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Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energynet™

PIER FINAL PROJECT REPORT

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

APPENDICES

PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies

What follows is the final report for the Development/Demonstration of a Methodology to Assess the Value of Distributed Generation and Demand Reduction to the T&D Network, PIER Contract 500-01-039, conducted by New Power Technologies. The report is entitled Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energynet." This project contributes to the PIER Energy Systems Integration program area.

For more information on the PIER Program, please visit the Energy Commission's Web site or contact the Energy Commission at (916) 654-4628.

ABSTRACT

This project addresses the question of whether distributed generation (DG), demand response (DR), and localized reactive power (VAR) sources, or distributed energy resources (DER), can be rigorously shown to enhance the performance of an electric power transmission and distribution (T&D) system. This report presents a methodology to systematically determine the characteristics of DER projects that enhance the performance of a power delivery network and quantify the potential benefits of these projects. This report also portrays the functioning and potential benefits of an integrated, intelligently managed power delivery network with embedded generation and loads responsive to network conditions, which we refer to as an EnergynetT™ infrastructure.

We conclude that DER projects in the right locations and with the right characteristics and operating profiles can improve the performance of a given network in terms of reduced real power losses, reduced VAR flow and consumption, reduced network voltage variability and eliminated low- and high-voltage buses, reduced network stress, increased load-serving capability, and avoided or deferred network improvements in both the distribution and transmission portions of the network. We demonstrate a methodology to systematically identify these beneficial DER projects and quantify their benefits.

We modeled a T&D system as a single, integrated power delivery network, enabling direct observation of network-wide improvements from changes in the distribution system and the impacts of distribution-connected DER projects. We used AEMPFAST™ software to rank-order locations where real and reactive capacity additions make the greatest contribution to optimal performance of the integrated network.

We identified a portfolio of individual DG and DR projects yielding the greatest enhancement to network performance by location and size and determined their operating profiles for an expected annual range of network conditions.

We quantified the network benefits from this portfolio of DER projects, valued them in economic terms, and compared to the network benefits from specific traditional network improvements. We showed how this portfolio could be used to target DER initiatives and incentives for the greatest impact on those DER projects yielding the most benefits is demonstrated.

KEYWORDS: Project, Network, DER, Condition, Benefit, Power

EXECUTIVE SUMMARY

The purpose of this project was to demonstrate a methodology that would (a) objectively assess and quantify the benefits of distributed energy resources (DER) to the performance of a power transmission and distribution system (b) determine the location and attributes of beneficial DER projects, and (c) quantify their network benefits. The lack of a systematic method or tool to make these determinations has prevented the full incorporation of DER in system planning. Such a methodology was seen by the Energy Commission as contributing to the use of DER and other non-wires approaches to improve power quality and reliability and relieving congestion in the power system and expanding the deployment of DER as a choice for customers.

We successfully demonstrated using power system models that DER projects in the right locations and with the right characteristics and operating profiles can improve the performance of a given power delivery network. Moreover, we demonstrated an objective method to determine where in the network these projects should be located – whether in the transmission or distribution systems – as well as their sizes, and operating profiles. We were also able to quantify the network benefits these projects would achieve. We refer to these ideally located, sized, and operated projects as the "Optimal DER Portfolio" for a given system.

Approach

We included a variety of DER projects as candidates, including the use of demand response as a measure for network performance improvement rather than simply as an intermittent reduction in energy consumption. In this project we considered as DER the following:

- Distributed power generation embedded in the network at customer sites (DG),
- Demand response that could be dispatched by the network operator (DR), and
- Distributed, switchable reactive sources such as capacitors.

We assessed network benefits of DER using a broad range of measures – measures that would fairly capture the range of network benefits DER could provide, and measures that could also be used to assess network impacts of other types of network upgrades on a comparable basis. We considered the following as indicators of network benefits:

- Real power loss reduction,
- Reduced reactive power consumption,
- Improved voltage profile,
- Reduction in network "stress,"
- Increase in the load-serving capability of the network under contingency conditions, and
- System capacity provided by DER measures.

In this project the subject power delivery network was the Silicon Valley Power (SVP) system, which serves the City of Santa Clara, CA, and lies within the Pacific Gas & Electric (PG&E) regional transmission system, which is part of the Western US transmission grid. The SVP system as configured in 2002 is characterized in regional power system planning models as only two points, with SVP loads split between the points and all embedded SVP generation connected at those two points. SVP characterizes its own system as an approximately 80-bus transmission system, with neither the associated distribution nor the surrounding regional transmission discretely characterized.

Notably, neither of these simulations of the SVP system depicts the specific locations where distribution-connected DER projects would be connected. One key innovation in our approach is the integration of distribution with transmission into a single, combined power delivery network model for use with transmission modeling and analysis tools. In this project we modeled the SVP system as an approximately 850-bus system combining both transmission and about half of the primary distribution feeders, with nodes, components, loads and resources modeled discretely. This part of the system is then wholly integrated into the surrounding Western regional transmission system. We derived individual distribution-level loads from actual SCADA records taken under a range of load conditions and from forecast loads.

As a key feature of this project, we used the AEMPFAST™ power system optimization package developed by Optimal Technologies as our primary tool for the identifying the locations of beneficial resource additions in the network. We established the minimization of real power losses, reactive power consumption, and voltage deviation with a target voltage of 1.05 per unit (PU) as the objective for optimization. AEMPFAST directly calculates the incremental improvement in this objective that would result from real and reactive resource additions at each bus in the network. In doing so, AEMPFAST can rank the hundreds of potential DER locations in the integrated network terms of the value of resource additions at that location, identifying the most valuable locations for DER additions at a bus-by-bus level of detail.

We used AEMPFAST and integrated models for this network to identify resource additions and ultimately specific DER projects that have the location, size, and operating profile needed to enhance the performance of the network. Because resource additions within a network are arguably beneficial right up to where there is no power flow, we placed external limits on additions of both DR and DG projects. We limited DR projects to medium and large customers (over 200 kVA). We also specified DR as ranging from a low of 2% of peak load to a high of 15% of peak load for the largest customers under "1% peak hour" load conditions, while we also assumed DR could be dispatched by location at different levels depending on system conditions. We limited DG projects to 60% of the host customer's peak load and imposed non-export feeder limits as well. For purposes of this study we also modeled all DG projects as synchronous generators with reactive power output independently dispatchable within limits.

Results and Findings

We found that the value of Optimal DER Portfolio Projects in terms of their contribution to network benefits was driven primarily by their location. At least for this network, we found that smaller projects at more electrically remote locations had more value in terms of network benefits than did large projects at well-supported network locations such as substations or transmission-level customer sites.

We found that the dispatch of at least some distribution-connected DER projects should also vary in response to changing network conditions. However, we also demonstrated that these network-centric operational requirements for DER are commercially practical – they are limited, and, using this methodology we can specify them ahead of time with a modest amount of analysis so they can be incorporated in project specification and commercial arrangements.

The 2002 Optimal DER Portfolio for this network includes DR at essentially all of the 390 eligible (over 200 kVA) customer locations. These projects are ranked according to their value in terms of network benefits under each of the conditions we analyzed. These projects are dispatched or called individually at different levels depending on network conditions. Under the "1% highest hour" Summer Peak conditions these projects represent 10.52 MW, or 2.6% of load, and under more typical summer seasonal conditions these projects represent 3.65 MW or 1.1% load.

Of the DR projects at the 130 large (over 1,000 kVA) customer sites, a portion is dispatchable at two levels under typical conditions (that is, other than the "1% highest hour" summer peak). The locations of the preferred sites for higher levels of dispatch under these conditions are specified. Of these large customer DR projects, only 61 are preferred locations for higher levels of dispatch under both summer and winter seasons and minimum load conditions as well. Accordingly, the remainder of the large customer DR projects could be made available for higher levels of dispatch on a limited seasonal basis only without compromising network performance.

Under just the "1% highest hour" summer peak conditions, a portion of both the medium (200 – 1,000 kVA) customer and large customer DR projects is dispatchable at the highest DR level. Locations of the preferred sites for higher levels of dispatch under these conditions are also specified.

The 2002 Optimal DER Portfolio for this network consists of DG projects at 380 of the 419 eligible customer locations. These projects are also dispatched individually at different levels depending on network conditions, and they are ranked according to their value in terms of network benefits. These projects average 160 kW in size, with the largest 8.9 MW. They total 60.73 MW on a nameplate basis, and dispatched as specified would represent 54.88 MW, or 13.8% of the system's load, under Summer Peak conditions. We found that the majority (60%) of these projects would not need to vary their real power output in response to changing network conditions to maintain network performance, and could operate on a base load basis for the customer.

The 2005 Optimal DER Portfolio consists of DR projects at all eligible sites and DG projects at 149 customer sites, averaging 450 kW in size with the largest 14.3 MW. Again, these projects are individually identified and ranked by their value in terms of network benefits.

We found that the Optimal DER Portfolio projects for this system as a group yield quantifiable and meaningful network benefits. Real power losses within the SVP system are reduced by 33-40%, and reactive power consumption is reduced by 28-45%. We showed that the reduction in real power losses within the SVP system was due to due to an increase in network efficiency, and not purely due to a reduction in the load being served through the network. There are significant loss reductions in the surrounding regional transmission system as well. We found that these projects also eliminate low- and high- voltage buses, that they improve network voltage profiles, and that they reduce the amount of real power stress in the system. Importantly, we found that these benefits are not limited to peak load conditions. In some cases there are greater benefits under conditions other than the Summer Peak. We found that these projects provide a significant increase in the load-serving capability of the network. We found that the Optimal DER Portfolio projects have the potential to yield network benefits in the same range as those of transmission-level system upgrades using these same measures.

In addition, we found that using detailed, integrated network models yields insight into network conditions, and opportunities for improvement, that would be invisible using models of the transmission system alone and/or models of individual distribution feeders – the local and network-wide impact of incremental distribution-connected DER resources is but one such insight. In particular, we found that localized measures have impacts across the network.

We directly estimated the economic value of network benefits such as reduced losses, reactive capacity, and system capacity, and found that the value of network benefits from these projects might approach $450/kW if system capacity is taken into account. Additional quantifiable network benefits such as increased load-serving capability, improved voltage profile and reduced system stress might have significant value in dollar terms, but are not as readily priced. Conceivably the dollar value of network benefits associated with Optimal DER Portfolio projects could be used to derive value-sharing financial incentives for real projects that yield network benefits.

The Optimal DER Portfolio for this power system contemplates a high penetration of relatively small generation projects to achieve the network benefits described above. We assessed the feasibility of siting the 133 top-ranked 2002 Optimal DER Portfolio generation projects based on their location, size, and operating profile. We found that all of these projects would be located in commercial or industrial districts of Santa Clara, and concluded that they could probably all be sited as either a permitted use or under a conditional use permit. In fact, we found that 18 of these project locations already have power generation units of comparable sizes installed for backup power.

However, we also found siting issues with specific impacts on this particular set of projects. Even if these projects are certified as "ultra clean and low-emission" DG projects by the state Air Resources Board and meet all local noise and visual requirements, they would likely be subject to an individual "Best Available Control Technology" demonstration and issuance of an air permit by the local air quality management district with jurisdiction over these projects. Also, either an Environmental Impact Report or Mitigated Negative Declaration under the California Environmental Quality Act would likely be required for these projects. We also found that local land use ordinances in Santa Clara do not specify requirements for onsite power generation units. This would place an additional burden on the planning staff to familiarize themselves with power generation technologies and exercise judgment to interpret and apply requirements for these projects.

Conclusions and Recommendations

This project demonstrates a way to systematically determine the specific location and operating characteristics of DER projects that benefit a power delivery system. We believe this information would be useful to any grid operator contemplating potential DER development, network upgrades, or simply improved network performance. This project also demonstrates that the grid benefits associated with these projects are readily assessed and quantified. Thus, this methodology could be used to incorporate DER alongside traditional network upgrades in system planning. Further, as real DER projects and network upgrades are implemented, the Optimal DER Portfolio is easily updated to incorporate their network impacts. This project also demonstrates that at least some of these grid benefits can be readily valued in dollar terms. Pricing these benefits permits their exchange among DER stakeholders for improved economic decisionmaking, e.g., through value-sharing incentives. Lastly, this project also demonstrates that characterizing beneficial DER projects individually permits identification of those barriers to project development that have the greatest impact on the most beneficial projects.

We judge the analysis of the network as an integrated whole, including both distribution and transmission and with loads and resources discretely modeled, to be essential to fully assess the impact of distribution-connected DER on the overall performance of the entire power delivery network. In this project we demonstrated that the development and use of such detailed networks model is practical. We also demonstrated the interoperability of such integrated network models with GE PSLF, a commonly-used, legacy network analysis tool. We believe these integrated Energynet datasets could be an important platform for a variety of system planning tasks given the visibility they provide.

An assessment of AEMPFAST as an analytical tool emerged as a key interest in this project. Based on our results and review of our approach by the project Technical Advisory Committee, we are able to conclude that AEMPFAST is both a valid and useful tool for this application.

We judge the barriers noted above to the siting of beneficial generation projects identified for this network to be significant barriers given the small size of most of these projects, especially if these projects are customer-sponsored. We conclude, therefore, that an ordinance establishing an objective set of local requirements for small power generation units, along with exemptions from local air permitting and CEQA review for certified "ultra clean and low-emission" DG projects under a certain size, would facilitate the types of generation projects shown to yield network benefits for this particular power system, providing a meaningful non-financial incentive for projects of this type.

As noted above, network operators and policy makers could use this approach to design financial incentives specifically targeted to DER projects that would improve network performance. However, as we have shown that attributes of projects providing network benefits are highly location-specific, we emphasize that network benefit-driven incentives should also be location specific – not all candidate projects even within a given municipality would be eligible for the same incentive.

An integrated power delivery network, populated by a portfolio of ideally-placed, highly-flexible generation and responsive loads whose operation is can be coordinated for grid performance under varying network conditions is entirely consistent with a distributed, conceivably intelligent energy infrastructure we refer to as the Energynet™ infrastructure. This project presents an opportunity to assess the benefits of migration to such an infrastructure. It also offers the opportunity to develop and/or assess fundamental requirements for enabling Energynet-related technologies. Such technologies include analytical the datasets integrating transmission and distribution in a single power delivery network described above, capabilities for monitoring and control of DER to yield network performance benefits under varying conditions, and measures to make these interoperable with legacy systems.

This project represents an initial demonstration of this methodology, using the transmission and distribution network of SVP, a municipal utility serving a single city. SVP was willing to host this effort and make their system data available, and their relatively compact system made testing the feasibility of this methodology less risky. The Energy Commission has funded a second project that will demonstrate the methodology in a much larger, more complex subject power system of a major California investor-owned utility. The subsequent project will expand this methodology by further demonstrating the adaptation of legacy utility system data into an integrated Energynet dataset. It will consider additional DER devices such as storage and distribution automation, and additional measures of network benefit, such as reliability. The use of the methodology will be demonstrated in a planning setting to identify network problems and expand the set of potential solutions.

1.0 Introduction

1.1. Background and Overview

It has been asserted in many forums that small strategically located DER projects, in addition to providing benefits to the customer who builds or hosts the project, have the potential to improve the operational reliability and quality of the T&D network serving all customers. Beyond reliability, built in the right place, DER also has the potential to defer, offer new alternatives to, or eliminate the need for T&D network improvements that might be required to remedy deficiencies in the T&D network.

What is missing is an analytical tool that is capable of assessing, simultaneously, the impacts of embedded generation, particularly distribution-connected generation, on both the transmission and distribution systems. At the distribution level, there has been very little study to determine if DER projects can provide network benefits, therefore they are generally not considered when distribution planning is done.

Also, T&D systems are analyzed separately, therefore it is not well understood how distribution-connected generation affects the transmission grid. Without an analytical tool that is capable of doing such an integrated analysis, it is not possible to fully understand the potential economic value and engineering impacts and benefits of DER projects on both the T&D networks.

If a tool is developed that will identify and quantify these potential benefits, T&D planners and policy makers can work together to develop a planning process that will recognize the value of these non-wire projects as potential alternatives to system power problems and standard T&D projects.

1.2. Project Objectives

1.2.1. Overall Project Goals

The overall goal of this project was to demonstrate an analytical methodology that can identify:

- Where a DER project or group of projects, including distribution-connected DER, can provide specific T&D network benefits;
- The value of those network benefits in engineering and economic terms;
- A suggested set of financial and non-financial incentives to facilitate the development of DER projects, including locational pricing of energy and real and reactive capacity; and
- Value-sharing, rather than cost-shifting incentives for DER projects that are beneficial to the operation of the T&D network, as well as targeted policy initiatives that will facilitate the recognition and development of beneficial DER projects.

For this project, SVP, a municipal utility serving a single city, agreed to assist in the testing of this methodology, However, this methodology is scalable to a larger system and would be applicable and useful to any party seeking to determine the potential performance benefits of DER in a power system, the specific types and locatiosn of DER projects that will achieve those benefits, the most impactful barriers to the implementation of projects that benefit that system, and value-sharing incentives for DER projects based on those benefits.

This project was predicated upon the following PIER program goals:

- Improving the reliability/quality of California's electricity system by developing an analytical tool that can identify where DER and other nonwire alternatives can be located to help alleviate power quality and T&D capacity and congestion problems in the state; and
- Providing more choices to California consumers by helping overcome the barriers to the deployment of distributed generation.

1.2.2. Technical and Economic Performance Objectives

The technical and economic performance objectives of this project were to:

- Develop a methodology to put a value on DER as a core component of a T&D network. The study will have several components that will:
- Verify that an Energynet dataset for a utility network can integrate both T&D and accept dispatched load sheds and embedded generation and can be used by both GE PSLF and Optimal Technologies, Inc.'s AEMPFAST.
- Characterize the condition of the SVP network before the addition of DER projects under present Summer Peak, Winter Peak, Light Load, and future Summer Peak conditions.
- Characterize two sets of DER additions to improve or optimize network performance. DER additions will be identified by type, size, location on the network, and ordered by contribution to Energynet performance. The first group of DER additions will be created to optimize or improve performance under present Summer Peak conditions; the second will be created to optimize or improve performance under future Summer Peak conditions.
- Establish Optimal DER Portfolios of specific types of DER projects having specific technical and operational attributes that can measurably improve the performance of the Energynet relative to the other cases.
- Quantify the operational benefits and avoided network improvements for the Energynet enabled by the Optimal DER Portfolios in both engineering and financial terms. Benefits will be attributed to individual DER projects or groups of projects, in addition to the portfolio as a whole.
- Determine how the Optimal DER Portfolio can be used to guide policies and design incentives to facilitate the development of real DER projects that enhance T&D network performance.

1.3. Report Organization

This project was developed based on a stepwise application of this methodology. The following steps are sequential:

- Create models characterizing the subject power delivery system as an integrated network
- Determine recommended DER capacity additions
- Characterize capacity additions as Optimal DER Projects

Once these beneficial DER projects are identified and characterized, the following steps proceed in parallel:

- Assess the network performance benefits of the DER projects, and quantify these in technical and economic terms.

… and …

- Assess the siting requirements for beneficial DER projects and determine the most impactful barriers to the siting of beneficial projects
- Identify incentives and policies to facilitate the siting of beneficial projects

These six steps are discussed in Sections 2.1 through 2.6 respectively. Each section describes our approach for that step and provides the analytical results achieved for each step.

Section 3 gathers the results of each step into overall outcomes and relates them to the project objectives.

Section 4 draws conclusions and their implications.

2.0 Project Approach, or Methods

2.1. Development of Integrated Datasets

2.1.1. Approach

In existing regional power system models used for transmission planning, the SVP electric power delivery network is characterized as two 115 kV buses representing Kifer and Scott substations. SVP's estimated real (P) and reactive (Q) loads are modeled as two identical block loads at the two buses. Power generation embedded within the SVP system (consisting of the CCA cogeneration unit, SVP's two cogeneration units, and the two Gianera peaking units) is modeled as located at one or the other of the two 115 kV buses. Capacitors are not discretely characterized.

For its own system planning, SVP models its electric power system as the two 115 kV buses, Kifer and Scott, 115 kV to 60 kV stepdown transformers at those two substations, and a looped transmission system of 60 kV substations and 60 kV to 12 kV stepdown transformers. Loads are modeled as block loads at each of the 12 kV stepdown transformers; further, loads are modeled net of real or reactive power provided by station or line capacitors or generators – capacitors and generators are not modeled individually. No 12 kV distribution feeders are included in a systemwide model.

For this project, we created an Energynet dataset modeling the SVP power delivery network as 12 kV distribution feeders, 60 kV transmission, and 115 kV transmission, integrated as a single system within the West-wide regional transmission system. Customer loads are modeled individually as either transformers stepping down to secondary distribution delivery voltage or transformers of customers who receive service at the primary distribution level. Power generation as well as line and station capacitors are modeled individually at their actual locations in the network, whether distribution or transmission. Switches connecting distribution feeders modeled in detail are also included.

We sought originally to model those primary distribution feeders that served primarily commercial or industrial customers, which would be likely candidates for distributed generation projects. We modeled 48 of SVP's 12 kV primary distribution feeders – about half their primary distribution system – along with SVP's entire 60 kV and 115 kV transmission system. The modeled feeders are interconnected by 106 switchable branches, including 47 load-serving branches. There are 419 individually-modeled customer sites – 29 "small" (<200 kVA), 260 "medium" (200 kVA-1,000 kVA), and 130 "large" (over 1,000 kVA) including 3 transmission-level customers. There are six existing embedded generating units, which we modeled as independent MW and MVAR sources subject to their operating limits. There are also 106 existing reactive power sources – capacitors – which we modeled as individually switchable. This network detail was integrated into a model of the 13,000-bus WECC transmission system serving the Western US for the "present" cases and a model of the entire PG&E transmission system for the "future" cases.

"Present" Cases

Based on conversations with SVP we established specific days and hours for Summer Peak, Winter Peak and Minimum Load cases we would develop incorporating actual historical load data. We refer to these as "present' cases. The Summer Peak case was selected as the highest-temperature (and highest load) hour in 2002. The Summer Peak case may be thought of as representative of the "1% highest peak hour" load condition for this year. The Minimum Load case was selected as one of the lightest-load hours of the year, an early Sunday morning hour in spring with little heating or cooling requirement. The Winter Peak case was selected as a representative winter peak day. To distinguish the 1% highest hour Summer Peak case from a more typical heavy summer condition, we selected a "Knee Peak" case. The Knee Peak case may be thought of as characterizing the "99th percentile peak" load condition for this year.

We agreed based on conversations with SVP that the system topology would be the same for all "present" (2001-2002) cases. SVP's transmission system in this configuration consists of three loops, the South Loop, Center Loop, and North Loop, emanating from two 115 kV receipt points in the Core. We designate 60kV transmission to 12 kV distribution stepdown transformers based on their loop position. We obtained detailed data on SVP's distribution system from SVP's engineering drawings. This information was augmented with data from other sources, such as air permits for existing generators. With input from the Technical Advisory Committee we adopted a fully-radial topology for the distribution system, with all branched connections between radial feeders modeled as "open." SVP also provided information on seasonal switch position variation and hourly and weekday variation in capacitor settings.

Distribution loads for each "present" case were derived from actual SCADA data from the distribution substations, transformers, and feeders for the actual hours selected, with P and Q contribution from generation and capacitor reversed out of the SCADA reads. One of the primary reasons for modeling the system under "present" conditions (really a back-cast view) is to assess the variation of the system (and later, the related impacts on and from DER) under different load conditions using actual, recorded load data rather than estimates or forecasts. Since SCADA provided real and reactive load data at the distribution bus level only, we allocated distribution bus loads to each feeder based on a share of MVA basis, with feeder MVA derived from feeder current SCADA reads.

Based in part on input from Cal ISO, we used WECC Summer, Winter, and Spring/Light Load operating cases to characterize the regional transmission system outside SVP for our "present" cases, and a PG&E transmission planning case to characterize the regional transmission system for the Summer 2005 "future" case, described below. By using these existing cases we were able to adopt characterizations of the regional transmission system, including loads and resources, that are consistent with those conventionally used by planners for operational and planning analyses. Also, by using the Summer, Light Load, and Winter operating cases for our Summer Peak & Knee Peak, Light Load, and Winter Peak cases, respectively, and the Summer 2005 planning case for our Summer 2005 case, the integrated cases are internally consistent.

We decided not to partition the regional transmission datasets to perform the analyses for these studies. We found no difficulties that warranted partitioning the datasets, and this avoided developing and justifying a partition approach. We did treat the SVP-owned "subject system" (115 kV, 60 kV and 12 kV distribution) as operationally distinct form the regional transmission system, functionally as its own control area, and limited the optimization process to that part of the system.

By this means we developed a single dataset for each case that would yield essentially matching load flow results in both AEMPFAST LF and PSLF. These "as found" load flow results are discussed below.

"Future" Case

We chose Summer 2005 as the "future" Summer Peak case. In-process or completed, and capital plan network additions represent substantial transmission-level changes to SVP's system in 2005 relative to the its 2002 configuration. Specifically, these changes are:

Northern Receiving substation as a third 115 kV receipt point. This project includes installation of the Northern Receiving 115/60 kV stepdown transformer and bifurcation of the 60 kV North Loop into Northeast and Northwest loops.

230 kV interconnect at Northern Receiving. This project includes a 230 kV tie at Northern Receiving to PG&E's Los Esteros substation. We will treat this project as a "capital plan" project for comparison of its benefits against those of recommended DER additions. In incorporating this project we make no changes to the topology of the underlying 12 kV distribution system, and retain the parallel 115 kV interconnect at Northern Receiving, per discussions with SVP.

