgrades with DG alternatives, nonetheless, imputed lost revenue is a relevant factor.[19]

As discussed in Section 3, despite this authorization, for purposes of the DG Pilot Program distribution utilities generally did not consider lost revenues in bid evaluation, nor did it appear to be a determinant in deciding the outcome of RFPs.

Required Level of Reliability

The Commission's Order makes clear that the DG Pilot Program should not result in any degradation of reliability: "The DG proposal must provide for the same level of system reliability and assured quality of service to the utility's customers as the alternative

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[18] Id. at 12.
[19] Id. at 27.

distribution system upgrade." The distribution utility was authorized to specify the required level of redundancy in its RFP.[20]

Treatment of Environmental Differences

Disagreement surfaced in working group discussion on the proper treatment of environmental impacts, specifically air emissions, associated with DG projects. On the one hand, utilities and large consumers generally took the view that the utility should not be obliged to consider environmental characteristics among bid resources other than to verify that the DG project has received all applicable environmental permits. Environmentalists, on the other hand, urged the Commission to establish pre-qualification requirements designed to limit participation of the highest emitting DG technologies. The Commission ultimately rejected the introduction of environmental impacts as an evaluation factor, concluding that it would "unduly complicate the utility distribution planning process."[21] In lieu of a substantive requirement, the Commission directed utilities to collect environmental information and characteristics of DG bids for consideration in the utility's post-program evaluation.[22]

2.2 PROGRAM IMPLEMENTATION

2.2.1 Central Hudson Gas and Electric

Central Hudson issued a total of 4 RFPs over a two-year period beginning in 2003 for DG alternatives. These bids generally sought to reinforce distribution and transmission system needs (transmission, sub-transmission, and substation) expected to reach or exceed capacity limits within the 5 year forecast horizon.

The company identified projects for competitive solicitation based on the following factors:

[20] Id. at 11.
[21] Order at 28.
[22] Order at 28.

- DG is technically feasible;

- High capital cost associated with traditional wires project;

- Relatively low peak load growth, uncertain load growth or poor load factor in area needing reinforcement;

- Traditional wires project subject to construction risks; and

- DG capable of enhancing reliability to area of radial system.

Three of the four projects targeted summer peaking areas experiencing relatively high peak load growth. The fourth project was in proximity to a ski area experiencing relatively low growth in its winter peak load. Although Central Hudson would have preferred to bid projects for areas with relatively low load growth that have reached their peak loading in order to maximize DG's deferral value, these were <u>the only</u> major capital projects identified by the company in its planning process as meeting the threshold criteria established for the DG Pilot Program.[23] All four projects bid were significantly in excess of the minimum value (i.e. greater than $250,000) identified in the DG Pilot Order.

- East Fishkill (2003) – an area experiencing high summer peak load growth, with an expectation of 155 hours over contingency capacity limits by Year 5 of the forecast. Central Hudson sought bids for 22-MVA of capacity reinforcement over 5 years as reinforcement for a 115-kv transmission loop.
- Hunter/Tannersville Area (2003) – an area experiencing low growth in winter peaks but nonetheless expected to experience 164 hours over contingency capacity limits by Year 5 of the forecast. Central Hudson sought bids for 5.2 MVA of capacity reinforcement for a sub-transmission loop.

[23] Personal communication with Sephir Hamilton, CHGE on February 24, 2005.

- Wappinger Falls (2004) – a summer peaking area experiencing significant load growth. Central Hudson sought bids to satisfy 11.2 MVA of capacity reinforcement for a 69-kv transmission loop and substation by Year 5 of the planning horizon.
- Maybrook Area (2004) – a high load growth, summer peaking area necessitating reinforcement and/or load relief for the 69-kv transmission loop. The company forecasted 120 hours over contingency capacity limits by Year 5.

Table 2.1 Program Results – Central Hudson Gas and Electric

	Central Hudson	**Central Hudson**
	RFP 1 and 2	**RFP 3 and 4**
Date issued	1/17/03	1/16/04
Date of bidders conference, if any, and number of attendees	2/4/03	2/3/04
Bid submission date	3/3/03	4/1/04
Number of bids received	RFP 1- 0 bids RFP 2 - 0 bids	RFP 3 – 2 bids RFP 4 – 3 bids
Number of bidder which met pre-qualification requirements	6	23
Whether any of the bids were sufficiently meritorious to warrant further discussions or negotiations with developer	No	No
Did the company "bid" its own DG project, or consider a partnership with a DG project developer?	No	No
Area of the electrical system in which DG projects must be installed	RFP 1- East Fishkill RFP 2 – Hunter/Tannersville	RFP 3 – Wappingers Falls RFP 4- Maybrook
Nature and expected cost of the proposed distribution system upgrade	RFP 1 - 115-kv transmission loop in need of reinforcement/load relief RFP 2 – Sub-trans. loop in need of reinforcement/load relief	RFP 3 & 4 – 69 kv transmission loops each in need of reinforcement/load relief Each project > $1 million in value
In-service date required for the DG system	May '04	May '05
Special technical requirements, if any	RFP 1- 22 MVA over 5 years RFP 2 – 5.2 MVA over 5 years	RFP 3 – 11.2 MVA over 5 years RFP 4 - 9.2 MVA over 5 years
Specified financial security or performance guarantees	N/A	N/A
Other utility-system circumstances bearing on the preparation of the DG proposals		
Factor(s) which gave rise to the DG system need (e.g., load growth, voltage conditions)	RFP 1 – Steady Load Growth RFP 2 – High Load Growth	High Load Growth
Whether the company has moved forward with the "wires" project	Yes	Yes

Results

Six bidders were pre-qualified for the first round of bidding. None submitted bids. The response in the second round was somewhat more robust, with five proposals received from three of the 23 pre-qualified bidders. Central Hudson attributes this increased interest in the second round to several factors, including:

- Outreach to bidders – Central Hudson enlisted NYSERDA's support in publicizing the program to the DG developer community.
- Outreach to customers – Working through its large accounts customer representatives, Central Hudson notified potential host sites of the program and contact information for pre-qualified bidders.
- Eased program requirements – Central Hudson instituted several reforms to facilitate greater participation ranging from relaxed site control requirements to extension of the bid process to enable bidders to put bid packages together.

Two bids involved customer-sited CHP; two involved turnkey projects sited at a Central Hudson substation. The fifth bid consisted of a price quote for a gas turbine generator.

None of the bid resources were accepted, all having come in at costs on a present value basis above the utility's default option. Cost premiums for the DG solution ranged from 7% to 60% higher,[24] excluding interconnection costs and lost revenues. Because the bids were rejected on price grounds, Central Hudson did not further evaluate the bids on other non-price factors. Likewise, Central Hudson did not engage in further discussions with bidders to attempt to negotiate a lower bid price on the grounds that bidders were on notice that the bid was to be their best and final offer and that such practice ran counter to company policy.

Central Hudson's program manager expressed some surprise that the prices quoted were not more cost competitive and, in his view, were higher than if the Company had asked

[24] Customer-sited proposals were at the high end of this range. Email communication from S. Hamilton, dated March 16, 2006.

for quotes for a project that the Company developed specifications for in the first instance. He attributed this to the fact that, under the DG Pilot Program project specification was left to bidders, thus leaving the bidder to assume all of the development risk.[25]

The results for Central Hudson are summarized in Table 2.1.

2.2.2 New York State Electric and Gas and Rochester Gas and Electric

NYSEG and RGE jointly implemented the DG Pilot Program, having consummated their corporate merger by 2002. Following a screening of potential distribution system upgrades (Year 1):

- NYSEG issued one RFP for DG alternatives in each of the subsequent two years of the pilot program. This was only half the total number of projects targeted for DG consideration via an RFP, however, the Company determined that only a limited number of projects met the technical and economic criteria for project selection. See Section 2. The Company attributed this dearth of distribution system capital improvement projects to the slow rate of projected load growth in its service territory.

- RGE issued one RFP in Year 1 and two RFPs in Year 2. Like NYSEG, limited projected load growth in the RGE service territory translated into a limited number of distribution system construction projects.

Projects focused on deferring distribution system level investment. In all instances the primary driver was area load growth. In one instance, a secondary consideration was voltage stability.

Projects to deferred ranged in value from $676,000 to $2,386,000 – all well in excess of the dollar thresholds established by the Commission. Project size ranged from 2-3 MWs,

[25] Personal communication with Sephir Hamilton, CHGE on February 24, 2005.

based on NYSEG/RGE's professional judgment that this size range was most amenable to a DG solution and most likely to elicit interest from the DG developer community.

NYSEG/RGE initially offered contracts of three years. This was extended to 5 year terms for the second bid cycle.

Payments were to be based on availability during peak load periods**.** In the second cycle, NYSEG notified bidders that it would additionally entertain energy and capacity contracts.

The utility opted against participating in the RFP by submitting its own DG resource.

<u>Results</u>

A total of 15 developers were pre-qualified by NYSEG/RGE for the first bid round. (Bidders pre-qualified by one distribution company were recognized as eligible by the sister company). No bids were submitted in response to the first cycle of RFPs.

Following the first bid round, NYSEG/RGE introduced several program changes in order to elicit a greater response from DG developers. Among the steps taken included incorporating the contractual reforms noted above, granting of additional time for developers to put together bid packages, and the offering of company property for DG placement within the substation yard. Notwithstanding these changes, the combined companies again received no bids.

The company is going forward with the distribution system upgrades in the designated locations in all but one case. As of the date of this report, projected load growth had not materialized and the project had been deferred.

The results of the NYSEG and RGE processes are presented in Table 2.2.

Table 2.2 Program Results – New York State Electric and Gas and Rochester Gas and Electric

	NYSEG RFP1	NYSEG RFP2	RGE RFP1	RGE RFP2	RGE RFP3
Date issued	1/8/03	12/5/03	2/14/03	11/21/03	11/21/03
Date of bidders conference, if any, and number of attendees	1/22/03 3 Attendees	1/7/04 1 Attendee	2/28/03 4 Attendees	12/16/03 5 Attendees	12/16/03 5 Attendees
Bid submission date	2/14/03	2/28/04	3/26/03	3/1/04	3/1/04
Number of bids received	0	0	0	0	0
Number of bids which met pre-qualification requirements	0	0	0	0	0
Whether any of the bids were sufficiently meritorious to warrant further discussions or negotiations with developer	N/A	N/A	N/A	N/A	N/A
Did the company "bid" its own DG project, or consider a partnership with a DG project developer?	No	No	No	No	No
Area of the electrical system in which DG projects must be installed	Distribution	Distribution	Distribution	Distribution	Distribution
Nature and expected cost of the proposed distribution system upgrade	$831,000	$707,000	$1,387,000	$2,386,000	$676,000
In-service date required for the DG system	5/1/04	5/1/05	5/15/04	6/1/05	6/1/05
Special technical requirements, if any	2MW	2MW	3MW	3MW	2MW
Specified financial security or performance guarantees	Security 10%	Security 10%	Security 10%	Security 10%	Security 10%
Other utility-system circumstances bearing on the preparation of the DG proposals	Reliability	Reliability	Reliability	Reliability	Reliability
Factor(s) which gave rise to the DG system need (e.g., load growth, voltage conditions)	Load Growth	Load Growth	Load Growth	Load Growth, Voltage Conditions	Load Growth
Whether the company has moved forward with the "wires" project	Not at this time	Yes	Alternative project constructed	Yes	Yes

2.2.3 Niagara Mohawk Power [National Grid]

Niagara Mohawk selected a total of four projects to competitively bid for the potential deployment of DG in lieu of distribution system upgrades. These projects were chosen among the approximately 30 projects identified in the company's annual five-year transmission and distribution capacity plan based, in significant part, on the following considerations:

- "Wires" projects with the highest cost per kW
- Fuel availability
- Proximity to a cogeneration host site
- Lead time
- Ease of interconnection

The four selected projects and objectives were identified by the Company as follows:

- Colonie and Hamburg Area Projects – the Company sought DG projects providing reinforcement incrementally over a 5 year period in order to defer the construction of a substation, transmission line tap and distribution work in the vicinity of the Towns of Colonie and Hamburg, respectively. In each case, the RFP specified the distribution feeders where the DG would be located and which were capable of accommodating some level of DG with minimal interconnection costs.

- Clymer Area Project – called for DG to provide winter-time reinforcement to the 34.5kV system voltage at the end of a distribution line in the vicinity of a major ski area. The Company envisioned that this RFP would elicit proposals for a seasonal DG system that could be relocated to serve summer peaking needs elsewhere in the state.

- Amherst Project – to defer construction of a substation proximate to large customer in the Buffalo area.

The Company required DG to be available for peak shaving operation during specified times of the year and offered to consider in return various pricing arrangements consisting of: 1) readiness payments; 2) operating payments; and 3) termination fees.

A threshold condition for acceptance of bid resources was a demonstration of DG availability comparable to the historical area availability of the distribution network over the past 5 years. This was a major point of contention with developers insofar as it necessitated a certain level of system redundancy.

The worst-case "cost to compare" used for the Year 1 projects was $3.5 million (excluding land), although the actual cost of each of the projects was closer to $2.8 million. No figures are available on the cost of the Year 2 infrastructure projects.

Results

A total of twenty-one developers pre-qualified for the NIMO process for the first round of bids. For the second round, this number increased to twenty-five.

The company received a total of three bids from two developers for the Hamburg Project. One developer submitted an alternative project utilizing a cleaner technology than proposed for the base bid. The lowest bids received were approximately $10 million for a five year agreement – several times higher than the utility option.

The company received a total of four bids for the Colonie Project. Bids submitted for these proposed projects were also roughly four times higher than the utility build option.

Based on Year One results, the company made various changes to its RFP approach. Most significantly, NIMO introduced greater flexibility in specifying its target area for DG need. Rather than specify distinct feeders as in the first round of bidding, the company identified a geographically targeted zone and allowed DG to locate anywhere within that zone. Additionally, the company gave developers a description of the utility "bogey" project, although it continued to resist developer requests for project costs.

No bids were received in response to either the Clymer or Amherst Project. Both the utility and project developers pointed to the results of the first round of bidding as having dampened developer interest.

These results are reported in Table 2.3.

Table 2.3 Program Results – Niagara Mohawk Power Corporation

	NIMO RFP 1 and 2	NIMO RFP 3 and 4
Date issued	7/1/02	9/1/04
Date of bidders conference, if any, and number of attendees	7/15/02 21 Attendees	10/6/04 11 Attendees
Bid submission date	9/3/02	1/4/05
Number of bids received	RFP 1- 3 bids RFP 2 - 4 bids	RFP 3 – 0 bids RFP 4 – 0 bids
Number of bidder which met pre-qualification requirements	21	25
Whether any of the bids were sufficiently meritorious to warrant further discussions or negotiations with developer	No	No
Did the company "bid" its own DG project, or consider a partnership with a DG project developer?	No	No
Area of the electrical system in which DG projects must be installed	RFP 1- Hamburg (Specific distribution feeders) RFP 2 – Colonie (Specific Distribution feeders)	RFP 3 – Clymer (Sub-transmission) RFP 4- Amherst (Area of 34.5 kV distribution, including substation)
Nature and expected cost of the proposed distribution system upgrade	Defer installation of substation, transmission line tap and dist. work - $3.5 million (est.)	RFP 3 – winter-time reinforcement to 34.5 kv voltage RFP 4 – Defer installation of substation, transmission line tap and dist. work
In-service date required for the DG system	In increments beginning 5/1/04	2-1/2 years from bid date
Special technical requirements, if any	RFP 1- 20 MVA by 2008 RFP 2 – 26 MVA by 2009	RFP 3 – N/A RFP 4 –N/A
Specified financial security or performance guarantees	No; damages and other remedies for non-performance	No; damages and other remedies for non-performance
Other utility-system circumstances bearing on the preparation of the DG proposals	Reliability	Reliability
Factor(s) which gave rise to the DG system need (e.g., load growth, voltage conditions)	Load Growth	Load Growth; voltage
Whether the company has moved forward with the "wires" project	Yes	In progress

2.2.4 Consolidated Edison

Consolidated Edison issued RFPs for DG projects in two Distribution Planning Areas (DPAs) in the first cycle (2003 RFP) and four DPAs in the second cycle (2004 RFP). To arrive at these high value RFP projects from among the full gamut of T&D infrastructure projects included in Con Ed's five-year capital plan, the company developed and utilized an area selection tool. This screening tool helped the company rank capital projects meeting technical thresholds (i.e., more than 18-month lead time; DG capable of solving the need which gives rise to the project) on the basis of the value per kW of installed DG.

Additionally, Con Ed developed a "reliability tool" designed to calculate the level of redundancy that the company required of bid resources to approach the level of reliability associated with the T&D solution. Con Ed's methodology was a source of some controversy. See discussion at Section 3.1.3.8, *infra.*.

The 2003 Con Ed RFP generally sought DG resources for the 3-year period beginning in 2004. The 2004 Con Ed RFP generally sought resources commencing in 2007 and available for up to 3 years thereafter. Con Ed's solicitation also generally identified peaking capability needs beyond the 3-year horizon of the contract term for informational purposes, however the company did not entertain longer contract terms in light of forecasting uncertainty. The six selected DPAs included:

- Flushing Area (Queens) – DG was sought to allow deferral of the replacement and upgrade of four transformers at an area distribution system substation. Con Ed selected this project because it believed that a modest amount of DG could defer the transformer upgrade. Con Ed was seeking from 8-11 MW of peaking capacity over three years.

- Cooper Square Area (Manhattan) – DG was sought to enable the deferral of replacement and upgrade of underground circuits. The company believed this project was amenable to a DG solution given the modest amount of DG required to defer the upgrade (1-7 MW over 3 years) and the slow load growth in the area.

- Westchester Planning Area – Con Ed pursued from 2-3 MW of peaking DG to defer an additional transformer and supply feeder at a Westchester area substation. Con Ed believed this was a good candidate for testing of DG given the slow load growth in this largely residential area, along with the amount of DG needed for multi-year deferral.

- Brooklyn Planning Area – The Company's RFP sought DG to provide peak capability of 3-11 MW over 3 years in order to defer substation work (additional transformer and supply feeder) in a mixed residential/commercial area of Brooklyn.

- Staten Island Planning Areas – Con Ed invited proposals for DG to defer the installation of an additional transformer at a Staten Island substation as well as the deferral of load transfer capability between two Staten Island substations serving predominantly residential loads. Peaking capability needs ranged from 2-4 MW and from 0-1 MW, respectively, for the two planning areas over the 3-year contract term.

Bids were to be priced on a $ per MW-year basis. Bidders were not precluded from participating in other markets maintained by the New York Independent System Operator (e.g., UCAP) so long as this participation would not interfere with the bidder's contractual obligations to Con Edison for peak capability.

One overarching issue identified by the company with respect to half the proposed projects was that substation breakers were at or near their maximum duty. In some instances, given the lack of available lead-time, upgrading of breaker duty was not a feasible option and any DG project could not contribute to fault current. In other instances where upgrades were conceivable, any costs associated with the breaker upgrades necessitated by DG would nevertheless be netted against any potential cost savings.

In the initial cycle, Con Ed required bidders to provide a Letter of Credit of $100/kW of capability per year or the proposal would be disqualified. For the second round of bidding, the performance security was to be determined on a case-by-case basis.

Results

Results for Consolidated Edison are summarized in Table 2.4.

For the first RFP cycle, Con Ed pre-qualified a total of 9 bidders. For the second cycle, this number reached 16 developers.

The company received one bid for the first RFP cycle, and no bids for the second round. The sole bid was rejected on the grounds that it was not cost competitive with the traditional solution. It is not known how much more expensive the DG option was than the distribution system improvement.

One especially noteworthy aspect of the Consolidated Edison DG Pilot program was the company's active consideration of DG as a utility distribution system asset. Con Ed reports that it considered deployment of DG to defer a significant upgrade of its Glendale substation. The company undertook certain "optioning" actions that put it in the position of quickly deploying DG if load conditions required, including reserving mobile DG generators from an equipment vendor and installing interconnection equipment. The optioning cost was approximately $528,000. Since the units were not required, the company avoided the full cost (including DG rental costs) of slightly over $2 million. More significantly, the DG option allowed the company to delay major expenditures on the substation upgrade, resulting in revenue requirement savings of $4.44 million.

Table 2.4 Program Results – Consolidated Edison

	DPA 1	DPA 2	DPA 3	DPA 4	DPA 5A	DPA 5B
Date issued	6/17/02	6/17/02	7/15/03	7/15/03	7/15/03	7/15/03
Date of bidders conference, if any, and number of attendees	6/28/02	6/28/02	7/28/03	7/28/03	7/28/03	7/28/03
Bid submission date	8/15/02	8/15/02	10/31/03	10/31/03	10/31/03	10/31/03
Number of bids received	1	0	0	0	0	0
Number of bidders which met pre-qualification requirements	8	8	17	17	17	17
Whether any of the bids were sufficiently meritorious to warrant further discussions or negotiations with developer	No	N/A	N/A	N/A	N/A	N/A
Did the company "bid" its own DG project, or consider a partnership with a DG project developer?	No	No	No	No	No	No
Area of the electrical system in which DG projects must be installed	Flushing (Queens)	Cooper Sq. (Manhattan)	Westchester	Brooklyn	Staten Island	Staten Island
Nature and/or expected cost of the proposed distribution system upgrade	Substation – transformer upgrades & feeders	Network load transfer – upgrade/ replace underground circuits	Substation – transformer upgrades	Substation – transformer upgrade	Substation – transformer upgrade	Load transfer
In-service date required for the DG system	5/1/04	5/1/04	5/1/07	5/1/07	5/1/07	5/1/07
Special technical requirements, if any	8-11MW peaking capability (3 yr projections)	1-7 MW peaking capability (3 yr projections)	2-3 MW peaking capability (3 yr projections)	3-11 MW peaking capability (3 yr projections)	2-4 MW peaking capability (3 yr projections)	0-1 MW peaking capability (3 yr projections)
Specified financial security or performance guarantees	$100/kW	$100/kW	Security TBD	Security TBD	Security TBD	Security TBD
Other utility-system circumstances bearing on the preparation of the DG proposals	Short circuit contribution	Short circuit contribution		Short circuit contribution		
Factor(s) which give rise to the need for DG system	Load Growth	Load Growth	Load Growth	Load Growth	Load Growth	Load Growth
Whether the company has moved forward with the "wires" project	Not known	Not known	Not known	Not known	Not known	Not known

2.2.5 Orange and Rockland Utilities

ORU generally followed the methodology employed by Consolidated Edison in identifying RFP locations and in evaluating bids. ORU issued RFPs for DG projects in two Distribution Planning Areas (DPAs) in the first cycle (2003 RFP) and two DPAs in the second cycle (2004 RFP). These included the following:

- East Walkill Distribution Planning Area - ORU sought 20 MW of DG peaking capability (ramping up to 29 MW by the year three of the contract period). Cost-effective DG resources would defer the planned upgrade of the East Walkill Transmission loop. Bid resources would have to be available during the peaking period commencing May 1 and ending September 30 and be available for dispatch upon 30 minutes notice within that window. ORU indicated that it would accept proposals consisting of an aggregation of multiple DG units, and would provide potential bidders with a list of existing generators upon request. For bids consisting of multiple, currently uninstalled units, bidders were restricted to propose identical units in terms of manufacturer, model and output levels.
- Middletown -Walkill Distribution Planning Area – ORU sought 18 MW of DG peaking capability (growing to 19.5 MW by year 3) in order to defer the installation of a second 69 – 13.2 kv transformer in a distribution substation. Bid specifications were otherwise quite similar to those developed for the East Walkill DPA, described immediately above.
- Lumberland Distribution Planning Area – ORU sought approximately 800kW of DG in order to defer the upgrade of area lines to 34.5 kV and the relocation of step transformers to enhance backup capability. One limitation noted by ORU was the lack of transmission gas mains located within the DPA.
- Clarkstown Distribution Planning Area – ORU sought DG bids with an eye towards cost-effectively deferring the addition of a new 69-13.2kV substation in a predominantly mixed residential/small commercial part of the company's service territory. A significant amount of peaking capacity

would have been needed to defer the Snake Hill Road Substation Project – from 23.5 MW in 2005, rampinig up to a projected 32.7 MW in 2015. This size requirement, coupled with the need for the project to be centrally located on the distributions system where the substation would be located, had certain implications for the configuration of the required DG project. As noted in the ORU RFP, "due to the relatively large amounts of Peaking Capability needed and the limit on the size of the DG that can connect to any one circuit (7MW), DG will have to be installed on most of the area's distribution cirucuits and located in multiple sites throughout the area.

Table 2.5 Program Results – Orange and Rockland

ORU	**DPA 1**	**DPA 2**	**DPA 3**	**DPA 4**
Date issued	June 17, 2002	June 17, 2002	June 3, 2005	June 3, 2003
Date of bidders conference, if any, and number of attendees	June 27, 2002 4 companies	June 27, 2002 4 companies	June 13, 2003 12 companies	June 13, 2003 12 companies
Bid submission date	August 1, 2002	August 1, 2002	August 29, 2003	August 29, 2003
Number of bids received	0	0	1	0
Number of bidder which met pre-qualification requirements	4	4	14	14
Whether any of the bids were sufficiently meritorious to warrant further discussions or negotiations with developer	N/A	N/A	No	N/A
Did the company "bid" its own DG project, or consider a partnership with a DG project developer?	No	No	No	No
Area of the electrical system in which DG projects must be installed	Distribution or Transmission	Distribution	Distribution	Distribution
Nature and expected cost of the proposed distribution system upgrade	Transmission loop upgrade	Substation – transformer upgrade	New substation	Distribution circuit upgrade
In-service date required for the DG system	May 1, 2004	May 1, 2004	May 1, 2005	May 1, 2005
Special technical requirements, if any	No	No	No	No
Specified financial security or performance guarantees	Yes	Yes	Yes	Yes
Other utility-system circumstances bearing on the preparation of the DG proposals	No	No	No	No
Factor(s) which gave rise to the DG system need (e.g., load growth, voltage conditions)	Load Growth	Load Growth	Load Growth	Load Growth
Whether the company has moved forward with the "wires" project	Yes	Yes	Yes	Yes

3.0 CRITICAL REVIEW OF THE NEW YORK DG PILOT PROGRAM

The following discussion highlights the many factors contributing to the "bottom line" result that the DG Pilot Program did not produce any successful DG projects capable of deferring the traditional wires solution at lower cost. One way to review this outcome is to consider the various stages of the process - from RFP project selection to contract negotiation – and to isolate the factors that limited bidder interest and participation, or which eroded the competitiveness of submitted bids. This can be envisioned as a succession of screens for narrowing the field of potentially cost-effective deferment projects:

ACTIVE NY DG DEVELOPERS

↓

DEVELOPERS SEEKING TO PREQUALIFY FOR PILOT PROGRAM

↓

PREQUALIFIED BIDDERS SUBMITTING PROPOSALS

↓

PROPOSALS MEETING ECONOMIC CRITERIA

↓

CONTRACT NEGOTIATION AND EXECUTION

↓

IMPLEMENTATION OF DG OPTION

Program experience under each of these successive stages is evaluated in Section 3.1, immediately below. This discussion lays a foundation for the process recommendations offered in Chapter 5 for future integration of DG in distribution system planning. Section 3.2 then explores the extent to which, notwithstanding the bottom line result, the DG Pilot Program may have achieved subsidiary program objectives. This discussion, too, forms a basis for recommendations for better meeting these objectives in future initiatives.

3.1 A Process Review of the DG Pilot Program

3.1.1 Pre-Qualification Process

Pre-qualification procedures were instituted to assure that developers participating in the bidding process had the financial and technical wherewithal to design, engineer and implement responsive DG solutions. Utilities – and indeed participating developers – saw this as an important step in ensuring that bidders were "real players, and that bids would not be submitted from businesses run from the back of someone's car."[26] Developers also generally supported the types of information collected, and while the detailed nature of the questionnaire did entail considerable time and expense, they did not regard this as a major impediment to participation. Further, it appears that the utilities set a relatively low bar to participation; we are not aware of any developer being denied participation in the pilot program on the basis of their prequalification application. In sum, the pre-qualification requirements do not seem to have been a significant deterrent.

That said, there is room for improvement of prequalification procedures in a future market-driven DG program. For one, the process could be made more transparent and efficient if the criteria by which prospective developers are to be screened are communicated to the developer community.

[26] Personal communication with Bert Spaeth, Siemens Building Technologies, May 18, 2005.

More generally, the costs of the pre-qualification process should be compared to the expected benefits. For this pilot experience, pre-qualification provided assurance to the utility that its reviewers would not be overwhelmed with a flood of non-meritorious proposals, while at the same time providing assurance to *bona fide* developers that they would not be denied an opportunity to compete. In the event, it appears that developers "self-screened" in light of the considerable time and risk associated with the RFP process itself.

3.1.2 Projects Selected for Bid

3.1.2.1 Utilities responding to regulatory imperative

As noted, in order to gain sufficient experience with procurement and deployment of DG alternatives, the Commission adopted a target number of RFP projects for each utility. In all but one instance, distribution utilities participating in the DG Pilot Program were able to identify their assigned number of RFP projects. Although these 22 projects met or exceeded the minimum economic value and technical criteria, it is clear in retrospect that the prerequisites for an optimal DG solution (e.g., feasibility of interconnection, slow load growth for increased deferral value) were lacking in many instances. For some utilities, the RFP projects represented the only major system upgrades included in the utility capital expansion plan, precluding a screening and ranking for appropriateness from among a plethora of their projected distribution system needs.

3.1.2.2 Incongruence between utility system need and DG "best fit"

The utility system planner's primary responsibility is to identify projected weaknesses in the distribution system that will need to be addressed to maintain reliable service. The experience of the DG Pilot Program reveals that there is not always a close congruence between areas of the distribution system infrastructure in need of upgrade and areas of the utility service territory that are prime targets from a DG development perspective. In most instances, the distribution utilities saw the task of identifying prime targets for DG as outside their province. This led to instances where RFP projects were selected that lacked one or more of the following key attributes for a viable DG project:

- proximity to natural gas supply or other fuel source;
- opportunities for low-cost interconnection;
- potential host sites for CHP applications;
- nature and composition of the area load (e.g., commercial and industrial versus residential; flat versus peaky) that is suitable for DG applications;
- ease in obtaining local land use and environmental permits;.

As one developer put it, “building owners are where they are; leads come at the developer randomly.”[27] These leads do not always align with utility distribution system needs.[28]

3.1.2.3 Geographic scope of target area

One area of some contention, at least for the first round of solicitations, between the utilities and eligible bidders related to the geographic delineation of the target area. In the first round of RFP projects, some utilities identified specific circuits within the area of need that they deemed most amenable to DG interconnection. DG developers we interviewed saw this as a significant impediment to participation. Comments submitted in Niagara Mohawk Power Company’s post-program evaluation refer to this dynamic:

> We were too prescriptive in where the DG would be applied. Many venders [sic] felt we were too helpful in identifying where on the feeder we believed it could work. They felt it would be better if we could identify the geographic area of need, identify the substations in the area with the associated voltage level, and provide the amount of DG required, it would give them the added flexibility of identifying a possible cogen partner.[29]

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[27] Personal communication with Bill Cristofaro, May 16, 2005.
[28] Personal communication with Deno Demaskos, Northern Power Systems, April 27, 2005.
[29] Communication from Scott Leuthauser, Vice President Distribution Investment for Niagara Mohawk, to James Gallagher, Director Office of Electricity and Environment, dated June 27, 2005.

3.1.3 Bidder Participation

The discussion immediately preceding highlights RFP project selection as a prime factor in limiting the number of pre-qualified developers who ultimately participated in the RFP processes. Several other issues associated with the structure of the competitive solicitations were cited by project developers as contributing to their business decision to sit out the program, or as impeding their ability to develop a cost-competitive project.

3.1.3.1 Lead-time

Developers identified the short lead-time available to them to package a project as a barrier to participation. For the first round of bidding, the time between release of the solicitation and the bid due date was from 36 to 62 days, with 48 days as the mean. Developers indicated that this is extremely aggressive given the many steps involved in preparing a responsive bid such as identifying a potential host site, securing land, conducting detailed engineering and financial analysis, obtaining equipment quotes and so forth. In the normal course, DG project development can take a year or more. Utilities generally accommodated the developer request for more time in the second round, adding from 42 to 56 additional days to the solicitation period. Nonetheless, even with this added time, unless projects were already *en train*, developers found themselves hard pressed to finalize them in time and to the level of firmness needed to satisfy bid requirements.

3.1.3.2 Securing development site

One of the more significant barriers to participation identified by DG project developers was the difficulty in securing a developable site with the degree of site control and in the time frame required by utilities.

[1] Option requirement

Some utilities, such as Central Hudson and NYSEG/RGE initially required a demonstration from the developer that they owned, leased, or had an option agreement in place for the DG development site at the time of bid submission. This was viewed by project developers as unduly burdensome.[30]

[2] Availability of utility land at substation

Developers also proposed that the utility make available to them property adjacent to the utility substation for placement of the DG equipment as a means of mitigating project risk. NYSEG/RGE offered the use of company property within the substation for the second round,[31] while CHGE expressed its willingness to make its substation property available to potential bidders.[32] By contrast, NIMO declined to make utility substation property available to project developers, citing security and safety concerns and the need to retain this property for future substation expansion.[33]

3.1.3.3 Transparency of "price to compare"

From the vantage point of the developers, a major risk factor was the lack of transparency as to the cost of the wires solution, and thus the value to the utility of the DG alternative. Developers contend that this information is critical to a determination of whether DG can present a viable alternative and hence whether the RFP warrants the company's attention. Moreover, developers with whom we spoke regarded this as a "level playing field issue"

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[30] NYSEG/RGE and Central Hudson subsequently relaxed the requirements for site control. For the second round, CHGE accepted a letter of intent to convey appropriate interest in the site to the project developer. Personal communication with Sephir Hamilton, CHGE, February 24, 2005 Similarly, NYSEG/RGE made site control a condition of receiving milestone payments, but did not require that this be demonstrated by the bid submission date. Personal comunication with Dennis Ballard and James Harvilla, March 24, 2005.

[31] NYSEG and RGE DG Pilot Program Assessment, dated July 22, 2005. Other utilities, such as Niagara Mohawk, did not make this a condition of bid submission, but gave preference to bids with this degree of site control.

[32] DG Pilot Program Evaluation Report of Central Hudson Gas & Electric Corporation In Compliance With Order of October 26, 2001 For Distributed Generation Pilot Program, June 30, 2005.

[33] Personal communication with James Bunyan, NIMO, February 2, 2005.

– if the utility is privy to bidder cost information, fairness requires that the utility costs be disclosed.

However, utilities were equally adamant that their estimated project costs not be disclosed. They worry that disclosure of cost information would allow developers to game the bidding process by pricing their DG alternative at or just below the utility's cost. This, they continue would erode any ratepayer benefits that might otherwise flow from a competitive process. For similar reasons, Commission Staff advised against disclosing cost information.[34]

As a middle ground, several utilities disclosed more substantial information about the nature, if not the cost, of the wires project. One utility distribution planner opined that bidders should have been able to estimate the cost of the wires project within +/- 10% on the basis of the information they provided.[35]

3.1.3.4 Transaction cost versus perceived probability of award

Stakeholder groups all cited the high cost of preparing detailed bids as a major factor in discouraging participation. Bidders estimated their bid preparation costs in the range of $50,000-$70,000. As with any competitive solicitation, bidders must make a calculation as to whether these upfront costs are justified given the risk adjusted value of being awarded a contract. Most concluded that the costs and risks were too high. In the words of one developer, the DG Pilot Program was tantamount to "a roll of the dice."[36]

3.1.3.5 Low incentive payment relative to cost of DG

Parties generally concurred that it was hard to make the economic case for a DG project on the basis of pilot program revenues alone or in significant part. This is borne out by

[34] Personal communication with Michael Rieder, New York Public Service Commission, February 16, 2005
[35] Personal communication with Sephir Hamilton, CHGE, February 24, 2005.
[36] Personal communication with Bert Spaeth, Siemens Building Technologies, May 18, 2005.

the wide cost gap between maximum capacity payments offered by the host utility and the cost of DG. As noted in the final O&R evaluation report, for example:

> In the second and third year of the DG Pilot, the capacity value in the highest value planning areas during the DG Pilot in O&R's service territory ranged from $20/kw-year to $60/kw-year over a three year contract. Based upon DG projects and industry benchmarks, however, the cost of the DG ranges from $80/kw-year to $120/kw-year (or higher) once interconnected, installed and available for dispatch. Given this marked mismatch between the capacity value and the cost of the DG, even though RFPs were issued for the highest value areas, they still had little chance to result in a successful bid.[37]

At best, the DG Pilot Program afforded the developer and site owner a modest supplemental revenue stream to support already economically viable projects or transform marginal projects to those capable of meeting decision maker's payback criteria. One developer posited that recovery of 20-25% of the total project cost through the DG Pilot incentives would have been meaningful.[38] Utility incentives must be packaged with other customer values including but not limited to electricity savings and thermal energy benefits for CHP configurations, revenues derived through participation in NYISO demand response programs, or financial incentives through NYSERDA's R&D program. As noted previously, this convergence of win-win-win conditions was rare and difficult to exploit within the confines of the DG Pilot Program.

3.1.3.6 Contract period

Distribution utilities implementing the DG Pilot Program offered contracts ranging in duration from three to five years. Utilities generally reserved the right to evaluate at the termination of the contract whether continued deferral of distribution system

[37] Summary of Findings and Recommendations of Distributed Generation Requests for Proposals by Orange and Rockland Utilities, Inc. at 18.
[38] Personal communication with Deno Demaskos, Northern Power Systems, April 27, 2005.

reinforcements through DG remained feasible.[39] This is generally consistent with the view that DG provides a temporary fix capable of postponing, but not generally supplanting, the transmission or distribution system investment indefinitely.
From the vantage point of the developer, this was a significant constraint on their ability to put forward competitive proposals, essentially forcing them to propose recovery of investment within this initial 3-5 year window, and/or run the risk of completing a project that may not be able to cover its costs over the long term. One developer noted that 10-15 year contracts with host sites are the industry norm, and a contract of similar duration with the utility would be the minimum necessary to encourage participants to make this financial commitment.[40] Another developer saw the 3-5 year contract and financial recovery period as creating a bias in favor of utility assets which, for ratemaking purposes, are amortized over their useful lives (e.g., 40 years).[41]

3.1.3.7 Financial security and penalties

The DG Pilot Program is premised on third-party operation of DG in order to maintain sufficient reliability to avoid contingency conditions and customer outages. Thus, there is a strong motivation on the part of the distribution company to ensure that DG developers are creditworthy and meet construction and performance milestones. The premium placed on the solid financial condition of the developer is described in Consolidated Edison's evaluation of the DG Pilot Program: "Should something happen to the business responsible for the DG, such as bankruptcy; it is unlikely that the DG would be available. Similarly, if a business is financially stressed the DG may not be repaired or maintained properly."[42] Utilities generally relied upon some combination of financial ratings, the posting of financial security, and penalties to encourage developer performance.

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[39] See e.g., Niagara Mohawk Power Corporation Distributed Generation Pilot Program Request for Proposals #DG-1 July 1, 2002 at 10; Consolidated Edison Company of New York, Inc. Request for Proposal to Provide Distributed Generation Services, July 15, 2003 at 7-8.
[40] Personal communication with Deno Demaskos, Northern Power Systems, April 27, 2005.
[41] Personal communication with Brian Balcom, Cummins Northeast Energy Systems, March 24, 2005.
[42] Consolidated Edison Evaluation Report at 21.

While not disputing the legitimacy of these requirements, developers nonetheless cited both the level of financial surety requirements and the risk of financial penalties for non-performance as major factors influencing their participation in the DG Pilot Program. These requirements affected both the developers' decision as to whether to submit a bid, and ultimately, the price of their bid.

3.1.3.8 DG reliability/redundancy requirement

Another highly contentious issue concerns the treatment of DG projects from a reliability standpoint. As noted, in instituting the DG Pilot Program, the Commission imposed a binding constraint that the integration of the DG resource may not compromise the reliability of the system. However, the Commission did not prescribe a particular methodology for making this demonstration, leaving it to individual utilities to implement in their respective RFP processes. Developers contend, we believe with some justification, that the approach taken by at least some utilities holds DG to a more rigorous standard of reliability.[43] The method also ignores improvements that DG units make to system reliability.

In evaluating reliability, it appears that at least some utilities compared the reliability of the DG *project* to the reliability of the integrated distribution system *as a whole*. For example, NIMO rejected one bid for the Hamburg project at least in part on the basis that the DG resource could only meet 98% reliability on the area aggregate basis compared to

[43] The reliability analysis principal set out by the Commission stated that:

> The DG proposal must provide for the same level of system reliability and assured quality of service to the utility's customers as the alternative distribution system upgrade. Opinion No. 01-5 at 11.

This principal has been misinterpreted to mean that a given DG project must be designed to the same availability as a particular distribution system upgrade. Standard utility planning analysis does not mandate that each transformer, pole, wire, or breaker meet a specific availability target, but rather that the distribution (or transmission) system as a whole meet a certain standard *for the proposed system as a whole*—often a first or second contingency standard, but sometimes a probability based standard. Projects that deliver that standard are then considered based on their other planning attributes, such as revenue requirement, total resource cost, societal cost, aesthetics, etc.

the availability of the feeder of 99.9795%.[44] This creates an uneven playing field, first, because the pre-existing distribution system is advantaged by its diversity of generation and distribution assets – if one component fails, the system is configured to still serve load, and second, because the analysis does not include the reliability benefits of distributed generation, as discussed below.

Similarly, Consolidated Edison and Orange and Rockland adopt a methodology, developed by the consulting firm E3, for considering reliability of distributed generation which may unduly penalize DG. Their approach[45] is ostensibly designed to determine the number of DG units to be considered as "firm" for purposes of meeting reliability targets (i.e., 99.99% availability for radial distribution circuits; 99.999% for distribution networks). The forced outage rate (FOR) of a single DG unit, i.e., the probability of the unit not operating during an event, was assumed to be 5%. A binomial distribution was then used to estimate the combined reliability of multiple DG units. These results were then translated into a 'look-up' table. DG redundancy requirements are determined by discounting a certain number of the largest and smallest DG units in a multi-unit configuration, and their associated nameplate capacity, in comparison to the system need.

A more appropriate analysis for purposes of the DG Pilot Program would be to consider whether the integration of the DG unit(s) has a net negative impact on the reliability of the overall system such that the reliability target can no longer be maintained. The level of DG redundancy required such that the distribution system, together with the project being considered, achieves an appropriate target level of reliability will be specific to a distribution system area and system need.

Moreover, the approach adopted by these utilities would appear to hold the DG *project* to the standard realized by the utility distribution *system* – in our view, an unfair comparison. Utilities do not generally apply such a standard to assessing the reliability

[44] Presentation of Scott Leuthauser, Vice President for Distribution Investment Management, presentation at the NYSERDA Second Biennial Conference: CHP in New York State, New York, NY, June 24, 2004.
[45] This methodology is described generally in Consolidated Edison's evaluation of the DG Pilot Program at 19-21. *See also* Energy and Environmental Economics *Newsletter*, Winter 2005.

benefits of their own generating units or those of independent power producers. As part of the reliability analysis, potential benefits of DG must be modeled along with any possible degradation to system reliability. Such reliability benefits include: the ability of DG to continue to provide power to downstream customers if there is a failure on the transmission or distribution system upstream from the DG unit; voltage or reactive power support at times of peak demand or significant bulk system scheduled outages, and reductions in the time required to restore partial service in the event of an outage.