PICO generating station. This is a 122 MW base/147 MW peaking power generation facility interconnected to the SVP Scott and Kifer substations at 115 kV. We will also treat this project as a "capital plan" project for comparison of its benefits against those of the recommended DER additions.

We treated the third 115 kV Northern Receiving receipt point as an "in process or completed" capital addition, and incorporated it in the future cases. The other two projects were treated as "capital plan" projects for comparison of network benefits with those of DER as discussed in Section 2.4. We also treated removal of the third 115 kV receipt point as a sensitivity, also discussed in Section 2.4.

12 kV stepdown transformer-level loads were taken from SVP's 2005 Transmission Plan. We allocated these loads to each customer location on a share of rated kVA basis.

2.1.2. Analytical Results

We successfully integrated SVP distribution detail into three regional transmission datasets to create four "present" cases, and into a fourth regional transmission dataset to create the "future" case. We obtained power flow solutions in both AEMPFAST and PSLF with essentially identical results, as shown in Table 1.

In doing so, we demonstrated the ability to create a dataset for the network with integrated transmission and distribution, ready for introduction of dispatchable demand response and embedded generation and confirm that GE PSLF and AEMPFAST analytical tools can solve such a model. These were the major technical risks in this project.

We also demonstrated a method for estimating detailed distribution bus-level loads without the use of customer-specific meter data. We also demonstrated a method for gathering and refining distribution system detail from a readily-available source, and incorporating it into a regional transmission model by machine with essentially no hand entry.

2.1.2.1. Load Flow Results

The Base Case load flow results and the "as found" performance of the system in each case are summarized in Table 1.

Table 1 Base Case Load Flow Results

Summer Peak 2002 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	397.598	209.076	397.598	209.076
Net Interchange	-366.519	-70.868	-366.56	-69.725
Losses	1.248	51.313	1.262	50.943

Knee Peak 2002 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	329.095	184.226	329.095	184.226
Net Interchange	-297.952	-19.250	-297.954	-19.488
Losses	0.888	32.735	0.895	32.425

Winter Peak 2001-02 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	336.971	181.565	336.971	181.565
Net Interchange	-304.439	-11.853	-304.44	-9.75
Losses	0.908	35.917	0.909	33.102

Light Load 2002 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	254.521	141.075	254.521	141.075
Net Interchange	-221.651	-27.925	-221.652	-28.147
Losses	0.610	18.287	0.611	18.089

Summer 2005 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	581.999	348.747	581.999	348.747
Net Interchange	-552.792	-260.904	-552.86	-261.57
Losses	3.09	92.049	3.17	92.56

Table 2 compares the electrical loss rates (loss as a percent of load) in the different cases:

Table 2 Loss Rates

	Real Power Losses (P)	Reactive Power Cons. (Q)
Summer Peak 2002	0.3%	24.5%
Knee Peak 2002	0.3%	17.8%
Winter Peak 2001-2	0.3%	19.8%
Light Load 2002	0.2%	13.0%
Summer 2005	0.5%	26.4%

These loss rates are indicative of a relatively lightly loaded system, particularly in the 2002 cases.

2.1.2.2. Voltage Profile

We often use a voltage profile plot such as Figure 1 to visually display the characteristics of the power delivery network. These plots show the voltage at each transmission or distribution bus in the system in per-unit terms, with the buses arranged by loop and feeder. The lines connecting the buses help show the contour of profile in a particular part of the network but are not necessarily the actual physical connections.

The integrated network depicted by the Energynet dataset is vastly more detailed than a transmission-only model, as evidenced by a comparison of the voltage profile plots in Figure 1 and Figure 2. The Energynet plot shows voltage deviations at individual points along distribution feeders that are simply not visible in a transmission-only analysis.

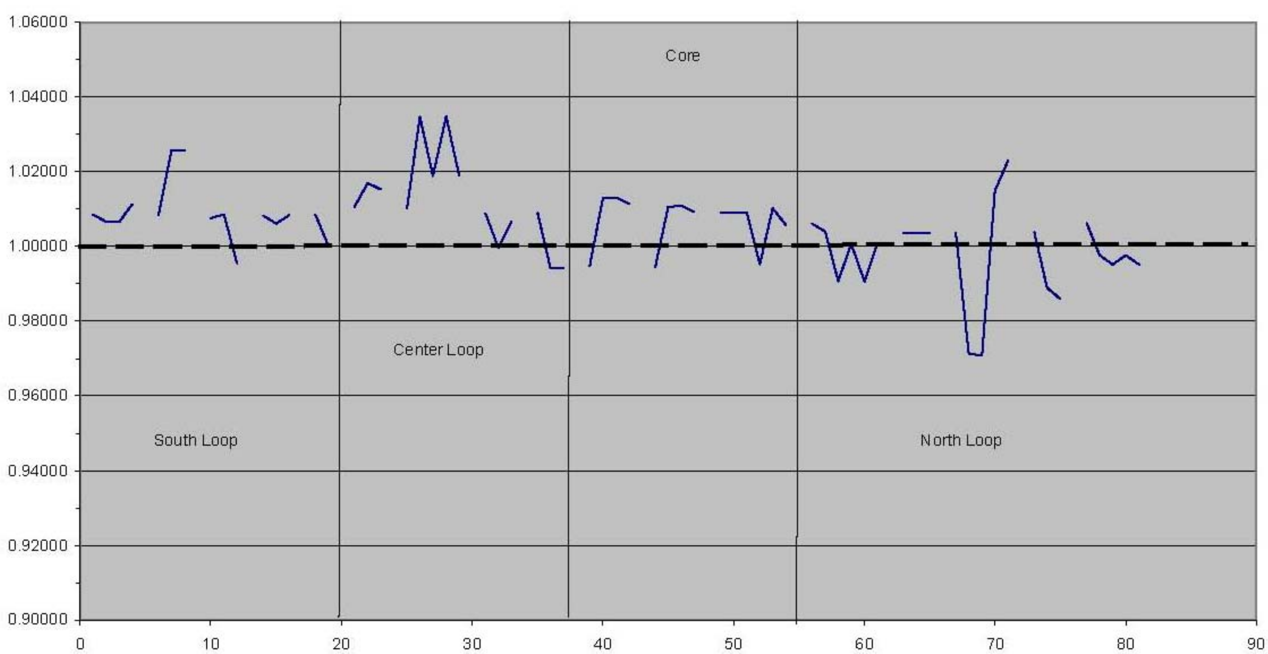

Figure 1 Summer Peak 2002 Transmission Voltage Profile - Base Case

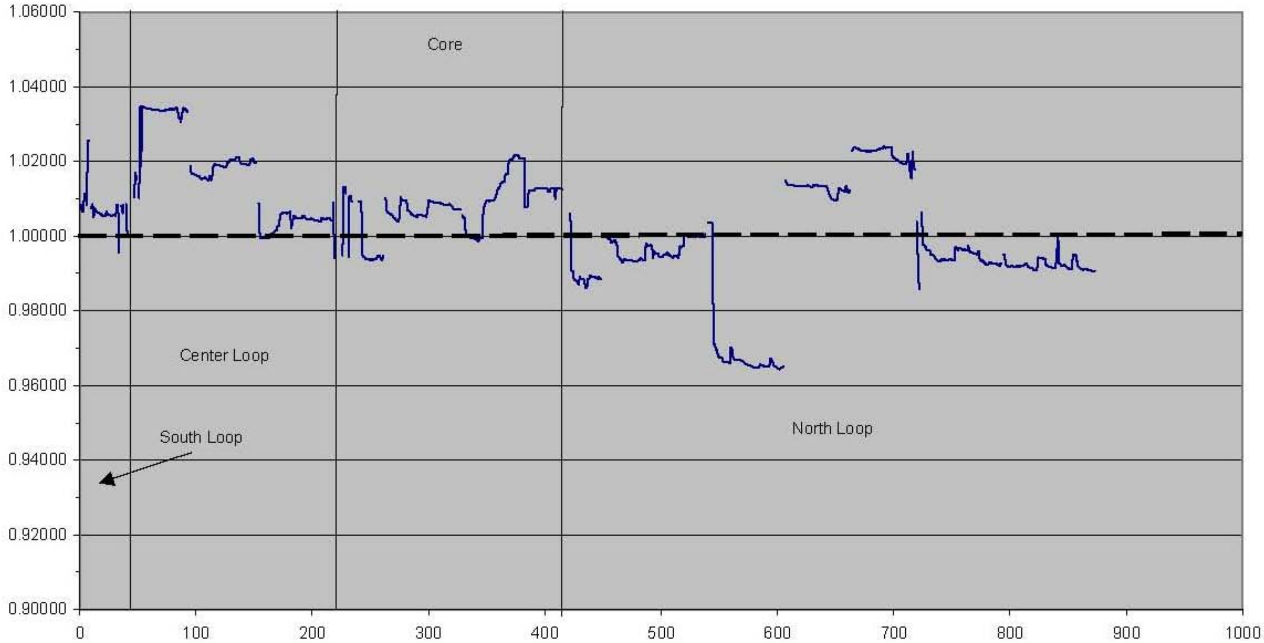

Figure 2 Summer Peak 2002 Energynet Voltage Profile - Base Case

Table 3 compares the transmission-only and Energynet voltage profiles of the Summer 2002 case.

Table 3 Comparison of Transmission only to Energynet Voltage Profiles

Voltage Profile Comparison – Summer 2002 Case

Voltage per-unit (PU)

	Transmission Only (65 buses)	Distribution and Transmission (833 buses)
Average	1.00	1.00
High	1.034	1.035

Low	.97	.96
Variation (std dev)	.012	.015

Voltage Profile Comparison – Summer 2005 Case

Voltage per-unit (PU)

	Transmission Only (80 buses)	Distribution and Transmission (848 buses)
Average	.98	.96
High	1.003	1.003
Low	.96	.94
Variation (std dev)	.015	.013

In the Summer Peak 2002 case the range of voltages (high and low) and the voltage variability are masked in the transmission-only view. In the Summer 2005 case the transmission-only view masks the many low-voltage buses in the distribution portion of the system, some of which are below .95 PU.

Figure 3 shows the base case voltage profiles of the four "present" (2002) cases.

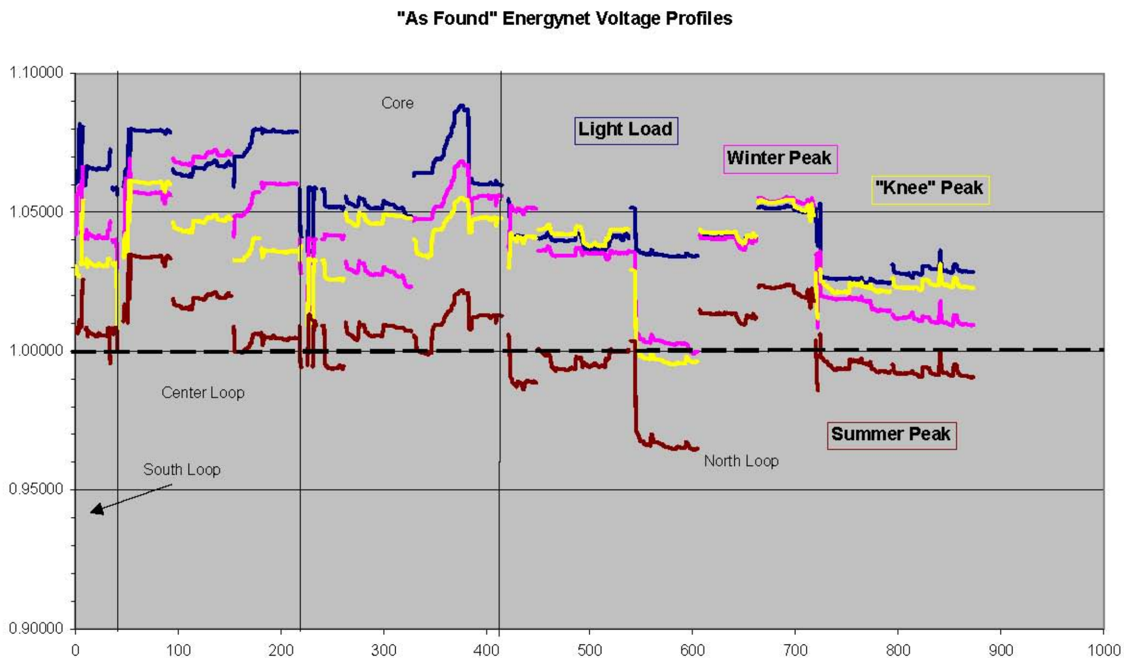

Figure 3 "As Found" Energynet Voltage Profiles

There are no buses with voltages below .95 PU, indicative of a healthy system. However, the voltage profile under Summer Peak conditions is something of an outlier. The Winter Peak, Knee Peak, and Light Load voltage profiles are grouped together. Also these more lightly loaded cases have generally higher voltage profiles than the voltage profile under Summer Peak conditions, illustrating the impact of shunt elements. The three cases other than the Summer Peak case have many buses with voltages above 1.05 PU.

Figure 2 and Figure 3 illustrate some of the additional insight offered by the integrated Energynet datasets and the use of actual SCADA data for loads. Figure 2 shows the greater variability of voltage in the distribution portion of the system. Figure 3 illustrates the seasonal variability of the condition of the network, particularly at the distribution level.

Figure 4 shows the “as found” voltage profile of the Summer 2005 case.

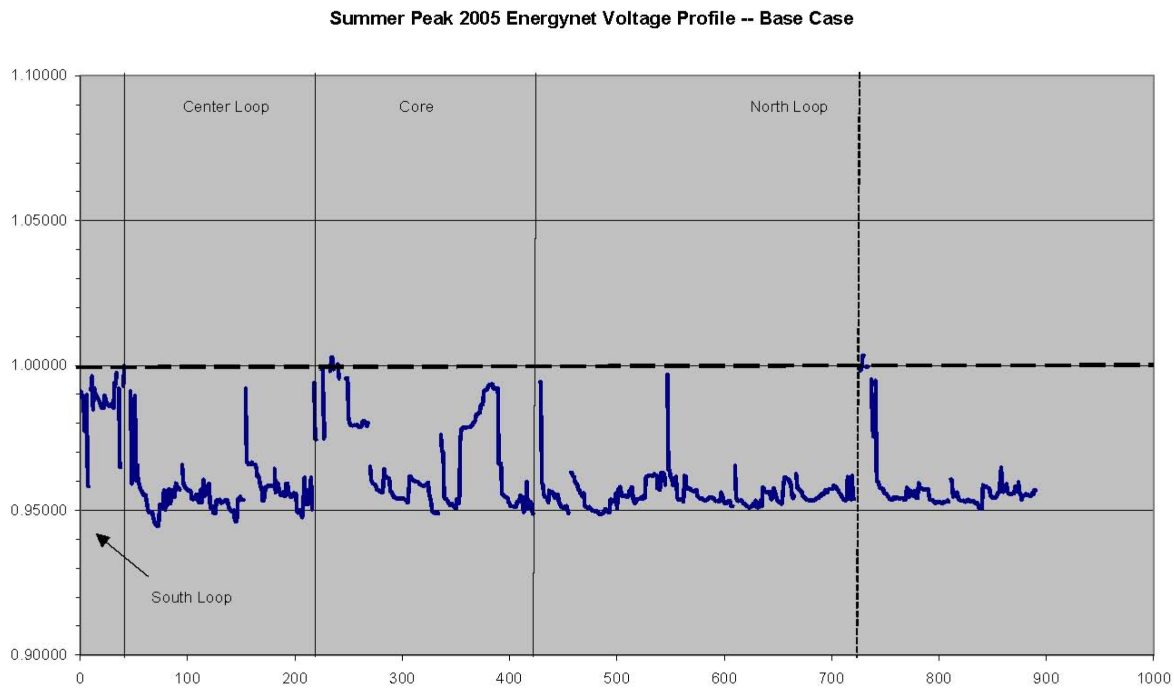

Figure 4 Summer Peak 2005 Energynet Voltage Profile - Base Case

The Summer 2005 case is much more heavily loaded than any of the 2002 cases. This case has 40% higher P load and 25% higher Q load than the Summer Peak 2002 case. In addition, allocation of substation-level load to individual distribution buses using an allocation based on share of total KVA results in a greater share of the 2005 system load modeled at the individual distribution buses than was the case for the 2002 system. Accordingly the voltage is generally lower. As indicated above, there are some buses at the distribution level with voltages as low as 0.94 PU. Even with the additional loading, the Summer 2005 Case has no additional reactive sources in the base case, resulting in a relatively low network-wide power factor.

2.1.2.3. Stability

A voltage range of .92 to 1.06 per unit might be typical of a transmission system; a distribution system is less forgiving because it has less electrical inertia, and a range this wide would be a sign of potential instability. As noted in Table 3, the integrated SVP T&D system in the Summer Peak 2002 case has voltage ranging from .96 PU to 1.035 PU with an average of 1.00. This lies well within this range, and stability should to not be a concern. The integrated SVP T&D system in the Summer 2005 case has voltage ranging from .94 PU to 1.003 PU with an average of 0.96. The voltage deviation range is actually narrower than the Summer Peak 2002 case, but the individual and overall low voltages may be a cause for concern, particularly given that contingency conditions could drive voltages lower still.

2.1.2.4. Other Analyses

With the benefit of distribution integrated with transmission, and in particular, discrete modeling of capacitors as well as loads at individual buses, we can conduct a detailed analysis of the load flow results and the behavior of the network. Specifically we are able to identify individual line segments in the transmission system, within the distribution system, and along distribution feeders exhibiting characteristics that are either of concern or suggest opportunities for improvement. As one of several examples we found, in the Summer 2002 case, South4 and Center3 are real power (MW) sinks but reactive (MVAR) *sources*, generating opposing P and Q power flows on nearby line segments. At Center3 D2 this is caused by the capacitors located in the substation, but at Center3 D3 this is caused by the pole-mounted capacitors on the feeders themselves, particularly on Center3 feeder 303. These distinctions are only visible in an analysis that characterizes distribution and transmission as part of a single, integrated network.

2.1.3. Conclusions

We determined that the nature of the data required to simulate a distribution system using a transmission-oriented power flow model is readily obtained from engineering drawings of the form used by SVP. Gathered in a systematic way, these data are fairly easily checked and put in a form for integration into a regional transmission dataset.

We demonstrated a method for estimating loads at the individual distribution bus level from SCADA data and other sources, avoiding the need for individual customer meter data. However, we conclude that the quality of these estimates would be improved if power factor data for individual feeders were available.

We determined that both PSLF and AEMPFAST have the capability to reach a power flow solution analyzing a model that includes distribution and transmission elements, including short lines with low impedances which were our greatest concern. There are specific steps required to facilitate an initial solution in PSLF when a large amount of new data is added. We also determined that the size of the dataset did not present problems for the power flow tools. In fact, we elected not to partition the west-wide transmission dataset to perform these analyses, as we had anticipated in the original work scope.

We determined that even though PSLF and AEMPFAST perform their analyses using incompatible data formats, there is a common data format that permits the exchange of data between PSLF and AEMPFAST. This translation ability facilitates the use of integrated datasets developed in this project with PSLF, a legacy system analytics package that is in widespread use. However, while it was not apparent when dealing with "as found" results, we did find the potential for errors in this translation when DER additions were incorporated in the datasets, and we conclude that translation between these environments requires care. The results discussed above confirm that the load flow results using the two models and a single dataset identical except for translation are identical within the accuracy of the solutions.

We also determined that a load flow solution using an integrated dataset incorporating distribution and transmission gives visibility into system conditions that would be invisible using the traditional approaches of modeling transmission only or feeders individually. Knowledge of conditions at buses and on line segments along individual distribution feeders as part of an integrated network forms the basis for network improvements and ideal placement of DER resources.

2.2. Development of Recommended DER Capacity Additions

2.2.1. Method for Identification of Recommended Real and Reactive Capacity Additions

In general, load flow results for a simulated power delivery system indicate voltage at each bus in the model and the real and reactive power flow between each bus. Under this methodology, with distribution and transmission characterized together in a single model, voltage at each bus in the network and power flows between them are determined based on conditions in both the distribution system and the transmission system. Moreover, conditions at any point directly reflect conditions in the rest of the system at both the distribution and transmission level. This permits direct observation of the impacts of conditions in the distribution system on the transmission system and other parts of the distribution system.

An engineer may, through analysis of the load flow results showing the voltage at each bus and real and reactive power flows between buses in the system, identify locations where changes and additions to the system, particularly capacity additions, may improve network performance. Again, by modeling distribution and transmission in a single model, we can determine where in the distribution system, and actually along individual distribution feeders, these conditions exist, and, thus, where in the distribution system additions of capacity would improve the performance of the overall network. Further, we can consider demand response analytically as a source of proportional real and reactive capacity, (synchronous) power generation as a source of real with variable reactive capacity, and capacitors as a source of reactive capacity. With these associations, we can derive a portfolio of DR, DG, and capacitor projects that can improve network performance. Some results using this approach are provided below.

However, the primary means we used in this study to determine the locations of real and reactive capacity additions was AEMPFAST, a proprietary power system optimization tool developed by Optimal Technologies. Demonstrating and understanding AEMPFAST's capabilities in this application has emerged as one of the desired outcomes of this research. For our purposes, AEMPFAST has the unique capability to directly optimize the voltage of the system. In other words, AEMPFAST can distinguish among various system configurations, all of which satisfy applicable voltage constraints at every point, to determine which is the "best" relative to a predetermined objective. Further, and of particular interest in this study, AEMPFAST can directly calculate the degree to which addition of real or reactive resources at a given location (i.e., at a particular bus in the network) will improve the performance of the system relative to the objective, taking into account the resource addition and its impacts across the system.

In this study, AEMPFAST gives us the ability to identify those individual locations (buses) in the system where incremental changes (e.g., additions) of capacity will yield the greatest improvement in performance as defined by the predetermined objective, taking into account impacts across the combined distribution and transmission systems. AEMFAST can draw distinctions in the value of capacity additions between individual, adjacent buses on a feeder without doing extensive trial-and-error or "what if" studies. This capability permits us to identify the most beneficial locations for capacity additions from among hundreds of candidate sites, while taking into consideration not only local system impacts, which might be predicted from an analysis of load flow results, but also more remote system impacts.

For this study, we used a multi-objective AEMPFAST optimization with the following objectives:

- Minimize real power losses
- Minimize reactive power consumption
- Minimize system voltage variability, with a target voltage of 1.05 per unit (pu).

The AEMPFAST objective function used is a uniformly-weighted sum of these objectives.

As part of the optimization analysis, AEMPFAST generates resource indices for real (P) and reactive (Q) resource changes at every bus in the analyzed system. We refer to these as P and Q indices, respectively. Each index is a single number that indicates the benefit of resource changes at that bus. For example, a negative P index at a bus means adding real capacity (generation) at that bus will have an overall negative impact on the system with respect to the specified system optimization objective. A positive index means adding generation at the bus will have overall positive impact on the system for the given objective. The greater the value of the index at a particular location, the greater the impact of the change at that location on the analyzed system overall. The P and Q indices are also a measure of the real or reactive "stress" on the system at that point – the further from a zero value the P index, the more valuable incremental real capacity addition or reduction is, or, by inference, the further the system already is to its theoretical optimum condition.

As noted in Section 2.1, we defined the portion of the system owned by SVP as the area available for optimization of controls and addition of incremental capacity.

We used AEMPFAST first to determine the maximum level of performance of the system without additions of capacity, and which control variable changes (discussed further below) would achieve that performance. During this initial AEMPFAST "recontrol optimization" step, the system is optimized by minimizing the stated objective function within the system voltage limits using the existing control devices. The recontrol optimization process also generates the initial P and Q indices of the system.

We then began the capacity addition steps by using AEMPFAST to determine and rank the locations where additions of reactive capacity alone would provide the most improvement to system performance based on the Q index. In this case there were no such locations. We found that the Q indices for the system were relatively close to zero and did not have significant variations. This type of a Q index profile generally indicates a "healthy" system, from a "system Q point of view." The existing SVP system had sufficient Q resources -- no additional Q resources were required. (As discussed below, in some cases re-scheduling of existing Q resources was required for system optimization based on their effect on the objective. In at least one case the system had an excessive number of shunts and AEMPFAST recommended in the recontrol step turning off some of the shunts for system optimization.)

We then used AEMPFAST to determine and rank the locations where additions of demand response would provide the most improvement to system performance. We identified the most valuable location first, based on the initial P and Q indices, then incorporated the addition, and then recontrolled and recalculated the P and Q indices with the addition added to determine the next most valuable location. We repeated this process until there was little or no incremental system benefit from additional demand response or all eligible sites had been populated. All additions of demand response were subjected to the limits discussed below.

We then used AEMPFAST to determine and rank the locations where additions of power generation would provide the most improvement to system performance. We assumed all beneficial demand response previously identified was in place and dispatched. Again we identified the most valuable location first, based on the P and Q indices, incorporated the addition, then recontrolled the system and recalculated the P and Q indices with the generation addition incorporated to determine the next most valuable location. We repeated this process until there was no incremental system benefit from generation additions or all eligible sites had been populated. Again, all additions of power generation were subjected to the limits discussed below.

This ordering of demand response and generation is based on our reasoning that demand response at these performance levels is more readily-accessible than onsite generation and, to the extent network benefits could be achieved through this type of demand response, they should not be counted as available benefits for onsite generation.