Given that distributed generation is part of the integrated system and interacts with system operations in a complex way, an accurate assessment of the reliability impact of DG can only be gained through a system level analysis. Such system reliability analyses often use "Markov Chains" to model the events and facility interactions in a probabilistic manner.

It appears from the information available to us, though Markov Chains were used in the model developed by E3 for Consolidated Edison and Orange and Rockland to analyze DG reliability impacts, the method was applied inappropriately to the DG plants as separate from rather than integrated into the distribution system. This method is inappropriate because it focuses on the potential negative impacts of DG without recognizing the reliability benefits of these facilities. The method reported by Consolidated Edison and Orange and Rockland, and discussed above, of simply derating each DG plant by a fixed number of units, is equally inappropriate for determining the impact of DG on system reliability.[46] Such a deterministic step is inappropriate in a problem that needs a probabilistic approach to analyzing reliability.

This is not an academic point. Overly stringent targets for DG translate into greater redundancy than necessary to maintain system reliability. This in turn imposes

[46] Bidders were told that they were free to submit their own reliability analysis for Company review. We understand that none did. However, given the realities of staffing for project development and the complexity of distribution reliability analysis, this is not surprising and should not be taken to prove that the utility's analysis was viewed as correct by the developers, especially the many developers who may have chosen not to participate.

significantly higher costs on the bidder – to the point where the DG bid may no longer be cost-competitive with the wires alternative.

3.1.3.9 "Risk premium" for project unknowns

Another factor that appears to have driven up the DG bid price is the implicit "risk premium" factored in by project developers. This provides the developer some limited protection against the many project unknowns and associated financial risks that may be encountered in final project specification and construction in accordance with distribution utility needs and contractual requirements. The risk of non-performance and associated financial penalties (including but not limited to forfeiture of security bonds and liquidated damages) is all transferred to the developer and must be accounted for in the bid price.

One utility representative noted that bids submitted pursuant to their RFPs came in considerably higher than expected based on prototypical DG plant costs; and attributed this primarily to the risk premium associated with a developer-driven process (i.e., where the burden is shifted to the developer to come up with solutions to the utility distribution system needs). The representative believed that this risk premium could be reduced in future solicitations if the utility were to do more of the up-front project engineering.[47]

3.1.4 Contracting Stage

Because of the prohibitively high cost level of the DG resources bid, no project reached the negotiations stage. As best as we can determine, the closest DG bid to the utility benchmark for a traditional wires upgrade was for the Central Hudson Wappingers Falls project. In this case, the bid cost for a DG resource (a turnkey DG project located at a CHGE substation) was 7% higher than the T&D solution on a present value basis.[48] It is conceivable that post-bid negotiations could have closed this differential; however,

[47] Personal communication with Sephir Hamilton, CHGE, February 24, 2005.
[48] CHGE Evaluation Report at 7-8. This differential does not account for interconnection costs and lost revenues.

CHGE adhered to its stated policy of not negotiating over price in order to encourage developers to disclose their best offer at the bid stage and to prevent gaming.[49]

3.2 Evaluation of Program In Achieving Pilot Objectives

The DG Pilot Program was designed to test several objectives related to the deployment of DG as a distribution system resource. The following discussion examines the extent to which the program satisfied these objectives.

3.2.1 Whether DG Can be a Least-Cost Strategy to Satisfy Distribution System Needs

It would be easy to conclude on the basis of ultimate results of the DG Pilot Program that DG cannot compete head-to-head with traditional wires solution. We think this overstates the case.

The DG Pilot Program revealed that, at current state of technological development and cost, the universe of distribution system projects amenable to a DG solution is a relatively small part of the New York utilities' capital expansion programs. However, DG *can* provide a least cost means of satisfying certain distribution system needs *if* favorable conditions exist, specifically:

- high capacity value of DG;
- good spark spread;
- slow to moderate load growth in area served by DG;
- availability of a host site for CHP application;
- suitable infrastructure (e.g., low cost of interconnection, proximity to natural gas); and
- ability to leverage utility payment with other available incentives.

[49] Personal communication with Sephir Hamilton, February 24, 2005.

At present, these conditions are not ubiquitous, nor are they uniformly distributed across the state. Nonetheless, the results of the DG Pilot do not support any categorical conclusion that DG is intrinsically incapable of meeting distribution system needs. Based on projected utility expenditures for distribution system upgrades,[50] efforts to formally and systematically review potential opportunities for deferring T&D investments should continue.

Additionally, the distribution utility is in a position to enhance the attractiveness of DG as a least cost distribution system alternative on the basis of its policies and practices. This can take many forms, including but not limited to:

- making land available to DG developers at utility substations;
- extending contract terms to enable developers to recover their capital cost over a longer period of time;
- lowering the developer risk premium by reducing project uncertainty wherever possible;
- sharing interconnection costs under appropriate circumstances.

Some moves in this direction were made in the last bid cycle. Further accommodations that could make the process more attractive to developers and customers are possible. As discussed in the next chapter, other approaches to the delivery of DG as distribution system resources should also be considered.

3.2.2 Develop Case Specific Information on DG Costs, Benefits and Impacts Across a Range of Conditions

The DG Pilot Program consisted of over twenty separate utility RFPs, encompassing a wide range of distribution system needs and contexts:

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[50] See, e.g., "Con Edison Investing $1.2 Billion to Ensure Reliable Electricity Delivery This Summer", Consolidated Edison press release, www.coned.com/publicissues/, <visited on July 10, 2006>.

- RFPs encompassed a mix of capacity needs, eliciting bids for small systems (<1MW) to those requiring DG at the upper end of the technology size range or in multiple-DG configurations (>11 MW).
- Some RFPs were quite specific in terms where DG could tie-in to the utility system; other RFPs provided developers with greater flexibility.
- The DG Pilot Program produced a good mix of DG deployment contexts - from remotely sited DG at the end of a radial line, to DG interconnected to networked systems in densely populated urban areas.
- Some RFPs targeted areas with a large commercial and industrial base for potential host CHP host sites; other RFPs would have favored mobile DG gensets.
- RFPs featured DG deployment to serve both summer and winter peaking needs.
- Although no utility bid its own DG project in competition with those elicited from the developer community, one utility did experiment with DG optioning.

Despite this rich variety of possible DG settings, it is clear that the DG Pilot fell short of its objective of testing DG in real-world situations. This essentially R&D objective is borne out in the DG Committee Report:

> Many DG technologies are just now entering the market with the level of scope and scale necessary to resolve uncertainties regarding cost and performance. Consequently, utility distribution system planners, DG developers and other stakeholders have limited practical experience in evaluating the impacts of customer-owned DG capacity on distribution system performance and the effectiveness of such DG capacity as a substitute for distribution facilities.[51]

[51] Report of the Designated-Parties Committee Regarding the Integration of Distributed Generation in Utility System Planning Processes, submitted December 21, 2000 (set forth as Appendix B to Opinion No. 01-5, Opinion and Order Approving Pilot Program for Use of Distributed Generation in the Utility Distribution System Planning Process, issued and effective October 26, 2001).

There is an inherent tension between the DG Pilot Program's objective of testing DG and developing an empirical basis for DG performance and impacts, and its overriding emphasis on deploying a least-cost solution. There are clearly other, more direct, means of developing a better understanding of DG performance and impacts in the context of serving distribution system requirements. This would necessitate orienting the program more towards traditional R&D objectives, where costs and benefits are viewed longer term, and away from the DG Pilot Program's competitive procurement posture.

3.2.3 Refine Utility In-House Capability to Evaluate Customer-Owned DG Against Traditional Distribution System Improvement Projects

In carrying out their responsibilities under the DG Pilot Program, New York's distribution utilities have unquestionably developed a greater capacity to integrate DG in conjunction with their traditional distribution system planning practices. This has taken many forms including but not limited to:

- experience in marketing DG as target area resources to developers and customers;
- the development of screening tools to identify and prioritize high value distribution system needs;
- a greater ability to assess DG from the standpoint of reliability and cost; and
- developing an enhanced understanding of developer requirements, capabilities and limitations in delivering least cost distribution system assets.

O&R's assessment is fairly typical of the perceived value of the DG Pilot Program to the distribution utilities:

> Even though O&R's efforts did not lead to the implementation of any third party DG projects, the DG Pilot did expand the Company's T&D planning process to identify high value DG applications on the electric delivery system…

> Evaluating DG involves close coordination of many aspects of planning including distribution engineering, load forecasting and capital budgeting. O&R learned a great deal about the challenges of coordinating this process with third party DG vendors during the DG Pilot.[52]

As part of the Designated Party discussions resulting in the DG Pilot Program, the participants recommended a framework for evaluating of DG as an alternative to traditional wires approaches. (See Figure 3.1, facing). A comparison of this framework to the conduct of the utilities' respective RFP processes reveals that utilities gained considerable experience with Steps 1-6 and 9 – essentially placing themselves in the position to elicit and systematically evaluate DG as components of the integrated distribution system.

It is equally clear, however, that the early elimination of DG bid resources meant that effectively no experience was gained in negotiating the commercial terms for the installation and operation by third party developers of DG resources. Perhaps more importantly, the lack of winning DG bids to emerge from the competitive solicitations translated into a foregone opportunity for utility distribution system planners to test, and perhaps ultimately become more comfortable with, the performance of DG as distribution system assets.[53]

[52] Summary of Findings and Recommendations of Distributed Generation Requests for Proposals by Orange and Rockland Utilities, Inc. at 7-8.
[53] One developer drew the analogy to options for corrective vision, with DG akin to laser surgery and poles and wires more like glasses. His contention was that there will be always be a tendency among distribution system planners to support the traditional approach until DG is "tried and tested". Balcom interview.

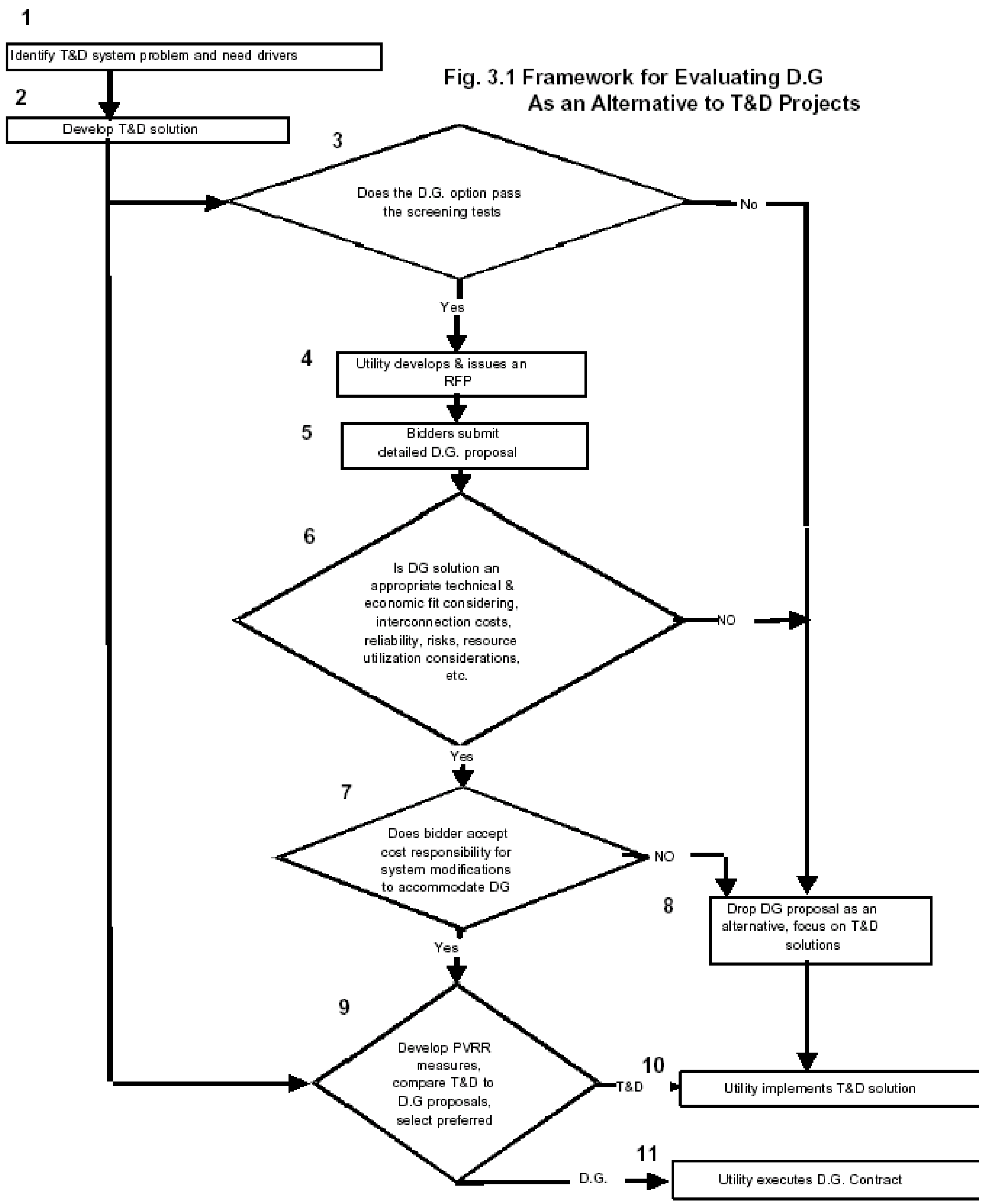

Fig. 3.1 Framework for Evaluating D.G
As an Alternative to T&D Projects

3.2.4 Determine Whether Competitive Solicitation Process is Viable and Optimal Means of Eliciting a Market Response

The choice of competitive bidding as a means of securing DG resources was a significant factor contributing to the lackluster program results. This has several aspects:

High transaction costs. Implementation of the DG Pilot Program imposed significant costs on all participants. For distribution utilities, much of the program's costs came in the form of building the in-house capacity to evaluate and more formally integrate DG in distribution system planning and are therefore one-time costs that can provide benefits over a longer time horizon. At the same time, however, the designation, development, marketing and conduct of individual solicitations impose significant, recurring costs on the utility.

Likewise, there is a high cost threshold for developers to participate in a process of this sort. Developers were essentially asked to engineer a solution to distinctive utility distribution system requirements. Not only does this make it difficult for DG to compete with traditional "wires" solutions; development of project specifications has little carryover value to future solicitations. Put simply, the high degree of customization required to respond to an individual utility RFP cannot readily be supported by project revenues.

Perception of utility bias. This speaks less to whether the RFP is a viable means of eliciting DG than it does to *who* should be overseeing the process. Virtually all developers with whom we spoke – both pilot program participants and non-participants - expressed concern over the utility's multiple role as "judge, jury and litigant" in the RFP process. Developers saw the utilities as far from indifferent as to the outcome given: 1) the distribution utility planners' greater familiarity with transformers and wires than with

DG; 2) the different cost recovery treatment for utility capital assets and DG services[54]; and 3) the potential for lost revenues associated with behind-the-meter DG. We make no judgment as to whether bias actually skewed the outcome of the competitive solicitations; the point, rather, is that the perception of bias discouraged greater bidder participation and caused many in the developer community to question the legitimacy of the pilot program.

State of the DG marketplace. The ideal conditions for use of a competitive solicitation are those in which the market for the sought-after goods or services is mature and competitive, as exemplified by multiple providers offering standardized (or reasonably equivalent) products at costs that allow recovery of fixed capital investment plus a reasonable return. These conditions do not yet exist with respect to the provision of DG, particularly in the context of DG as servicing distribution system needs.

As discussed in the following chapter, the New York Public Service Commission and other stakeholders may wish to consider other approaches to eliciting DG proposals that minimize the high transaction costs and perception of bias that plagued the DG Pilot Program.

[54] The assumption is that utilities would be entitled to a fair return on investment in distribution system infrastructure, whereas the utility would only be allowed to recover its costs associated with a DG contract on a dollar for dollar basis as an expense item.

4.0 OTHER EXAMPLES OF UTILITY DG INTEGRATION IN TRANSMISSION AND DISTRIBUTION SYSTEM PLANNING

To inform our analysis of New York's DG pilot program, we have reviewed similar efforts in other areas of the country. We first identified other utilities that were integrating DG into their respective planning processes. Table 1 below shows twelve cases where an investor-owned utility, a federal agency, or an independent system operator (ISO) has examined DG projects with the goal of supporting power generation, distribution and/or transmission systems.

Table 4.1 Examples of Utility DG Integration into Planning[55]

Case name[56]	Area	Approach	Focus	Status
BPA	region	T planning/Collaborative	T constraints	2
Conectiv	NJ	D planning	T and/or D constraints	2
Detroit Edison	MI	D planning	D constraints/Generation	3
ISO NE	region	T planning/RFP	T constraints	3
Massachusetts	MA	D planning/Collaborative	D constraints	1
NY DG aggregation	NY	DG aggregation	Generation	2
NY IOUs DG RFP	NY	D planning/RFP	T and/or D constraints	1
PGE	OR	IRP/utility program	Generation	3
PJM	region	T planning/Market Window	T constraints	1
PSE	WA	IRP	T&D constraints/Generation	2-3
SCE	CA	IRP/Collaborative/RFP	T and/or D constraints	1
Vermont	VT	T&D planning/Collaborative	T&D constraints	1

From this list we performed detailed case studies on three utilities: Southern California Edison (SCE), Detroit Edison (DE) and Bonneville Power Administration (BPA). Of these three companies, SCE and DTE are integrating DG into distribution planning and BPA is integrating it into transmission planning. In addition to these case studies, we summarize the activities of two Independent System Operators: ISO New England and the Pennsylvania/New Jersey/Maryland (PJM) Interconnection. We selected cases in

[55] Note: T planning refers to transmission planning, D planning distribution planning, and IRP integrated resource planning. Status 1 indicates that grid constraints have been identified and/or DG is being examined as a solution; 2 indicates that one or more DG unit(s) have been installed; and 3 indicates that utilities or third parties have installed and have been operating DG for some time.

[56] BPA (Bonneville Power Administration), Conectiv (Conectiv Power Delivery), ISO NE (ISO New England), Massachusetts (Massachusetts DG Collaborative), NY DG Aggregation (NY DG aggregation pilot program), NY IOUs DG RFP (New York Investor Owned Utility's DG RFP pilot program), PGE (Portland General Electric), PSE (Puget Sound Energy), SCE (Southern California Edison), Vermont (Vermont Area Specific Collaborative).

which: work has been ongoing for some time, information is available in the public domain, and the work is relevant to the objectives of the New York DG Pilot Program. We also attempted to select case studies that were significantly different from each other in terms of their approach. Below are brief descriptions of the selected cases. Further detail on each of these cases is presented in Appendix C.

4.1 Case Study Summaries

4.1.1 Southern California Edison

SCE has been participating in the Electric Power Research Institute's (EPRI) Distributed Energy Resource Partnership (DER Partnership), in which the Company is collaborating with stakeholders and seeking to find ways to evaluate, procure, and operate distributed generation as a way to relieve distribution grid congestion. SCE has been looking for DG hosts located in congested areas of its system for the past few years. If and when the Company finds appropriate customers, it will consider issuing a request for proposal (RFP) or using a similar bidding process.

4.1.2 Detroit Edison

Detroit Edison has been incorporating DG into electricity distribution since 2003. The Company often uses portable generators to relieve congestion on the grid and defer distribution system work. The mobility of the units enables the Company to deploy them rapidly and to use them in more than one location. The capability to reuse a generator in a new location improves the economics of the investment in the generator. The Company also installs DG at large customer sites on/near congested areas and operates these units (utility-owned) for the customers.

4.1.3 Bonneville Power Administration

BPA has been collaborating with stakeholders to examine Non-Wires Solutions (NWS) as transmission alternatives to delay transmission upgrades or construction. NWS include DG, demand response, energy efficiency, and direct load control. BPA is also conducting a number of pilot projects to gain real experience with certain NWS technologies and measures. A stakeholder group established by BPA has been reviewing the pilot projects and BPA's methods of evaluating and procuring NWS and also discussing economic, technical and institutional barriers to NWS with BPA.

4.1.4 ISO-New England and PJM

ISO-New England (ISO-NE) issued an RFP and was successful in procuring roughly 250 MW of demand-side resources including demand response and on-site generators (mainly back-up generators) to relieve transmission congestion in the Southwest Connecticut (SWCT) region. These resources will be operational until at least 2008. To date, ISO-NE has called on the resources once (in July 2005). PJM is taking a "market window" approach to soliciting bids from market participants for congestion relief projects. In this approach, PJM notifies market participants of the locations of transmission congestion and provides an estimate of the cost of mitigating the congestion with transmission assets. As of September 2005, PJM had opened and closed market windows for 39 congested transmission facilities. PJM has received very few bids from market participants to relieve transmission congestion, and PJM is currently revising its market window approach.

4.2. Key Features of DG Integration Efforts

Below we discuss the important features identified in the case studies.

4.2.1 DG Ownership

Detroit Edison's use of DG centers on utility-owned units. This is largely driven by the facts that the company owns both generation and a distribution system and it is able to earn a return on investments in DG. SCE and BPA are not focused on utility owned DG. SCE is currently evaluating the benefits of owning portable DG units that could be used for distribution system support but recognizes that economic justification and regulatory approvals will be significant hurdles.