We measured network performance improvement in each individual addition, or step, by its reduction in the multi-objective. Those steps with the greatest improvement in the objective per unit of capacity addition were judged the most beneficial and ranked the highest. We also measured the impact of the capacity addition steps as a group in terms of the resulting reduction in real and reactive power losses, reduction in variability and increase in overall voltage, and reduction in variability and reduction in the overall P Index.

We conducted an analysis of this type for the 2002 Summer Peak case and for the 2005 Summer Peak case. We also performed this analysis for the 2002 Knee Peak, Minimum Load, and 2001/2 Winter Peak cases to determine how different seasons' load conditions would dictate changes to the set of capacity additions identified for summer peak conditions.

2.2.1.1. Control Variables

Within the analysis, we reset control variables where appropriate before determining recommended DER capacity additions, so network performance benefits available from recontrols would not be attributed to DER additions. More fundamentally, however, we developed the recommended DER capacity additions for this network within the context of a power network incorporating Energynet monitoring and control elements and capabilities that permit a high level of active management of the network.

For example, we assumed that all existing sources of reactive capacity are switchable as control variables. In addition, in the stepwise capacity addition process of AEMPFAST described above, to the extent capacity additions included controllable capability (e.g., the VAR output of an added generator), we assumed that capability became available for recontrol in succeeding steps. Near the end of a sequence of capacity additions the recontrol step has literally hundreds of highly distributed variable output controls available.

This is a greater level of network operator control of generators and capacitors as routine control variables than in fact exists in the SVP system presently. As a practical matter, we found that the primary control variable for optimization was redispatch of capacitors and reactive power output from existing generators.

We specified the following control variables for the SVP system:

Generators

All generators have variable real power output (P) and reactive power output (Q) within specified P and Q limits. However, we assumed the variability of the P output of the existing high-load-factor generators was limited either because they have limited turndown capability or because they must operate for thermal power production. Q limits are based on an assumed generator power factor range of .9 lagging to .95 leading.

We assumed the Gianera units are not available for either real or reactive power operation under our cases, which depict "normal" operation.

Shunts

We assumed all existing capacitors are switchable on/off, with no intermediate step capacitance values. Several buses have many individual 1200 kVAR capacitors and are actually individual capacitors on lines we did not model in detail; again, they are individually switchable on/off.

Timer-operated pole-top capacitors and routinely switched pad-mounted capacitors were characterized initially in each case as "on" or "off" according to their normal operating schedule provided by SVP.

Transformer Taps

We assumed that all SVP transmission to primary distribution stepdown transformers are tap changing under load (TCUL) type with a 60/12 kV nominal tap and off-nominal turns ratio range of + 10% and – 10% and sixteen tap changer steps either way. The current (preset) off-nominal turns ratio for each transformer was set at 1.0. However, we also assumed that the TCULs would only be changed to correct a voltage limit violation, as with a power flow solution, and not for overall optimization within AEMPFAST.

Line Switching

SVP distribution feeders are connected by switch to switch "branches" and "load branches." We modeled the system as operated radially, and assumed no switches could be repositioned as a routine control variable.

Load Curtailment

We assumed that SVP has no existing loads that are curtailable as a routine control variable; that is, in non-emergency conditions.

2.2.1.2. Capacity Additions Limits

Because the capacity additions represent DER projects, and because addition of any capacity can be shown to have some benefit up to the point where there is no power flow, we imposed limits to keep additions within the bounds of practicality.

For **reactive capacity** additions, we assumed that any customer location, or any switch, pole, or existing capacitor location was an eligible location.

For **demand response**, we assumed only customers rated at 200 kVA and higher were eligible sites. This reflects a presumption that smaller customers would lack the sophisticated metering and telecommunications required for DR that is dispatchable by the network operator. We assumed that medium (200 – 1,000 kVA) customers were generally capable of a reduction equal to 2% of their peak load on demand. We also assumed that the majority of large (over 1,000 kVA) customers were generally capable of a reduction equal to 5% of their peak load on demand with the remainder capable of a 2% reduction.

We also assumed that customers could achieve additional demand reduction if limited to the "1% highest hour" summer peak condition. Under these conditions, we assumed that 20% of medium customers were capable of a reduction of 15% of their peak load, up from 2% under more normal conditions. We assumed that 60% of large customers were capable of a 15% reduction, and the remaining 40% of large customers were capable of a 6% reduction, in each case up from 5% and 2% demand reduction respectively under more normal conditions.

In every case we modeled demand response as incremental negative load, or more specifically, real capacity with corresponding reactive capacity at the customer's power factor.

For **distributed generation**, we assumed any customer location was eligible. We assumed incremental distributed generation would be limited to 60% of the customer's peak load. We also assumed distributed generation would be subject to non-export feeder limits – either the total load on the feeder under minimum load conditions (the "Light Load Limit") or the Rule 21 limit of 15% of the feeder's peak load (the "15% Limit"). In general, we conducted two sets of analyses for generation additions, one for each non-export limit.

In every case, distributed generation was modeled as incremental real capacity with associated reactive capability ranging from .90 leading to .95 lagging power factor indicative of a synchronous generator.

These capacity additions limits were reviewed by several experts in the industry and approved by the Energy Commission.

Underlying the demand response assumptions noted above is the assumption of Energynet monitoring and communication capabilities that allow demand reductions to be dispatched on an individual customer basis and at different levels. Individual customer DR dispatch capability has been demonstrated in other PIER-funded projects such as Automated Facility Demand Response.[1] We believe the capability of achieving higher levels of DR on a network-dispatchable basis at specific locations and/or during limited-duration periods such as the "1%

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[1] http://drrc.lbl.gov/drrc-1.html

highest hour" summer peak is also consistent with the Energy Commission's draft Demand Response Information Exchange Reference Design.[2] Different levels of DR at customer sites could be triggered by different price signals, with technology acting as a proxy for direct end-user decisionmaking as envisioned by the reference design. The reference design is intended to enable implementation of a variety of different DR applications by different entities. Demand response for optimized network performance by the network operator could be one such application.

Because we did not model all primary distribution feeders, not all customer sites are characterized discretely and some load is shown as aggregated at the distribution transformers. We choose not to consider this load and these locations as available sites for DR or DG. We conducted a separate analysis that showed that in instances where loads were modeled as aggregated at a distribution transformer and distributed on feeders emanating from that transformer, the aggregated load sites ranked lower in terms of benefit to the system from capacity additions than all or virtually all of the sites on the feeders themselves at individual customer sites. We concluded from this analysis that we were not eliminating high-value locations for DR and DG additions with this approach. This issue would disappear if all feeders and customer load were discretely modeled, an approach we would adopt in future applications.

The DG limits were intended to capture projects of a reasonable scale for a customer/developer that would also avoid the need for detailed system studies for interconnection. Higher levels of DG penetration and/or DG projects that export power are the subject of other CEC-funded research such as the Distributed Utility Integration Test and the FOCUS II project.[3] The FOCUS II project has also demonstrated the type of advanced power quality metering discussed in Section 2.3.3.

2.2.2. Analytical Results

We successfully identified the locations and sizes of additions of reactive, real, and real plus reactive capacity (nominally, DER capacity additions) to optimize network performance relative to the base case for two cases representing present and future conditions – the Summer Peak 2002 case and the Summer 2005 case. We also evaluated the Summer Peak 2002 capacity additions under Knee Peak, Winter Peak and Minimum Load conditions to determine whether or how the recommended additions should be adjusted for varying network conditions.

We performed this analysis primarily using AEMPFAST. We also illustrated how identification of locations for capacity additions would be performed "by hand."

In each case, before considering capacity additions, we used AEMPFAST to determine settings of available controls that would yield network performance closest to the optimum with no capacity additions.

In each case we also considered additions of pure reactive capacity and determined that they would not incrementally improve the performance of this particular network. We also considered the need for additional lines or import capability for the Summer 2005 case and

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[2] http://ciee.ucop.edu/dretd/ReferenceDesign.pdf

[3] http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2005-006.html

determined that the 2005 network with the "in process or completed" projects noted above was capable of serving the 2005 loads without these additions.

2.2.2.1. Summer 2002 DER Capacity Additions

Through a limited hand analysis of the Summer Peak 2002 power flow results as described above, we determined the following:

North4 substation is a VAR source at the transmission level. However, at the same time, North4 transformer D1 is the one of the lowest-voltage buses, and Feeders 101, 104 and 105 are heavily loaded with low power factors, suggesting locations for incremental capacity additions. Feeders 204 and 304 are also relatively heavily loaded with low power factors. Capacitors on North4 transformers D2 and D3 and on Feeder 301 overcompensate and mask these effects.

North2 Feeders 202, 203, and 204 are heavily loaded, 203 and 204 also with low power factors, suggesting locations for incremental capacity additions. North2 Feeder 104 is also relatively heavily loaded. North2 Feeder 202 also has high loss segments. North2 Feeder 205 is a real power source and is a poor location for incremental capacity.

North6 Feeder 203 is heavily loaded, but is also a VAR source due to feeder capacitors. Feeders 102, 103, 105, 201, 202, and 205 are heavily loaded with low power factors, suggesting locations for incremental capacity additions.

Center3 Feeders 203 and 204 are heavily loaded, suggesting locations for incremental capacity. Feeder 303 is also heavily loaded, but is a VAR source due to feeder capacitors. Substation capacitors at the Center3 D2 transformer overcompensate for feeder reactive loads and turn Center3 into a VAR source.

Center4 Feeders 201 and 203 are relatively heavily loaded, suggesting locations for incremental capacity. Center4 Feeder 104 is lightly loaded and a VAR source.

Core1 Feeders 203 and 304 are heavily loaded with low power factors, suggesting locations for incremental capacity. Feeders 204 and 302 are also heavily loaded but are VAR sources. Feeder 305 is lightly loaded but a large VAR source. Feeder 304 also has high loss segments.

All of these statements are in relative terms, keeping in mind that overall, this particular subject system is lightly loaded. In many instances reactive power was added at the substation level while individual feeders still carried reactive loads, suggesting a potential benefit from installation of additional reactive capacity on the feeders themselves with concurrent reduction in reactive output in the substations. We did not list those locations here.

For readability, results from this load flow analysis are summarized in tabular form in Table 4. To evaluate these locations for DER additions, we would test the improvement in network performance with these additions individually and in groups using a series of additional load flow runs. Though we don't present the results here, we could have taken the analysis down to the detail of the preferred individual buses by looking at flows on line segments and voltages on buses on each identified feeder.

Table 4 Potential Optimal DER Locations Based on Load Flow Analysis Summer Peak 2002 Case

Substation	Add Incremental Capacity	High Loss Segments	Avoid Incremental Capacity	Reduce VAR Production
Center3				Transformer D2
	Feeder 203			
	Feeder 204			
	Feeder 303			Feeder 303
Center4				Feeder 104
	Feeder 201			
	Feeder 203			
Core1	Feeder 203			
	Feeder 204			Feeder 204
	Feeder 302			Feeder 302
	Feeder 304	Feeder 304		
				Feeder 305
North2	Feeder 104			
	Feeder 202	Feeder 202		
	Feeder 203			
	Feeder 204			
			Feeder 205	
North4				Transformer D2
				Transformer D3
	Feeder 101			
	Feeder 104			
	Feeder 105			
	Feeder 204			
				Feeder 301
	Feeder 304			
North6	Feeder 102			
	Feeder 103			
	Feeder 105			
	Feeder 201			
	Feeder 202			
	Feeder 203			Feeder 203
	Feeder 205			

The first step in the AEMPFAST analysis was to determine the performance of the subject system with control settings optimized. Figure 5 shows the voltage profile of the subject system under Summer Peak 2002 conditions before and after the recontrol step, indicating that the recontrol measures yielded meaningful improvement, particularly reducing low-voltage buses in the North Loop.

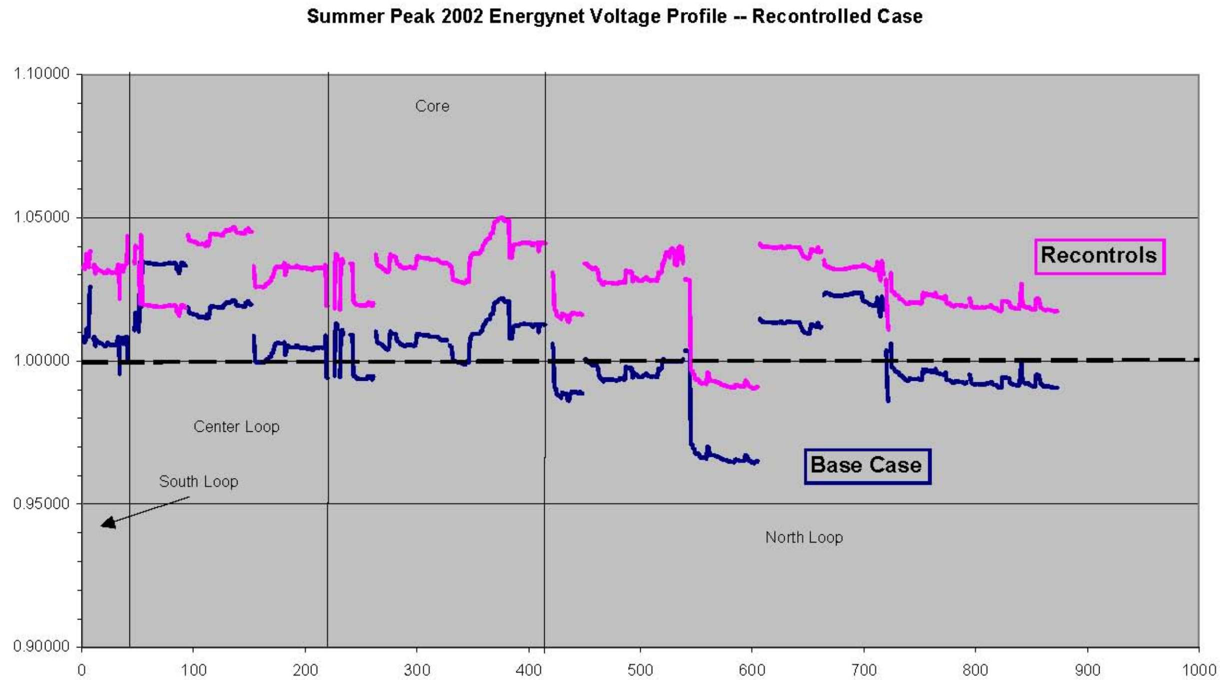

Figure 5 Summer Peak Engerynet Voltage Profile - Recontrolled Case

The recontrols voltage profile reflects the following control changes:

Generation:

South1 substation: increase VAR output by 4.7 MVAR

North4 Feeder 205: increase VAR output by 1.3 MVAR

Capacitors:

South4 feeders: switch off two 1.2 MVAR capacitors

Center3 D2: switch off two 4.8 MVAR capacitors

North4 Feeder 301: switch off three 1.2 MVAR capacitors

With these changes, the minimum-voltage bus in the network increased from 0.964 PU to 0.990 PU, and losses decreased from 1.262 MW as found to approximately 1.188 MW.

The AEMPFAST recontrol results also provide the initial P Index, or the first indication of the relative benefit from incremental additions of real capacity at each bus in the network. Again, sites with a positive P Index will realize a greater improvement in overall network performance as indicated by the objective function, per unit of real capacity added. Similarly, sites with a negative P Index will realize a greater improvement in overall network performance per unit of real capacity removed. These results are shown graphically in Figure 6. AEMPFAST also calculates an analogous Q Index for each point in the network.

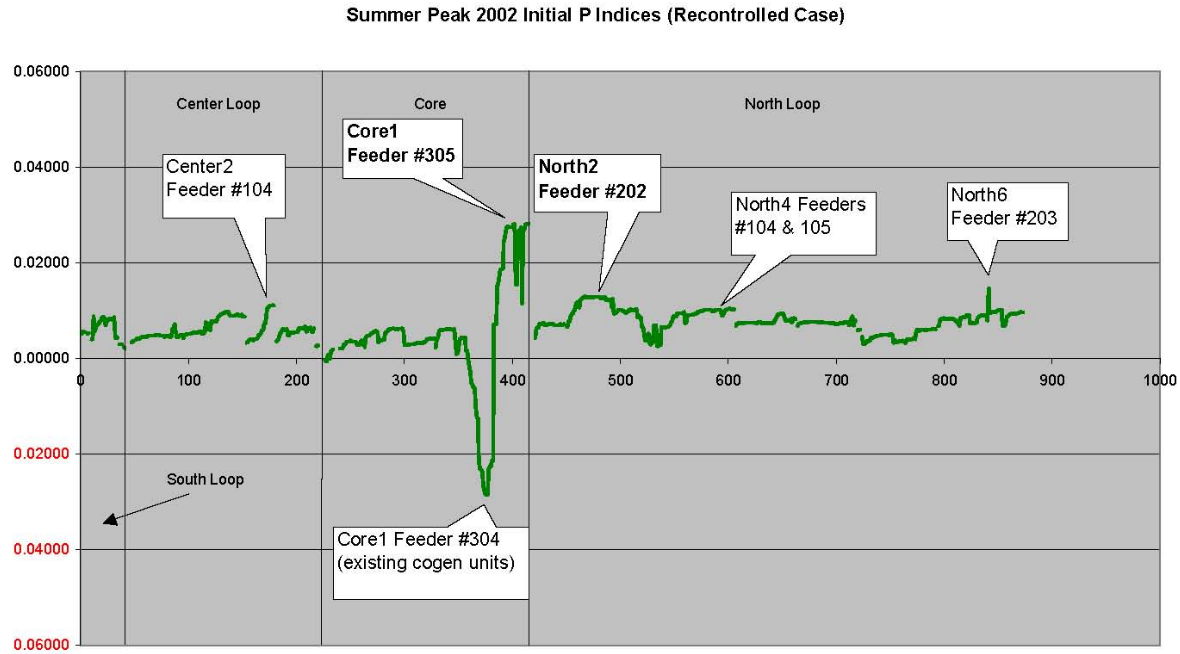

Figure 6 Summer Peak 2002 Initial P Indices (Recontrolled Case)

It bears repeating that this is a lightly-loaded system under little stress. According to Optimal, P Index values with a loss minimization and voltage profile optimization objective (such as the objective used in this study) of 3.00 are not unheard of in other systems. In the case of this system, a "high" P Index value is about 0.03, or two orders of magnitude lower.

Again, the absolute value of the P Index is a measure of the P "stress" at each point the system – again, the larger the P Index in absolute terms, the greater opportunity to improve network performance (as measured by the objective function) by adding or removing real capacity at that location. Examination of the initial P Indices for this system, before the addition of DER capacity, indicates that the maximum absolute P Index value is about 0.028. The average absolute P Index value (a measure of stress across the system) is about 0.0073 and the standard deviation (a measure of the variability of the stress across the system) is about 0.0049.

Specific locations of high or low P Index values are indicated in Figure 6. Note that in several cases locations with high P Indices based on the AEMPFAST analysis were also identified in the "hand" analysis of potential locations to add capacity summarized in Table 4.

Having first evaluated the network and determined that there were no additions of reactive capacity alone that would improve network performance, we next identified 389 rank-ordered locations where demand response would benefit network performance. These are listed in rank order in Appendix 2.2-1. A key observation of this table is that the ranking of DR additions is largely independent of the customer size or customer class. Another key observation is that DR at the sites of transmission-level customers received among the lowest ranks in terms of network benefit.

By way of an illustrative example, Figure 7 shows the initial P Indices on Core1 Feeder 305 and the DR rankings of eligible sites on that feeder. The feeder buses are shown in topological order with Bus 2275, the bus directly adjacent to the stepdown transformer, on the far left. Figure 7 shows that buses with the highest initial P Index were also the most beneficial (highest-ranking) locations for DR capacity additions and the most-beneficial locations were furthest electrically from the substation.

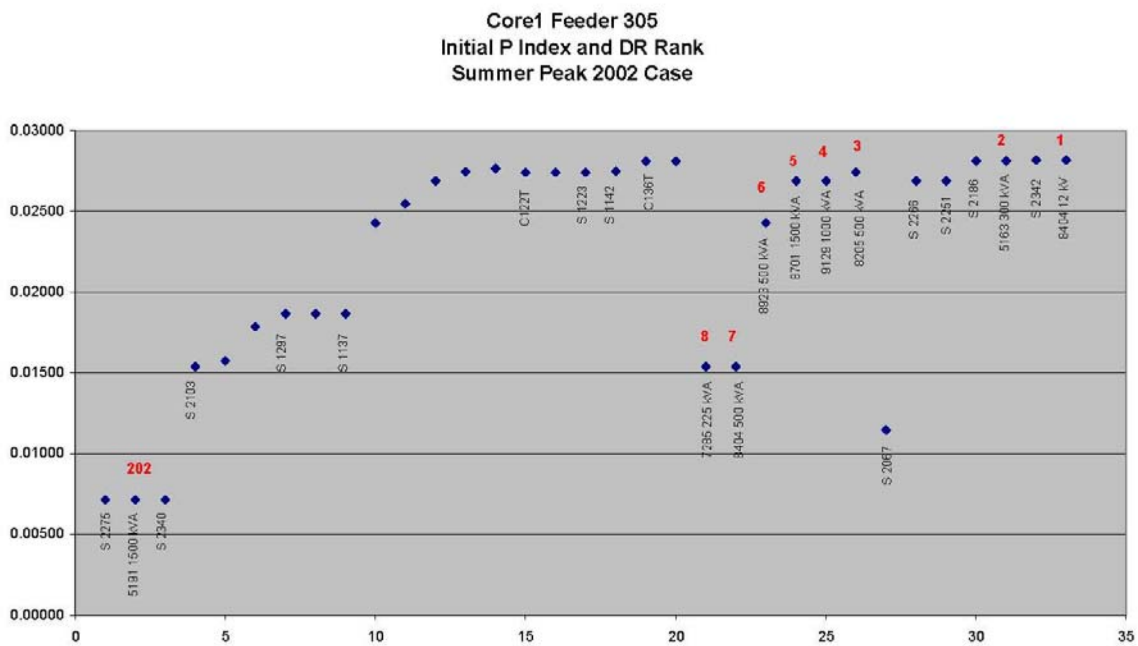

Figure 7 Core1 Feeder305 Initial P Index and DR Rank Summer Peak 2002 Case

Core1 Feeder 305 is an interesting example because it has some of the most beneficial (highest ranked) DR locations. It has a relatively wide range of site rankings, as well as one of the lowest-ranking DR locations.

These results may be evaluated either on a feeder level or with the additional granularity of the individual bus level. However aggregating individual bus level results such as those in Appendix 2.2-1 can easily lead to misinterpretation. For example, note that the number of beneficial locations on a feeder for DR capacity additions is largely a function of the number of eligible sites on that feeder. Thus, a large *number* of identified sites on a feeder is not necessarily an indication of the importance of capacity additions on that feeder. Similarly, the total DR in MW terms represented on a feeder is largely a function of the size of the loads on that feeder. So the total *amount* of DR on a feeder is also not necessarily an indication of the importance of those capacity additions. We feel one useful indicator of the importance of capacity additions on a given feeder is the average rank of that feeder's additions. Table 5 summarizes the top-ranked 133 DR capacity additions for the Summer Peak 2002 case in terms of the feeders with the most beneficial DR sites.

Table 5 Summer Peak 2002 Top 133 DR Locations by Feeder

Substation	Feeder	Buses/Sites	Total DR (kW)	Avg Rank
Core1	Feeder 305	8	61	5
North4	Feeder204	1	241	16
North2	Feeder 202	20	673	19
Center2	Feeder 104	1	76	29
North4	Feeder 105	7	253	50
North6	Feeder 203	10	452	54
North 2	Feeder 203	12	531	66
North 4	Feeder 104	23	296	67
North 4	Feeder 203	4	272	82
North4	Feeder 101	7	235	86
Center3	Feeder 303	6	97	88
North6	Feeder 205	11	413	97
North2	Feeder 204	1	335	99
North 4	Feeder304	1	305	101
North6	Feeder 202	6	208	114
North6	Feeder 201	8	200	118
South3	Feeder 104	5	249	121
North4	Feeder 205	1	136	122
North4	Feeder 305	1	284	133

We next identified rank-ordered locations where distributed generation (DG) capacity additions would benefit network performance over and above the benefit provided by these DR additions. Under the constraint that total DG capacity would be limited to 15% of the feeder's peak demand, we identified 111 beneficial locations. Under the constraint that total DG capacity would be limited to the feeder's total demand under minimum load conditions, we identified 317 beneficial locations. These are also listed in rank order in Appendix 2.1-1.

As with DR, the ranking of DG capacity additions is largely independent of the customer size or customer class, and DG at the transmission-level customer locations received among the lowest ranks in terms of per-unit network benefit. Among the light-load limited DG capacity additions, there are additions at 114 of the 130 large (> 1,000 kVA) customer sites, additions at 183 of 260 medium (200 kVA-1,000 kVA) customer sites, and additions at 21 of 29 at small (< 200 kVA customer sites. The average rank of additions at large customer sites is 145 out of 317, the average rank at medium customer sites is 167, and the average rank of additions at small customer sites is 171. The average rank of additions at the transmission-connected customer sites is 277, 299, and 304.

Customer sites not identified as beneficial locations for DER were those with the lowest rankings that remained when the non-export feeder limits were reached.