The following factors facilitate utility ownership of DG:

- Being in the generation business (advantage for customer-sited DG);
- Sells energy at retail (advantage for customer-sited DG);[57]
- The ability to earn a return on investments in DG (advantage for both mobile DG and customer sited DG);
- Having the local regulatory commission regard investment in DG as distribution or transmission infrastructure instead of generation (advantage for mobile DG: In California, DG is regarded as a generation investment in ratemaking, which makes it more difficult for utilities to find cost effective DG projects.)[58]

This utility-driven model of developing DG is likely to provide certain benefits while precluding others. This tradeoff can be summarized as follows.

- Short-term deployment of mobile DG units on the grid can lower the cost of distribution service by deferring distribution system work and serving customers during work. This appears to be an unmitigated benefit to customers. The utility may be able to provide this service more efficiently than third-party DG providers.
- Detroit Edison's provision of *customer-sited DG* provides benefits to the utility and to customers. However, this service may preclude customers from receiving other benefits. Specifically, third-party DG providers are likely to provide large customers with more innovative and comprehensive DG services, but these companies may be reluctant to invest resources in Detroit Edison's service area due to perceived unfair competition with the utility. A key difference in the services provided by Detroit Edison and those that might be provided by third-party DG companies is that the utility owns and operates all customer-sited DG. Third party DG providers would likely explore other ownership and operation

[57] Utilities that sell energy at retail may find it profitable to own and operate a DG unit at a customer site and sell the energy generated to the customer. Utilities that do not sell energy at retail do not have this business model as an option.
[58] DG projects are typically more costly on a per-kW basis than large power plants. Thus, if DG is compared to large plants, few projects will appear cost effective.

scenarios (e.g., customer-owned DG or a turnkey system) with customers as well as broader process changes at the customer site that could improve efficiency. In addition, a utility is unlikely to pursue onsite generation aggressively with customers in areas where grid support is not needed. Competitive DG providers would market their services to all large customers.

4.2.2 DG Control

Both SCE and BPA have determined that they only need control over customer sited DG units for a small number of hours per year. SCE has agreed to have control over customer-owned DG units for 200 to 400 hours per year. BPA does not envision including an explicit limit on their ability to operate the unit in the contract, however BPA is clear that they will only operate a small number of hours each year. As a result, the customer is free to control the DG during most of the year.

4.2.3 Other Resources

SCE, BPA, and ISO-NE have found that other resources, in addition to DG, can be cost effective alternatives to distribution or transmission infrastructure, including energy efficiency (EE), demand response (DR) and direct load control (DLC). In the portfolio of these resources identified by BPA at one deferral project, other resources (DR, DLC, and EE) contribute more capacity than DG.[59] In the ISO-NE's case, around 40 percent of the procured resources (around 100 MW) consist of load reduction projects and a mix of DG and load reduction projects.[60]

4.2.4 Stakeholder Input

BPA and SCE have gained a considerable amount of information from stakeholders through collaborative processes. Collaboratives can identify aspects of utility planning to which stakeholders are likely to object and provide a forum for seeking win-win solutions. The addition of stakeholders' knowledge and experience is likely to lead to a better utility DG planning process. Further, information exchange through BPA's Round

[59] DR 16 MW, DLC 20 MW, EE 15 MW, and DG 4 MW.
[60] DG projects selected by ISO-NE are mainly back-up generators.

Table has increased regional acceptance of using non-wires solutions to support transmission and stakeholder acceptance of the utility's final planning process.

While BPA and SCE have solicited stakeholder input in the development of a process for screening T&D projects for potential DG solutions, there does not appear to be a vehicle for ongoing stakeholder involvement in the screening process (after the dissolution of the collaboratives). In the future, the companies might screen distribution or transmission projects for DG applicability "in house." A process in which wires projects are screened by a number of parties, including large customers and third party DG providers, would likely identify more cost effective opportunities for NWS than a closed screening process.

4.2.5 Pilot Projects

On a parallel track with the development of a non-wires planning process, BPA has pursued pilot projects to gain experience with specific technologies and measures. BPA is testing non-wires solutions to see how, when, where and under what circumstance non-wires solutions can relieve grid congestion cost-effectively and reliably. These pilots are also useful opportunities to address institutional barriers and build stakeholder confidence in NWS. It seems efficient to conduct pilots while developing a utility planning process rather than waiting until the planning process is finalized.

4.2.6 Assuring Reliability

Another important point is the "physical assurance" policy that California Public Utilities Commission (CPUC) requires for DG operation. Physical assurance refers to on-site controls to ensure that a DG unit will operate when needed for grid support and that the load served by DG will be automatically curtailed if the unit fails to operate during peak load conditions. Providing physical assurance does not typically add unreasonable costs to DG projects, and it can remove the need to install redundant equipment to ensure reliability.

4.2.7 Air Quality Issues with Diesel DG

While Detroit Edison has had success using diesel-fueled engines for distribution deferral projects, tighter air regulations in others areas of the country, such as the Northeast and California, may make this approach more difficult. For example, in order to include diesel generators in its Southwest Connecticut RFP, ISO New England had to work with Connecticut air regulators to allow diesel back-up generators to operate under a newly defined emergency condition that includes the Southwest Connecticut RFP program. In making this change, the operating limit applicable to diesels was lowered from 500 hours per year to 300.

4.2.8 Screening Threshold

BPA has found a cost trigger to be an effective tool for ensuring comprehensive screening of transmission projects. BPA screens all transmission projects costing $2 million and above for non-wires projects applicability. Because distribution projects are typically less expensive than transmission, the trigger should be set considerably lower than this for distribution planning.

4.2.9 Utility Facilitation of Projects

Both SCE and BPA have found it necessary to remain actively involved in the development of non-wires projects after constrained areas are identified. In particular, these companies are facilitating communication between large customers and third party DG providers. Utility involvement in this stage of project development is probably necessary for a successful DG program, given utilities' detailed knowledge of customer use patterns.

4.2.10 DG Solicitation Process and Identification of DG Projects

Utilities and ISOs are taking different approaches to procuring DG projects. ISO-NE used an RFP and was successful in procuring sufficient, cost-effective DG and other non-wires projects. SCE is considering issuing an RFP if it finds situations amenable to DG projects on/near constrained areas.

- SCE is considering issuing an RFP or using a similar bidding process if it finds sufficient number of potential candidates who have DG or who could host DG projects on/near constrained area. However, SCE has not been able to identify sites that could host sufficient DG capacity to meet their needs, and thus they have not issued an RFP.

- BPA is using more than one approach to identify non-wires projects, including an RFP, and BPA has successfully procured DG resources from market participants.

- PJM has developed a “market window” approach for soliciting DG proposals.

- Detroit Edison relies entirely on utility-owned DG and has been successful in identifying DG projects to defer several distribution projects.

Based on these cases, we do not believe that the mechanism used to solicit DG projects is the most important driver of success. For example, while ISO NE used a traditional RFP, the success of that effort is attributable to other factors. The area ISO New England targeted is relatively large, encompassing 16 towns in the Southwest Connecticut; large backup generators are often located at the transmission level; several different resource types were eligible for the ISO’s RFP, including distributed generation, load reduction and energy conservation; and payment is guaranteed for a long period of time.

The SCE’s unsuccessful search for DG resources does not appear to be related to the Company’s use of a collaborative or an RFP. SCE’s distribution system is relatively flexible and load shifting is often a highly cost effective option, which reduces the number of cases where DG is cost effective. Also SCE is in need of a relatively large amount of capacity (between 5-7 MW), and it is difficult to find customers at the distribution level who can provide this much capacity.

PJM's failure to find resources using a market window appears to be related to the way that avoidable costs are calculated, not to the market window mechanism. In fact, this mechanism appears to offer competitive DG providers with some of the best information of any of the mechanisms.

Detroit Edison has invested in DG itself, rather than soliciting DG from customers or third parties. This strategy has been successful largely because DE owns both generation and a distribution system, it can earn a return on DG investments and it can sell the energy from DG projects to customers (so lost utility revenues are not an issue).

4.2.11 Capturing Benefits in Different Areas

Several utilities and ISOs are making efforts to expand the benefits that DG and other non-wires solutions projects can capture. ISO-NE requires participants in the SWCT RFP (except energy efficiency projects) to be enrolled in existing load response programs, in which participants receive revenues from capacity and energy markets. SCE is considering investigating DG projects with customers who are already involved in the Company's curtailment and demand response programs, providing opportunities for participants to gain benefits associated with both generation and distribution. Finally, BPA is seeking ways to collaborate with local distribution utilities, hoping to increase the total value of non-wires projects. One approach BPA is considering is to use funds from local utility programs (such as efficiency and demand response programs) to support DG that could contribute to deferring transmission projects.

4.3 Lessons Learned for New York

Several findings emerge from this survey of other distribution planning and DG integration efforts:

- The market in New York might well offer more cost effective distribution deferral projects if a broader array of demand- and supply-side resources were eligible.
- For New York's investor owned utilities, it is worth exploring synergies between utilities' efforts to relieve distribution constraints and NY ISO's efforts to relieve transmission constraints. It is also worth exploring ways to use existing utility and

public benefit programs in New York to mitigate distribution, transmission, and capacity constraints and ways to ensure that DG and other non-wires projects are compensated for all the benefits they provide.

- New York should seek to develop a DG planning process that includes ongoing involvement of customers and DG providers.
- New York should also examine the feasibility of using utility-owned portable DG units as distribution capacity. Utility owned DG units could be a quick, cost-effective DG solution to a congested area that is (a) expected to experience a modest capacity shortfall (e.g., less than 2-3 MW) and a low load growth in the near future and (b) away from densely populated area and (c) not suitable for CHP applications.
- While building the capacity for integrating DG in utility distribution planning processes, New York utilities should consider conducting pilot projects to gain experience with specific technologies and measures. Pilot projects will be helpful to identify institutional barriers and build stakeholder confidence in operating distributed generation and other on-site measures such as demand response.
- New York should explore defining a standardized set of protection equipment that protects the grid but does not place unreasonable burdens on DG developers.
- New York utilities are well positioned to facilitate communication between large customers and third party DG developers and demand response service providers in order to identify more opportunities for such resources to support the grid. Those utilities that have not already adopted this practice should consider doing so.
- Through a stakeholder collaborative process, interested and affected parties should explore various aspects of the DG procurement process including but not limited to (a) criteria to identify and screen attractive areas for DG/CHP projects; (b) criteria to screen out proposed DG projects; (c) contract term and payment structures; and (d) development of model contract language.

SECTION 5.0. RECOMMENDATIONS FOR FUTURE INTEGRATION OF DG AS DISTRIBUTION SYSTEM RESOURCES

The following discussion highlights our recommendations for improving upon the status quo. These recommendations fall into two basic categories. First, while we offer no opinion on whether the DG Pilot Program should be continued in its current vein of utility administered Requests for Proposals, we make several suggestions for improving upon the current system. Secondly, we proffer for consideration several alternative approaches for deployment of DG.

5.1 Recommendations for Improvements to Future RFP Processes for DG

5.1.1 Constrain Mandatory Use of RFP's to Utility Service Territories with More Attractive DG/CHP Economics

For the DG Pilot Program, each utility was expected to issue a pre-determined number of Requests for Proposals for DG resources. These RFP targets were set without regard to the applicable utility rate levels, and their ability to support economic DG/CHP projects. As a case in point, Central Hudson and Orange and Rockland, two of the state's lowest cost utilities, were required to issue the same number of RFPs as National Grid, a relatively high cost provider.

An alternative approach would be to limit the competitive procurement of DG resources to those utility service territories offering more favorable spark spreads alone or in conjunction with high avoided T&D system costs. This approach has as its principle virtue the cutting down on the number of lackluster bid processes.

5.1.2 Consider a Greater Role for Distribution Utilities in Project Development

The approach invariably taken by New York's distribution utilities in implementing the pilot program was to identify a distribution system need, and ask DG project developers to craft a least-cost solution to this need. While this approach afforded developers considerable latitude in what they could offer, proposals submitted by developers for DG resources came in significantly above industry cost benchmarks. This result led some to conclude that the cost proposals included a significant risk premium component, to accommodate final utility specifications differing materially from the bid resource, potential project modifications, and other project risks.

One potential way to reduce this risk premium is for the utility to assume a much greater role in project specification, essentially procuring the DG resource under a turnkey contract. This has the advantage of providing much greater certainty and clarity about the proposed project, which would ideally translate into reduced risk placed on the project developer and support more competitive DG bids. This is also consistent with a more activist and expansive view of the utility distribution system planning function, embracing at its extreme a greater utility role in identifying DG customer opportunities and DG deployment. On the other hand, it may also be argued that this more prescriptive approach all but eliminates one of the greatest values that the DG development community can bring to the table; namely, a familiarity with their client's needs and the creativity in fashioning solutions to meet those needs.

Some utilities may wish to go further. Although no utility implemented its own DG project pursuant to the DG Pilot Program, the Detroit Edison experience indicates this is a viable model particularly where the utility retains some residual responsibility for generation and/or retail service.[61] New York utilities either reluctant or unable to get into a long-term ownership position may wish to build and retain DG assets for only as long

[61] See discussion at Section 4.2.1, *supra*.

as these units continue to provide deferral value; whereupon the utility could transfer ownership to private hands.

5.1.3 Initiate Post-Pilot Program Collaborative Process for Soliciting Stakeholder Input and Development of Best Practices

The meetings called by Staff after the first cycle of bidding led to several program changes to address participation barriers identified by DG developers. If the DG Pilot Program is continued in some fashion, we would recommend that the Commission Staff convene a working group to continue to explore the lessons learned from the three-year pilot program and evaluate process reforms and alternative program constructs for integrating DG that are potentially more effective at identifying and securing cost-effective resources.

Various collaborations between utility and DG stakeholders have proven successful in identifying and resolving difficult issues. The Southern California Edison collaborative is a case in point. The EPRI report on this process reveals:

> The stakeholder collaborative approach was a significant factor in achieving the successes of the California DER Pilot Project that can be measured to date. The pilot project demonstrates the ability of the stakeholder collaborative process to create innovative and robust solutions that address all stakeholder interests. The approach of stakeholders partnering together to find win-win solutions provides a distinct advantage compared with the typical adversarial mode seen in proceedings and hearing rooms. Working together as partners builds trust and understanding of each other's perspective.[62]

The collaborative evaluators pinpoint several specific successes of the collaborative in resolving difficult issues.[63]

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[62] DER Stakeholder Collaboration at Work: Shaping a California DER Procurement, A Report of the EPRI Distributed Energy Resources Public/Private Partnership, Draft Final Report (April 2005) at 7-1.
[63] Id. at 7-1.

Similarly a collaborative process convened by BPA has played a vital role in identifying and resolving complex issues surrounding the incorporation of DG in utility planning. The collaborative focuses on BPA's methods of procuring DG and other resources and detailed studies of particular problem areas, evaluates distributed resources technologies and measures, and discusses barriers to implementing such resources. This process has increased the regional acceptance of using distributed resources to support transmission problems and stakeholder acceptance of the utility planning process, while recommendations by stakeholders are reflected in many aspects of the utility planning process.

A more local example of a collaborative effort to address DG investment as a distribution system resource is the process for development of targeted and system-wide distributed energy resources in the Consolidated Edison service territory. As part of the company's three-year rate plan, the Commission authorized $224 million in funding for demand management initiatives for at least 150 MW of targeted demand reductions, and at least another 150 MW of demand reductions systemwide. In addition to authorizing funding, the Commission initiated a collaborative process to develop an Action Plan and to address a variety of ancillary goals enumerated in the rate order for demand management.[64]

Rather than a single meeting offering the parties to exchange views, our recommendation would be for the process to be ongoing and more oriented towards active problem-solving. The key issues that the collaborative might assume as part of its mandate are indicated by this report and might include:

- criteria to identify and screen congested areas for DG/CHP projects;
- criteria to screen out proposed DG projects;
- methods for evaluating and assuring DG reliability;
- DG developer information requirements;
- contract term and payment structures;

[64] See Case 04-E-0572, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc., Order on Demand Management Action Plan, issued and effective March 16, 2006.

- development of model contract language;
- level of bid specification and/or feasibility of turnkey solutions; and
- an exploration of alternatives to an RFP process.

5.1.4 Experiment with Cooperative Management of Bid Review Process with Independent Third Party

A major concern expressed by participants in the DG Pilot Program is the exclusive role played by the distribution utility in administering the process. Given the utility's legal responsibility for managing distribution system assets, its active involvement in all facets of the program is essential. However, it is equally clear that the utilities' unfettered discretion in identifying projects for competitive solicitation, reviewing bids, and evaluating DG bids against its own "build" option, has created level playing field concerns. This is exacerbated by the more favorable cost recovery treatment afforded the utility's capital improvement project over contracts for customer-sited resources, which lead to concerns that bid review will be skewed in favor of the utility's own project.[65]

One way to mitigate the concern over utility bias is to have an independent third party, such as NYSERDA, administer the bid review process. Although any of a number of different approaches could be taken, NYSERDA might administer this bid review in much the same fashion as it currently selects contractors pursuant to its role as New York's System Benefits Charge Administrator. That is, proposals for DG resources would be invited and reviewed against pre-defined criteria by a Technical Evaluation Panel (TEP) consisting of teams of internal and external subject matter experts. The host utility would also be expected to participate in this process, but any ranking of projects would be done by the TEP as a whole.[66] The TEP would also be expected to provide a "reality check" on the cost estimate provided by the utility for its own "build" option.

[65] Again, it is important to point out that while we found no evidence of systematic bias, we did document repeated instances of developers opting not to participate in the program because of its structure.
[66] The TEP selection processs would also be regarded as evidence of the prudence of the utility's decision to enter into contracts with the higher-ranking projects for ratemaking purposes.

5.1.5 Allow DG to be Bid in Combination with Other Distributed Energy Resources

The New York DG Pilot Program was established as an outgrowth of the Public Service Commission's investigation into the benefits and costs of distributed generation. As such, the program arose in the context of a particular institutional framework, directed to DG resources exclusively and precluding experimentation with a broader array of distributed energy resources.

As revealed in our national case studies, other experiments in procurement of DG as alternatives to distribution and transmission system investment have permitted DG to be paired with other distributed energy resources. The Southern California Edison collaborative process, the Bonneville Power Administration Non Wires Solution process, and the ISO-NE RPF for the Southwest Connecticut region are good cases in point of where the use of a broader definition of distributed resource eligibility was deemed mutually advantageous to the host utility and prospective bidders.

Notably, the BPA process developed a plan to procure a package of distributed energy resources to defer the Olympic Peninsula transmission upgrade. Included in the package are 16 MW of demand response, 20 MW of direct load control, 4 MW of distributed generation, and 15 MW of energy efficiency measures. As pilot projects, BPA has already procured or is testing some of these measures including 2.5 MW aggregated DG units located at hospitals and governmental facilities, demand response measures from four large customers, direct control of water and space heating equipment in residences, and energy savings from local utilities' energy efficiency programs.

Similarly, the SCE collaborative identified demand response as a potentially cost-effective means of providing the host utility with resources in the amount and at the critical times these resources were most needed. Like the NY DG Costs and Benefits proceeding:

> The history of the CPUC proceedings that directed utilities to incorporate DG in their planning and procurement…initially led SCE to conceptualize the RFP as a procurement limited strictly to DG. Issues group discussions revealed that the economics of these projects could often be improved by recognizing other sources of demand reduction at customer facilities along with the DG installation. The discussions also revealed that SCE's purposes would be served if customers reduced their on-site demand at critical times, whether they did that with onsite generation alone, or by combining DG with other demand response measures…That said, Issue Group participants recognized that the CPUC's intent was to encourage DG deployment. The group therefore urged that SCE's RFP should recognize some amount of demand reduction offered by customers, as long as they installed DG sufficient to cover their facility's critical loads…"[67]

ISO-NE issued an RFP and was successful in procuring about 250 MW of demand-side resources including DG and demand response for relieving transmission congestion in the Southwest Connecticut region. Nearly 100 MW of the resources consisted of demand response measures alone or a combination of demand response and on-site generators.

As noted previously, New York's DG Pilot Program was designed to meet several objectives simultaneously. A predominant objective was that of providing practical experience with DG installations and their interactions with distribution system assets. Another objective, more amenable to satisfaction through DER resources more generally is that of identifying least-cost distribution system deferral strategies.

For future solicitations, we would recommend relaxing the somewhat artificial distinction between distributed generation and demand-side strategies and allow the submission of bids which optimize the use of these respect resources.

[67] DER Stakeholder Collaboration at Work: Shaping a California DER Procurement, A Report of the EPRI Distributed Energy Resources Public/Private Partnership, Draft Final Report (April 2005) at 5-3.

5.1.6 Explicitly Allow Commitments for Load Shedding in Lieu of Redundant DG Capacity

The specification of redundant generation to meet utility reliability requirements was identified as a significant driver contributing to the high cost of bid resources. For future solicitations, the utilities should consider accepting customer commitments to shed load in the event the distributed generator fails when called upon by the utility. When coupled with penalties for non-performance these demand-side actions can serve as the functional equivalent of back-up generation. Alternatively demand-side actions could be facilitated by providing physical assurance equipment on customer site as in SCE's case.

5.1.7 Provide Greater Transparency of the Value of Deferral to the Distribution Utility

A goal of future solicitations should be to provide enough transparency to enable the DG developer community to know within some reasonable range the deferral value of the distribution system investment (such that they can ascertain whether the submission of a bid is warranted), without being so specific that bidders can "game" the process and erode any potential ratepayer benefit. We believe it is possible to find a happy medium. For example, CHGE provided bidders with enough information about the wires solution that bidders could estimate with sufficient precision the cost to the utility of this project. Similarly, the Southern California Edison collaborative established the concept of a "market reference price" that would provide bidders with some indication of the relative value for projects being presented, without necessarily reflecting the utility's avoided cost. These concepts merit consideration for future solicitations in New York.