Figure 8 shows the change in the AEMPFAST optimization objective value, expressed numerically, as the successive steps of DR additions are added. We found that the 15% of peak load non-export feeder limit is a restrictive limit; Figure 8 illustrates that this limit leaves significant benefit from additional DG. Figure 8 also shows the impact of DG additions at large, transmission-level customer sites that while ranked low in terms of per-unit network benefit, have a large impact due to their size.

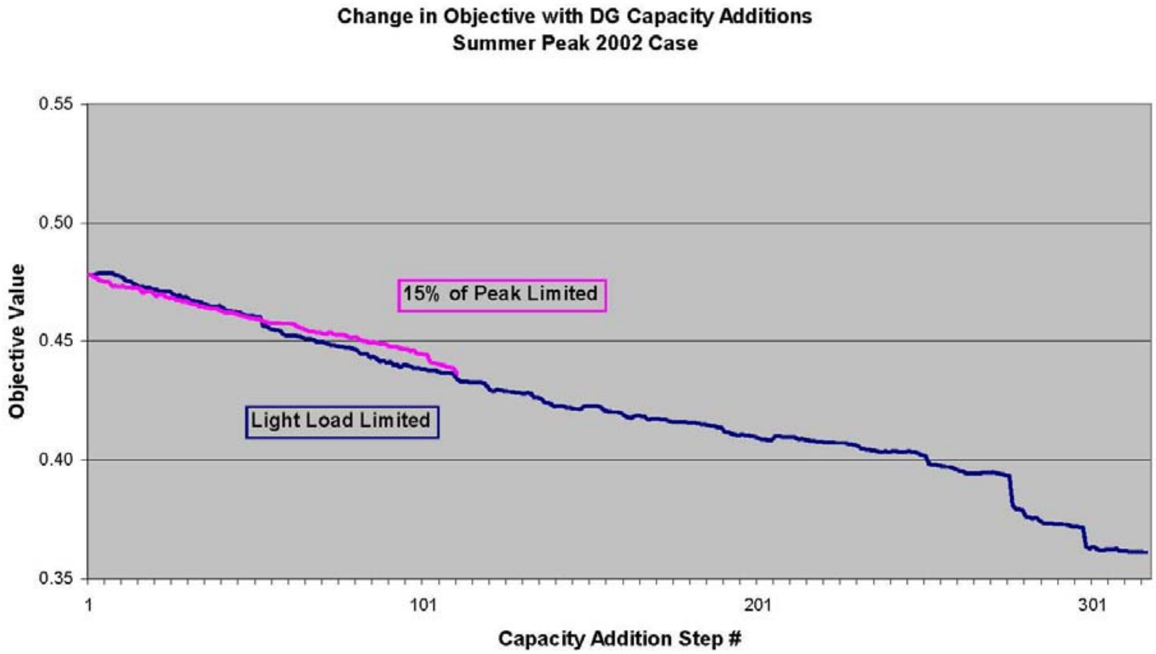

Figure 8 Change in Objective with DG Capacity Additions Summer Peak 2002 Case

Table 6 summarizes the Top 133 DG projects under the light load feeder limit in terms of the feeders with the most beneficial DG sites.

Table 6 Summer Peak 2002 Top 133 DG Locations by Feeder (Light Load limited)

Location		Buses/Sites	Total DG (kW)	Avg Rank
North2	Feeder 202	5	1,070	11
Center2	Feeder 104	1	305	14
Core 1	Feeder 305	9	287	15
North4	Feeder 105	6	860	43
North6	Feeder 203	10	1,481	44
North2	Feeder 204	1	1,341	53
North4	Feeder 104	21	1,162	53
North4	Feeder 304	1	130	56
North4	Feeder 204	1	690	59
North4	Feeder 101	6	869	62
Center3	Feeder 303	11	1,864	63
North2	Feeder 203	13	2,132	65
North4	Feeder 203	4	1,059	69
North4	Feeder 205	1	545	69
North6	Feeder 205	4	608	78

North6	Feeder 201	6	905	86
North4	Feeder 305	1	520	87
North6	Feeder 202	4	240	92
South3	Feeder 10	12	1,485	102
North4	Feeder 303	1	136	102
North4	Feeder 201	1	33	107
Center3	Feeder 203	1	850	111
North4	Feeder 103	1	530	120
North2	Feeder 102	1	695	121
North4	Feeder 301	11	880	122
North4	Feeder 202	1	125	132

We conducted essentially identical analyses for the "present" system under Knee Peak, Winter Peak, and Minimum Load conditions, identifying rank-ordered DR and DG capacity additions. We used these results to identify any beneficial locations for DER under Summer Peak conditions that could have adverse network impacts under these different conditions. Through this process, we identified three buses of interest, Buses 5062, 7617, and 8795.

Buses 5062 and 7617 are located on Core1 Feeder 304, highlighted in Figure 8 above as a feeder with many negative P Index buses. Buses 5062 and 7616 are customer buses that are electrically the closest to the two generating units on that feeder. The first, Bus 5062, was identified as a beneficial (albeit low-ranked) DG location under Summer Peak conditions. However, Bus 5062 had a negative initial P Index under all load conditions except Summer Peak conditions, suggesting that even though this bus was identified as a beneficial DG location under Summer Peak conditions, DG capacity addition at that location could have adverse network impacts under different load conditions. Accordingly, DG capacity addition at Bus 5062 could arguably be excluded from an "optimal DER portfolio" when seasonally-varying loads are taken into account, or, at a minimum, designated for limited operation.

The second, Bus 7617, had a negative initial P index under all load conditions and was not identified in any case as a beneficial DG site.

Bus 8795 is located directly adjacent to an existing generating unit on North4 Feeder 202. Similar to Bus 7617, Bus 8795 had a negative initial P index in two of four load conditions evaluated, and was not identified in any case as a beneficial DG location.

2.2.2.2. Summer 2005 DER Capacity Additions

We repeated the previously described analysis for the Summer 2005 system, modeled with projected Summer 2005 loads. Figure 9 shows the voltage profile of the subject system under Summer 2005 conditions before and after the recontrol step. Figure 9 shows that in this case recontrols made a substantial improvement in overall voltage and elimination of many low-voltage buses across the network.

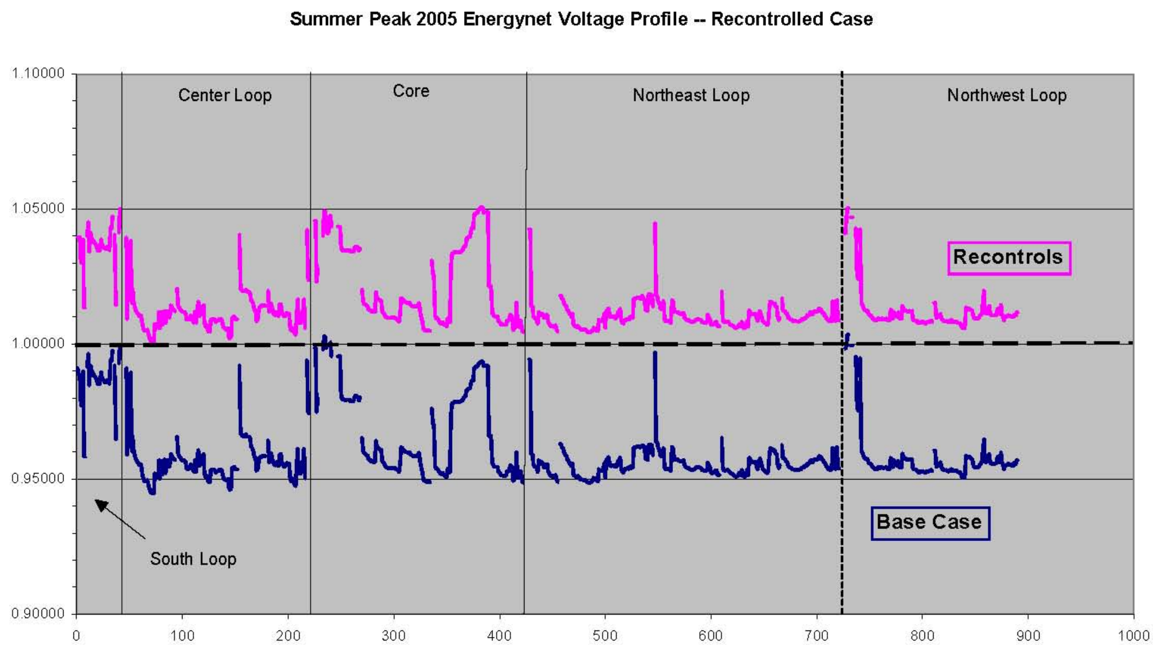

Figure 9 Summer Peak 2005 Energynet Voltage Profile - Recontrolled Case

The recontrols voltage profile reflects the following control changes (plus additional changes of < 0.100 MW or MVAR):

Imports:

Northern Receiving: increase VAR imports by 6.5 MVAR

Kifer Receiving: decrease VAR imports by 40.4 MVAR

With these changes, the minimum-voltage bus in the network increased from 0.944 PU to 1.000 PU, and losses decreased from 3.172 MW as found to approximately 2.971 MW. It is worth noting that while the VAR redistribution is localized at two buses, the voltage impact of this redistribution extends across the entire system. This is probably the most striking example of how far reaching we found the impacts of localized measures to be.

The AEMPFAST initial P Index results for the Summer 2005 case are shown graphically in Figure 10, using the same scale as used above for the Summer 2002 initial P Index plot.

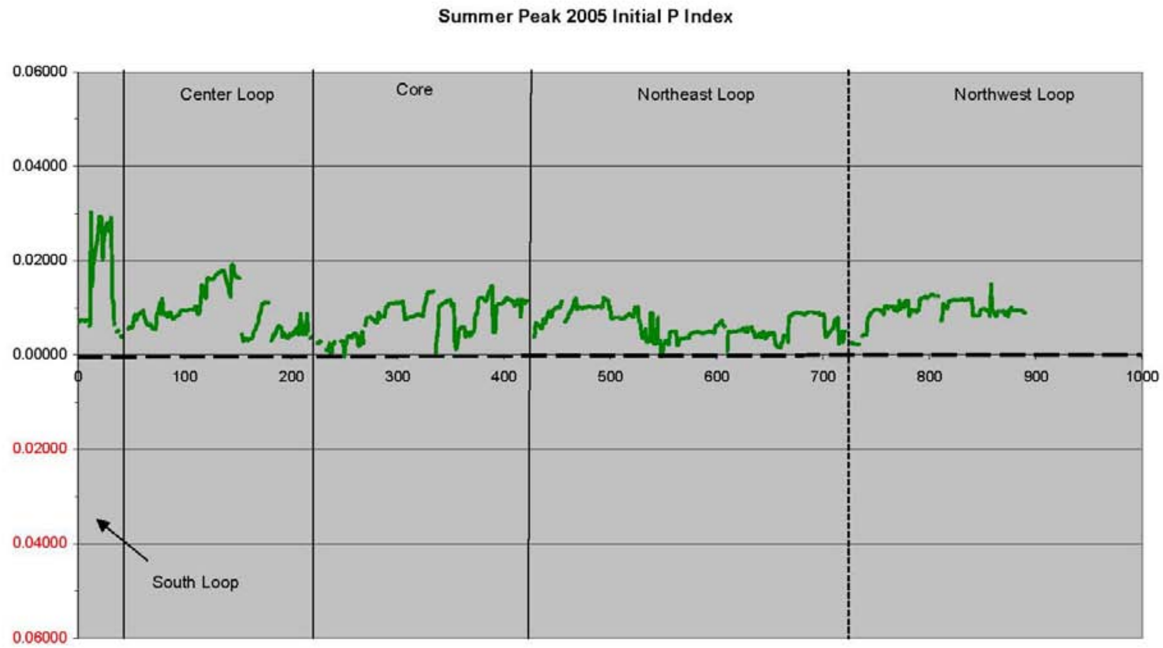

Figure 10 Summer Peak 2005 Initial P Index

It is interesting that even with approximately 46% more load,[4] the network is not appreciably more stressed. This is due presumably to the addition of Northern Receiving as the third 115 kV receipt point, bifurcating the former North Loop.

Examination of the initial P Indices for this system, before the addition of DER capacity, indicates that the maximum absolute P Index value is about 0.03. The average absolute P Index value (a measure of stress across the system) is about 0.008, or slightly higher than the Summer Peak 2002 case. The standard deviation (a measure of the variability of the stress across the system) is about 0.0044, or slightly less than for the Summer Peak 2002 case.

It is also visible in Figure 10 that the locations in the network with the greatest stress are now in the South Loop, with some stressed buses in the Center Loop.

We evaluated the 2005 network using AEMPFAST and determined that there were no additions of reactive capacity that would improve network performance.

We next identified 390 rank-ordered locations where demand response would benefit network performance. These are listed in rank order in Appendix 2.1-1. Consistent with the Summer 2005 Initial P Index plot, the highest-ranking locations for DR capacity additions are on South3 Feeder 104.

Table 7 summarizes the top 99 ranked DR projects in terms of the feeders with the most beneficial DR sites.

[4] The Total Load in the Summer 2005 case is 581.999 MW. The Total Load in the Summer Peak 2002 case is 397.589 MW.

Table 7 Summer 2005 Top 99 DR Locations by Feeder

Substation	Feeder	Buses/Sites	Total DR (kW)	Avg Rank
South3	Feeder 104	10	1573	6
Core1	Feeder 205	5	466	22
Center3	Feeder 303	14	2374	25
North6	Feeder 105	14	1089	34
South3	Feeder 105	1	556	45
North6	Feeder 201	16	819	63
Core1	Feeder 305	8	1045	63
Core1	Feeder 302	7	898	71
North2	Feeder 105	2	733	73
North2	Feeder 202	5	514	73
North6	Feeder 102	4	674	73
Center3	Feeder 202	2	20	79
Core1	Feeder204	8	293	82
South3	Feeder 104	1	2	82
North6	Feeder 101	2	207	95

We next identified rank-ordered locations where distributed generation (DG) capacity additions would benefit network performance over and above the benefit provided by these DR additions. Under the constraint that total DG capacity would be limited to 15% of the feeder's peak demand, we identified 114 beneficial locations. Under the constraint that total DG capacity would be limited to the feeder's total demand under minimum load conditions, we identified 149 beneficial locations. These are listed in rank order in Appendix 2.1-1.

Among the light-load limited DG capacity additions, there are additions at 66 of the 130 large customer sites, additions at 76 of 260 medium customer sites, and additions at 7 of 29 at small customer sites.

The average rank of additions at large customer sites is 75 out of 149, the average rank at medium customer sites is 77, and the average rank of additions at small customer sites is 54. The rank of additions at the transmission-connected customer sites is 143 and 144.

Again, it is evident that DG capacity additions at sites of large customers as a class did not rank appreciably higher in terms of their network benefit.

Customer sites not identified as beneficial locations for DER were those with the lowest rankings that remained when the feeder limits were reached.

Figure 11 change in the AEMPFAST optimization objective value, expressed numerically, as the successive steps of DR additions are added.

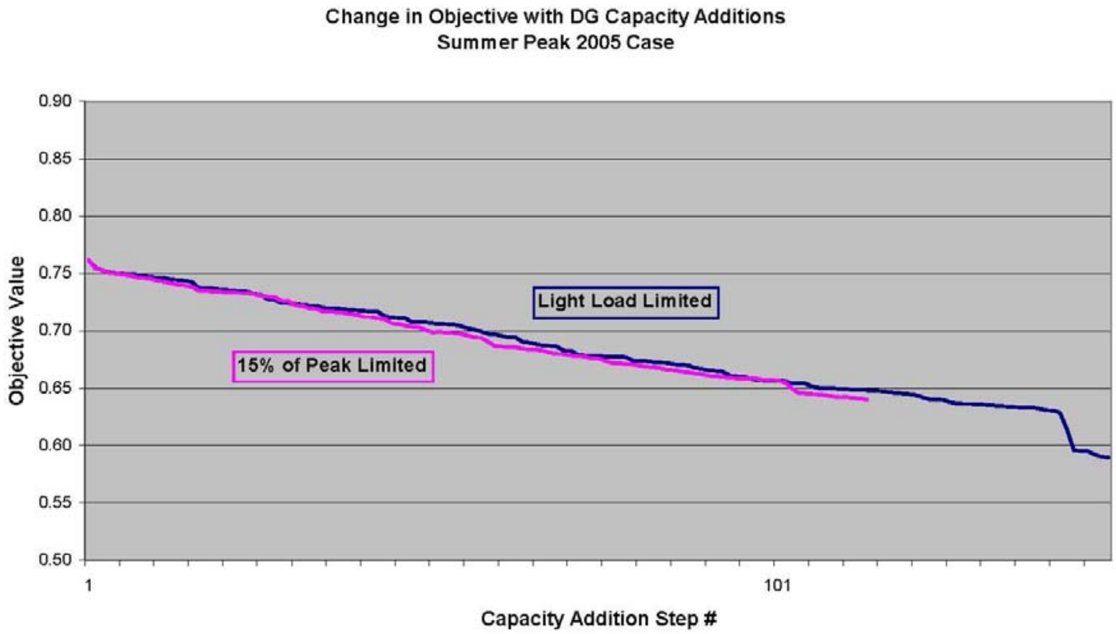

Figure 11 Change in Objective with DG Capacity Additions Summer Peak 2005 Case

One difference to note with the Summer 2005 DG results is that there are fewer DG capacity additions under the Light Load feeder limit, and the difference between the two feeder limits is less. As indicated in Section 2.1, we used different methods to develop distribution bus-level loads for the 2002 cases and the 2005 case in our effort to avoid the need for individual customer data. One of the impacts of the method used for the 2005 cases was that a greater (and probably more representative) share of the total system load was allocated to individual customer sites, even after consideration of the block load modeling of those feeders not modeled in detail. Another consideration is that the light load feeder limit for the 2005 case was derived from the Spring 2002 minimum load case, since we developed only the Summer 2005 load case.

As a result of both of these factors, the Light Load limit is less generous relative to the 15% of peak feeder limit in the 2005 case than it is in the 2002 case. Also, since the 2005 case individual customer loads represent a greater share of the total system load, DG capacity additions representing up to 60% of the host customer's peak load reach the same Light Load feeder limit more rapidly. The Summer 2005 average DG capacity addition is roughly twice the size of the Summer 2002 case capacity addition, so there are roughly half as many under the same Light Load feeder limit.

Table 8 summarizes the Top 100 DG projects under the light load feeder limit in terms of the feeders with the most beneficial DG sites.

What is evident is that the DG capacity additions in the 2005 case are more highly distributed. In Table 8 there are more feeders represented and many feeders have only one site identified. This is because in many cases the non-export feeder limit was met with the first capacity addition step on that feeder, again a result of the differently-distributed customer loads in the 2005 case.

Table 8 Summer 2005 Top 100 DG Locations by Feeder (Light Load limited)

Substation	Feeder	Buses/Sites	Total DR (kW)	Average Rank
Center3	Feeder 303	1	1660	2
Core 1	Feeder 305	2	400	6
South3	Feeder 104	2	1880	8
North6	Feeder 105	7	1401	12
Core1	Feeder 302	1	40	12
Center2	Feeder 104	1	55	19
North2	Feeder 202	4	1071	31
North6	Feeder 201	6	1240	31
North4	Feeder 301	4	880	35
North2	Feeder 204	1	1090	44
North2	Feeder 104	3	2470	45
North6	Feeder 101	1	300	45
Core 1	Feeder 204	14	2119	45
Center3	Feeder 202	5	751	46
Center3	Feeder 302	2	1400	53
Core 1	Feeder 205	14	2709	54
North4	Feeder 303	1	530	58
North6	Feeder 202	1	600	59
North6	Feeder 104	1	1106	64
North2	Feeder 205	2	440	65
Core 1	Feeder 304	1	265	73
North6	Feeder 205	2	1150	76
North4	Feeder 105	4	394	83
North6	Feeder 103	2	1659	84
North2	Feeder 203	6	2130	87
Core1	Feeder 203	6	1190	88
Center3	Feeder 204	2	1687	90
North2	Feeder 102	1	550	98

Core1 Feeders 204 and 205 have many sites identified, but this is largely due to the fact that there are many loads on these feeders. North2 Feeder 104 has a large volume of DG in terms of kW, largely because this feeder has large loads. Again, we think the average rank of sites on a feeder is a good indication of the “importance” of that feeder. By this measure, Center3 Feeder 303, Core1 Feeder 305, and South3 Feeder 104 are more important than the others.

2.2.3. Conclusions

We determined that the integrated Energynet dataset, incorporating distribution with transmission, provides a platform for analysis that gives far more detailed insights into localized measures that can improve network performance. Using such a dataset, power flow results and conventional analysis can identify specific feeders or buses where capacity additions will improve network performance by reducing losses and reactive power flow. Such an analysis can also distinguish between impacts of substation and feeder-installed devices, and detect problems at the distribution level that may be masked by devices at the transmission or substation level.

Our recontrol analysis using AEMPFAST yielded a somewhat unexpected conclusion – that limited resetting of a few localized controls can have a pervasive impact on voltage and performance across the network. These impacts may be far less localized than conventionally thought.

We determined that AEMPFAST can make meaningful distinctions among locations for DER capacity additions in terms of their benefit to the network. AEMPFAST has the capability to identify both beneficial locations and locations with negative benefits (or adverse impacts) from capacity additions.

It is also evident that while a hand analysis can identify a number of "good" locations for capacity additions, the "best" locations for capacity additions may not be visible except with a tool such as AEMPFAST. Hand analysis of the Summer Peak 2002 case identified North2 Feeder 202 and North4 Feeder 105 as feeders with "good" locations for capacity additions, but it did not identify Core1 Feeder 305 and North4 Feeder 204 as having the "best" locations for capacity additions.

We also determined that the differences in the two methods for projecting bus-level loads have different impacts on the recommended DER capacity additions. The differences between these two methods probably need to be reconciled.

We conclude that a reasonable set of limits on the size and number of DER capacity additions can avoid the more-or-less useless conclusion that adding capacity at every load location improves network performance, and help to bring visibility to those locations where capacity additions will provide the most network benefit. However, at the same time, these external limits also had a significant impact on the makeup of the recommended capacity additions in each category. We believe the limits used here are reasonable, but it is clear that a different set of limits would yield at least a slightly different set of DER additions.

It is also evident that the Rule 21 15% of peak feeder load limit may be a fairly restrictive limit on potential beneficial DG capacity additions even with an objective of preventing export from DG projects.

2.2.4. AEMPFAST Evaluation

As described in this section, this project relied on AEMPFAST results as a way to select from among a large number of candidate DER additions to benefit network performance and its unique capability to measure the sensitivity of network performance to additions of real capacity at specific locations in the system.

Because the AEMPFAST analysis figures so prominently in the results of this project, the Energy Commission asked a subcommittee of this project's TAC consisting of Drs. Jim Kavicky and Maria Ilic to perform an additional evaluation of AEMPFAST under non-disclosure agreements and assess the suitability of this analytical engine for this application.

The TAC subcommittee developed a set of seven questions relating to the functionality and capability of AEMPFAST and its underlying algorithms as well as a set of six literature references to provide an existing context against which to evaluate AEMPFAST. Optimal Technologies provided written responses, and the TAC subcommittee also discussed these responses with Optimal in several teleconferences.

In its closure document provided to the Energy Commission, the TAC subcommittee stated their conclusion based on this review that "AEMPFAST performed satisfactorily while evaluating possible enhancements of the distribution system studied under this CEC project conducted by New Power Technologies." Drs. Kavicky and Ilic indicated that they had high confidence in AEMPFAST results where modeled system conditions were such that a power flow solution converges, where incremental capacity additions are small in relative terms, and where the Hessian Matrix is positive definite. These conditions were met in all the cases of this study.

2.3. Characterization of DER Capacity Additions as DER Projects

2.3.1. Approach

In Section 2.2 we illustrated how the integrated Energynet dataset can be used to identify beneficial locations for DER capacity additions, and we developed a set of recommended additions of real, reactive, and real plus reactive capacity for the Summer Peak 2002 and Summer 2005 cases using AEMPFAST. We provisionally characterized these additions as DR and DG additions primarily in light of their characteristics and limits. In this section we refine these recommended capacity additions as DR and DG projects, and assess their impact on the performance of the subject system.

In characterizing the recommended DER capacity additions as DR and DG projects, we considered the operability of DER capacity additions identified for Summer Peak 2002 conditions under seasonally-varying conditions using the Knee Peak, Winter Peak, and Minimum Load cases. In this section we demonstrate how this limited seasonal analysis can be used to provide the additional dimension of the operating profile to Optimal DER Portfolio projects and identify those projects that require system-level dispatch control.

In evaluating the impact of recommended DER capacity additions we considered the change in network performance yielded by these additions relative to base case (as found) conditions and compared these to the increase in network performance that could be achieved by adjustments in control variables (recontrols) alone. We also used PSLF to confirm that benefits of the changed network configuration with the DR and DG projects observed in AEMPFAST.

To develop Optimal DER Portfolios for "present" and "future" conditions, we followed the following stepwise process:

"Present" Case

Characterize a portfolio of DER projects for the present Summer Peak case from the results of, and based on the recommended DER additions from, Section 2.2.

Validate the network performance improvement yielded by these recommended additions using new load flow runs for comparison with the base cases from Section 2.1.

Verify the operability of these additions under alternative load conditions through Winter Peak and Light Load flow runs.

Include in the results an assessment of the operational improvement achieved through recontrols alone vs. improvements from DER additions.

Derive operational requirements for DER projects from analysis of the performance of the network with DER additions under Winter Peak and Light Load conditions.

"Future" Case

Characterize the changes to the portfolio of DER projects for the future Summer Peak case from the results and based on the recommended DER additions from Section 2.2.

Validate the network performance improvement yielded by these recommended additions using new load flow runs for comparison with the base cases from Section 2.1.

Include in the results assessment of the operational improvement achieved through recontrols alone vs. improvements from DER additions.

Derive operational requirements for DER projects from analysis of changes in the performance of the network with DER additions from present Summer Peak conditions and future Summer Peak conditions.

Include in the results an assessment of the relative ability of recontrols, DER additions, and line and import additions to handle anticipated load growth in the future case.

2.3.2. Analytical Results

Optimal DER Portfolios of DR and DG projects for "present" and "future" conditions result from the steps itemized above. For the present case the Optimal DER Portfolio consists of DR projects at most customer locations, but with projects at specific locations specified for higher levels of demand reductions, and those higher levels dispatched selectively depending on the network benefits they provide under different network conditions. This portfolio also consists of 380 DG projects, some of which have variable operating profiles, also depending on the network benefits they provide under different network conditions.

For the future case the Optimal DER Portfolio also consists of DR projects at most customer locations, but with projects at specific locations specified for higher levels of demand reduction. Presumably these projects would also be dispatched selectively depending on the network benefits they provide under different network conditions. This portfolio also consists of DG projects at some customer sites, some of which have variable operating profiles, also depending on the network benefits they provide under different network conditions.

From the network's standpoint, Optimal DER Portfolio DR projects with different capabilities are placed in specific locations, and then dispatched on a customer-specific basis at different DR levels under different conditions to achieve network benefits, functionally operating as capacity injections at the location and voltage of the customer. Likewise, DG projects are placed in specific locations and can be dispatched (with MW and MVAR independently dispatchable within limits) to achieve network benefits.

2.3.2.1. 2002 Optimal DER Portfolio – DR Projects

The demand response (DR) projects for the Optimal DER Portfolio are characterized in terms of their location, their capability as a share of the peak load of the customer at that location (and by association, in kW or MW terms), and when (seasonally) and at what level that capability is dispatched.

We have assumed that the demand response (DR) projects to be included in the Optimal DER Portfolio are dispatchable – that is, that DR once installed at a customer site can be dispatched to respond to the needs of varying system conditions. Further, as discussed in Section 2.2, we have also assumed different levels of DR capability at the sites of different classes of customers under different load conditions. Accordingly, the DER limits discussed in Section 2.2 imply not only limited penetration of demand response, but also the ability to dispatch different levels of demand response at specific locations in the network to gain optimum performance.

Large Customer DR Projects

As described in Section 2.2, for large (> 1,000 kVA rated) customer DR projects, we assumed two levels of dispatchable DR – reductions of 2% and 5% of the customer's peak load – on under Knee Peak, Winter Peak, and Minimum Load conditions, and two higher levels – reductions of 6% and 15% of the customer's peak load – available only under the 1% highest hour Summer Peak load condition. We also assumed that only specified share (60%) of those customers were capable of achieving a higher demand reduction level of 5% under conditions other than the Summer Peak, and that only 60% of large customers were capable of achieving demand reductions of 15% under Summer Peak conditions. Basically, we sought to identify those customer locations where higher levels of DR were preferred under different conditions to maximize network benefits.

We identified 61 large customer DR projects that, based on the network benefits of incremental DR capability at their locations, were preferred locations for the higher 5% demand reduction level during all three of Knee Peak, Winter Peak, and Minimum Load conditions. These are listed by location in Table 9.

We identified 32 "seasonal" large customer DR projects which were preferred locations for the higher 5% demand reduction capability only during specific seasonal conditions, based on the network benefit of incremental DR capability at those locations under those conditions. 17 of these seasonal DR projects are preferred locations for the higher 5% demand reduction capability during summer season (Knee Peak) conditions. These are listed in Table 10. The other 15 are preferred locations for the higher 5% demand reduction capability during winter season conditions. These are listed in Table 11.

Two of the summer season projects are preferred locations for the higher 5% DR capability under winter conditions, and one under minimum load conditions, again, based on the network benefit of incremental DR capability in those locations under those conditions. These projects are designated respectively as "WP" and "ML" in Table 10.

Twelve of the 15 winter season DR projects are preferred locations for the higher 5% DR capability under minimum load conditions. These twelve are designated in Table 11.

We identified four "minimum load" DR projects that are preferred locations for the higher 5% demand reduction capability only during minimum load conditions based on the network benefit of incremental DR capability at those locations under those conditions. These are listed in Table 12.

As noted above, we also identified those large customer DR projects which, based on the network benefit of incremental DR capability at their locations, are preferred locations for the highest 15% DR capability under the 1% highest hour Summer Peak conditions. Most of these were also identified as preferred locations for the higher 5% DR capability under one or more of the regular seasonal conditions; these projects are designated as "SP" in Table 9 through Table 12. However, we also identified two large customer DR projects that are preferred locations for the highest DR capability under Summer Peak conditions but that are otherwise preferred for only the 2% DR capability under other seasonal conditions. These two projects are listed in Table 13.

All of the remaining large customer DR projects are specified for reductions of 2% of the customer's peak load during the Knee Peak, Winter Peak, and Minimum Load conditions and reductions of 6% of the customer's peak load during highest-load-hour Summer Peak conditions. All three transmission-connected customer sites fell into this class.

Table 9 Large Customer DR Projects Preferred for 5% DR Capability under Knee Peak, Winter Peak, and Minimum Load Conditions

Bus ID	Substation	Feeder
500 North2	Feeder 102	SP
5130 North2	Feeder 102	SP
7965 North2	Feeder 104	SP
5149 North2	Feeder 104	
502 North2	Feeder 105	SP
501 North2	Feeder 105	
8661 North2	Feeder 202	SP
503 North2	Feeder 202	SP
8662 North2	Feeder 202	SP
8514 North2	Feeder 202	SP
8890 North2	Feeder 202	SP
504 North2	Feeder 203	SP
5113 North2	Feeder 203	SP
8595 North2	Feeder 203	SP
5144 North2	Feeder 203	SP
8594 North2	Feeder 203	SP
8038 North2	Feeder 203	SP
5168 North2	Feeder 203	SP
8973 North2	Feeder 203	SP
505 North2	Feeder 204	SP
5226 North4	Feeder 101	SP
9093 North4	Feeder 101	SP
9091 North4	Feeder 101	SP
9090 North4	Feeder 101	SP
9088 North4	Feeder 101	SP
526 North4	Feeder 101	SP
525 North4	Feeder 101	SP
527 North4	Feeder 103	SP
5148 North4	Feeder 104	SP
8698 North4	Feeder 104	SP
9087 North4	Feeder 104	SP
8905 North4	Feeder 104	SP
5115 North4	Feeder 104	SP
8161 North4	Feeder 105	SP
5034 North4	Feeder 105	SP
8894 North4	Feeder 201	SP
8591 North4	Feeder 201	SP

Bus ID	Substation	Feeder
528 North4	Feeder 201	SP
529 North4	Feeder 201	SP
9092 North4	Feeder 202	SP
8700 North4	Feeder 202	SP
5190 North4	Feeder 202	SP
531 North4	Feeder 203	SP
8893 North4	Feeder 203	SP
8904 North4	Feeder 203	SP
530 North4	Feeder 203	SP
532 North4	Feeder 204	SP
533 North4	Feeder 205	SP
7690 North4	Feeder 301	SP
8281 North4	Feeder 301	SP
7689 North4	Feeder 301	SP
8541 North4	Feeder 301	SP
5098 North4	Feeder 301	SP
5324 North4	Feeder 303	SP
5201 North4	Feeder 303	
534 North4	Feeder 304	SP
535 North4	Feeder 305	SP
515 North6	Feeder 203	SP
506 South3	Feeder 104	SP
5051 South3	Feeder 104	SP
8542 South3	Feeder 104	SP

Table 10 Large Customer DR Projects Preferred for 5% DR Capability under Summer Seasonal Conditions

Bus ID	Substation	Feeder	
538	Center3	Feeder 203 ML	SP
524	Core 1	Feeder 305	SP
8701	Core 1	Feeder 305	SP
5171	North6	Feeder 101	
8280	North6	Feeder 101	
8587	North6	Feeder105 VV	
5097	North6	Feeder 201	SP
5198	North6	Feeder 201	SP
5304	North6	Feeder 201	SP
9086	North6	Feeder 202	SP
514	North6	Feeder 202	SP
8517	North6	Feeder203 VV	SP
5052	North6	Feeder 205	SP
8592	North6	Feeder 205	SP
517	North6	Feeder 205	SP
8164	North6	Feeder 205	SP
8659	North6	Feeder 205	SP

Table 11 Large Customer DR Projects Preferred for 5% DR Capability under Winter Seasonal Conditions

Bus ID	Substation	Feeder	
5183	Center3	Feeder 302 ML	
5182	Center3	Feeder 302 ML	
541	Center3	Feeder 303 ML	SP
5169	Center3	Feeder 303 ML	SP
519	Core1	Feeder 103	
520	Core 1	Feeder 204 ML	
7439	Core 1	Feeder204 ML	
521	Core1	Feeder205 ML	
8971	Core1	Feeder205 ML	
7971	Core1	Feeder205 ML	
8516	Core1	Feeder 205 ML	
8767	Core 1	Feeder 205 ML	
8682	North2	Feeder205 ML	
8768	North6	Feeder 105	
513	North6	Feeder 105	

Table 12 Large Customer DR Projects Preferred for 5% DR Capability under Minimum Load Conditions

Bus ID	Substation	Feeder	
539	Center3	Feeder 204	
8699	Center3	Feeder 204	
5302	Center3	Feeder 303	SP
540	Center3	Feeder 303	SP

Table 13 Large Customer DR Projects Preferred for 15% DR Capability under Summer Peak Conditions

Bus ID	Substation	Feeder
5191	Core 1	Feeder 305 SP
8225	North6	Feeder 202 SP

Medium Customer DR Projects

For medium (200 - 1,000 kVA rated) customer DR projects, we assumed two levels of dispatchable DR – reductions of 2%, and 15% of the customer's peak load. We assumed all medium customers were capable of at least 2% DR. Under the highest-load-hour Summer Peak conditions only, we assumed a specified share (20%) of those customers capable of achieving

15% demand reduction.

Those medium customer DR projects that are preferred locations for the higher 15% DR capability under Summer Peak conditions based on the network benefit of incremental DR capability at those locations under those conditions are listed in Table 14.

Table 14 Medium Customer DR Projects Preferred for 15% DR Capability under Summer Peak Conditions

Bus ID	Substation	Feeder
8854	Center2	Feeder 104
5163	Core1	Feeder 305
8205	Core 1	Feeder 305
9129	Core1	Feeder 305
8923	Core1	Feeder 305
8404	Core1	Feeder 305
7285	Core1	Feeder 305
5185	North2	Feeder 202
5178	North2	Feeder 202
8313	North2	Feeder 202
8630	North2	Feeder 202
5225	North2	Feeder 202
5028	North2	Feeder 202
8271	North2	Feeder 202
8314	North2	Feeder 202
8690	North2	Feeder 202
8250	North2	Feeder 202
8204	North2	Feeder 202
7697	North2	Feeder 202
8388	North2	Feeder 202
8689	North2	Feeder 202
8303	North2	Feeder 202
5248	North2	Feeder 203
9011	North2	Feeder 203
8126	North2	Feeder 203
5205	North2	Feeder 203
8-527	North4	Feeder 104
5176	North4	Feeder 104
7668	North4	Feeder 104
8283	North4	Feeder 104
8341	North4	Feeder 104
9048	North4	Feeder 104
8411	North4	Feeder 104
5118	North4	Feeder 104
8497	North4	Feeder 104
8633	North4	Feeder 104
8131	North4	Feeder 104
8417	North4	Feeder 104
8228	North4	Feeder 105

Table 14 (cont.)

Bus ID	Substation	Feeder
7736	North4	Feeder 105
7495	North4	Feeder 105
8269	North4	Feeder 105
7645	North6	Feeder 203
7654	North6	Feeder 203
7662	North6	Feeder 203
8401	North6	Feeder 203
8787	North6	Feeder 203
7449	North6	Feeder 203
7557	North6	Feeder 203
5027	North6	Feeder 203
5273	North6	Feeder 205
5053	North6	Feeder 205

2.3.2.2. 2002 Optimal DER Portfolio – DG Projects

The distributed generation (DG) projects for the Optimal DER Portfolio are characterized in terms of their location, their interconnection voltage, their size in kW or MW, and their operating seasonal profile. All are assumed to have the capability to be dispatched at the power factor that best optimizes network performance within the operating range of the unit.

We start by considering each of the 317 DG projects identified in Section 2.2 for the Summer Peak 2002 case as a DG project in the Optimal DER Portfolio, concluding that adopting the "Light Load" non-export feeder limit will permit superior network performance.

Of these, the majority, 213 projects, would operate at their full-rated P capacity under Summer Peak, Knee Peak, Winter Peak, and Light Load conditions – that is, at a 100% operating factor – based on the network benefit of capacity at those locations under those varying conditions. An additional 33 projects would operate under Summer Peak, Knee Peak, Winter Peak, and Light Load conditions, but at a reduced level under one or more of those conditions to ensure non-export. There are an additional 17 projects that would operate through Summer Peak, Knee Peak, and Winter Peak conditions, but be shut down during Minimum Load conditions.

There are 54 of the 317 projects that would operate only seasonally – that is, that would not operate under certain seasonal conditions. 27 projects would be shut down during Knee Peak conditions and 20 would be shut down during Winter Peak conditions. Seven projects would be shut down during both Knee Peak and Winter Peak conditions. Some of the projects in each of these groups would also be shut down during Minimum Load conditions.

Assuming the operating flexibility above to ensure non-export, there are an additional 63 projects not identified for the Summer Peak 2002 case that would provide greater network benefits under other operating conditions than certain of the 317 projects that were identified for the Summer Peak case, provided they are shut down under Summer Peak conditions to maintain the non-export feeder limit. Of these 63, 9 would operate under Knee Peak, Winter Peak, and Light Load conditions. Five would operate under Knee Peak and Winter Peak conditions, 20 would be shut down under Knee Peak conditions, and 11 would be shut down under Winter Peak conditions. Of these, some would be shut down under Minimum Load conditions. There are 18 that would only operate under Minimum Load conditions.

The entire set of Optimal Portfolio DG projects, the 317 identified for the Summer Peak case and the 63 projects identified as beneficial under other seasonal conditions, is listed in Table 15 by location. The interconnection voltage of each project is given in kV. The operating factor of those projects operating under all load condition is also given. Projects not operating under some load conditions are noted as #NA.

These 380 projects average 160 kW in size, with the largest 8.9 MW, only five over 1,000 kW, and only 54 over 250 kW.

As noted earlier, we have modeled all Optimal DER Portfolio DG projects as synchronous generators, and these projects are located and dispatched in part due to the electrical characteristics and capabilities of synchronous generators. For purposes of this study we assume these DG projects are reciprocating engines firing natural gas delivered via the gas utility. Those with high operating factors may be combined heat and power (CHP) projects. While it is not critical, we note that Kohler, Hess, and Cummins have a range of natural gas genset packages in these size ranges.

Table 15 2002 DG Projects

BUS#	Substation	Feeder	kV	Summer Peak DG (MW)	Knee Peak DG (MW)	Winter Peak DG (MW)	Minimum Load DG (MW)	Operating Factor
36650	Center1	Substation	12	4.670	4.670	4.670	4.67	1.000
8854	Center2	Feeder 104	12	0.305	0.305	0.305	0.305	1.000
7493	Center2	Feeder 104	12	0.265	0.265	0.265	0.265	1.000
542	Center2	Feeder 201	12	1.110	1.110	1.110	1.11	1.000
9049	Center2	Feeder 203	12	0.073	0.073	0.073	0.073	1.000
9041	Center2	Feeder 203	12	0.055	0.055	0.055	0.055	1.000
5197	Center2	Feeder 203	12	0.055	0.055	0.055	0.055	1.000
5301	Center2	Feeder 203	12	0.055	0.055	0.055	0.055	1.000
8589	Center2	Feeder 203	12	0.109	0.109	0.095	0.109	0.957
9196	Center2	Feeder 203	12	0.057	0.057	0.109	0.109	0.682
5188	Center2	Feeder 203	12	0.073	0.073	#N/A	0.073	
8621	Center2	Feeder 203	12	0.055	0.055	#N/A	0.022	
7272	Center2	Feeder 203	12	0.036	0.036	#N/A	#N/A	
9050	Center2	Feeder 203	12	0.073	0.073	#N/A	#N/A	
8304	Center2	Feeder 203	12	0.073	0.073	#N/A	#N/A	
9085	Center2	Feeder 203	12	#N/A	#N/A	0.073	0.073	
9053	Center2	Feeder 203	12	#N/A	#N/A	0.073	0.073	
9038	Center2	Feeder 203	12	#N/A	#N/A	0.016	0.016	
5132	Center2	Feeder 203	12	#N/A	#N/A	0.109	#N/A	
5011	Center3	Feeder 202	12	0.006	0.006	0.006	0.006	1.000
7418	Center3	Feeder 202	12	0.006	0.006	0.006	0.006	1.000
7554	Center3	Feeder 202	12	0.006	0.006	0.006	0.006	1.000
7102	Center3	Feeder 202	12	0.003	0.003	0.003	0.003	1.000
8646	Center3	Feeder 202	12	0.006	0.006	0.006	0.006	1.000
7674	Center3	Feeder 202	12	0.020	0.020	0.020	0.02	1.000
7445	Center3	Feeder 202	12	0.013	0.013	0.013	0.013	1.000
5122	Center3	Feeder 202	12	0.020	0.020	0.020	0.02	1.000
8406	Center3	Feeder 202	12	0.026	0.026	0.026	0.026	1.000
8158	Center3	Feeder 202	12	0.026	0.026	0.026	0.026	1.000
8274	Center3	Feeder 202	12	0.020	0.020	0.020	0.02	1.000
8041	Center3	Feeder 202	12	0.040	0.040	0.040	0.04	1.000
5186	Center3	Feeder 202	12	0.026	0.026	0.026	0.026	1.000
7637	Center3	Feeder 202	12	0.008	0.008	0.008	0.008	1.000
7759	Center3	Feeder 202	12	0.013	0.013	0.013	0.013	1.000
536	Center3	Feeder 202	12	0.105	0.105	0.105	0.105	1.000
537	Center3	Feeder 202	12	0.105	0.105	0.105	0.105	1.000
7974	Center3	Feeder 202	12	0.020	0.020	0.020	0.02	1.000
7969	Center3	Feeder 202	12	0.020	0.020	0.020	0.02	1.000
538	Center3	Feeder 203	12	0.850	0.850	0.850	0.85	1.000
539	Center3	Feeder 204	12	0.786	0.786	0.786	0.786	1.000
8699	Center3	Feeder 204	12	0.295	0.295	0.295	0.295	1.000
8826	Center3	Feeder 204	12	0.059	0.059	0.059	0.059	1.000
8887	Center3	Feeder 204	12	0.197	0.197	0.197	0.197	1.000
8665	Center3	Feeder 204	12	0.197	0.197	0.197	0.197	1.000
8349	Center3	Feeder 302	12	0.090	0.090	0.090	0.09	1.000
8226	Center3	Feeder 302	12	0.090	0.090	0.090	0.09	1.000
7673	Center3	Feeder 302	12	0.090	0.090	0.090	0.09	1.000
5183	Center3	Feeder 302	12	0.239	0.239	0.239	0.239	1.000
5182	Center3	Feeder 302	12	0.239	0.239	0.239	0.239	1.000
8764	Center3	Feeder 302	12	0.060	0.060	0.060	0.06	1.000
9044	Center3	Feeder 302	12	0.036	0.036	0.036	0.036	1.000
5187	Center3	Feeder 302	12	0.119	0.119	0.119	0.119	1.000
8747	Center3	Feeder 302	12	0.060	0.060	0.060	0.06	1.000
7760	Center3	Feeder 302	12	0.060	0.060	0.060	0.06	1.000
6821	Center3	Feeder 302	12	0.036	0.036	0.036	0.036	1.000
7711	Center3	Feeder 302	12	0.036	0.036	0.036	0.036	1.000
5169	Center3	Feeder 303	12	0.098	0.098	0.098	0.098	1.000
5302	Center3	Feeder 303	12	0.098	0.098	0.098	0.098	1.000
8590	Center3	Feeder 303	12	0.098	0.098	0.098	0.098	1.000

BUS#	Substation	Feeder	kV	Summer Peak DG (MW)	Knee Peak DG (MW)	Winter Peak DG (MW)	Minimum Load DG (MW)	Operating Factor
541	Center3	Feeder 303	12	0.262	0.262	0.262	0.262	1.000
9130	Center3	Feeder 303	12	0.065	0.065	0.065	0.065	1.000
5256	Center3	Feeder 303	12	0.033	0.033	0.033	0.033	1.000
5250	Center3	Feeder 303	12	0.033	0.033	0.033	0.033	1.000
5255	Center3	Feeder 303	12	0.065	0.065	0.065	0.065	1.000
540	Center3	Feeder 303	12	0.262	0.262	0.262	0.262	1.000
8365	Center3	Feeder 303	12	0.065	0.065	0.065	0.065	1.000
7671	Center3	Feeder 303	12	0.033	0.033	0.033	0.033	1.000
8191	Center3	Feeder 303	12	0.033	0.033	0.033	0.033	1.000
8125	Center3	Feeder 303	12	0.033	0.033	0.033	0.033	1.000
7765	Center3	Feeder 303	12	0.033	0.033	0.033	0.033	1.000
8526	Core1	Feeder 102	12	0.022	0.022	0.022	0.022	1.000
8857	Core1	Feeder 102	12	0.149	0.149	0.149	0.149	1.000
8885	Core1	Feeder 102	12	0.074	0.074	0.074	0.074	1.000
8886	Core1	Feeder 102	12	0.074	0.074	0.074	0.074	1.000
8629	Core1	Feeder 102	12	0.022	#N/A	0.022	0.022	
5040	Core1	Feeder 102	12	0.008	#N/A	0.008	0.008	
8631	Core1	Feeder 102	12	#N/A	0.030	#N/A	#N/A	
5234	Core1	Feeder 103	12	0.013	0.013	0.013	0.013	1.000
519	Core1	Feeder 103	12	0.700	0.700	0.700	0.7	1.000
6093	Core1	Feeder 203	12	0.049	0.049	0.049	0.049	1.000
8429	Core1	Feeder 203	12	0.163	0.163	0.163	0.163	1.000
8660	Core1	Feeder 203	12	0.325	0.325	0.325	0.325	1.000
5121	Core1	Feeder 203	12	0.108	0.108	0.108	0.108	1.000
7275	Core1	Feeder 203	12	0.108	0.108	0.108	0.108	1.000
5224	Core1	Feeder 203	12	0.065	0.065	0.065	0.065	1.000
5305	Core1	Feeder 203	12	0.433	0.433	0.433	0.433	1.000
8049	Core1	Feeder 203	12	0.433	0.433	0.394	0.433	0.970
8306	Core1	Feeder 203	12	0.177	0.177	0.217	0.177	0.877
7725	Core1	Feeder 204	12	0.012	0.012	0.012	0.012	1.000
8531	Core1	Feeder 204	12	0.012	0.012	0.012	0.012	1.000
7614	Core1	Feeder 204	12	0.012	0.012	0.012	0.012	1.000
7575	Core1	Feeder 204	12	0.012	0.012	0.012	0.012	1.000
7747	Core1	Feeder 204	12	0.025	0.025	0.025	0.025	1.000
6481	Core1	Feeder 204	12	0.109	0.109	0.109	0.109	1.000
520	Core1	Feeder 204	12	0.436	0.436	0.436	0.436	1.000
8157	Core1	Feeder 204	12	0.109	0.109	0.109	0.109	1.000
5158	Core1	Feeder 204	12	0.055	0.055	0.055	0.055	1.000
8725	Core1	Feeder 204	12	0.055	0.055	0.055	0.055	1.000
8431	Core1	Feeder 204	12	0.082	0.082	0.082	0.082	1.000
7737	Core1	Feeder 204	12	0.032	0.032	0.032	0.032	1.000
7439	Core1	Feeder 204	12	0.163	0.163	0.163	0.163	1.000
7255	Core1	Feeder 204	12	0.272	0.272	0.272	0.272	1.000
8523	Core1	Feeder 204	12	0.109	0.109	0.109	0.109	1.000
6881	Core1	Feeder 204	12	0.032	0.032	0.032	0.032	1.000
8355	Core1	Feeder 204	12	0.082	0.082	0.082	0.082	1.000
8272	Core1	Feeder 205	12	0.011	0.011	0.011	0.011	1.000
521	Core1	Feeder 205	12	0.151	0.151	0.151	0.151	1.000
8971	Core1	Feeder 205	12	0.076	0.076	0.076	0.076	1.000
7971	Core1	Feeder 205	12	0.056	0.056	0.056	0.056	1.000
8516	Core1	Feeder 205	12	0.056	0.056	0.056	0.056	1.000
8767	Core1	Feeder 205	12	0.076	0.076	0.076	0.076	1.000
8385	Core1	Feeder 205	12	0.008	0.008	0.008	0.008	1.000
8369	Core1	Feeder 205	12	0.004	0.004	0.004	0.004	1.000
5013	Core1	Feeder 205	12	0.008	0.008	0.008	0.008	1.000
5306	Core1	Feeder 205	12	0.076	0.076	0.076	0.076	1.000
8203	Core1	Feeder 205	12	0.019	0.019	0.019	0.019	1.000
7496	Core1	Feeder 205	12	0.004	0.004	0.004	0.004	1.000