5.1.8 Encourage More Aggressive Utility Co-Marketing of DG Program to Large Customer Accounts

Several New York distribution utilities, responding to the disappointing results in the first cycle of the DG Pilot Program, more actively intervened in promoting the program to large customer accounts for subsequent rounds. This is consistent with experience at a national level, wherein utilities have found it necessary to help facilitate projects once constrained areas are identified. It should be noted that this practice was not universally applied in New York, as some utilities see this as outside their responsibility and role.

We believe there is much to gain from this practice and, to the extent future solicitations are conducted, should be encouraged. At a minimum, utilities should notify large customers of the existence of the program and its potential benefits. Additionally, these customers should be provided contact information for qualified DG developers in the event they are interested in obtaining further information and/or more detailed site analysis.

5.1.9 Utilities Should Not Automatically Foreclose Post-bid Negotiations for Marginally Non-Cost Effective Resources

Our evaluation revealed at least one case where a developer bid DG resources at a price within +/- 10% of the utility's projected avoided cost of the wires solution. Nonetheless, the soliciting utility chose not to enter into negotiations with this developer. We think this is overly rigid and may result in lost opportunities for cost-effective DG deployment; in close cases, the utility should make a greater attempt to determine through negotiations whether a more price competitive outcome could be arrived at.

5.1.10 Explore Synergies between Local Utilities and NY-ISO in Relieving Grid Congestion

Distributed resources used for relieving transmission level congestions could possibly reduce local congestions in the distribution system. BPA is exploring ways to capture the benefits of non-wires solutions to both distribution systems and transmission systems, because those benefits could increase the total value of non-wires solutions and could provide additional sources of funding. For New York's investor owned utilities, it is worth exploring synergies between utilities' efforts to relieve distribution constraints and NY-ISO's efforts to relieve transmission constraints.

5.1.11 Provide Parties with Greater Guidance on the Evaluation of Reliability

In the event the Commission reauthorizes an RFP-based DG procurement process, it should provide parties with clearer guidance on the appropriate treatment of reliability.

The reliability analysis principal set out by the Commission stated only that: "The DG proposal must provide for the same level of system reliability and assured quality of service to the utility's customers as the alternative distribution system upgrade."[68]

We believe that this principal has been misinterpreted to mean that a given DG project must be designed to the same availability as a particular distribution system upgrade. Standard utility planning analysis does not mandate that each transformer, pole, wire, or breaker meet a specific availability target, but rather that the distribution (or transmission) system as a whole meet a certain standard *for the proposed system as a whole*—often a first or second contingency standard, but sometimes a probability based standard. Projects that deliver that standard are then considered based on their other planning attributes, such as revenue requirement, total resource cost, societal cost, aesthetics, etc.

Consequently, the Public Service Commission should clarify its intentions regarding the requisite standard of reliability for DG as a distribution system asset. We recommend that the Commission adopt the following principles:

- The deployment of DG should not lead to a material degradation of the reliability of the circuit as a whole. DG projects need not meet an availability target of the comparable "wires" solution standing in isolation.
- Any review of the reliability impacts associated with DG should, to the maximum extent possible, identify and quantify any DG reliability benefits (including but not limited to local voltage or reactive power support and the ability to provide continuous service to downstream customers on radially configured networks).

[68] Opinion No. 01-5 at 11.

- The analysis of the reliability impacts of DG should, in the first instance, be the responsibility of the distribution utility rather than the DG developer. Given the inherently system-wide nature of this analysis, the distribution utility is better positioned to conduct this review than individual developers.

5.2 Alternatives to an RFP Process for Integration of DG in Distribution Planning

Given the results of the DG Pilot Program, alternative procurement methods and planning approaches warrant further consideration as a means of better meeting the programs' varied objectives. These approaches include: 1) localized incentives for DG in constrained areas; 2) annual disclosure of utility capital expansion plans to qualified DG developers; and 3) the deployment of DG as part and parcel of research and development into an advanced "smart grid".

5.2.1 Localized Incentives for DG in Constrained Areas

An alternative to the RFP processes conducted by New York's distribution utilities would be to send stronger price signals to encourage the deployment of DG in distribution constrained areas of the network. The most straightforward and "pure" approach from a rate design perspective – "deaveraging" of distribution system rates to reflect the geographic variance in the cost of providing distribution service – is widely regarded as politically infeasible given the abrupt price increases this would impose on those in high cost areas.[69]

As a consequence, a variant of this approach has been developed under which "zonal credits" are offered to stimulate deployment of distributed energy resources in areas

[69] Moskovitz, David et.al., "Distributed Resource Distribution Credit Pilot Programs: Revealing The Value To Consumers and Vendors", http://www.raponline.org/Pubs/DRSeries/DRCredit.pdf, September 2001, at 6.

where these resources are most needed.[70] Under this approach, a distribution utility would identify high cost zones of the distribution system through its annual distribution planning exercise and offer a “bounty” to developers installing DG within these targeted zones. The actual dollar value of the bounty would be set up to the deferral value of the necessary distribution system upgrade. Provision could be made for a sharing of the benefits between the DG developer/host site, utility shareholders and customers at large to encourage win-win-win solutions.

This approach has some significant practical advantages over the RFP-type approach adopted for the DG Pilot Program. First, it significantly reduces the transaction costs associated with the development of bids responsive to utility RFPs, as well as the costs to utility distribution system planners to administer the RFP process. High program costs were identified as a barrier to participation and a cost burden on the utility. Second, by largely obviating the need for a comparative analysis of bids and the utility benchmark proposal, it mitigates the concern among developers that the utility will bias the process to its own advantage. Third, a standing credit will provide developers the longer lead-time necessary to cultivate and design DG projects than is possible under a competitive solicitation.

If this approach is pursued, it will be necessary to develop mechanisms to assure that the distribution utility is not obligated to pay for either too much or too little DG capacity.

Because the zonal credit will be available to all comers, it is at least a theoretical possibility that DG supply will exceed the distribution utility’s capacity need. This can be easily addressed by instituting such conventions as making the credit available on a first-come, first-served basis with a circuit breaker that will be triggered when the capacity quota is filled.

[70] See, e.g., Richard S. Brent, “A Blueprint for DG”, Public Utilities Fortnightly, January 1, 2003; California Public Utilities Commission, Order Instituting Rulemaking into Distributed Generation, Decision 03-02-068 in Rulemaking 99-10-025, issued February 27, 2003, at 48; Moskovitz at 13.

Similarly, the host utility needs some protection to assure that it is not obligated to pay for DG systems that only partially address, but do not fully avoid, the wires investment. Under this scenario, the utility's costs would be greater than if it had pursued the wires solution alone. While this is a somewhat more challenging problem, we do not believe it is insurmountable. One potential solution would be to make the availability of the zonal credit contingent upon a sufficient demonstration that a critical mass of DG projects are available.

5.2.2 Annual Disclosure of Utility Capital Expansion Plans to Qualified DG Developers

The utility RFP processes presented a finite number of opportunities for deployment of DG as a distribution system alternative. These solicitations featured areas prioritized by distribution system planners as those in greatest need of grid support but, except in the most general way, did not take into account whether these were areas of commercial focus for DG developers, or indeed, whether these represented good candidate locales for DG development. Moreover, these RFPs provided prospective bidders a limited window of opportunity to plan and finance projects – within 3-4 months of notice of the RFP – that do not comport with DG project development realities.

We recommend a more cooperative and inclusive process for project identification. Consideration should be given to a process in which the utility annually discloses to pre-qualified bidders its 5-year capital expansion plans. This would provide DG developers a much better opportunity to step forward with projects already in the works, or give greater guidance on future projects of high value, that may simultaneously resolve the distribution system problem. In short, such a process - either as a supplement to or substitute for the regular issuance of RFPs - is more likely to yield win-win solutions.

Developers would have to understand that these 5- year plans are dynamic, subject to change, and do not represent firm financial commitments on the part of the distribution utility, particularly as to needs identified in the latter years of the planning horizon.[71]

5.2.3 Experimentation with DG as Part of Utility R&D Programs

With no projects having been procured, the DG Pilot Program failed in its objective of providing distribution utilities greater practical experience with and understanding of DG performance, benefits and risks. This result was a direct consequence of subordinating all other program objectives to a "least cost" constraint.

New York stakeholders may determine that there is value in allowing distribution system engineers greater latitude to experiment with integration of DG, and to develop a deeper empirical understanding of how DG equipment compares to traditional "poles and wires" solutions. These longer-term and difficult to quantify benefits are more appropriately understood and secured in the context of utility research and development initiatives, than in the context of the utility's short-term obligations to provide reliable service at reasonable cost.

The New York Public Service Commission's recent Order extending the System Benefits Charge for another 5-year term may provide a vehicle for greater experimentation with DG as a distribution system component.[72] That order sets aside up to $2 million annually for transmission and distribution-related research and development. We recommend that NYSERDA and the PSC consider limited use of these funds to support analysis of DG as a critical component of the future grid.

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[71] A partial step in this direction has been taken as a result of the recent Consolidated Edison electricity rate settlement. The Settlement Agreement, Section J, stipulates that: "The Company will continue to develop detailed annual forecasts of T&D capital budget requirements and will identify for each major T&D project (*i.e.*, projects of $10 million or more), the location, rationale, scope, estimated capital costs, appropriate load, and other data. This information will be included in the Company's annual reports described in Section D.3. The Company will evaluate and implement cost-effective measures as alternatives to major T&D projects that defer major T&D system projects through the use of technologies or services that could reduce peak T&D loads." Case 04-E-0572, Consolidated Edison Company of New York, Inc. – Electric Rates, Order Adopting a Three-Year Rate Plan (issued March 24, 2004) at Appendix I.

[72] Proposed Plan for New York Energy $mart™ Programs (2006-2011) at 7.3.

5.2.4 Explore the Feasibility of Optioning DG at Certain Congested Areas

It appears that utility optioning of mobile DG could be a quick, cost-effective solution to addressing utility distribution system needs under certain circumstances. As demonstrated in the Con Edison pilot program, utility optioning of DG could result in significant savings in congested areas for which the load growth is uncertain; if the load growth fails to materialize the utility can simply decline to exercise its option. Alternatively, the utility may choose to redeploy the same mobile unit at a different location. However, because of air quality concerns, particularly in areas that are not in attainment with ambient air quality standards, we suggest that the deployment of mobile DG be limited to: 1) non-diesel generator such as reciprocating engines or those utilizing ultra-low sulfur diesel; 2) areas expecting a modest need for new capacity (e.g., 1-3 MW); 3) are away from densely populated urban areas; and 4) do not have commercial/industrial facilities suitable for CHP applications.

APPENDICES

APPENDIX A.1
DG PILOT PROGRAM QUESTIONNAIRE
UTILITY REPRESENTATIVES

Interviewee Information

1. What is your position with the company?
2. What is your role with respect to the integration of distributed generation into your company's distribution system?
3. What is your role with respect to your company's implementation of the DG Pilot Program RFPs?
4. Were you involved in the drafting your company's DG Pilot Program RFPs?
5. Were you involved in the evaluation of your company's DG Pilot Program RFPs?

Quantitative Information about RFPs

1. How many bidders has your company pre-qualified to participate in the DG Pilot Program?
2. How many RFPs have been issued pursuant to the DG Pilot Program?
3. For each such RFP, please indicate the following:
   a. Date issued
   b. Date of bidders conference, if any, and number of attendees
   c. Bid submission date
   d. Number of bids received
   e. Number of bids which met pre-qualification requirements
   f. Whether any of the bids were sufficiently meritorious to warrant further discussions or negotiations with developer
   g. Did the company "bid" its own DG project, or consider a partnership with a DG project developer?
   h. Area of the electrical system in which DG projects must be installed
   i. Nature and expected cost of the proposed distribution system upgrade
   j. In-service date required for the DG system
   k. Special technical requirements, if any
   l. Specified financial security or performance guarantees
   m. Other utility-system circumstances bearing on the preparation of the DG proposals
   n. Factor(s) which gave rise to the DG system need (e.g., load growth, voltage conditions)
   o. Whether the company has moved forward with the "wires" project

RFP Approach

1. What were the primary factors which led to the selection of particular improvements for the DG bidding process?
2. Generally speaking, how far in advance of the "need date" for a particular distribution system improvement did the company go out for bid for DG projects?

3. Please indicate what, if any, steps the company took to publicize the RFP?
4. Please explain how your company's process for prioritizing and allocating financial resources to distribution system improvements would affect the ability to secure DG resources through competitive bidding?
5. Did the company consider bids that would defer the distribution upgrade, or allow a downsizing of the project? Or did the bid resource have to fully satisfy the specified need?
6. Was there any attempt to coordinate the DG RFP with known DG projects under development in the service territory?
7. Was there an attempt to coordinate the DG RFP with other incentive programs, such as the NYSERDA Energy Smart Program or NYISO demand response initiatives?
8. Was the cost of the utility "wires option" made known to bidders prior to bid submission?
9. Please explain in as much detail as possible the company's process for evaluating bids:
    a. Please specify any threshold eligibility requirements or other pre-screening criteria.
    b. Please indicate the criteria used in ranking submitted bids.
    c. If a weighting system was used, please indicate the weights associated with each of the criteria above.
10. Please explain in as much detail as possible the outcome of each bid process? Please indicate whether the following were factors in rejection of DG bids:

DG inferior to wires option on basis of:	Major factor	Moderate factor	Limited factor	Not a factor
Reliability/ Availability				
Cost				
Risk of not meeting milestones/need date				
Utility control				
System impacts				
Environmental permitting				
Flexibility to respond to changing needs				
Reliability/ Credibility of Bidder				

11. Please indicate whether there were other common factors contributing to rejection of DG bids.
12. Please indicate how the potential for lost revenues associated with the DG bid option was treated for purposes of bid evaluation.
13. Please indicate how environmental performance was treated for purposes of bid evaluation.
14. Please specify the cost to the utility to implement the DG Pilot Program.
    a. How many person-hours would you estimate were devoted to each bid process?
    b. What additional costs did the utility incur in the purchase of software, computer models and the like?
    c. Did the company retain any outside expertise to assist in the development of RFPs or analysis of bids received? Is so, at what cost?

Other Issues

1. How has the company's implementation of the DG Pilot Program evolved from RFP to RFP? Were any specific steps taken to enhance bidder participation? Were any specific steps taken to enhance the likelihood of eliciting cost-effective DG projects?
2. Outside the DG Pilot Program, does the company undertake any activities to apprise DG developers of the company's distribution system capital expansion plans?
3. Has the company considered supplemental methods (i.e., other than an RFP process) of considering and administering customer-owned DG as a planning resource? Have any of these alternative methods been implemented?
4. Please describe any enhancements that were made to your company's distribution system planning processes to facilitate review of distributed generation options.

DG Pilot Program Assessment

1. As specified in the Public Service Commission's Order Approving Pilot Program for Use of Distributed Generation in the Utility Distribution System Planning Process, the DG Pilot Program was initiated to meet a number of program objectives. In your opinion, to what extent has the DG Pilot Program increased understanding of:

    a. whether and to what extent distribution system needs can be satisfied on a least cost basis by DG?
    b. case-specific information on DG costs, benefits and impacts across a range of distribution system conditions?
    c. methods for evaluating customer-owned DG proposals against traditional distribution system improvement projects?
    d. whether a competitive solicitation process using requests for proposals (RFPs) is a viable and optimal means of eliciting a market response to the utility distribution system needs?

2. Do you think the DG Pilot program should be continued? If not, why not? If so, what changes should be made to improve the program's effectiveness?

3. Do you think there are other program models that may more effectively elicit customer-owned DG proposals?

APPENDIX A.2
DG PILOT PROGRAM QUESTIONNAIRE
DEVELOPER REPRESENTATIVES

Interviewee Information

6. What is your position with the company?
7. What is your role with respect to your company's participation of the DG Pilot Program RFPs?
8. Were you involved in the drafting your company's response to the DG Pilot Program RFPs?

Bidder Pre-Qualification

1. Did your company seek to pre-qualify to participate in any of the utility's RFP processes? For which utilities?
2. Where applicable, please explain why you did not seek to pre-qualify with certain distribution utilities.
3. Were you successful in pre-qualifying?
4. Did you find any of the utility's pre-qualification requirements to be burdensome? If so, how (e.g., required detailed and/or proprietary information, imposed stringent financial conditions)?
5. Were the utilities' criteria for pre-qualification transparent? Were they fair?

Participation in Bid Processes

1. Did you participate in any aspect of the utilities' RFP processes? Did you submit a competitive bid in any such process? If so, please specify which.

2. Did you attend any bidders conference? Were these conferences helpful in clarifying the utilities' distribution system needs, and in assisting you in constructing a responsive proposal? Is there any information you wish the utility would have shared at the conference?

3. Did you have adequate notice and time to prepare a responsive bid? How much lead time in advance of the due date is necessary, in your opinion?

4. How would you assess the utility RFP process in terms of providing <u>adequate guidance</u> on:
   a) the area on the electrical distribution system requiring upgrades;
   b) the required in-service date of the DG unit;
   c) the nature of the utility's preferred capital improvement project;
   d) the cost of the utility's preferred capital improvement project;
   e) the required level of utility control of the DG project;
   f) the required level of reliability of the DG project;

g) special system requirements/constraints.
h) expected utility payment to support the project (e.g., energy-only, capacity, ancillary services).
(i) the criteria (and associated weighting) the utility would use in evaluating bids.

5. For each of the above issues, would the RFP process been enhanced had the utility given bidders: 1) more latitude to respond to the system need; 2) relaxed the level of stringency in meeting technical or financial requirements.

6. In your opinion, did the projects chosen for competitive bid represent good candidates for deferral or avoidance through DG?

7. Was there any attempt made by the utility to coordinate the DG RFP with DG projects you were developing in the service territory? Are you aware of any such effort with other developers?

8. Was there an attempt to coordinate the DG RFP with other incentive programs, such as the NYSERDA Energy Smart Program or NYISO demand response initiatives?

9. Outside the DG Pilot Program, are you aware of any effort made by the distribution utility(ies) to apprise DG developers of the company's distribution system capital expansion plans? Would such a process be helpful in identifying potential "win-win" projects?

10. How much time (worker days) and/or money did your firm spend in preparing its bid?

11. Were any financial obligations (e.g., bonding requirements, the possibility of liquidated damages for non-performance, insurance, etc.), significant factors in your firm's decision to pursue or not to pursue bidding opportunities?

DG Pilot Program Assessment

2. As specified in the Public Service Commission's Order Approving Pilot Program for Use of Distributed Generation in the Utility Distribution System Planning Process, the DG Pilot Program was initiated to meet a number of program objectives. In your opinion, to what extent has the DG Pilot Program increased understanding of:

a. whether and to what extent distribution system needs can be satisfied on a least cost basis by DG?
b. case-specific information on DG costs, benefits and impacts across a range of distribution system conditions?
c. methods for evaluating customer-owned DG proposals against traditional distribution system improvement projects?

d. whether a competitive solicitation process using requests for proposals (RFPs) is a viable and optimal means of eliciting a market response to the utility distribution system needs?

4. Do you think the DG Pilot program should be continued? If not, why not? If so, what changes should be made to improve the program's effectiveness?

5. Do you think there are other program models that may more effectively elicit customer-owned DG proposals?

6. Would you support any of the following suggestions for increasing distributed energy deployment on utility systems?

   - Allow utilities to bid into the RFPs, with an impartial third party selected to make awards decisions?
   - Allow utility ownership of DG more generally?
   - Establish an "open season" program or standard offer for DG?
   - Initiate a "right of first refusal" for DG developers to bid to offset certain kinds of distribution system upgrades, whenever they may occur?
   - Create the ability for developers to share system upgrade costs with the utility, when that could facilitate interconnection? (For example, to increase substation fault current capacity.)
   - Make developers privy to utility 5-year capital expansion plans to facilitate CHP deployment?
   - Others?

APPENDIX B

PERSONS INTERVIEWED FOR DG PILOT PROGRAM EVALUATION

Utility Personnel	**Interview Date**
Sephir Hamilton, Central Hudson Gas & Electric	February 24, 2005
James Bunyan, National Grid	February 25, 2005
Jim Harvilla, New York State Gas & Electric	March 24, 2005
Dennis Ballard, Rochester Gas & Electric	March 24, 2005
Tom Dossey, Southern California Edison	June 9 and 17, July 8, 2005
Hawk Asgerisson and Richard Seguin, Detroit Edison	July 12 and November 3, 2005
David Le, Bonneville Power Administration	August 17, 2005

Distributed Generation Developers

Brian Balcom, Cummins NE Energy Systems	March 24, 2005
Deno Demaskos, Northern Power Systems[73]	April 27, 2005
Marc Aronson, Cogenix Corporation	May 10, 2005
William Cristofaro, Energy Concepts LLC	May 16, 2005
Bert Spaeth, Siemens Building Technologies	May 18, 2005

New York Agency Personnel

Michael Rieder, NYDPS	February 16, 2005
Mark Torpey, NYSERDA	November 29, 2004 and May 2, 2006

[73] Formerly with Real Energy

APPENDIX C

CASE STUDY DETAIL

Southern California Edison

1. Introduction

The state government and the investor-owned utilities (IOUs) in California have been active in promoting distributed generation (DG) through several policies, such as net metering, interconnection standards, and standby rates. The integration of DG into distribution planning is also one of the important issues on its agenda. In 2003, the California Public Utilities Commission (CPUC) directed the IOUs to incorporate DG into their distribution planning and to develop a methodology to evaluate DG as a distribution alternative. Among the IOUs, Southern California Edison (SCE) is taking a proactive approach to identifying opportunities for DG deployment to support the distribution system. SCE has participated in the Electric Power Research Institute (EPRI)'s Distributed Energy Resources Public/Private Partnership initiative (DER Partnership) since 2003.