BUS#	Substation	Feeder	kV	Summer Peak DG (MW)	Knee Peak DG (MW)	Winter Peak DG (MW)	Minimum Load DG (MW)	Operating Factor
8604	Core1	Feeder 205	12	0.008	0.008	0.008	0.008	1.000
9099	Core1	Feeder 205	12	0.028	0.028	0.028	0.028	1.000
6943	Core1	Feeder 205	12	0.019	0.019	0.019	0.019	1.000
9005	Core1	Feeder 205	12	0.019	0.019	0.019	0.019	1.000
8186	Core1	Feeder 205	12	0.019	0.019	0.019	0.019	1.000
5258	Core1	Feeder 205	12	0.019	0.019	0.019	0.019	1.000
8232	Core1	Feeder 205	12	0.004	0.004	0.004	0.004	1.000
6525	Core1	Feeder 205	12	0.008	0.008	0.008	0.008	1.000
5020	Core1	Feeder 205	12	#N/A	0.019	0.019	0.019	
522	Core1	Feeder 302	12	0.040	0.040	#N/A	#N/A	
9051	Core1	Feeder 302	12	#N/A	#N/A	0.040	0.04	
5062	Core1	Feeder 304	12	0.277	#N/A	0.277	#N/A	
5191	Core1	Feeder 305	12	0.043	0.043	0.043	0.043	1.000
8404	Core1	Feeder 305	12	0.014	0.014	0.014	0.014	1.000
7285	Core1	Feeder 305	12	0.007	0.007	0.007	0.007	1.000
8923	Core1	Feeder 305	12	0.014	0.014	0.014	0.014	1.000
9129	Core1	Feeder 305	12	0.029	0.029	0.029	#N/A	
8701	Core1	Feeder 305	12	0.043	0.043	0.043	#N/A	
8205	Core1	Feeder 305	12	0.014	0.014	0.014	#N/A	
524	Core1	Feeder 305	12	0.115	0.115	0.115	#N/A	
5163	Core1	Feeder 305	12	0.008	0.008	0.008	#N/A	
36612	North1	Substation	60	8.927	8.927	8.927	8.927	1.000
5130	North2	Feeder 102	12	0.175	0.088	0.260	0.175	0.996
500	North2	Feeder 102	12	0.695	0.695	0.523	0.695	0.918
8127	North2	Feeder 102	12	#N/A	0.087	0.087	#N/A	
8128	North2	Feeder 104	12	0.127	0.127	0.127	0.127	1.000
5149	North2	Feeder 104	12	0.360	0.510	0.510	0.51	0.902
7965	North2	Feeder 104	12	0.382	0.382	0.233	0.382	0.870
9010	North2	Feeder 104	12	0.191	0.042	0.191	0.071	0.740
6633	North2	Feeder 104	12	0.029	0.029	0.029	#N/A	
502	North2	Feeder 105	12	0.464	0.464	0.464	0.464	1.000
501	North2	Feeder 105	12	0.464	0.464	0.464	0.464	1.000
8248	North2	Feeder 105	12	0.035	0.035	0.035	0.035	1.000
8420	North2	Feeder 105	12	0.058	0.058	0.058	0.058	1.000
8504	North2	Feeder 105	12	0.058	0.058	0.058	0.058	1.000
5166	North2	Feeder 105	12	0.013	0.013	0.013	0.013	1.000
503	North2	Feeder 202	12	0.595	0.595	0.549	0.549	0.974
8890	North2	Feeder 202	12	0.029	0.298	0.298	0.298	0.699
8313	North2	Feeder 202	12	0.074	0.074	#N/A	#N/A	
8661	North2	Feeder 202	12	0.223	0.103	#N/A	#N/A	
5185	North2	Feeder 202	12	0.149	#N/A	#N/A	#N/A	
8689	North2	Feeder 202	12	#N/A	#N/A	0.112	0.112	
8303	North2	Feeder 202	12	#N/A	#N/A	0.112	0.112	
504	North2	Feeder 203	12	0.466	0.466	0.466	0.466	1.000
5113	North2	Feeder 203	12	0.233	0.233	0.233	0.233	1.000
8126	North2	Feeder 203	12	0.058	0.058	0.058	0.058	1.000
9011	North2	Feeder 203	12	0.058	0.058	0.058	0.058	1.000
5248	North2	Feeder 203	12	0.058	0.058	0.058	0.058	1.000
5144	North2	Feeder 203	12	0.233	0.233	0.233	0.225	1.000
8594	North2	Feeder 203	12	0.175	0.175	0.175	0.175	1.000
8595	North2	Feeder 203	12	0.175	0.175	0.175	0.175	1.000
5168	North2	Feeder 203	12	0.175	0.175	0.175	0.175	1.000
8973	North2	Feeder 203	12	0.225	0.233	0.233	0.233	0.989
8038	North2	Feeder 203	12	0.175	0.167	0.175	0.175	0.985
5240	North2	Feeder 203	12	0.013	0.013	#N/A	0.013	
5205	North2	Feeder 203	12	0.088	0.088	#N/A	0.088	
505	North2	Feeder 204	12	1.341	1.341	1.341	1.341	1.000
5108	North2	Feeder 205	12	0.012	0.012	0.012	0.012	1.000

BUS#	Substation	Feeder	kV	Summer Peak DG (MW)	Knee Peak DG (MW)	Winter Peak DG (MW)	Minimum Load DG (MW)	Operating Factor
8528	North2	Feeder 205	12	0.049	0.049	0.049	0.049	1.000
8682	North2	Feeder 205	12	0.323	0.323	0.323	0.323	1.000
7448	North2	Feeder 205	12	0.049	#N/A	#N/A	#N/A	
9091	North4	Feeder 101	12	0.112	0.112	0.112	0.112	1.000
9093	North4	Feeder 101	12	0.112	0.112	0.112	0.112	1.000
5226	North4	Feeder 101	12	0.187	0.187	0.187	0.187	1.000
526	North4	Feeder 101	12	0.234	0.299	0.234	0.299	0.855
9090	North4	Feeder 101	12	0.112	#N/A	0.112	#N/A	
9088	North4	Feeder 101	12	0.112	#N/A	0.112	#N/A	
525	North4	Feeder 101	12	#N/A	0.159	#N/A	0.151	
7476	North4	Feeder 101	12	#N/A	#N/A	#N/A	0.008	
527	North4	Feeder 103	12	0.530	0.530	0.530	0.53	1.000
8527	North4	Feeder 104	12	0.021	0.021	0.021	0.021	1.000
9048	North4	Feeder 104	12	0.069	0.069	0.069	0.069	1.000
5148	North4	Feeder 104	12	0.139	0.139	0.139	0.139	1.000
8633	North4	Feeder 104	12	0.069	0.069	0.069	0.069	1.000
8698	North4	Feeder 104	12	0.104	0.104	0.104	0.104	1.000
8905	North4	Feeder 104	12	0.139	0.139	0.139	0.139	1.000
8497	North4	Feeder 104	12	0.052	0.052	0.052	0.052	1.000
8411	North4	Feeder 104	12	0.069	0.069	0.069	0.069	1.000
8227	North4	Feeder 104	12	0.031	0.052	0.052	0.052	0.865
8131	North4	Feeder 104	12	0.069	0.069	0.069	#N/A	
8501	North4	Feeder 104	12	0.035	0.035	0.035	#N/A	
8417	North4	Feeder 104	12	0.035	0.035	0.035	#N/A	
8658	North4	Feeder 104	12	0.069	0.069	0.048	#N/A	
5118	North4	Feeder 104	12	0.035	0.035	#N/A	#N/A	
7687	North4	Feeder 104	12	0.008	#N/A	0.008	0.008	
8283	North4	Feeder 104	12	0.035	#N/A	0.035	0.035	
8341	North4	Feeder 104	12	0.035	#N/A	0.035	0.035	
9087	North4	Feeder 104	12	0.104	#N/A	0.104	0.104	
5176	North4	Feeder 104	12	0.016	#N/A	0.016	0.016	
7668	North4	Feeder 104	12	0.021	#N/A	0.021	#N/A	
8156	North4	Feeder 104	12	0.007	#N/A	0.007	#N/A	
8342	North4	Feeder 104	12	#N/A	0.035	0.035	0.035	
8412	North4	Feeder 104	12	#N/A	0.031	#N/A	0.069	
5115	North4	Feeder 104	12	#N/A	0.139	#N/A	0.139	
7465	North4	Feeder 104	12	#N/A	#N/A	#N/A	0.007	
8228	North4	Feeder 105	12	0.139	0.139	0.139	0.139	1.000
8161	North4	Feeder 105	12	0.277	0.277	0.277	0.277	1.000
5034	North4	Feeder 105	12	0.369	0.369	0.369	0.369	1.000
7606	North4	Feeder 105	12	0.020	#N/A	0.020	#N/A	
7736	North4	Feeder 105	12	0.055	#N/A	0.055	#N/A	
7495	North4	Feeder 105	12	0.000	#N/A	0.000	#N/A	
8413	North4	Feeder 105	12	#N/A	0.021	#N/A	0.076	
8269	North4	Feeder 105	12	#N/A	0.055	#N/A	#N/A	
8591	North4	Feeder 201	12	0.025	0.025	0.025	0.025	1.000
5366	North4	Feeder 201	12	0.013	0.013	0.013	0.013	1.000
9098	North4	Feeder 201	12	0.013	0.013	0.013	0.013	1.000
8748	North4	Feeder 201	12	0.008	0.008	0.008	0.008	1.000
8284	North4	Feeder 201	12	0.008	0.008	0.008	0.008	1.000
8132	North4	Feeder 201	12	0.013	0.013	0.013	0.013	1.000
528	North4	Feeder 201	12	0.066	0.066	0.066	0.066	1.000
7656	North4	Feeder 201	12	0.004	0.004	0.004	0.004	1.000
7094	North4	Feeder 201	12	0.004	0.004	0.004	0.004	1.000
8623	North4	Feeder 201	12	0.013	0.013	0.013	0.013	1.000
8282	North4	Feeder 201	12	0.008	0.008	0.008	0.008	1.000
8189	North4	Feeder 201	12	0.017	0.017	0.017	0.017	1.000
5147	North4	Feeder 201	12	0.008	0.008	0.008	0.008	1.000

BUS#	Substation	Feeder	kV	Summer Peak DG (MW)	Knee Peak DG (MW)	Winter Peak DG (MW)	Minimum Load DG (MW)	Operating Factor
8903	North4	Feeder 201	12	0.017	0.017	0.017	0.017	1.000
7970	North4	Feeder 201	12	0.013	0.013	0.013	0.013	1.000
529	North4	Feeder 201	12	0.066	0.053	0.066	0.053	0.934
8894	North4	Feeder 201	12	0.033	0.033	0.023	0.033	0.899
7763	North4	Feeder 201	12	0.004	0.004	#N/A	0.004	
8311	North4	Feeder 201	12	#N/A	0.013	0.013	0.013	
5190	North4	Feeder 202	12	0.125	0.092	0.050	0.092	0.712
9092	North4	Feeder 202	12	0.125	0.125	#N/A	0.125	
8907	North4	Feeder 202	12	0.029	#N/A	0.042	#N/A	
8133	North4	Feeder 202	12	#N/A	0.062	0.062	0.062	
8700	North4	Feeder 202	12	#N/A	#N/A	0.125	#N/A	
8893	North4	Feeder 203	12	0.181	0.181	0.181	0.181	1.000
530	North4	Feeder 203	12	0.335	0.362	0.362	0.362	0.975
531	North4	Feeder 203	12	0.362	0.362	0.335	0.362	0.975
8904	North4	Feeder 203	12	0.181	0.154	0.181	0.154	0.950
532	North4	Feeder 204	12	0.690	0.690	0.617	0.69	0.965
8710	North4	Feeder 204	12	#N/A	#N/A	0.073	#N/A	
533	North4	Feeder 205	12	0.545	0.545	0.498	0.545	0.971
8229	North4	Feeder 205	12	0.055	0.055	0.102	0.055	0.693
7612	North4	Feeder 301	12	0.068	0.068	0.068	0.068	1.000
8541	North4	Feeder 301	12	0.103	0.103	0.103	0.103	1.000
8190	North4	Feeder 301	12	0.068	0.068	0.068	0.068	1.000
5094	North4	Feeder 301	12	0.052	0.052	0.052	0.052	1.000
7689	North4	Feeder 301	12	0.103	0.103	0.103	0.103	1.000
5054	North4	Feeder 301	12	0.034	0.034	0.034	0.034	1.000
7702	North4	Feeder 301	12	0.068	0.068	0.068	0.068	1.000
8281	North4	Feeder 301	12	0.103	0.103	0.103	0.103	1.000
8187	North4	Feeder 301	12	0.068	0.068	0.068	0.059	1.000
5098	North4	Feeder 301	12	0.110	0.059	0.059	0.137	0.691
7690	North4	Feeder 301	12	0.103	0.103	0.103	#N/A	
5096	North4	Feeder 301	12	#N/A	0.052	0.052	0.052	
7755	North4	Feeder 301	12	#N/A	#N/A	#N/A	0.034	
7986	North4	Feeder 303	12	0.136	0.136	0.136	0.136	1.000
8522	North4	Feeder 303	12	0.108	0.021	0.021	0.025	0.463
5324	North4	Feeder 303	12	0.272	0.272	0.272	#N/A	
7682	North4	Feeder 303	12	0.015	#N/A	#N/A	0.015	
8277	North4	Feeder 303	12	#N/A	0.102	0.102	#N/A	
8582	North4	Feeder 303	12	#N/A	#N/A	#N/A	0.015	
5311	North4	Feeder 303	12	#N/A	#N/A	#N/A	0.136	
5201	North4	Feeder 303	12	#N/A	#N/A	#N/A	0.204	
534	North4	Feeder 304	12	0.130	0.130	0.130	0.13	1.000
535	North4	Feeder 305	12	0.520	0.520	0.520	0.52	1.000
5171	North6	Feeder 101	12	0.170	0.170	0.170	0.021	1.000
5088	North6	Feeder 101	12	0.057	0.057	#N/A	#N/A	
8351	North6	Feeder 101	12	0.073	#N/A	#N/A	#N/A	
5142	North6	Feeder 101	12	#N/A	0.034	#N/A	0.034	
8280	North6	Feeder 101	12	#N/A	0.038	#N/A	#N/A	
5155	North6	Feeder 101	12	#N/A	#N/A	0.026	0.026	
5154	North6	Feeder 101	12	#N/A	#N/A	0.026	0.026	
5133	North6	Feeder 101	12	#N/A	#N/A	0.026	#N/A	
5087	North6	Feeder 101	12	#N/A	#N/A	0.052	#N/A	
7474	North6	Feeder 101	12	#N/A	#N/A	#N/A	0.013	
7753	North6	Feeder 101	12	#N/A	#N/A	#N/A	0.026	
7686	North6	Feeder 101	12	#N/A	#N/A	#N/A	0.013	
8732	North6	Feeder 101	12	#N/A	#N/A	#N/A	0.085	
5289	North6	Feeder 101	12	#N/A	#N/A	#N/A	0.057	
508	North6	Feeder 102	12	0.344	0.344	0.344	0.344	1.000
509	North6	Feeder 102	12	0.344	0.344	0.344	0.344	1.000

BUS#	Substation	Feeder	kV	Summer Peak DG (MW)	Knee Peak DG (MW)	Winter Peak DG (MW)	Minimum Load DG (MW)	Operating Factor
510	North6	Feeder 102	12	0.344	0.344	0.344	0.323	1.000
8627	North6	Feeder 102	12	0.064	0.023	0.023	#N/A	
5276	North6	Feeder 102	12	0.044	#N/A	0.086	#N/A	
8188	North6	Feeder 102	12	#N/A	0.086	#N/A	0.086	
8340	North6	Feeder 102	12	#N/A	#N/A	#N/A	0.043	
511	North6	Feeder 103	12	0.647	0.647	0.647	0.647	1.000
8972	North6	Feeder 103	12	0.323	0.323	0.323	0.323	1.000
8278	North6	Feeder 103	12	0.242	0.242	0.242	0.242	1.000
8666	North6	Feeder 103	12	0.161	0.161	0.161	0.161	1.000
512	North6	Feeder 104	12	1.172	1.172	1.172	1.172	1.000
7067	North6	Feeder 105	12	0.095	0.095	0.095	0.095	1.000
8768	North6	Feeder 105	12	0.190	0.190	0.190	0.19	1.000
7463	North6	Feeder 105	12	0.047	0.047	0.047	0.047	1.000
8036	North6	Feeder 105	12	0.047	0.047	0.047	0.047	1.000
7627	North6	Feeder 105	12	0.047	0.047	0.047	0.047	1.000
8199	North6	Feeder 105	12	0.047	0.047	0.047	0.047	1.000
8350	North6	Feeder 105	12	0.071	0.071	0.071	0.071	1.000
7988	North6	Feeder 105	12	0.071	0.071	0.071	0.071	1.000
8162	North6	Feeder 105	12	0.142	0.142	0.142	0.142	1.000
8587	North6	Feeder 105	12	0.142	0.142	0.142	0.142	1.000
513	North6	Feeder 105	12	0.285	0.357	0.380	0.38	0.954
7705	North6	Feeder 105	12	0.095	0.095	0.048	0.048	0.835
7550	North6	Feeder 105	12	0.047	0.047	#N/A	#N/A	
8426	North6	Feeder 105	12	0.071	#N/A	0.071	0.071	
5123	North6	Feeder 201	12	0.104	0.104	0.104	0.104	1.000
5181	North6	Feeder 201	12	0.059	0.069	0.069	0.069	0.952
5097	North6	Feeder 201	12	0.276	0.276	0.276	#N/A	
6879	North6	Feeder 201	12	0.041	0.041	0.041	#N/A	
6837	North6	Feeder 201	12	0.104	0.104	0.101	#N/A	
5304	North6	Feeder 201	12	0.276	0.276	#N/A	0.276	
8924	North6	Feeder 201	12	0.104	#N/A	0.104	0.104	
9012	North6	Feeder 201	12	0.104	#N/A	#N/A	0.104	
9140	North6	Feeder 201	12	0.104	#N/A	#N/A	0.038	
7198	North6	Feeder 201	12	0.069	#N/A	#N/A	#N/A	
5198	North6	Feeder 201	12	#N/A	0.032	0.207	0.207	
7563	North6	Feeder 201	12	#N/A	0.031	0.031	0.031	
5060	North6	Feeder 201	12	#N/A	0.031	0.031	0.031	
7761	North6	Feeder 201	12	#N/A	0.069	0.069	#N/A	
8506	North6	Feeder 201	12	#N/A	0.069	0.069	#N/A	
7973	North6	Feeder 201	12	#N/A	0.138	0.138	#N/A	
5253	North6	Feeder 201	12	#N/A	#N/A	#N/A	0.138	
8792	North6	Feeder 201	12	#N/A	#N/A	#N/A	0.069	
7758	North6	Feeder 201	12	#N/A	#N/A	#N/A	0.069	
514	North6	Feeder 202	12	0.361	0.361	0.439	0.243	0.882
8363	North6	Feeder 202	12	0.025	0.025	#N/A	#N/A	
5172	North6	Feeder 202	12	0.025	0.025	#N/A	#N/A	
8445	North6	Feeder 202	12	0.025	0.025	#N/A	#N/A	
9086	North6	Feeder 202	12	0.165	0.165	#N/A	#N/A	
8656	North6	Feeder 202	12	#N/A	#N/A	0.110	0.11	
7613	North6	Feeder 202	12	#N/A	#N/A	0.025	0.025	
5116	North6	Feeder 202	12	#N/A	#N/A	0.026	0.055	
8444	North6	Feeder 202	12	#N/A	#N/A	#N/A	0.025	
8524	North6	Feeder 202	12	#N/A	#N/A	#N/A	0.11	
8829	North6	Feeder 202	12	#N/A	#N/A	#N/A	0.033	
8233	North6	Feeder 203	12	0.024	0.024	0.024	0.024	1.000
8517	North6	Feeder 203	12	0.320	0.320	0.320	0.32	1.000
7557	North6	Feeder 203	12	0.107	0.107	0.107	0.107	1.000
515	North6	Feeder 203	12	0.608	0.672	0.853	0.853	0.834

BUS#	Substation	Feeder	kV	Summer Peak DG (MW)	Knee Peak DG (MW)	Winter Peak DG (MW)	Minimum Load DG (MW)	Operating Factor
8787	North6	Feeder 203	12	0.107	0.107	0.006	0.006	0.685
7645	North6	Feeder 203	12	0.048	0.048	#N/A	#N/A	
7654	North6	Feeder 203	12	0.048	0.048	#N/A	#N/A	
7662	North6	Feeder 203	12	0.048	0.048	#N/A	#N/A	
8401	North6	Feeder 203	12	0.107	0.107	#N/A	#N/A	
7449	North6	Feeder 203	12	0.064	#N/A	0.064	0.064	
5027	North6	Feeder 203	12	#N/A	#N/A	0.107	0.107	
517	North6	Feeder 205	12	0.542	0.354	0.576	0.576	0.905
5273	North6	Feeder 205	12	0.032	0.032	0.032	#N/A	
5052	North6	Feeder 205	12	0.288	0.288	#N/A	#N/A	
8592	North6	Feeder 205	12	0.216	0.216	#N/A	#N/A	
5053	North6	Feeder 205	12	0.072	0.072	#N/A	#N/A	
7266	North6	Feeder 205	12	#N/A	0.072	0.038	0.07	
8044	North6	Feeder 205	12	#N/A	0.072	#N/A	#N/A	
8155	North6	Feeder 205	12	#N/A	0.043	#N/A	#N/A	
7619	North6	Feeder 205	12	#N/A	#N/A	0.072	0.072	
8164	North6	Feeder 205	12	#N/A	#N/A	0.216	0.216	
8659	North6	Feeder 205	12	#N/A	#N/A	0.216	0.216	
8730	South3	Feeder 104	12	0.097	0.097	0.097	0.097	1.000
8499	South3	Feeder 104	12	0.097	0.097	0.097	0.097	1.000
506	South3	Feeder 104	12	0.515	0.515	0.515	0.515	1.000
5051	South3	Feeder 104	12	0.257	0.257	0.257	0.257	1.000
5254	South3	Feeder 104	12	0.129	0.129	0.129	0.129	1.000
8827	South3	Feeder 104	12	0.038	0.038	0.038	0.038	1.000
9133	South3	Feeder 104	12	0.014	0.014	0.014	0.014	1.000
5016	South3	Feeder 104	12	0.064	0.064	0.064	0.064	1.000
5135	South3	Feeder 104	12	0.029	0.029	0.029	0.029	1.000
5222	South3	Feeder 104	12	0.038	0.038	0.038	0.038	1.000
7412	South3	Feeder 104	12	0.014	0.014	0.014	0.014	1.000
8542	South3	Feeder 104	12	0.193	0.193	0.193	0.193	1.000
507	South3	Feeder 105	12	0.040	0.040	0.040	0.04	1.000

2.3.2.3. 2005 Optimal DER Portfolio – DR Projects

The character of the subject system in its 2005 configuration with revised topology and loads is significantly different when compared to the 2002 system. The initial P Indices and locations in the network with the greatest "stress" are very different in the two cases. As a result, the nature of the Optimal Portfolio DR projects for Summer 2005 conditions is also significantly different.

We considered the Summer 2005 case a 1% highest hour load condition case, analogous to the Summer Peak 2002 case. Again, for large (> 1,000 kVA rated) customer DR projects under these conditions, we assumed all large customers were capable of achieving 6% demand reduction, with a specified share (60%) of those customers capable of achieving 15% demand reduction under this 1% highest hour load condition.

Those large customer DR projects that are preferred locations for the higher 15% DR capability under 2005 Summer Peak conditions, based on the network benefit of incremental DR capability at those locations under those conditions, are listed in Table 16.

Of the Summer 2005 DR projects that are preferred locations for higher 15% DR capability, 40 had also been identified as preferred locations for the higher 15% DR capability under Summer Peak 2002 conditions. 38 of the projects that are preferred locations for the highest 15% DR capability under Summer Peak 2002 conditions are now specified at the standard 6% DR capability under Summer 2005 conditions.

For medium (200 - 1,000 kVA rated) customer DR projects under the 1% highest hour 2005 Summer Peak conditions, we assumed a specified share (20%) of those customers capable of achieving 15% demand reduction, again analogous to the medium customer DR projects in the Summer Peak 2002 case.

Those medium customer DR projects that are preferred locations for the higher 15% DR capability under Summer Peak conditions, based on the network benefit of incremental DR capability at those locations under those conditions, are listed in Table 17. Only six of these projects had also been preferred locations for the higher 15% DR capability in the 2002 portfolio.