The DER Partnership has provided invaluable opportunities for SCE to discuss with other stakeholders numerous issues surrounding the integration of DG into distribution planning. These issues include, but are not limited to, the expected cost-benefits of DG/distribution deferral projects from various stakeholders' perspectives, cost allocation among stakeholders, a DG screening and solicitation process, eligible resources for distribution deferral, and DG operational rules. As a result, SCE has developed a solicitation process and model contracts. SCE is currently searching for customers on or near constrained areas who either have DG units or could host them. If and when the Company finds sufficient customers with DG resources in such areas who are willing and able to participate in demand limitation arrangements, it will offer and negotiate agreements that allow customers with DG to use their capacity to defer planned upgrades to its system.

2. Background

SCE serves approximately 13 million people, 5,000 large businesses, and 280,000 small businesses in 430 cities and communities. Its service area extends over 50,000 square miles, covering 11 counties in central, coastal and Southern California. SCE owns and operates nearly 5,000 transmission and distribution circuits. The majority of the Company's distribution circuits are operated at 12 kV or 16 kV. During the restructuring process in California, SCE sold many of its power plants. The Company now owns and operates its Big Creek hydro facilities[74] (1,020 MW), the Mohave coal-fired plant at Laughlin, NV (1,580 MW), and the San Onofre nuclear power plant (2,254 MW).

[74] Several other smaller hydroelectric plants (about 20 MW total) were also retained and continue to be operated by SCE

The California Public Utilities Commission (CPUC) has been actively promoting distributed energy resources since mid-1990s. In 1999, the CPUC initiated an extensive rulemaking focused on DG, and directed California's investor-owned utilities to engage with stakeholders in discussions of policy issues related to DG, such as interconnection, standby rates, and integrating DG into distribution planning.[75] This rulemaking culminated in 2003, with a CPUC decision and order regarding ownership and operation of DG and its integration into utility planning.[76]

CPUC Decision 03-02-068 directed the California IOUs to (1) develop a methodology to evaluate DG as a distribution alternative; (2) incorporate the procurement process proposed by the San Diego Gas & Electric Company; (3) develop model contracts for DG facilities that could be used to defer distribution upgrades; and (4) pay compensation to DG projects that defer distribution system investments. Further, the Decision established four criteria to be used to determine the feasibility of DG projects as alternatives to distribution system investments. The DG must be:

(1) Located in the right place: "[t]he distributed generation must be located where the utility's planning studies identify substations and feeder circuits where capacity needs will not be met by existing facilities, given the forecasted load growth."

(2) Installed and operational: "[t]he unit must be installed and operational in time for the utility to avoid or delay expansion or modification."

(3) Provide sufficient capacity: "[d]istributed generation must provide sufficient capacity to accommodate [the utility's] planning needs."

(4) Provide physical assurance: "distributed generation must provide appropriate physical assurance to ensure a real load reduction on the facilities where expansion is deferred."[77]

In response to the CPUC Decision, SCE expanded its efforts to more fully incorporate DG into its distribution system planning process. SCE had been participating in the EPRI's DER Partnership since 2003. The DER Partnership explores with stakeholders ways to identify, evaluate, and solicit DG resources on constrained power grids and to integrate these resources into distribution planning. In 2004, SCE agreed to allow the DER Partnership to facilitate a stakeholder collaborative in Southern California to help incorporate DG into SCE's planning process.

3. Key features

Collaborative Approach

Through the DER Partnership, SCE was aware of experience in several other regions, including preliminary results of the NY RFP Process. Awareness of the New York experience led SCE to seek improvements in its process through collaboration with other

[75] CPUC Rulemaking 99-10-25, October 21, 1999.
[76] CPUC Decision 03-02-068 in R. 99-10-025, February 27, 2003.
[77] Ibid. page 18.

stakeholders. Specifically, industry feedback "suggested that utility solicitations could benefit from a better understanding of the needs of prospective DG providers, and that providers could be more responsive if they learned more about utility system planning processes and constraints."[78]

Since then, SCE has been working with a collaborative, facilitated by the DER Partnership, to explore ways to identify, evaluate, and solicit DG/DER (including energy storage and/or demand response) resources that may allow the deferral of upgrades or expansions to its distribution systems at lower costs and equivalent levels of reliability. The DER Partnership formulated a working group initially consisting of 16 parties representing all segments of the DER industry. Subsequently, this group grew to 30 parties, including SCE, DG manufacturers, utilities, customers, and representatives of the U.S. Department of Energy, the California Energy Commission, CPUC and others.

The goals of this collaborative process are as follows:

- "Using a stakeholder collaborative process to develop a DG or DER solicitation that developers, customers, vendors, and other third parties will confidently bid on, and that will lead to a pilot that can serve as a model for other procurements;
- Testing and demonstrating the stakeholder collaborative process;
- Developing innovative win-win approaches for encouraging DER and advancing DER market integration and policy;
- Documenting lessons learned and win-win approaches developed from the stakeholder collaboration so they can be duplicated and scaled in California and other states."[79]

The DER Partnership project team has played a critical role in the collaborative in recruiting participants and organizing the collaboration, planning and preparing materials for collaborative meetings, supporting SCE's analysis of distribution system needs, analyzing costs and benefits of DG to key stakeholder groups and facilitating stakeholder discussions and documenting the work of the collaborative and its conclusions on key issues.[80]

The DER Partnership held two workshops in 2004. The first workshop, in July, focused on educating stakeholders about the planning constraints and business needs of other stakeholders and identifying critical issues regarding DG procurement process. The second workshop, in October, focused on integrating recommendations developed by the stakeholder working group over the summer.[81] Before each workshop, the project team, in cooperation with SCE, worked on various issues such as the utility's analysis of distribution planning area needs, developing screening criteria for distribution projects and estimating the costs and benefits to various stakeholders of potential DG solutions.

[78] EPRI 2005, page 2-2.
[79] Ibid. page 2-4.
[80] Ibid. page 2-4.
[81] Ibid. page 3-3.

Type and/or location of DG or DER

CPUC Decision 03-02-068 clarified issues around DG ownership for both customer-side and grid-side applications. For customer-side DG, the Decision does not limit a utilities' ability to own DG units. Yet, the CPUC does not encourage utility ownership of DG units because the CPUC does not believe that utilities or their affiliates offer any specialized expertise in the manufacture, sale, or operation of DG (see page 24 – 29 of Decision 03-02-068). In the case of grid-side DG, the CPUC allows utilities to own and operate DG "only when it provides distribution value, not based on any perceived value of generation output," and when the DG solution is identified as the least cost investment under the utility planning process.[82] However, the CPUC also determined that utility ownership of grid-side DG is not necessary if the DG is equipped with sufficient control and "physical assurance" measures that will protect the utilities grid from problems should the non-utility generation fail to operate when needed.

SCE's primary focus in the DER Partnership has been on identifying customer-side DG projects that can provide benefits to both the customer and SCE's grid. SCE has concluded that grid side DG used solely to defer distribution investments is unlikely to be economically viable. SCE is actively seeking customers with existing Combined Heat and Power (CHP) units or customers who could install CHP, because CHP is often the most economically viable DG application, and because CHP systems tend to provide more capacity than other types of DG resources. The capacity provided by a DG unit is important to SCE, because the amount of capacity it needs to defer an upgrade to a constrained distribution circuit tends to be relatively large – in the range of 5 to 7 MW. It is also notable, that diesel-fueled backup generators are not considered as viable candidates for deferring system upgrades because California air quality regulations restrict their use to only meeting emergency needs or as temporary power sources for isolated facilities.[83]

Discussions with the collaborative identified two other important issues regarding the type of DER on which SCE will focus. First, the collaborative identified a need for SCE to help match customers with DG providers.[84] Second, collaborative discussions persuaded SCE to incorporate demand response as a supplement to DG in its distribution planning efforts as additional resources that may increase then number of participants able to participate in a deferment program. However, based on the wording and intent of the CPUC's Decision, demand response efforts alone are not being considered as a resource option to be used for deferrals. (The Company has other demand response programs for customers interested in demand response only.)[85]

Aside from the focus of the collaborative process, in order to meet the more immediate needs of SCE's distribution system, the company also "has been exploring and

[82] CPUC Decision 03-02-068, page 29.
[83] Personal communication with Tom Dossey, SCE, June 9, 2005.
[84] EPRI 2005, page 7-2.
[85] EPRI 2005, page 7-2.

developing the capability to use temporary, rented, portable generation units for load relief in situations where planned line and substation capacity improvements and expansions have been delayed."[86] In connection with this effort, SCE is also evaluating the benefits of owning portable DG units that could be used for distribution system support, but recognizes that economic justification and regulatory approvals will be significant hurdles.[87] DG investment in California is currently regarded as a generation investment and it would be difficult to find DG to be a least-cost generation investment.

DG Operation

The CPUC has required that DG units used for grid deferral purposes be coupled with "physical assurance" measures to ensure the distribution system will be able to serve its connected customers during peak load conditions. Physical assurance refers to on-site controls to ensure that the unit will operate when needed for grid support or that the amount of load normally served by the DG equipment will be automatically curtailed, if necessary, during peak load conditions.[88] To comply with this requirement, SCE has proposed an "Automated Load Reduction Scheme," consisting of metering, communication, relaying and control equipment and software.[89] The collaborative discussed allocation of the cost of physical assurance in detail. Initially, SCE proposed that customers should pay all costs of notification and control systems, however the Company ultimately agreed to cover a portion of these costs.[90] Thus, customers will be responsible only for that portion of the cost of physical assurance systems that is used to control the customer's generation and load. SCE proposes to fund the costs of its communication and notification systems from the amounts to be made available for customer deferral payments.

The SCE collaborative concluded that distribution systems are typically loaded to maximum capacity for only 200 to 400 hours per year. Accordingly, SCE believes that physical assurance requirements can be limited to these peak loading periods and can offer contractual arrangements that limit the number of hours that physical assurance measures will be required. [91] Initially, SCE interpreted the CPUC's requirement for physical assurance to mean that the utility would need to require physical assurance measures to be in place during all hours. However, discussions within the collaborative convinced the Company that control was only needed during a relatively small number of hours each year, reducing the risks and considerably increasing the likelihood that a DG customer might participate in a deferral program.

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[86] Ann P. Cohn and Michael D. Montoya 2004, *Southern California Edison Company's (U 338-E) Update on the Methodology and Process for Evaluating Distributed Generation as a Distribution Alternative* in R. 04-03-017, filed March 16, 2004, page 3.
[87] Personal communication with Tom Dossey, SCE on July 8, 2005.
[88] CPUC Decision 03-02-068, page 14.
[89] Tom Dossey 2004, "Key Elements of SCE's Proposed Distributed Generation RFP," a presentation on July 14, 2004.
[90] EPRI 2005, 7-2.
[91] Ellen Petrill 2005, "Creating Win-Win DER Opportunities through Stakeholder Collaboration, " a presentation at Restructuring Roundtable in Boston, MA on June 17, 2005.

Identifying Potential Upgrade Deferrals

SCE's screening of distribution projects is comprised of four steps: (1) initial upgrade project screening; (2) detailed analysis; (3) identification of candidate customer/participants; and (4) solicitation of participants. The first two steps focus on identifying proposed distribution upgrade projects that may lend themselves to deferment through capacity supplements or controls. The third and fourth steps focus on identifying and screening customers located in congested areas of the distribution system that either operate DG projects, or have the reasonable potential to use DG/DER to allow the utility to defer a distribution system upgrade.

In the first quarter of each year SCE identifies and updates its distribution upgrade/expansion needs as part of its 10-year distribution planning process. SCE identifies constrained areas and proposes remedial actions (upgrades or expansions) to relieve the constraints. It then screens the distribution upgrade/expansion projects to be installed during the next two years for certain characteristics relevant to using DG/DR as an alternative including:

- The proposed incremental capacity addition;
- The estimated costs of the upgrade project;
- The forecasted actual capacity that will be required to be served during each year;
- Other factors such as equipment maintenance requirements or obsolescence; and
- The estimated accuracy of the load forecasts used to establish the upgrade project.

Identifying Candidate DG Projects

For "grid side" alternatives, SCE compares the requirements for each project to the expected cost and characteristics of an "ideal" DG alternative – typically, a single gas turbine exactly sized to the needed load. Incremental costs required to keep the DG as reliable as the traditional distribution equipment are not considered, because all DG units are required to provide physical assurance.[92] If the "ideal" grid side DG is shown to be cost effective in this initial screening, more detailed analyses are conducted, focusing on such factors as the availability of gas supply and measures needed to achieve acceptable reliability.[93]

For "customer side" DG alternatives the characteristics and costs of the generation are not significant screening factors. SCE focuses, instead, on searching for customers who have existing DG units or have the potential to install and use DG/DER in the constrained area. If SCE finds customers who can potentially meet the CPUC's four criteria for DG for distribution planning mentioned above, these customers become candidates and are approached to see if they have an interest in participating in a deferral program. If the

[92] Ann P. Cohn and Michael D. Montoya 2004, *Southern California Edison Company's (U 338-E) Update on the Methodology and Process for Evaluating Distributed Generation as a Distribution Alternative* in R. 04-03-017, filed March 16, 2004, page 2.
[93] Ann P. Cohn and Michael D. Montoya 2004, page 2.

Company were to find a sufficient number of potential candidates that could each use their capacity to defer a single upgrade project, it will consider issuing a request for proposal (RFP) or using a similar bidding process.

SCE's solicitations will describe the distribution projects proposed to be deferred by DG, the general location of the projects, generic requirements for interconnection under Rule 21 and WDAT [wholesale distribution access tariff], as applicable, and conditions including the provision of physical assurance for load removal upon loss of generation.[94] Customers and parties who enter into Non-Discloser Agreements (NDA) with SCE can obtain more specific information on the distribution project, including specific locational requirements, capacity and term requirements, demand limitation requirements, and market reference price[95] This last item is an indication of what SCE may pay to a selected DG project and is close to the cost of the deferrable distribution project, based on carrying cost of capital for distribution deferral. The actual deferral payment can be higher or lower than the market reference price, depending on submitted proposals.[96] SCE was initially reluctant to disclose any information on deferrable costs, however through negotiations in the collaborative, the Company agreed to disclose market reference pricing to parties willing to treat the information as confidential.[97]

SCE will retain responsibility for evaluating bids submitted in response to its solicitations. As noted, SCE is allowed to own DG units for distribution support if such units are found to be least cost solutions. Thus, SCE may submit its own DG proposal to compete with proposals from other parties. SCE is required to evaluate its own DG proposals on an equal footing with proposals from other parties. In the evaluation process, SCE will first evaluate each proposal's technical adequacy, such as interconnection requirements, specific locational requirements, capacity and term requirements, demand limitation requirements. If the Company finds multiple proposals that meet the technical requirements, it will select the lowest cost proposal.[98]

The only payments to be made under SCE's proposed distribution upgrade deferral program are based on the costs avoided by the deferral of distribution investments. However, the collaborative discussed a number of ways for customers to receive additional benefits for DG projects that support the grid. As previously discussed, SCE's initial proposal limited participants solely to using the capacity available from DG projects for the purpose of distribution deferral. However, work with the collaborative convinced the Company to allow customers to include demand response in their proposals (although customers cannot propose demand response alone).[99] Further, SCE is considering investigating DG projects with customers who are already involved in the Company's curtailment and demand response programs, program designed to reduce

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[94] Tom Dossey 2004.
[95] Tom Dossey 2005, "Integrating "Customer Operated" Distributed Generation Into Distribution Planning," a presentation for SCE/E2I Collaborative Pilot Program on October 7, 2005.
[96] Ellen Petrill 2004, E2I DER Partnership Market Integration: California Pilot Project Workshop #2 Workshop Report, October 20, 2004.
[97] EPRI 2005, page 7-1; Ellen Petrill 2005
[98] Ann P. Cohn and Michael D. Montoya 2004, Appendix A.
[99] EPRI 2005, page 5-4 and 7-2

electricity prices during peak periods, because some of these customers may be able to provide both generation and distribution benefits.

In addition to SCE's DG screening process, the project team under EPRI's DER Partnership developed a screening tool in the form of an excel spreadsheet, which evaluates the cost and benefit of DG projects from different stakeholder perspectives. The spreadsheet uses several cost tests, each of which identifies costs and benefits from different perspectives, such as customers, DG developers, the utility or society. The screening tool allows for the reallocation of costs and benefits among stakeholders to find solutions in which all parties are better off. Further, it enables users to change various inputs relevant to DG projects to explore how each input affects costs and benefits to different stakeholders.[100] Although SCE does not use this screening tool to select participants in its distribution deferral program, participants in the DER Partnership have used it to better understand various ways of evaluating DG projects and the factors that influence project costs and benefits.

4. Results

SCE has not yet identified a proposed distribution upgrade or expansion projects that may be deferred by the capacity made available from DG/DR installations. For the 2003-2004 planning cycle, SCE examined 85 proposed system improvement projects and screened them along with an ideal DG alternative. In each case, the DG alternatives turned out to be more costly than the traditional wires projects. For the planning cycles in the following years, SCE has again not able to identify distribution upgrade projects that may be deferred by DG/DER facilities in a cost-effective manner. It is currently examining areas for the 2008 planning cycle. The Company originally planned to issue a solicitation in November 2004, but this was delayed due to "changes in SCE's distribution planning cycle, and its desire to seek CPUC approval for improvements to its Model DG Agreement resulting from the collaborative's work."[101]

During the summer of 2005, the Company reviewed 39 candidate locations (that need distribution upgrades) proposed for construction in 2008, and is focusing on 13 of these to look for available or potential DG resources.[102] SCE is searching for customers in these areas who currently operate DG/CHP systems or could host new systems. If SCE finds sufficient existing or potential DG capacity, the Company plans to solicit customer participation.[103] However, SCE is having difficulty finding promising sites, because:

1. The capacity needed to defer an upgrade project for 2 or more years, between 5 and 7 MW, is typically greater than the capacity that is available from customers with DG.
2. CHP units are often the only viable DG resources available to satisfy such large capacity needs, and it is difficult to find sufficient CHP capacity potential in the

[100] EPRI 2005, page 1-3.
[101] EPRI 2005, page 2-5.
[102] Personal communication with Tom Dossey, SCE, July 8, 2005.
[103] Personal communication with Tom Dossey, SCE, June 9, 2005.

constrained area. Additionally, it has been found that CHP units of significant capacity levels are often located on higher voltage systems, such as 66 kV transmission lines.

3. SCE's distribution grid is relatively flexible. This flexibility typically allows the Company to shift excess loads to other lines or systems because its radial circuits normally have tie and segmentation capabilities. Load shifting is a highly cost effective option, and this reduces the number of cases in which DG is cost effective.[104]

Given these challenges, it is unclear when SCE will find its first candidate project where the combination of a proposed upgrade that can be deferred by a simple reduction in capacity and a set of customers using DG and willing to provide physical assurance can be matched with each other.[105]

5. Conclusions

Although SCE has not yet issued an RFP or other form of solicitation, it has made important progress in developing a DG planning process with the input of a collaborative. The collaborative process has resulted in benefits to both SCE and other parties. SCE has identified other potential opportunities and synergies, and it has also softened its position on several issues about which other parties felt strongly. Important issues the collaborative discussed include the following.

- SCE has included demand response as a resource that can supplement DG projects. This approach appears to provide more flexibility to customers and opens additional opportunities for grid-supporting DG.
- SCE is considering including participants in the Company's existing curtailment and demand response programs in its DG solicitation for distribution deferral projects. This will allow customers to gain both distribution and generation benefits.
- SCE has agreed to limit its control over customer-owned DG units used for demand reduction/distribution deferral to 200 - 400 hours per year. Initially the Company sought to control DG units all hours of the year.
- SCE has agreed to cover a portion of costs of notification and control systems. Initially the Company proposed having customers pay all of these costs.

Other aspects of the SCE experience that are relevant to activities in New York are as follows.

- While the requirement for physical assurance through load curtailment has the potential to limit customer participation, it may provide net benefits by ensuring the reliability of the resources participating in this program and the power grid. In addition, it could solve issues associated with utilities' requests for redundant

[104] Personal communication with Tom Dossey, SCE, June 17 and July 8, 2005.
[105] Ibid.

equipment in DG projects. It would be worthwhile to explore this approach in detail.

- While SCE has worked with stakeholders in developing their DG planning process, it does not appear that there will be an ongoing role for stakeholders. A broader review of the utility's proposed distribution projects might well lead to more DG projects than a process in which only one party – the utility – screens for DG applicability. It is not clear whether SCE has investigated this approach in developing its DG planning process.
- The DER Partnership developed a DG screening tool which evaluates the cost and benefit of DG projects from various stakeholder perspectives. Although SCE does not use this screening tool, it has been a valuable tool for participants to better understand various ways of evaluating DG projects and the factors that influence project costs and benefits.