Table 16 2005 Large Customer DR Sites with 15% DR Capability

Bus ID	Substation	Feeder
537	Center3	Feeder 202
536	Center3	Feeder 202
538	Center3	Feeder 203
8699	Center3	Feeder 204
5183	Center3	Feeder 302
5182	Center3	Feeder 302
541	Center3	Feeder 303
540	Center3	Feeder 303
5169	Center3	Feeder 303
5302	Center3	Feeder 303
8590	Center3	Feeder 303
8660	Core 1	Feeder 203
5305	Core1	Feeder 203
8049	Core1	Feeder 203
7439	Core1	Feeder 204
520	Core1	Feeder 204
7255	Core1	Feeder 204
7971	Core1	Feeder 205
8516	Core1	Feeder 205
521	Core1	Feeder 205
8971	Core1	Feeder 205
8767	Core1	Feeder 205
5306	Core1	Feeder 205
522	Core 1	Feeder 302
524	Core1	Feeder 305
8701	Core1	Feeder 305
7965	North2	Feeder 104
5149	North2	Feeder 104
502	North2	Feeder 105
501	North2	Feeder 105
503	North2	Feeder 202
8661	North2	Feeder 202
8514	North2	Feeder 202
8662	North2	Feeder 202
8890	North2	Feeder 202
5168	North2	Feeder 203
504	North2	Feeder 203
5113	North2	Feeder 203
505	North2	Feeder 204
8682	North2	Feeder 205
5098	North4	Feeder 301
7690	North4	Feeder 301
8281	North4	Feeder 301
7689	North4	Feeder 301

Table 16 (cont.)

Bus ID	Substation	Feeder
8541	North4	Feeder 301
5324	North4	Feeder 303
5171	North6	Feeder 101
5170	North6	Feeder 101
8280	North6	Feeder 101
508	North6	Feeder 102
510	North6	Feeder 102
509	North6	Feeder 102
8278	North6	Feeder 103
8972	North6	Feeder 103
511	North6	Feeder 103
512	North6	Feeder 104
8587	North6	Feeder 105
8162	North6	Feeder 105
8768	North6	Feeder 105
513	North6	Feeder 105
5097	North6	Feeder 201
5304	North6	Feeder 201
5198	North6	Feeder 201
8225	North6	Feeder 202
514	North6	Feeder 202
9086	North6	Feeder 202
515	North6	Feeder 203
8517	North6	Feeder 203
516	North6	Feeder 204
8592	North6	Feeder 205
8164	North6	Feeder 205
8659	North6	Feeder 205
517	North6	Feeder 205
5052	North6	Feeder 205
5051	South3	Feeder 104
8542	South3	Feeder 104
506	South3	Feeder 104
507	South3	Feeder 105

Table 17 2005 Medium Customer DR Sites with 15% DR Capability

Bus ID	Substation	Feeder
5011	Center3	Feeder 202
5255	Center3	Feeder 303
9130	Center3	Feeder 303
8365	Center3	Feeder 303
5256	Center3	Feeder 303
5250	Center3	Feeder 303
7671	Center3	Feeder 303
8191	Center3	Feeder 303
8125	Center3	Feeder 303
7765	Center3	Feeder 303
6481	Core1	Feeder 204
8705	Core1	Feeder 302
9051	Core1	Feeder 302
5204	Core 1	Feeder 302
7610	Core 1	Feeder 302
5163	Core 1	Feeder 305
9129	Core 1	Feeder 305
8205	Core1	Feeder 305
8923	Core 1	Feeder 305
8303	North2	Feeder 202
8689	North2	Feeder 202
8627	North6	Feeder 102
5276	North6	Feeder 102
7550	North6	Feeder 105
8199	North6	Feeder 105
7627	North6	Feeder 105
8036	North6	Feeder 105
7463	North6	Feeder 105
7705	North6	Feeder 105
7067	North6	Feeder 105
8426	North6	Feeder 105
7988	North6	Feeder 105
8350	North6	Feeder 105
6879	North6	Feeder 201
5181	North6	Feeder 201
7761	North6	Feeder 201
7973	North6	Feeder 201
8506	North6	Feeder 201
5060	North6	Feeder 201
7563	North6	Feeder 201
6837	North6	Feeder 201
9012	North6	Feeder 201
123	North6	Feeder 201
9140	North6	Feeder 201
8924	North6	Feeder 201
5135	South3	Feeder 104

Table 17 (cont.)

Bus ID	Substation	Feeder
8827	South3	Feeder 104
5222	South3	Feeder 104
5016	South3	Feeder 104
8730	South3	Feeder 104
8499	South3	Feeder 104
5254	South3	Feeder 104

2.3.2.4. 2005 Optimal DER Portfolio – DG Projects

The distributed generation (DG) projects for the Optimal DER Portfolio are characterized in terms of their location, their interconnection voltage, their size in kW or MW, and their operating seasonal profile. All are assumed to have the capability to operate at the power factor that best optimizes network performance within the operating range of the unit.

We consider each of the 149 DG projects identified in Section 2.2 and listed in Appendix 2.2-1 for the Summer 2005 case as a DG project in the Optimal DER Portfolio, concluding that adopting the "Light Load" non-export feeder limit will permit superior network performance. These are listed in Table 18.

While we don't have the benefit of seasonally-varying forecasts for 2005 loads, we can infer some things about the operating profile of these projects based on the 2002 results. Extrapolating from the 2002 results, it is reasonable to assume that the majority of these would operate at their rated P capacity at or near a 100% operating factor. A small share, perhaps 5%, would operate year-round but be shut down under minimum load conditions. A slightly larger share, perhaps 20%, would operate seasonally.

It is also reasonable to expect that there may be an additional 20% of DG projects that do not have as great a benefit as these during 1% highest hour load conditions but have superior benefits during other seasonal conditions. In other words, about a third of the DG projects would require some specification of operating profile to ensure the estimated network benefits are realized. An analysis incorporating seasonally-varying loads of the sort we completed for the 2002 cases would reveal the locations of these seasonally-varying projects.

The 149 DG projects listed in Table 18 average approximately 450 kW in size, with the largest 14.3 MW, fourteen over 1,000 kW, and 64 over 250 kW. DG projects in the Optimal DER Portfolio for the Summer 2005 case are somewhat larger due to the fact that loads modeled at customer sites are larger, as noted above, and the size of DG capacity additions is limited by individual customer and feeder limits.

Again, we have modeled all Optimal DER Portfolio DG projects as synchronous generators, and these projects are located and dispatched in part due to the electrical characteristics and capabilities of synchronous generators. For purposes of this study we assume these DG projects are reciprocating engines firing natural gas delivered via the gas utility. Again, Those with high operating factors might conceivably be combined heat and power projects.

Table 18 2005 DG Projects by Feeder

Bus ID	Substation	Feeder	kV	Customer Peak Load (MW)	DG Capacity (MW)
36650	Center1	Substation	12	11.07	6.642
8854	Center2	Feeder 104	12	0.092	0.055
7493	Center2	Feeder 104	12	0.092	0.055
542	Center2	Feeder 201	12	2.661	1.11
8589	Center2	Feeder 203	12	0.998	0.599
5197	Center2	Feeder 203	12	0.499	0.111
5011	Center3	Feeder 202	12	0.115	0.069
7637	Center3	Feeder 202	12	0.153	0.092
7759	Center3	Feeder 202	12	0.256	0.154
7418	Center3	Feeder 202	12	0.115	0.069
536	Center3	Feeder 202	12	2.045	0.367
538	Center3	Feeder 203	12	2.045	0.85
8699	Center3	Feeder 204	12	0.767	0.46
539	Center3	Feeder 204	12	2.045	1.227
8665	Center3	Feeder 204	12	0.511	0.307
8887	Center3	Feeder 204	12	0.511	0.307
8826	Center3	Feeder 204	12	0.153	0.092
5183	Center3	Feeder 302	12	1.712	1.027
5182	Center3	Feeder 302	12	1.712	0.373
541	Center3	Feeder 303	12	3.423	1.66
8629	Core1	Feeder 102	12	0.214	0.128
8885	Core1	Feeder 102	12	0.715	0.222
519	Core1	Feeder 103	12	2.86	0.79
8660	Core 1	Feeder 203	12	0.424	0.254
5305	Core 1	Feeder 203	12	0.565	0.339
8049	Core 1	Feeder 203	12	0.565	0.339
8306	Core1	Feeder 203	12	0.282	0.169
6093	Core 1	Feeder 203	12	0.064	0.038
5224	Core1	Feeder 203	12	0.085	0.051
7275	Core 1	Feeder 203	12	0.141	0.085
5121	Core1	Feeder 203	12	0.141	0.085
8429	Core 1	Feeder 203	12	0.212	0.127
6481	Core1	Feeder 204	12	0.282	0.169
520	Core1	Feeder 204	12	1.13	0.678
7725	Core 1	Feeder204	12	0.032	0.019
8531	Core 1	Feeder 204	12	0.032	0.019
8725	Core 1	Feeder 204	12	0.141	0.085
8431	Core1	Feeder 204	12	0.212	0.127
8157	Core1	Feeder 204	12	0.282	0.169
7614	Core1	Feeder 204	12	0.032	0.019
7575	Core1	Feeder 204	12	0.032	0.019

7439	Core1	Feeder 204	12	0.424	0.254

Table 18 (cont.)

Bus ID	Substation	Feeder	kV	Customer Peak Load (MW)	DG Capacity (MW)
5158	Core1	Feeder 204	12	0.141	0.085
7737	Core 1	Feeder 204	12	0.085	0.051
7255	Core 1	Feeder 204	12	0.706	0.424
8355	Core 1	Feeder 204	12	0.212	0.001
521	Core 1	Feeder 205	12	1.13	0.678
8971	Core 1	Feeder 205	12	0.565	0.339
7971	Core 1	Feeder 205	12	0.424	0.254
8516	Core1	Feeder 205	12	0.424	0.254
8767	Core 1	Feeder 205	12	0.565	0.339
5306	Core 1	Feeder 205	12	0.565	0.339
8272	Core1	Feeder 205	12	0.085	0.051
8604	Core 1	Feeder 205	12	0.064	0.038
7496	Core1	Feeder 205	12	0.032	0.019
8203	Core 1	Feeder 205	12	0.141	0.085
6943	Core 1	Feeder 205	12	0.141	0.085
9005	Core 1	Feeder 205	12	0.141	0.085
5013	Core1	Feeder 205	12	0.064	0.036
9099	Core1	Feeder 205	12	0.212	0.105
5204	Core1	Feeder 302	12	0.662	0.04
5062	Core1	Feeder 304	12	0.441	0.265
6205	Core1	Feeder 305	12	0.441	0.265
9129	Core1	Feeder 305	12	0.863	0.135
36612	North 1	Substation	60	23.91	.14.346
5130	North2	Feeder 102	12	0.916	0.55
8127	North2	Feeder 102	12	0.305	0.183
500	North2	Feeder 102	12	2.443	0.137
7965	North2	Feeder 104	12	0.916	0.55
5149	North2	Feeder 104	12	1.221	0.54
502	North2	Feeder 105	12	2.443	1.38
8303	North2	Feeder 202	12	0.341	0.205
8689	North2	Feeder 202	12	0.341	0.205
8890	North2	Feeder 202	12	0.908	0.545
503	North2	Feeder 202	12	1.817	0.116
504	North2	Feeder 203	12	1.817	1.09
5248	North2	Feeder 203	12	0.227	0.136
9011	North2	Feeder 203	12	0.227	0.136
5168	North2	Feeder 203	12	0.681	0.409
8126	North2	Feeder 203	12	0.227	0.136
5144	North2	Feeder 203	12	0.908	0.223
505	North2	Feeder204	12	1.817	1.09
5108	North2	Feeder 205	12	0.034	0.02
8682	North2	Feeder 205	12	0.908	0.42

5226	North4	Feeder 101	12	0.988	0.593

Table 18 (cont.)

Bus ID	Substation	Feeder	kV	Customer Peak Load (MW)	DG Capacity (MW)
9091	North4	Feeder 101	12	0.593	0.277
527	North4	Feeder 103	12	1.582	0.53
6341	North4	Feeder104	12	0.198	0.119
8283	North4	Feeder 104	12	0.198	0.119
5148	North4	Feeder 104	12	0.791	0.475
5116	North4	Feeder 104	12	0.198	0.119
8411	North4	Feeder 104	12	0.395	0.237
9048	North4	Feeder 104	12	0.395	0.092
7606	North4	Feeder 105	12	0.044	0.026
8228	North4	Feeder 105	12	0.297	0.178
7736	North4	Feeder 105	12	0.119	0.t>71
7495	North4	Feeder 105	12	0.198	0.119
8269	North4	Feeder 105	12	0.119	0.071
5034	North4	Feeder 105	12	0.791	0.394
7763	North4	Feeder 201	12	0.079	0.047
8748	North4	Feeder 201	12	0.175	0.105
5366	North4	Feeder 201	12	0.262	0.157
8132	North4	Feeder 201	12	0.262	0.02
8133	North4	Feeder 202	12	0.262	0.157
5190	North4	Feeder 202	12	0.524	0.123
8893	North4	Feeder 203	12	0.698	0.419
8904	North4	Feeder 203	12	0.698	0.419
530	North4	Feeder 203	12	1.397	0.222
532	North4	Feeder 204	12	1.397	0.69
533	North4	Feeder 205	12	1.397	0.6
7612	North4	Feeder 301	12	0.447	0.268
8190	North4	Feeder 301	12	0.447	0.268
5094	North4	Feeder 301	12	0.335	0.201
5096	North4	Feeder 301	12	0.335	0.143
5324	North4	Feeder 303	12	0.894	0.53
534	North4	Feeder 304	12	1.786	0.13
535	North4	Feeder 305	12	1.788	0.52
5170	North6	Feeder 101	12	0.691	0.3
508	North6	Feeder 102	12	1.843	1.106
510	North6	Feeder 102	12	1.843	0.034
511	North6	Feeder 103	12	1.843	1.106
8972	North6	Feeder 103	12	0.921	0.553
8666	North6	Feeder 103	12	0.461	0.062
512	North6	Feeder 104	12	1.843	1.106
7627	North6	Feeder 105	12	0.23	0.138
8199	North6	Feeder 105	12	0.23	0.138
8036	North6	Feeder 105	12	0.23	0.138

7988	North6	Feeder 105	12	0.346	0.208

Table 18 (cont.)

Bus ID	Substation	Feeder	kV	Customer Peak Load (MW)	DG Capacity (MW)
8587	North6	Feeder 105	12	0.691	0.415
7067	North6	Feeder 105	12	0.461	0.277
8162	North6	Feeder 105	12	0.691	0.087
6879	North6	Feeder 201	12	0.13	0.078
7761	North6	Feeder 201	12	0.216	0.13
5097	North6	Feeder 201	12	0.864	0.518
8506	North6	Feeder 201	12	0.216	0.13
7973	North6	Feeder 201	12	0.432	0.259
5304	North6	Feeder 201	12	0.864	0.125
514	North6	Feeder 202	12	1.729	0.6
515	North6	Feeder 203	12	1.729	1.037
7662	North6	Feeder 203	12	0.097	0.058
7645	North6	Feeder 203	12	0.097	0.058
5027	North6	Feeder 203	12	0.216	0.13
7654	North6	Feeder 203	12	0.097	0.058
7449	North6	Feeder 203	12	0.13	0.078
8787	Nor1h6	Feeder 203	12	0.216	0.06 59
8659	North6	Feeder 205	12	0.648	0.389
517	North6	Feeder 205	12	1.729	0.761
506	South3	Feeder 104	12	3.704	1.84
507	South3	Feeder 105	12	3.704	0.04

As noted above, the loads the 2005 system are very different from those of the 2002 system. The 2005 system's topology is also very different. Thus, for this system, drawing conclusions from a comparison of the 2002 Portfolio DG projects and the 2005 Portfolio DG projects is difficult. Of the 2005 DG projects, all but two are at locations also identified for DG projects in the 2002 Portfolio. However, only about 25 of the top 100-ranked 2005 DG projects also had rankings higher than 133 averaged across the 2002 Summer Peak, Knee Peak, and Winter Peak cases. We believe these differences, due in part to differences in our approach for the 2002 and 2005 cases, would prove unusual. Generally, such a comparison would provide useful insights into how a system is evolving and how DER can be incorporated in system planning.

2.3.2.5. Confirming Load Flow Results

Comparative load flow results from AEMPFAST and PSLF for the Summer Peak 2002 case with DR and Light Load-limited DG additions are summarized in Table 19, along with the base case (as found) results presented previously. Comparative load flow results for the Summer 2005 case are summarized in Table 20. Comparative load flow results for the Knee Peak, Winter Peak and Minimum Load 2002 cases are summarized in Table 21.

The results in each case illustrate the evolution of the state of the network from the base case or "as found" condition. The DR additions have the effect of reducing load, and the DG additions have the effect of increasing internal generation. Losses in the cases with DR and DG additions are reduced relative to the base cases.

The PSLF results confirm the overall performance of the network and the loss improvement resulting from the DR and DG additions.

Table 19 DER Portfolio Load Flow Results

Summer Peak 2002 Base Case Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**397.598**	**209.076**	**397.598**	**209.076**
Net Interchange	**-366.519**	**-70.868**	**-366.56**	**-69.725**
Losses	**1.248**	**51.313**	**1.262**	**50.943**
Summer Peak 2002 Recontrol Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**397.598**	**209.076**	**397.598**	**209.076**
Generation	**32.280**	**25.099**	**32.300**	**6.757**
Net Interchange	**-366.595**	**-62.194**	**-366.486**	**-68.865**
Losses	**1.277**	**50.879**	**1.188**	**48.066**
Summer Peak 2002 Load Flow Results with DR Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Gross Load	**397.598**	**209.076**	**397.598**	**209.076**
Load Net of DR	**387.089**	**202.784**	**387.081**	**202.767**
Generation	**32.300**	**21.867**	**32.300**	**6.063**
Net Interchange	**-355.932**	**-54.169**	**-355.868**	**-60.612**
Losses	**1.143**	**47.683**	**1.087**	**45.615**
Summer Peak 2002 Load Flow Results with DR and DG Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Gross Load	**397.598**	**209.076**	**397.598**	**209.076**
Load Net of DR	**387.089**	**202.784**	**387.081**	**202.767**
Generation	**87.190**	**29.013**	**87.185**	**39.075**
Net Interchange	**-300.677**	**-40.212**	**-300.694**	**-24.982**
Losses	**0.778**	**35.211**	**0.798**	**34.456**

Table 20 DER Portfolio Load Flow Results

Summer 2005 Base Case Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**581.999**	**348.747**	**581.999**	**348.747**
Net Interchange	**-552.792**	**-260.904**	**-552.86**	**-261.57**
Losses	**3.09**	**92.049**	**3.17**	**92.56**
Summer 2005 Recontrol Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**581.999**	**348.747**	**581.999**	**348.747**
Generation	**32.300**	**13.250**	**32.300**	**10.259**
Net Interchange	**-552.768**	**-253.062**	**-552.670**	**-227.707**
Losses	**3.069**	**91.268**	**2.971**	**81.604**
Summer 2005 Load Flow Results with DR Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**581.999**	**348.747**	**581.999**	**348.747**
Load (Net of DR)	**556.461**	**332.513**	**556.474**	**332.500**
Generation	**32.300**	**16.255**	**32.300**	**8.778**
Net Interchange	**-526.696**	**-212.710**	**-526.642**	**-202.437**
Losses	**2.535**	**78.074**	**2.468**	**72.870**
Summer 2005 Load Flow Results with DR and DG Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**581.999**	**348.747**	**581.999**	**348.747**
Load (Net of DR)	**556.461**	**332.513**	**556.474**	**332.500**
Generation	**98.980**	**30.232**	**98.959**	**38.886**
Net Interchange	**-459.416**	**-175.691**	**-459.300**	**-153.795**
Losses	**1.935**	**60.133**	**1.785**	**56.459**

Table 21 DER Portfolio Load Flow Results

Knee Peak 2002 Base Case Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**329.095**	**184.226**	**329.095**	**184.226**
Net Interchange	**-297.952**	**-19.250**	**-297.954**	**-19.488**
Losses	**0.888**	**32.735**	**0.895**	**32.425**
Knee Peak 2002 Recontrol Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**329.095**	**184.226**	**329.095**	**184.226**
Generation	**32.030**	**16.198**	**32.030**	**6.586**
Net Interchange	**-298.020**	**-70.458**	**-297.928**	**-69.135**
Losses	**0.957**	**33.964**	**0.863**	**31.389**
Knee Peak 2002 Load Flow Results with DR Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Gross Load	**329.095**	**184.226**	**329.095**	**184.226**
Load (Net of DR)	**325.441**	**182.044**	**325.448**	**182.032**
Generation	**32.030**	**15.773**	**32.030**	**8.012**
Net Interchange	**-294.319**	**-65.712**	**-294.250**	**-64.162**
Losses	**0.910**	**32.969**	**0.832**	**30.760**
Knee Peak 2002 Load Flow Results with DR and DG Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Gross Load	**329.095**	**184.226**	**329.095**	**184.226**
Load (Net of DR)	**325.441**	**182.044**	**325.448**	**182.032**
Generation	**86.600**	**33.769**	**86.610**	**49.342**
Net Interchange	**-239.408**	**-44.470**	**-239.391**	**-23.823**
Losses	**0.568**	**22.970**	**0.553**	**21.960**
Winter Peak 2001-02 Base Case Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**336.971**	**181.565**	**336.971**	**181.565**
Net Interchange	**-304.439**	**-11.853**	**-304.44**	**-9.75**
Losses	**0.908**	**35.917**	**0.909**	**33.102**
Winter Peak 2001-02 Recontrol Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**336.971**	**181.565**	**336.971**	**181.565**
Generation	**33.440**	**16.243**	**33.440**	**5.417**
Net Interchange	**-304.512**	**-92.881**	**-304.417**	**-89.132**
Losses	**0.981**	**38.641**	**0.886**	**32.968**

Table 21 DER Portfolio Load Flow Results (cont.)

Winter Peak 2001-02 Load Flow Results with DR Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Gross Load	**336.971**	**181.565**	**336.971**	**181.565**
Load (Net of DR)	**333.387**	**178.761**	**333.384**	**178.767**
Generation	**33.440**	**16.251**	**33.440**	**9.009**
Net Interchange	**-300.878**	**-76.950**	**-300.788**	**-72.636**
Losses	**0.931**	**37.015**	**0.844**	**32.149**

Winter Peak 2001-02 Load Flow Results with DR and DG Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Gross Load	**336.971**	**181.565**	**336.971**	**181.565**
Load (Net of DR)	**333.387**	**178.761**	**333.384**	**178.767**
Generation	**88.240**	**35.552**	**88.204**	**55.042**
Net Interchange	**-245.746**	**-50.560**	**-245.759**	**-23.535**
Losses	**0.599**	**25.876**	**0.579**	**22.242**

Minimum Load 2002 Base Case Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**254.521**	**141.075**	**254.521**	**141.075**
Net Interchange	**-221.651**	**-27.925**	**-221.652**	**-28.147**
Losses	**0.610**	**18.287**	**0.611**	**18.089**

Minimum Load 2002 Recontrol Load Flow Results				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Actual Load	**254.521**	**141.075**	**254.521**	**141.075**
Generation	**33.480**	**9.030**	**33.480**	**5.565**
Net Interchange	**-221.700**	**-84.122**	**-221.651**	**-85.845**
Losses	**0.604**	**19.672**	**0.610**	**19.115**

Minimum Load 2002 Load Flow Results with DR Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Gross Load	**254.521**	**141.075**	**254.521**	**141.075**
Load (Net of DR)	**250.893**	**138.417**	**250.894**	**138.402**
Generation	**33.480**	**0.677**	**33.480**	**5.114**
Net Interchange	**-217.986**	**-62.425**	**-218.014**	**-61.694**
Losses	**0.573**	**17.972**	**0.599**	**17.722**

Minimum Load 2002 Load Flow Results with DR and DG Additions				
	PSLF – SVP Control Area		**AEMPFAST LF**	
	P (MW)	**Q (MVAR)**	**P (MW)**	**Q (MVAR)**
Gross Load	**254.521**	**141.075**	**254.521**	**141.075**
Load (Net of DR)	**250.893**	**138.417**	**250.894**	**138.402**
Generation	**87.850**	**10.477**	**87.853**	**34.608**
Net Interchange	**-163.443**	**-48.251**	**-163.417**	**-61.694**
Losses	**0.379**	**11.005**	**0.376**	**10.582**

2.3.2.6. Relative Impact of Recontrols and DER Projects

Table 22 provides a comparison of several network parameters of the Summer Peak 2002 network to illustrate the impact of recontrols on the network relative to the change in the condition of the network with the addition of the Optimal Portfolio DER projects.

The DER additions leave the network with lower real power losses and reactive power consumption, a higher overall voltage level, and no low-voltage buses (i.e., with voltage under 1.0 PU) when compared to the network with ideal settings of existing controls. While there is a small increase at the highest P stress point in the system, overall the low level of P stress is maintained.

While the network is lightly loaded and stable in its "as found" condition, the improvement in voltage profile should leave the network even less prone to instability. The base case has buses with voltage approaching 4% below the nominal value. These are largely eliminated with the recontrols step and completely eliminated with the DER additions. The elimination of low-voltage buses throughout reduces the chance that a perturbation might cause a low-voltage problem, trip, or equipment damage.

In assessing the relative impact of recontrols and DER additions, the DER additions provided a greater benefit in terms of P and Q loss improvement than did recontrols. At the same time, recontrols had a greater impact on voltage profile. This stands to reason as the recontrol step deals mainly with tuning reactive power injections and flows.