Attachment: Collaborative Achievements as Reported by the EPRI DER Partnership

Topic	Initial Status	Final Results
Model for successful DG solicitation	Initial response from CA IOUs to CPUC Order did not address all stakeholder needs or capabilities	DER Partnership stakeholder process has engaged participants in defining their needs, recognizing co-parties' needs, and seeking common ground
Communication among stakeholders	Participants wary. Based on previous experiences skeptical that progress could be made	Participants openly communicate, are willing to listen, share and address problems jointly
Utility distribution planning process	Non-utility participants knew little about utility planning	Non-utility participants better understand utility service obligations, planning horizons and uncertainties, and investment process
Value of DG to utility & providers	Most participants unfamiliar with timing & valuation issues affecting utility deferral, or driving DG investment	Factors influencing DG value to utility are better defined; valuation methodology now explicit, and tools accessible; range of grid values explained; DG provider investment concerns explored
Information needs	Utility uncertain what info DG providers need to prepare responsive proposals	Specific types of information identified as critical to DG providers to allow rational participation, including physical location and deferral value in the form of a 'market reference price'
Confidentiality issues	Utility cautious about sharing information regarding system upgrade costs, needs or customers	2-step process proposed to qualify respondents and require non-disclosure agreements, to limit recipients of sensitive information
DG procurement process	Exclusive focus on traditional RFP approach	Considering alternatives to RFP approach for next solicitation, using credits, tariffs, etc.
Recognizing multiple DER values	Initial utility proposal did not address importance of multi-program participation to DG providers; would have foreclosed opportunities.	Considering ways for customers / providers to receive value from other programs for *generation*-related benefits (e.g., curtailment), in addition to *distribution deferral* value from this program
Recognizing non-DG demand response	RFP limited to capacity supplied by DG-only	If DG is used to meet critical loads, demand response resources may be offered to meet utility's needs
Reliability requirement	Initial 'physical assurance' concept required customer to drop its load whenever DG is down – 24 x7, 8760 hours/year	Customer commits only for utility's peaking needs, perhaps 200-400 hours/year, estimated in advance by month, hours of day, etc. with adequate provisions for maintenance of DG facilities
Matching DG providers & utility customers with potential host sites	Utility had not identified the need to assist	Utility willing to invite customers to request to be contacted by qualified respondents
Matching utility deferral needs with proposers' investment needs	Payments for 1 or 2-year deferral considered inadequate to assist project financing	Two-year agreement with right of first refusal or renewal option if deferral remains utility's least-cost or best-fit option may enhance attractiveness of customer participation
Response time for DG solicitation	Driven exclusively by utility planning cycle	Driven by combination of utility planning needs and developer time requirements to put projects together
Regulatory oversight of process	Strict literal interpretation of Commission directives to minimize utility regulatory risk	Recognition that Commission intent is better served by more flexible win-win approach supported by participants and regulatory staff
Cost to assure responsive load reduction	Host customer to absorb 100%	Utility to finance its portion of notification and control system costs, & deduct from deferral payments
Model contract between utility and successful proposers	Model agreement prepared by utility; DG providers challenged it	Model agreement rewritten and much improved from both utility & DG provider viewpoints
Overall project risk	To be borne almost entirely by DG customer / developer	To be allocated between utility and DG customer / developer as necessary to elicit win-win responses

Detroit Edison

1. Introduction

Detroit Edison has been taking a proactive approach to incorporating DG into electricity distribution since 2003. The company began applying DG for distribution system support in the summer of 2002, when growing loads were stressing several areas of their system. In that year the Company operated several mobile DG units for short periods of time to stabilize its system. Based on the success of these deployments, the Company has fully incorporated DG into distribution system, even adding dedicated DG staff to its distribution planning department and including DG in its capital budget planning.[106] The Company has found DG to be an effective way to deliver "just-in-time" and "right-sized" distribution capacity to resolve smaller short falls while minimizing the initial capital outlay.

To date, Detroit Edison has deployed 12 distribution DG projects totaling around 20 MW. Included in these projects were 3 used in an intentional islanding and a leased customer generator used to manage loading on an overloaded circuit. Most of the projects are considered temporary installations, designed to operate until system upgrades have been completed (from 1 to 5 years). However, the company has also established 18 longer-term DG projects (totaling 10 MW) at customer sites, through its Premium Power program. Though their primary goal is to provide premium power to customers, these projects provide some distribution system benefits as well. The Company has relied primarily on diesel and natural gas fueled engines, however they have also installed several demonstration projects utilizing fuel cells, photovoltaics and flow batteries.

2. Background

Detroit Edison generates and distributes electricity to 2.1 million customers in Southeastern Michigan. The Company's service area covers 7,600 square miles and includes nearly 975,000 poles and 42,000 miles of overhead and underground wire. Roughly 20,000 circuit miles are rated at 4.8 kV, and roughly 19,000 miles are rated at 13.2 kV. There are roughly 1,880 circuits at 4.8 kV and 930 at 13.2 kV.

The electricity restructuring process in Michigan required utilities to divest their transmission assets, but not generation assets.[107] Detroit Edison sold its transmission system and now operates as an electricity generation and distribution company, with nine major generating plants. Operating in these two business areas positions the Company particularly well to integrate DG into the distribution of electricity. In addition, one of Detroit Edison's sister companies, DTE Energy Technologies, is marketing various kinds of DG technologies across the U.S. This relationship may have also contributed to the acceptance of DG within the Company.

[106] Hawk Asgeirsson, 2004, "Detroit Edison Distributed Resources Utility Applications & Case Studies," Presentation at IEEE PES General Meeting on June 9, 2004.
[107] However, a utility with generation exceeding 30% of the market is required to mitigate its market power.

3. Key Features

Utility Driven Approach

Detroit Edison has developed a utility-driven approach to integrating DG into distribution planning. That is, the Company plans the deployment of DG units on its own, with little input from stakeholders. In addition, the Company owns (or leases) and operates all of its DG capacity. Two aspects of this DG development model are particularly important to the success of Detroit Edison's efforts. First, DG projects do not result in lost revenues for the Company. Because they own DG units, they earn revenue on the units' output. Second, the projects can be put into ratebase, allowing the Company to earn a return on the investment. The Company 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."[108] As discussed in other case studies, lost utility revenues and the ratemaking treatment of DG can be significant barriers to the incorporation of DG into distribution.

While Detroit Edison does the bulk of its DG planning on its own, the Company does interact with customers regarding DG in other ways. First, once they have identified a site where grid-support DG is a cost effective solution, they must work with the affected community to site a generator. The Company reports that, in many cases, the community is receptive to DG because the alternative could be service interruptions due to an overloaded circuit or system upgrade work and because the DG units only remain in the community temporarily. Second, Detroit Edison seeks to identify large customers on overloaded circuits who might host generation. The Company has worked with several such customers in the past to develop projects that provide premium power (increased reliability) for the customer and grid support for the Company. Another important component is that Detroit Edison's Protective Relay Group is an integral part of the site selection process and involved up front by helping to choose sites that are easy and inexpensive to protect. This is quite often not the case with typical customer generation interconnects, where the Utilities Protective Relay Group may be among the last to know where a generator interconnect will be.

Type and location of DG

Detroit Edison uses primarily natural gas and diesel fueled DG units mounted on trailers. The mobility of the units enables the Company to deploy them rapidly and to use them in more than one location. Reuse of a generator in a new location improves the economics of the investment in the generator. The Company differentiates DG applications among emergency (immediate relief of a problem), temporary (1 to 4 years), and permanent (5 years).[109] In addition, because Detroit Edison primarily deploys these DG units during the summer, it is now considering leasing its portable generators during the winter to

[108] The Journal for Onsite Power Solutions, 2004, September/October 2004 issue.
[109] Jakubiak, E. and Asgeirsson, H. (Detroit Edison) "DG Comes to Detroit Edison," a presentation on April 8, 2003.

utilities with winter peaking systems. Although, this concept has not been implemented at this point, Detroit Edison has had some preliminary discussions with Progress Energy on this topic. In the future, this would further improve the economics of the generators.

Detroit Edison typically deploys DG in one of three ways: internal to the distribution circuit, at a substation, and in an island mode to support maintenance work. However as noted, the Company is also working with large customers on overloaded circuits who could host generators. In these cases of customer-sited DG the company 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. As of July 2005, Detroit Edison had installed over 16 DG units on customer sites to provide premium power and grid support.[110] Detroit Edison also notes that customer-sited DG can be an effective customer retention tool.[111] (Customers in Michigan are able to choose their electricity supplier.)

When siting portable DG units, Detroit Edison performs community outreach, to help gain acceptance of the idea. The Company shows parties a short video, which introduces the idea portable power for grid support.[112] Property is leased for the projects from property owners, and lease payments provide a welcome revenue stream to schools churches and other organizations. To date, the Company has not encountered significant opposition to these facilities (e.g., based on noise or emissions) in the siting process. In fact, Detroit Edison uses former and existing hosts as references. Both community leaders as well as the customers contact information where the DG units have been sited are used as references when discussing the possibility of siting new DGs. In this way, the stakeholders in the new site area can have a non-utility reference of how the installation has been for others so they can become more comfortable with this new DG siting prospect.

The Company must obtain air permits for diesel units but not for gas-fired units, due to the lower emission rates of gas-fired units. The Company also notes that placing a temporary generator in a given location can facilitate the siting of permanent infrastructure over the longer term. That is, if the Company believes a new substation will be needed, the use of a temporary generator near the location can be an effective first step in establishing the new facility.

DG Operation

The company now uses sophisticated monitoring and remote control devices for DG units. While old DG units used a simple control system, which only allows for "on" and "off" controls of DG units, new units are typically equipped with a more sophisticated device (programmable logic controller chip) that transmits operational data such as oil pressure, loading level, fuel consumption and temperature. Operational data is sent to the substation control panel via various communication technologies, including radio,

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[110] The size of DG varies from 150 kW to 750 kW in this application.
[111] Personal communication with Hawk Asgerisson and Richard Seguin on July 12, 2005.
[112] The Journal for Onsite Power Solutions, 2004

satellite or cell phone signals, or broadband cable modem. The communication technology chosen depends on what is easiest at the specific location. Monitoring equipment is duplicated for safety and reliability. Both Detroit Edison and the hardware supplier, DTE Energy Technologies, can monitor DG units via this equipment. Also, relay protection is often installed to DG units in addition to the protection device embedded in the DG system. (Relay protection is required to protect the grid from abnormal operation of the DG such as under/over voltage and frequency).[113]

Notably, Detroit Edison has automated the operation of DG using new communication and monitoring technologies. Automated load following means that when the load reaches a predetermined level, the DG is dispatched and provides power at a base level. When the load reaches a second predetermined level, the generator increases its output in order to maintain a relatively constant load level on the circuit. No DG units have ever failed to operate in time for easing distribution constraints. In one instance, a natural gas generator did not automatically operate at its predetermined level of load, but the threshold was set well below emergency conditions, so Detroit Edison had sufficient time to fix the automated system before the grid experienced emergency conditions.[114]

Identifying High Cost Areas

The Company uses EPRI's Distribution Engineering Workstation (DEW) to identify and evaluate potential DG sites in its service area. The DEW is a load flow model with a graphical interface that allows for real-time modeling of a circuit and potential DG on the circuit.[115] The Company has used the DEW to:

- Identify locations where DG could support the grid or delay a system upgrade,
- Evaluate different types and sizes of DG units at a given location,
- Estimate the number of hours a particular DG facility would operate,
- Quantifying impact of a DG facility on the distribution system
- Model cogeneration, induction, inverter and synchronous generators
- Perform planning engineering analyses on load, voltage, and harmonics, and
- Perform multiple source fault analyses.

Identifying Cost-Effective DG

Detroit Edison's initial use of DG for grid support came in response to critical distribution system problems – overloaded equipment – that could not be solved quickly enough with distribution system upgrades. Cost was not an issue in these cases. However, the Company has found that temporary DG installations can lower overall costs by deferring distribution work in non-emergency situations.

[113] Ibid.
[114] Personal communication with Hawk Asgerisson on November 3, 2005
[115] Jakubiak, E. Detroit Edison, 2004, "Aggregating Distributed Generation to Participate in the Energy Market," A presentation at EEI Fall TD&M Conference on October 10-13, 2004.

The Company typically compares the annual cost of deploying the DG unit to the annual cost of the distribution upgrade project, to determine cost effectiveness. In addition, it is important to note that the Company does not allocate all of the cost of mobile DG units to one project, because they expect to use these units at multiple locations over the life of the equipment. Furthermore, the Company has found that comparing the costs of DG projects to the costs per kW *of the capacity shortfall* rather than per kW of *installed total capacity*, provides better planning information.[116] However, this cost comparison is only one factor of a decision to deploy DG at Detroit Edison. Other factors, such as distribution maintenance schedules and manpower, affect the decision to defer a project.

4. Results

To date, Detroit Edison has deployed nearly 12 projects totaling over 20 MW. These figures do not include DG units installed under the premium power program and technology demonstration. Below are descriptions of several projects.

Internal to distribution circuits

A 13.2 kV radial system near Ann Arbor was experiencing overloading due to a delay of the Collins substation project, unusually fast load growth and hot weather. The delay of constructing the Collins substation was caused by the delay of obtaining community approval to build the substation. The Company was not able to solve the problem with load transfers or a portable substation. A 2-MW diesel generator was installed to relieve the system at the location of the planned substation.[117]

Relay protection was installed to the DG unit for grid protection in addition to the unit's internal relay. 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.

We are aware of six other cases in which Detroit Edison installed DG units on a temporary basis (between 1 and 4 years) to relieve load on distribution circuits. In two of the cases, the grid upgrade had been already planned or was underway, but quick DG solutions were required in order to relieve loads until the upgrades were completed.

Substation applications

A 41.57 to 4.8 kV substation at Adair, 50 miles outside of Detroit, was experiencing excessive load. Although this rural area has low load growth, a 2.5 MVA transformer in

[116]Often planners evaluate the cost of a distribution investment per kW of capacity *added*. So a $10,000,000 investment that added 10 MW would be regarded as a $1,000-per-kW investment. A $2,000,000 DG project that added 2MW would also be regarded as a $1,000-per-kW project. However, in many cases only several MW are needed to relieve the shortfall, and large distribution projects may require much more investment than is needed. Evaluating projects per kW of capacity shortfall helps planners better match the investment to the need. In this example, if only 2 MW were needed, the DG project would cost $1,000 per kW of shortfall, while the distribution upgrade would cost $5,000 per kW of shortfall.
[117] Hawk Asgeirsson and Richard Seguin, 2002, "DG Comes to Detroit Edison," in Transmission & Distribution World magazine on Oct, 2002, at http://tdworld.com/mag/power_dg_comes_detroit/

the substation was periodically reaching its maximum loading. The Company installed a 1-MW natural gas generator to relieve the transformer. As in the Collins installation, there is redundant relay protection, but at Adair additional protections were instituted to prevent islanding of circuit.[118] The company operates the DG unit any time load on the transformer is above its nameplate rating.

Although the DG project was more expensive than the substation upgrade, the Company needed the DG because the substation project could not be completed soon enough.[119] The DG installation allowed the substation project to be deferred for two years

At Detroit Edison's Union Lake substation, the Company found the cost of a DG project to be significantly below a proposed substation upgrade. The annual cost of the T&D approach was $137,000. The annual cost of the DG project was $61,000. This T&D project has been deferred for 4 years.[120]

Island mode for maintenance work

In two other projects (at the Quail and Richville substations), DG units were operated in island mode to avoid service interruptions during maintenance work. In both cases, substation feeds were damaged by tornados, and the installation of portable generators saved certain customers from having 2-10 hour outages.[121]

5. Conclusions

Detroit Edison has found several effective niches for DG in its distribution system, and the Company has fully incorporated DG into its distribution planning process, with staff dedicated to DG added to the Company's planning staff. The following key factors have allowed and incentivized the Company to pursue DG aggressively.

- The Company owns and operates the DG, removing concerns about lost revenues from customer owned DG;
- The Company is able to own both generation and a distribution system;
- The Company is able to earn a return on investments in DG;
- The Company uses the DG as distribution capacity; and
- The Company's relationship with DTE Energy technologies, a DG vendor, may have increased its comfort level with DG technologies.

To date the Company has focused on deploying mobile DG units for temporary grid support. Mobile DG units are particularly economic solutions for short-term grid support (i.e., deployed for several years only) and for problems that exist for only a few hours per

[118] Hawk Asgeirsson and Richard Seguin, 2002, Section "DG Installed — Adair Substation"
[119] Hawk Asgeirsson, 2004.
[120] Hawk Asgeirsson and Richard Seguin, 2004; personal communication with Hawk Asgerisson and Richard Seguin on July 12, 2005.
[121] Ibid.

year. The Company is also working with large customers on overloaded circuits to develop customer-sited DG projects. These projects have multiple benefits including customer retention and grid support for the utility and reliability enhancement for the customer.

This utility-driven model of developing DG is likely to provide certain benefits while precluding others. This tradeoff can be summarized as follows.

- Short-term deployment of mobile DG units on the grid can lower the cost of distribution service by deferring distribution system work and serving customers during work. This appears to be an unmitigated benefit to customers. The utility may be able to provide this service more efficiently than third-party DG providers.

- Detroit Edison's provision of *customer-sited DG* provides benefits to the utility and to customers. However, this service may preclude customers from receiving other benefits. Specifically, third-party DG providers are likely to provide large customers with more innovative and comprehensive DG services, but these companies may be reluctant to invest resources in Detroit Edison's service area due to perceived unfair competition with the utility. A key difference in the services provided by Detroit Edison and those that might be provided by third-party DG companies is that the utility owns and operates all customer-sited DG. Third party DG providers would likely explore other ownership and operation scenarios with customers as well as broader process changes at the customer site that could improve efficiency. In addition, a utility is unlikely to pursue onsite generation aggressively with customers in areas where grid support is not needed. Competitive DG providers would market their services to all large customers.

BPA Non-Wires Solutions

1. Introduction

Since 2002, the Bonneville Power Administration (BPA) has been exploring "Non-Wires Solutions" (NWSs) as a way to delay the construction of transmission infrastructure. BPA defines NWSs as "the broad array of alternatives, including but not limited to demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system."[122]

BPA is in the process of incorporating NWS into its transmission planning process. They have developed a process in which NWS are first screened for cost effectiveness and then detailed, site-specific studies are performed for certain alternatives that pass the initial screening. In addition to this process, BPA has initiated a number of pilot projects to gain experience with certain technologies and better understand the role that NWS can play in providing transmission service.

To benefit from regional stakeholders' views and expertise, BPA created the Non-Wires Solutions Round Table (the Round Table) in 2003, and the agency has benefited from this stakeholder input considerably. The Round Table reviews BPA's methods of procuring NWS, discusses economic, technical and institutional barriers to NWSs and makes recommendations to BPA to refine the procurement process. The Round Table also reviews detailed studies and NWS pilot programs and provides input to BPA to refine and improve them.

2. Background

BPA provides approximately half the electricity consumed in the Pacific Northwest, and owns and operates 75 percent of the electrical transmission system in the region. BPA's transmission system includes more than 15,000 miles of high-voltage transmission line and 285 substations. At peak usage, the system transmits about 30,000 megawatts (MW) of electricity to customers in Oregon, Washington, Idaho and Montana, as well as to parts of Wyoming, Nevada, Utah and California.

BPA has not constructed a major transmission line since 1987. Instead, they have strengthened the operational capability of their transmission grid through projects like upgrades of communications and control systems and installation of voltage support equipment. During the past two decades, BPA has also extensively pursued energy conservation and load management programs. For example, BPA avoided the construction of a 500-kV line in Washington State line by building a new substation, installing voltage-support equipment and conducting targeted energy conservation program in the Puget Sound area.

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[122] Bonneville Power Administration (BPA), 2004, *Transmission Planning Through a Wide-Angle Lens: A Two-Year Report on BPA's Non-Wires Solutions Initiative*, September 2004.

However, loads on BPA's transmission system have been approaching the system's capacity in recent years, forcing them to consider major transmission construction. In 2001, BPA proposed $775 million in transmission projects.[123] Siting this new infrastructure represents a considerable endeavor – all of the projects must undergo review under the National Environmental Protection Act (NEPA). Thus, BPA began investigating options to defer or avoid transmission construction, commissioning an in-depth study of NWS. This study, performed by Energy and Environmental Economics, Inc., and Tom Foley and Eric Hirst in 2001 mainly recommended implementing a 10 year transmission planning study to provide BPA sufficient time to consider all available NWS and refining BPA's existing transmission planning process by adding a procedure to compare the costs of specific proposed transmission projects and NWS. Further, the study reviewed 20 existing transmission plans using the proposed method.

Based on the findings of the 2001 study, BPA launched its NWS initiative in 2002. The primary goals of the initiative are to investigate NWS and incorporate them into BPA's transmission planning process. In 2003, to support the initiative, BPA established a collaborative process called the Non-Wires Solutions Round Table to gain a regional perspective through discussions with stakeholders in the Northwest.

3. Key Features

Collaborative Approach

Since 2003, the Round Table has been engaged in four major issues: reviewing BPA's NWS screening criteria; reviewing screening analyses and detailed studies of particular problem areas on BPA's transmission system; developing information on non-wires technologies; and addressing institutional barriers.[124] Below are brief summaries of these activities.

- **Screening criteria**: BPA and its consultants developed a screening tool that allows them to evaluate a transmission problem quickly to determine whether NWS are applicable to the problem. The Round Table is reviewing this tool and making recommendations to refine it.
- **Detailed studies**: With assistance of consultants, BPA prepares more detailed analyses of transmission problems that pass initial screening. The Round Table reviews these studies and provides input.
- **Non-wires technologies**: The Round Table provides a forum for the exchange of information about NWS and their use to support transmission systems.
- **Institutional barriers**: Round Table participants have engaged in extensive discussions of institutional barriers to the deployment of NWS, such as lost utility revenues, lack of incentives for accurate load forecasting, lack of transparency in

[123] BPA, 2004.
[124] BPA, 2004.

transmission planning, inaccurate price signals for energy and transmission, the reliability of non-wires solutions, and the funding and implementation of NWS.

The Round Table is an advisory body, not a decision-making body. Its purpose is to aid BPA in incorporating NWS into its transmission planning, and it will cease to meet once BPA has established the process by which it will evaluate NWS. Currently, BPA expects to discontinue the group in 2006. The Round Table's input has been extremely valuable to BPA. Moreover, the exchange of information within the Round Table has increased acceptance of NWS among the various stakeholders in the Northwest, facilitating the implementation of BPA's pilot projects.

Type and Location of DG

As noted, BPA is exploring a full range of NWS to defer transmission upgrades and expansion. This includes not only DG but also other resources at customer sites, such as demand response, direct load control and energy conservation. To date, BPA has focused on customer-owned NWS. The agency does not view DG units owned by BPA as a cost effective option. That is, without benefits to a customer, the grid-support benefits of a DG unit would not exceed the costs.

Regarding DG technologies, BPA has testing microturbines and diesel generators through its pilot projects. However a subgroup within the Round Table has recommended that BPA should not rely on diesel generators for pilot projects, because the economics of diesel engines are well known and because of concerns over air emissions from diesels.[125] Further, BPA has not focused on wind power as an alternative to transmission; however, the subgroup has recommended further investigation of wind power, especially research into whether the wind resource in the Northwest is well correlated to peaks in electricity demand.[126]

DG Operation

In terms of DG operation, BPA seeks agreements with customers in which the customer allows BPA to install communication and control equipment on the DG unit and operate the unit during periods when grid support is needed. The customer is free to operate the DG at any time as well to meet their own needs. BPA does not envision including an explicit limit on their ability to operate the unit in the contract, however BPA is clear that they will only operate the unit when it is needed, and this is likely to be a small fraction of hours. In the case of diesel-fueled generators, operation is also limited by air regulations.

Screening Transmission Projects for NWS

Identifying and evaluating locations for NWS in BPA's transmission planning is an evolving process, and BPA is still refining it with input from the Round Table.

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[125] BPA Roundtable Recommendation, "Policy Issue #2 Design 2004 Pilots"
[126] BPA Roundtable Recommendation, "Policy Issue #2 Design 2004 Pilots"

Currently, the process involves three steps. Transmission planners first fill out an Excel-based screening questionnaire to determine the general characteristics of the transmission project being considered. This questionnaire is designed to determine whether the problem is amenable to a NWS and the magnitude of the deferrable costs. BPA has established a policy in which all transmission projects in excess of $2 million are screened using this tool.[127] They have found that the deferrable costs of transmission projects costing less than $2 million tend to be too small to make NWS viable.

BPA screens around a dozen projects out of over a thousand projects. After screening a number of transmission projects using the Excel-based initial screening tool, BPA ranks them according to certain criteria, such as the magnitude of the deferrable costs and the amount of capacity needed to defer the project. High level screening studies are then performed on the projects most suitable to NWS.[128] In this analysis, the lowest cost NWS are compared to the transmission project to determine whether any NWS are likely to be cost effective. These low-cost NWS options are evaluated using the following costs tests:

- Total Resource Cost Test (Net direct costs and benefits to tall stakeholders)
- Transmission Utility Cost Test (Impact on revenue requirement)
- Societal Cost Test (Net social costs and benefits including externalities
- Participant Cost Test (Net financial impact on customer)
- Ratepayer Impact Measure (Impact on rates)[129]

The Total Resource Costs (TRC) test is the most important test in this screening process. If NWS do not pass the TRC test, BPA does not continue to evaluate them. Other cost tests are used to identify stakeholder specific impacts and to gain useful insights about reasonable cost allocations among stakeholders. Notably, lost transmission revenues to BPA are included in the TRC test.

This screening analysis results in a fairly lengthy document (over 50 pages) summarizing the transmission problem, the deferrable costs, the NWS alternatives evaluated, the cost analysis of the NWS and various sensitivity.

Currently, BPA is considering streamlining the NWS planning process described here by merging the first two steps into one. They have found that the screening studies often come to the same conclusions as the initial screening questionnaire that transmission planners fill out. Thus, they are exploring ways to replace these two screening steps with one step that is less labor intensive than the current screening studies.[130]

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[127] BPA 2004, page 4.
[128] Non-Wires Solutions Roundtable, 2005a, "Non-Wires Roundtable Meeting Notes on April 20, 2005."
[129] The Energy Efficiency Group (EEG) & Transmission Business Line (TBL) of BPA and Energy and Environmental Economics, Inc. (E3), 2004, *Non-Wires Solutions to Lower Valley Power and Light Transmission System Reinforcement Project*, January 12, 2004, page ii; EEEA and EEG and TBL of BPA, 2004, *Olympic Peninsula Study of Non-Wires Solutions to the 500 kV Transmission Line from Olympia to Shelton and a Transformer Addition at Shelton*, January 12, 2004, page ii.
[130] Personal communication with David Le on August 17, 2005.

Notably, at least two high-level screening studies performed for BPA recommended exploring the benefits of NWS to distribution systems in addition to transmission systems, because those benefits could increase the total value of NWS and could provide additional sources of funding. In response to this recommendation, BPA and the Round Table have been discussing ways to collaborate with local distribution utilities to support NWS. Approaches that have been discussed include (1) the use of system benefits charge funds collected by distribution utilities to support BPA's pilot projects, and (2) the use of existing utility programs (e.g., efficiency and demand response programs) to support DG that could defer transmission investment.

Detailed Studies

As a third step, BPA conducts detailed studies, which seek to determine exactly how much capacity could be captured by the NWS at specific sites and to identify any site-specific problems that may prevent the use of NWS. If a detailed study identifies a viable NWS option, BPA either issues an RFP or works with a single NWS provider to develop the project. BPA notes that it uses an RFP in cases where there are multiple qualified providers.

At this point, the projects BPA has developed through this process are considered pilot projects, designed to test:

- "how, when, where, and under what circumstance portfolios of NWS can provide regionally cost effective power system reliability," and
- "how utilities and others (e.g., large consumers or third-party aggregators) can identify and capture benefits from the proposed [NWS] and [test] under what circumstances others are willing to cost-share in the non-wires pilot project development and implementation."[131]

Currently, detailed studies performed on NWS for BPA are reviewed by the Round Table participants. The Round Table and its subcommittees review study findings and provide recommendations to BPA for further review, program and/or pilot implementation and for improvements to future studies.[132]

4. Results

To date, BPA has completed a detailed study of one problem transmission area, the Olympic Peninsula, and has begun another study of the South Oregon Coast. On the Olympic Peninsula, BPA estimates annual load growth of 22 MW, and this is expected to exceed the transmission capacity in 2008. A 500 kV upgrade on a line from Olympia to

[131] BPA, "Program Overview and Requirements," a request for proposal for pilot projects issues in June 2004.
[132] BPA Roundtable Recommendation, "Policy Issue #4 Review of the Detailed Studies"

Shelton was proposed as the most cost effective conventional transmission project to meet the needs of this area.[133]

With the screening study and the detailed study of the Olympic Peninsula, BPA evaluated a number of different NWS, including DG, combined heat and power, energy efficiency, demand response and direct load control.

Based on the results of these studies, BPA developed a plan to procure a package of NWS to defer the Olympic Peninsula transmission upgrade for five years. This package is described as follows and summarized in the table below.

- Through a 4-5 MW DG aggregation project by Celerity Energy, BPA is testing the feasibility of aggregating small scale generators, such as backup generators located at hospitals and governmental facilities.[134] Celerity has installed automatic controls to dispatch generation from this resource on an emergency basis when it is needed to support the transmission system. Celerity has identified a dozen potential generators, and 2.5 MW of capacity had been aggregated as of May 2005.[135]
- Demand response measures are obtained from four large customers (Nippon Paper Industries, Port Townsend Paper Company, Manson PUD No. 3 and naval facilities) through an Internet-based trading platform, known as Demand Exchange (DX). The maximum reduction by the participants is 66 MW per hour in the evening and the average reduction is 22 MW per hour. Customers reduce their electric loads from the grid in different ways, including operating on-site generation and curtailing production.[136] BPA has been testing the reliability of this program since 2004 and plans to continue testing between 2005 and 2009.[137]
- BPA has established direct control of water and space heating equipment in 31,000 homes. Each home provides 2 kW, which totals 62 MW of load response.[138] BPA plans to rely on 20 MW of the 62 MW. This pilot was initiated in 2005 and the goal in 2005 is to obtain 5 MW of curtailable load by December, 2005 from one utility or a combination of utilities.[139]
- Energy efficiency measures are obtained from new energy efficiency programs with local utilities. BPA plans to obtain 15.4 MW of load reduction from energy

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[133] EEEA and EEG and TBL of BPA, 2004, *Olympic Peninsula Study of Non-Wires Solutions to the 500 kV Transmission Line from Olympia to Shelton and a Transformer Addition at Shelton*, January 12, 2004, page 1.
[134] BPA 2004; Brad Miller, 2005, "BPA's Approach to Risk: What we are working on. How we are changing the Northwest," available at www.peaklma.com/files/public/MillerBPA.ppt
[135] Non-Wires Solutions Roundtable, 2005a.
[136] Pacific Northwest Energy Conservation & Renewable Energy Newsletter, 2004, "Demand-Response Pilot Bodes Well for BPA's Non-Wires Transmission Alternatives," CWEB.101/May.28.2004 edition, available at http://www.newsdata.com/enernet/conweb/conweb101.html#cw101-3
[137] Ibid.
[138] Ibid.
[139] Brad Miller, 2005.

efficiency measures. These programs will also save 110 GW hours of energy during the five years of the project period.[140]

NWSs Portfolio for the Olympic Peninsula

Program	Expected MW
Demand Response	16
Direct Load Control (DLC)	20 (5 pilots)
Distributed Generation (DG)	4
Energy Efficiency (EE)	15
Total	55

In addition to projects developed through this planning process, BPA has been conducting other pilot projects based on a specific opportunity or to gather experience with certain technologies or challenges. These pilots are also useful opportunities to address institutional barriers and build stakeholder confidence in NWS. In one project, at the Pacific Northwest National Laboratory facilities in Richland, BPA is testing the use of a 30-kW microturbine for transmission support.[141] The system is controlled by BPA via an Internet-based system in Portland.

5. Conclusions

- BPA has found that a number of different resources can be cost effective alternatives to transmission infrastructure, including energy efficiency, demand response and direct load control. Transmission and distribution companies alike are likely to find more cost effective opportunities to defer and avoid investment in “poles and wires” when they expand the group of resources they consider beyond DG.
- A stakeholder collaborative provides many important benefits. It identifies aspects of NWS planning to which stakeholders are likely to object and provides a forum for seeking win-win solutions. The addition of stakeholders’ knowledge and experience is likely to lead to a better planning process. Stakeholders gain a better understanding of utility planning needs. Information exchange increases regional acceptance of using NWS to support transmission and stakeholder acceptance of the utility’s final planning process.
- On a parallel track with the development of a NWS planning process, BPA has pursued pilot projects to gain experience with NWS technologies. Further, they have used the Round Table to disseminate information on technology performance. It seems efficient to conduct pilots while developing a planning process rather than waiting until the planning process is finalized.
- A cost trigger for screening transmission projects is an effective way to ensure comprehensive screening for NWS. BPA has found that setting the trigger

[140] Non-Wires Solutions Roundtable, 2005a.
[141] Ibid.

number relatively low ($2 million) for first-level screening is desirable and not unduly burdensome.

- While BPA has solicited stakeholder input in the development of a process for screening NWS, there may not be a vehicle for ongoing stakeholder involvement in the screening process (after dissolution of the Round Table). A process in which transmission projects are screened by a number of parties, including large customers and third party providers of NWS, will likely identify more cost effective opportunities for NWS than a closed screening process.
- BPA does not own customer-sited DG, and has not found the ownership of customer-sited DG to be a cost effective option for transmission support.[142] One factor leading to this conclusion may be the fact that BPA does not sell energy at the retail level. Owning and operating a DG unit at a customer site may be cost effective only if the company can sell the customer the energy from the unit.
- BPA has found it necessary to remain actively involved in the development of NWS projects after opportunities are identified, by helping developers find customers who may be interested in developing NWS resources.
- The BPA Round Table has identified potential benefits of collaboration BPA and distribution companies in the region on NWS, although BPA has found little interest on the part of other T&D companies. More work is needed to explore the incentives facing distribution companies and the potential benefits of this type of coordination.

[142] Personal communication with David Le on August 17, 2005.

ISO Activities Regarding Distributed Generation

1. Introduction

In addition to utilities, Independent System Operators (ISOs) have started to consider DG as a solution to transmission congestion. The motives of ISO's tend to be different from those of utilities regarding DG, as ISOs are most concerned with regional transmission constraints and their impacts on price and reliability of service rather than local distribution service. Because of this, the experiences of ISOs are not entirely applicable to New York's DG planning efforts. However, because several aspects of the ISO experiences are worth noting, we briefly summarize below the activities of ISO New England and the Pennsylvania/New Jersey/Maryland Interconnect (PJM).

2. ISO New England's Gap RFP

For several years, ISO New England has been facing severe transmission and generation capacity constraints in Southwest Connecticut (SWCT). Transmission projects to relieve the constraints are under development, but the first project is not scheduled to be completed until 2007.

ISO New England issued an RFP in December 2003 to procure 250 MW of quick-start capacity in the SWCT region for the following 4 years (June 1, 2004 – May 31, 2008), with an option to extend another year if needed. The ISO's RFP sought generation resources, demand response resources, and/or peak-load reducing conservation and load management. The objective of the RFP was to "solicit, evaluate, and select proposals… that can offer resources that will reduce the probability of involuntary load shedding in SWCT at a price that minimizes total expected cost while ensuring reliability in the region."[143] The RFP was developed in consultation with NEPOOL's stakeholder committees and state regulatory agencies in Connecticut.

ISO New England received 34 proposal packages from 25 bidders. Forty projects were actually evaluated because several packages contained more than one distinct project. The number of qualified bid projects and their capacity are summarized by type in Table 1.

Table 1: Summary of RFP Projects Bid

Type Project	No. of Projects	MW bid by 2007
Demand Response	19	281
C&LM	5	11
Peaking Generation	16	789
Total	40	1081

Peaking generation includes dispatchable and emergency generation. Dispatchable generating units bid in the RFP ranged in size from 10 to 153 MW. Emergency generation projects ranged from 1 to almost 70 MW. Some proposals for peaking

[143] ISO New England Inc., 2003, *Request for Proposals for Southwest Connecticut Emergency Capability*, prepared by ISO New England on behalf of the NEPOOL Market Participants, December 1, 2003.

generation involved an upgrade to existing generating unit. A large portion of the resources offered in the RFP were existing emergency generators located at commercial and public facilities.[144] In order to be eligible for the SWCT Gap RFP, DG and demand response projects (except energy efficiency) must participate in other existing load response programs.[145] By participating in multiple programs, participants can receive payments from different programs, and this might have contributed to the large number of proposals to the SWCT RFP.

The ISO's evaluation of the projects focused on three primary considerations: viability, cost, and the reliability benefit for SWCT. Viability refers to the non-price factors that indicate the likelihood of project success by the proposed in-service date. Cost rankings were performed using both the sum of the projected costs over the four-year period, and the Net Present Value (NPV) of these same costs. Costs were normalized on a dollars per kW-year basis where the kW is the sum over the four years of the average kW for each summer period. Reliability benefits were determined by modeling the New England generation and transmission system in a Security Constrained Economic Dispatch model (SCED). This model was run for different cases to test the SWCT system's performance under different contingencies. The RFP resources were available as potential incremental resources to relieve thermal problems after the existing generation was used.[146]

Among the 34 bidders, 8 suppliers were selected for the summer of 2004, comprising 125 MW. More capacity was selected for later years. This is mainly due to changes made into existing air permit regulation for distributed generation. Most of existing emergency generators offered in the RFP have a General Permit for Emergency Engines (GPEE) which allows them to operate up to 500 hours but only during outage periods, i.e., at NE-ISO's OP-4 Action 12. In 2004, in order to be eligible to operate under SWCT RFP, generators needed to obtain a General Permit for Distributed Generation (GPDG) or an individual permit. A new regulation "Section 42" which replaced GPDG became effective January 2005. This regulation allowed the existing generators with GPEE to operate in SWCT RFP program by including the SWCT condition as part of an "emergency" under ISO-NE's OP-4 Action 12, while limiting the total hour of operation to 300 hours under such conditions This change in air permit regulation increased generators' participations as of 2005.[147]

Table 2. Results of SWCT RFP[148]

Technology	2004 MW	2005 MW	2006 MW	2007 MW
On-Peak Conservation	1	4	5	5
Generation	95	152	153	153
Load Reduction	22	53	74	74

[144] ISO New England, 2004a, *Final Report on Evaluation and Selection of Resources in SWCT RFP for Emergency Capability 2004-2008*.
[145] Day-ahead demand response program, real-time demand response program, real-time price response program, and real-time profiled response program.
[146] ISO NE, 2004a.
[147] ISO New England, 2004a
[148] Bob Laurita, 2004, "Distributed Generation and Demand Response," presentation on May 18, 2004: ISO-NE..

Generation and Load Reduction	3	12	22	27
Total	121	221	253	259

ISO New England reports that the average cost for all selected projects on a NPV basis is $123.3/kW-yr, or $10.30/kW-mo. Other proposed projects not selected have an average NPV of $189.32/kW-yr, or $15.80/kW-mo. Some projects with competitive cost profiles were not selected because they were either not viable or not located at locations that would result in benefits.[149]

All of the resources selected are customer owned and operated resources. ISO New England does not control any of the resources directly. The ISO notifies customers of the need for capacity via telephone or internet, and customers are required to respond within 30 minutes.

Selected participants receive payments for just being available every month for a maximum of four years plus one year if the program is extended. The capacity payment is between $5 and $10/kW/month, close to the estimated benchmark cost of capacity that a peaking unit would recover over a typical lifetime.[150] In addition, units get paid if they operate when called upon. The minimum payment for performance is between $0.10 to $0.50/kWh. It is important and interesting to note that these payments are not based on the cost of transmission project deferral.

The resources procured by ISO New England were not needed during the summer of 2004. However, on July 27 2005 the ISO called on all of its demand response resources, including those procured in the SWCT RFP. Roughly 180 MW responded within 30 minutes, or 80 percent of the resources enrolled in the program.

3. PJM's "Market Window"

PJM has taken a different approach to relieving congestion on its transmission system. While ISO New England focused its efforts on one area where constraints threaten reliability, PJM has gone to the market for solutions to transmission congestion across its entire system. While not all of these congested lines threaten reliability, they do impose costs on market participants, as system operators are forced to serve load with higher cost plants. The PJM market offers wholesale electricity customers ways to hedge congestion costs, however customers cannot buy protection from all congestion.

PJM has developed a "market window" approach to soliciting bids for congestion relief projects. First, PJM calculates monthly congestion costs for each congested transmission facility. Congestion costs that exceed a certain threshold are defined as "unhedgeable." When unhedgeable costs on a certain transmission facility reach a predetermined level, a period is opened for that facility during which market participants can submit proposals for projects that would relieve the congestion. To open the market window, PJM identifies the limiting element(s) of the facility, develops generic costs estimates and a

[149] ISO NE, 2004a.
[150] Current prices for Locational Installed Capacity Payment is between $0.10 to $0.50/kWh.

preliminary cost/benefit ratio and cost allocation scheme and posts the information on its website.[151]

Each market window remains open for one year. After this period, PJM determines whether any of the solutions proposed by market participants would mitigate the congestion cost effectively. To assess the net costs of a proposed project, the costs of the upgrade are compared to the 10-year projected benefit of the project. PJM also determines whether any upgrades proposed by transmission owners or planned under the Regional Transmission Expansion Planning (RTEP) process would relieve the congestion.

As of September 2005, PJM had opened and closed market windows for 39 congested transmission facilities. Of these market windows, RTEP or Transmission Owner Identified (TOI) projects have been selected for 27. (Information is not available on whether market-based bids were received in any of these 27 windows.) In only one window has a market-based project been selected. This project involves the replacement of the wavetrap limit on the Black Oak – Bedington 500 kV line.[152]

Currently, PJM is dissatisfied with the low level of response it has gotten from market participants (i.e., non transmission owners) in its market windows, and a proposal is under development to change the program. Much attention is focused on the way that congestion costs are calculated. Currently, “unhedgeable” congestion costs are defined as total congestion minus revenue from transmission hedges minus economic generation. Economic generation refers to generation that becomes economic to operate given the elevated wholesale prices (elevated due to the congestion). A number of parties have argued that economic generation is a cost of congestion and that it should not be subtracted in the determination of unhedgeable congestion costs. With higher costs to offset, market participants would be likely to submit more proposals.

4. Conclusions

ISO-NE’s RFP attracted a number of bidders (34 proposals received for 40 projects, totaling over 1,000 MW). Several factors contribute to this strong response, including:

- The area ISO New England targeted is relatively large, encompassing 16 towns in the Southwest Connecticut. Projects addressing distribution system constraints must often be located within a smaller area.
- ISO New England’s efforts were focused on transmission constraints, and large backup generators are often located at the transmission level.
- Several different resource types were eligible for the ISO’s RFP, including distributed generation, load reduction and energy conservation.

[151] PJM, 2005, Presentation to Regional Planning Process Working Group on September 1, 2005.
[152] PJM, 2005, Presentation to Regional Planning Process Working Group on September 1, 2005.

- Resources selected can receive capacity payments for being available as well as energy payments when they operate. The capacity payment is likely to be in the range of $8/kW/month.
- Capacity payments are guaranteed for maximum four years plus one year if the transmission project is delayed another year.
- In the SWCT Gap RFP, ISO-NE requires DG and demand response projects (excluding energy efficiency projects) to be enrolled in other existing demand response programs, and this might have contributed to the large number of proposals to the RFP. This basically allows the participants to gain both capacity and energy payments.

PJM's market window approach is worth investigating for utility distribution planning in New York. PJM has developed an efficient way to provide information to market participants about transmission constraints and the cost of projects being contemplated to relieve those constraints. PJM's review of this program, and its findings about why so few proposals were submitted by market participants, will be important.

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