Table 22 Summer Peak 2002 Results Summary

	Base	W/ Recontrols	W/ DER Portfolio
P Losses (MW)	1.262	1.188	0.798
Q Losses (MVAR)	50.943	48.066	34.456
P Losses (%)[5]	0.3%	0.3%	0.2%
Q Losses (%)	24.4%	23.0%	16.5%
Overall Voltage (PU)	1.003	1.027	1.033
Low Voltage Bus (PU)	0.964	0.990	1.002
Voltage Variability (PU)	0.016	0.013	0.010
Overall P Stress	N/A	0.007	0.007
High P Stress Bus	N/A	0.029	0.042
P Stress Variability	N/A	0.005	0.007

[5] Percentage based on served load, not modeled load.

Table 23 provides a comparison of the same network parameters for the Summer 2005 network illustrating the relative impact of recontrols on the network and the change in the condition of the network with the addition of the Optimal Portfolio DER projects.

Again, the DER additions leave the network with lower real power losses and reactive power consumption, as well as a higher overall voltage level and lower level of voltage variability when compared to the network with ideal settings of existing controls. The DER additions also increased the voltage at the lowest point in the system; however, the recontrols step eliminated all the low-voltage buses. The DER additions also provided a measurable improvement in overall P Stress, reduction in the highest P Stress Bus, and variability of P stress.

As with the Summer 2002 case, the network is lightly loaded and stable in its "as found" condition. Again, the improvement in voltage profile should leave the network even less prone to instability. The base case again has buses with voltage approaching 4% below the nominal value. In this case these are eliminated with the recontrols step and improved upon with the DER additions. The elimination of low-voltage buses throughout reduces the chance that a perturbation might cause a low-voltage problem, trip, or equipment damage.

In assessing the relative impact of recontrols and DER additions, the DER additions again provided a greater benefit in terms of P and Q loss improvement than did recontrols. At the same time, recontrols also had a greater impact on voltage profile.

Table 23 Summer 2005 Results Summary

	Base	W/ Recontrols	W/ DER Portfolio
P Losses (MW)	3.17	2.971	1.785
Q Losses (MVAR)	92.56	81.604	59.459
P Losses (%)[6]	0.5%	0.5%	0.3%
Q Losses (%)	26.5%	23.4%	16.2%
Overall Voltage (PU)	0.960	1.015	1.028
Low Voltage Bus (PU)	0.945	1.001	1.010
Voltage Variability (PU)	0.013	0.011	0.007
Overall P Stress	N/A	0.008	0.006
High P Stress Bus	N/A	0.030	0.023
P Stress Variability	N/A	0.004	0.003

Table 24 provides a comparison of the same network parameters for the Knee Peak 2002 network illustrating the relative impact of recontrols on the network and the change in the condition of the network with the addition of the Optimal Portfolio DER projects.

[6] Percentage based on served load, not modeled load.

The DER additions leave the network with lower real power losses and reactive power consumption, as well as a higher overall voltage level and lower level of voltage variability when compared to the network with ideal settings of existing controls. The DER additions also increased the voltage at the lowest point in the system; however, the recontrols step eliminated all the low-voltage buses. The DER had little effect on already low overall P Stress.

The recontrol step actually reduced overall voltage slightly, but eliminated the low-voltage buses and reduced voltage variability. With the DER additions the improvement in voltage profile should leave the network arguably less prone to instability. However, in the "as found" condition the network's lowest-voltage bus was at 0.995 PU.

In assessing the relative impact of recontrols and DER additions, the DER additions again provided a greater benefit in terms of P and Q loss improvement than did recontrols. In this case, the changes in P and Q losses due to DER additions were about ten times the change resulting from recontrols. In this case the DER additions also had a greater impact on overall voltage levels, but the recontrols had a larger impact on voltage variability.

Table 24 Knee Peak 2002 Results Summary

	Base	W/ Recontrols	W/ DER Portfolio
P Losses (MW)	0.895	0.863	0.553
Q Losses (MVAR)	32.425	31.389	21.960
P Losses (%)[7]	0.3%	0.3%	0.2%
Q Losses (%)	17.6%	17.0%	11.9%
Overall Voltage (PU)	1.036	1.035	1.039
Low Voltage Bus (PU)	0.995	1.005	1.012
Voltage Variability (PU)	0.015	0.010	0.009
Overall P Stress	N/A	0.006	0.006
High P Stress Bus	N/A	0.047	0.050
P Stress Variability	N/A	0.006	0.007

[7] Percentage based on served load, not modeled load.

Table 25 provides a comparison of the same network parameters for the Winter Peak 2001-2 network illustrating the relative impact of recontrols on the network and the change in the condition of the network with the addition of the Optimal Portfolio DER projects.

The DER additions leave the network with lower real power losses and reactive power consumption, and a lower overall level of P stress and variability of P stress.

In the case of the Winter Peak 2001-2 network, the lowest-voltage bus in the "as found" condition was at 0.999 PU and high voltage buses were perhaps of greater concern. The recontrol step actually decreased overall voltage, but reduced voltage variability significantly and eliminated the low-voltage buses. The DER additions increased the overall voltage level, and boosted the low-voltage bus.

In assessing the relative impact of recontrols and DER additions, the DER additions again provided a much greater benefit in terms of P and Q loss improvement than did recontrols. In this case, the changes in P and Q losses due to DER additions were well over ten times the change resulting from recontrols.

Table 25 Winter Peak 2001-2 Results Summary

	Base	w/ Recontrols	W/ DER Portfolio
P Losses (MW)	0.909	0.886	0.579
Q Losses (MVAR)	33.102	32.968	22.242
P Losses (%)[8]	0.3%	0.3%	0.2%
Q Losses (%)	18.2%	18.2%	12.3%
Overall Voltage (PU)	1.038	1.032	1.038
Low Voltage Bus (PU)	0.999	1.005	1.010
Voltage Variability (PU)	0.020	0.011	0.010
Overall P Stress	N/A	0.006	0.005
High P Stress Bus	N/A	0.060	0.043
P Stress Variability	N/A	0.007	0.005

[8] Percentage based on served load, not modeled load.

Table 26 provides a comparison of the same network parameters for the Spring/Minimum Load 2002 network illustrating the relative impact of recontrols on the network and the change in the condition of the network with the addition of the Optimal Portfolio DER projects.

The DER additions leave the network with lower real power losses and reactive power consumption, and a higher low-voltage bus and reduced voltage variability. The DER additions have little effect on P stress.

In the Minimum Load case, as with the Winter Peak 2001-2 case, high voltage buses are of perhaps greater concern than low-voltage buses, with the overall voltage level at the target in the as found in the base case. Again, the recontrol step resulted in a lower overall voltage level, but significantly reduced voltage variability. The DER additions increased overall voltage relative to the recontrol results.

In assessing the relative impact of recontrols and DER additions, the DER additions again provided a much greater benefit in terms of P and Q loss improvement than did recontrols. In this case, the recontrol step had almost no effect on P losses and actually slightly increased Q losses (again, its chief benefit was the reduction in voltage variability).

Table 26 Minimum Load 2002 Results Summary

	Base	w/ Recontrols	W/ DER Portfolio
P Losses (MW)	0.611	0.610	0.376
Q Losses (MVAR)	18.089	19.115	10.582
P Losses (%)[9]	0.2%	0.2%	0.1%
Q Losses (%)	12.8%	13.5%	7.5%
Overall Voltage (PU)	1.050	1.030	1.046
Low Voltage Bus (PU)	1.024	1.013	1.025
Voltage Variability (PU)	0.017	0.009	0.008
Overall P Stress	N/A	0.004	0.004
High P Stress Bus	N/A	0.061	0.067
P Stress Variability	N/A	0.008	0.008

[9] Percentage based on served load, not modeled load.

Figure 12, Figure 13, and Figure 14 show the voltage profiles of the 2002 cases beginning with the "as found" condition, with recontrols, and with DER Portfolio projects added, illustrating the impact on voltage profile.

Figure 12 is actually repeated from Section 2.1. This figure shows voltages that, depending on the season, can vary significantly from 1.0 PU (or our target 1.05 PU) either high or low. Figure 13 shows the capability of reactive power adjustments to bring voltage in line, raising low-voltage buses in the Summer Peak case and lowering high-voltage buses in the other cases.

Figure 14 shows dramatically the improvement made possible by the DER additions. Voltage profiles are visibly flat across the network. This illustrates the combined impact of setting controls for optimum performance, placement of both demand and supply DER additions in their ideal locations, and dispatching a portion of them preferentially in response to system conditions.

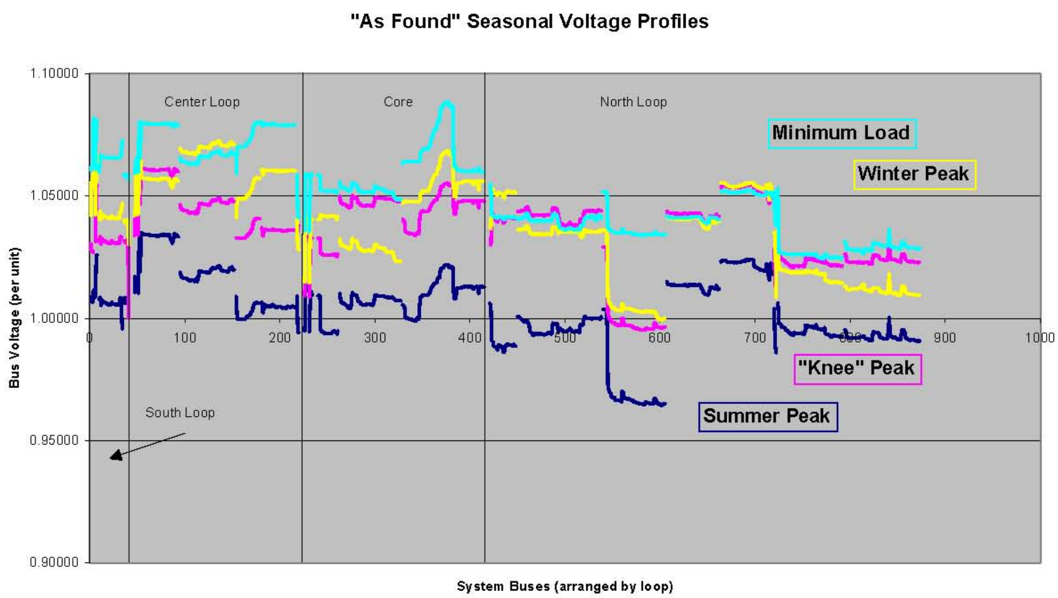

Figure 12 "As Found" Seasonal Voltage Profiles

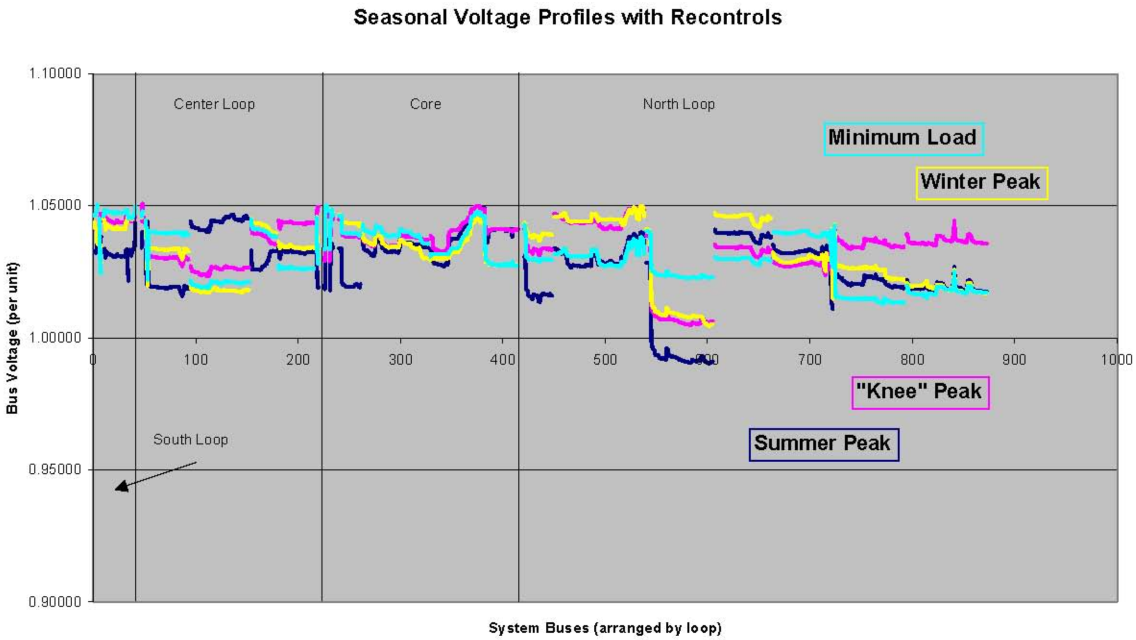

Figure 13 Seasonal Voltage Profiles with Recontrols

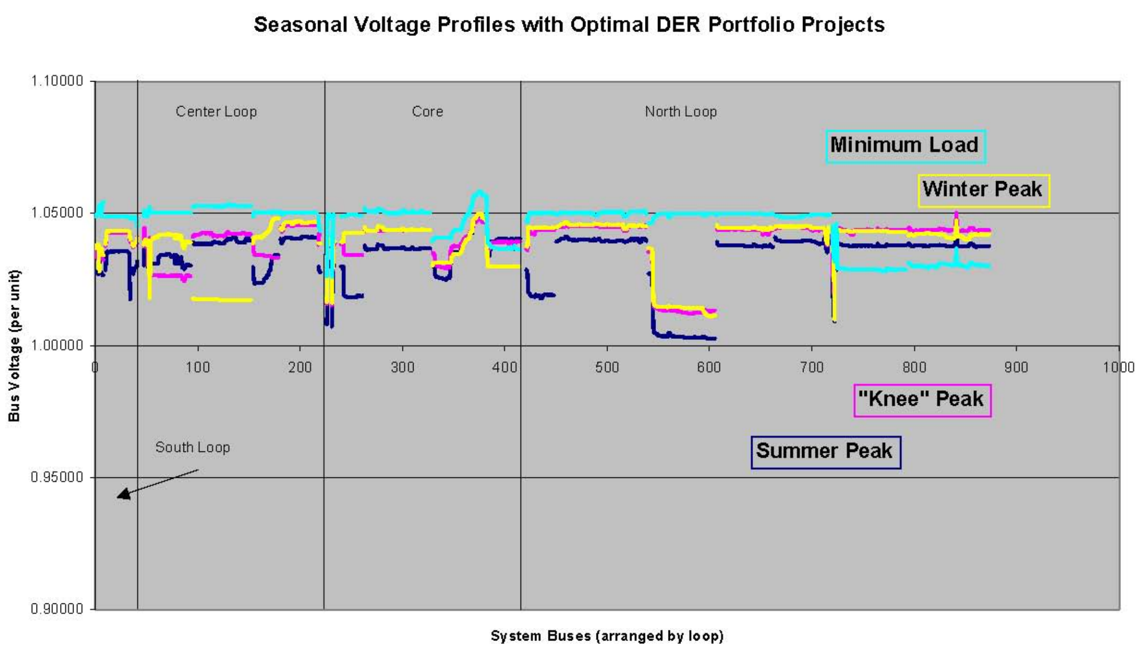

Figure 14 Seasonal Voltage Profiles with Optimal DER Portfolio Projects

Figure 15 shows the voltage profiles in for the Summer 2005 case progressing from “as found” through recontrols, DR additions, and DR + DG additions. Again, the voltage profile is flattened, and low-voltage buses are eliminated.

Fig. 2.3-4

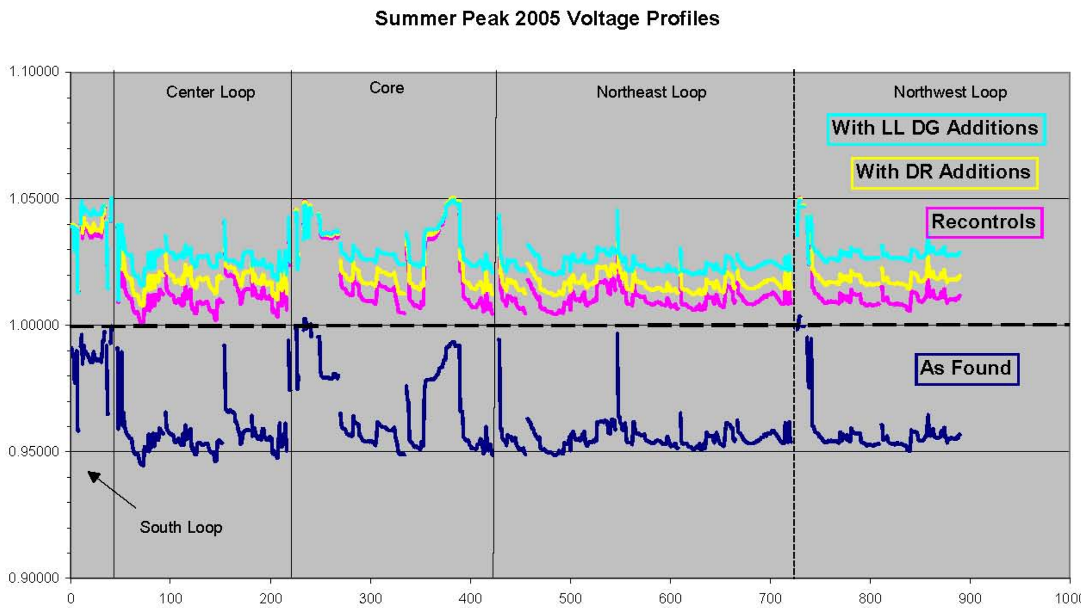

Figure 15 Summer Peak 2005 Voltage Profiles

2.3.3. Conclusions

Based on the results presented in Sections 2.1, 2.2, and this Section 2.3, we are able characterize a set of DER projects, the Optimal DER Portfolio, that maximizes network performance within the limits we have established for the 2002 (present) system and the 2005 (future) system.

These portfolios of projects consist of dispatchable demand response projects at most customer sites. The results presented here illustrate that there is value to the network in different levels of demand response at different locations for different network conditions. Therefore, these DR projects are flexible, dispatched by individual location at different levels according to system conditions. This permits the focus of demand reductions on those locations that provide the most benefit, both for network considerations and to reduce customer inconvenience. Using the approach demonstrated here we are able to identify how these projects should be dispatched under different operating conditions for maximum network benefit. Accordingly, the Optimal DER Portfolio consists of DR projects that, depending on their location, are specified for different curtailment levels under different network operating conditions.

These portfolios also consist of distributed generation projects at many customer sites.

Given realistic limitations on the amount of generation at a customer site and on a distribution feeder, these results demonstrate that some potential DG locations provide more network value than others, and that DG should be sited in specific locations to provide maximum network benefit.

With regard to location, these results show that at least for this subject system, locations electrically distant from the transmission backbone yield greater incremental network benefits from the addition of generating capacity. Accordingly, "close-in" customer sites such as transmission-level customer sites, which may also be the largest customers, have less network value and may receive low rankings or be excluded altogether from an idealized portfolio of DG projects in favor of capacity at other locations.

A related result of this is that these idealized projects are relatively small in MW terms, suggesting a network benefits-driven market "sweet spot" for distributed generation of perhaps 250 kW or less.

Another result is that at some customer sites DG is not beneficial simply because the capacity has more value to the network if located elsewhere on the feeder serving that customer.

There is value in flexibility from these DG projects. However, these results show that the flexibility needed is limited. The majority of Optimal DER Portfolio DG projects may operate at their full-rated real power capacity through most of the year; only a fraction need be dispatched seasonally or turned off during minimum load periods. Moreover, these results show that those projects for which more operating flexibility has value can be identified ahead of time rather than burdening all potential projects. This suggests that network benefits from DG can be highly compatible with DG projects operated primarily for customer needs.

The extraordinarily flat voltage profiles in the results that include DG arise from the ability to redispatch VAR injection on a variable basis (within operating limits) from hundreds of DG units distributed about the system to optimize the network's voltage profile. While it requires further study, another tentative conclusion is that the independent dispatch of VAR output of onsite generation units by the network operator has significant value to the network but modest cost to the DG project sponsor.

Accordingly, we find that the Optimal DER Portfolios consist of DG projects at specific locations (customer sites) that a) are limited in size by the customer's load and the total amount of DG on the customer's feeder, b) in some specified locations have the ability to turn down or off to allow preferential dispatch of other units, c) in some specified locations operate at variable operating factors, and d) have variable VAR output controllable by the network operator.

In our models, in its "present" configuration, as found, the SVP network consists of 419 customer sites, none of which represents dispatchable DR capability. It includes 6 embedded generation units, two of which are directly monitored and controlled by the network operator, two of which are customer or third-party owned with no network-level control, and two that are used for emergencies only. The network as found presently includes a total of 100 sources of reactive power, 20 of which are timer-operated, 18 of which are switchable pad-mounted and the remainder of which are on all the time. Voltage and real and reactive power flow are monitored through the SCADA system at transmission to distribution stepdown transformer locations.

With the Optimal DER Portfolio projects described above in place, the SVP network includes about 390 individually-dispatchable demand response resources. It also includes 380 embedded generation resources (or 149 in the case of the 2005 network) each of which represents, at a minimum, a variable source of reactive power dispatchable by the network operator. Per our assumptions noted in Section 2.2, all 100 capacitors are also individually dispatchable. Further, conceivably actual voltage and real and reactive power flow could be monitored by the network operator at all 390 dispatchable DR sites through advanced power quality metering, as could MW and MVAR output from each of the embedded generation units.

This is the very picture of an advanced Energynet power delivery infrastructure, with related technologies to monitor and coordinate these devices. According to the 2001 AQMD Public Back Up Generation System Inventory, there were 44 onsite power generation units at customer sites in the City of Santa Clara, 16 of which are actually at locations identified in this study as generation sites. Also, as noted in Section 2.2, these monitoring and control capabilities have in many cases already been demonstrated. Such a system is highly flexible, and through the use of advanced analytics such as AEMPFAST could be operated at a high level of performance under varying operating conditions.

2.4. Quantification of Network Benefits

2.4.1. Approach

We considered the following as potential network benefits attributable to the Optimal DER Portfolio:

- Real power loss reduction within the SVP system
- Reactive power consumption reduction within the SVP system
- Real power loss reduction within the PG&E system
- Reactive power consumption reduction within the PG&E system
- SVP system voltage profile improvement
- SVP system P stress reduction
- Increase in load-serving capability under contingency conditions
- Capacity value

In each case we summarized the total benefits and seasonal benefits attributable to the entire DER portfolio. We also sought to make a realistic determination of the how much of these benefits could be attributed to DG and how much to DR. We used the analytical results described in prior sections that characterized the condition (or state) of the network without and with Optimal DER Portfolio projects under different conditions to determine the net incremental impact of these DER projects on network performance.

For all measures we considered the impact of the Optimal Portfolio DR and DG projects on the SVP transmission and distribution system as an integrated system. For P and Q losses, we also considered the impact on the surrounding PG&E transmission system as well as on the SVP transmission and system.

We also made an assessment of whether benefits are appropriately attributed to individual projects or groups of projects. This is made possible by the analysis discussed in Sections 2.2 and 2.3 in which we rank ordered the capacity additions and layer them into the network in sequence.

In light of the fact that our analysis is based on a series of snapshots, we also sought to assess whether these benefits would be sustained or episodic. For example, DG projects specified for high load-factor operation will yield benefits on a sustained basis, where a DR project will yield benefits only when it is called or dispatched. It is worth reiterating here that the benefits we ascribed to DG projects are incremental to those that we found would be yielded by DR alone, as we assumed all DR was in place and dispatched before considering beneficial DG additions. Further, a condition we did not analyze was the benefits the DG projects would yield if the DR projects were not dispatched or operating.

We also developed new cases to assess the impact of these DER projects on network capability. Specifically, we simulated the network under contingency or outage conditions to determine if the addition of these DER projects would reduce the impact of outage or increase the load-serving capability of the network under outage conditions. These outage conditions were specified by SVP.

We also developed new cases simulating specific capital improvements in the 2005 network in order to determine the incremental network performance gain from these improvements. This was to permit a direct, "apples-to-apples" comparison with the network performance gain from the addition of Optimal Portfolio DER projects. We did not consider these specific network improvements as candidate "avoided network improvements" because they are either complete or well on the way to completion.

We anticipated that some network benefits could be valued in terms of market-clearing prices for energy and capacity. We obtained or developed unit estimates for the value of energy and capacity elements and applied them where appropriate. For the 2002 cases we used actual hourly prices for the year beginning December 1, 2001 for the Northern California zone of the Cal ISO control area.[10] For the 2005 case we used a forecast of hourly market-clearing energy prices for the Northern California zone developed by the Energy Commission.[11] To illustrate the valuation of capacity as distinct from energy we drew from prices resulting in the New York ISO's capacity markets.[12]

We also anticipated that some network benefits would be valued in terms of avoided equipment purchases such as new capacitors, so we obtained estimates for the unit cost of reactive capacity[13] and applied them where appropriate.

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[10] Cal ISO Ex Poste hourly energy prices for NP-15 and hourly ancillary services prices for NP-15.

[11] Joel Klein, 2004.

[12] New York ISO, http://www.nyiso.com/markets/icapinfo.html, 2001-2 and 2004-5 capacity market auction results.

[13] D. Shugar, "Photovoltaics in the Distribution System: The Evaluation of System and Distribution Benefits," IEEE PV Specialists Conference, May 1990.

While the network capital additions we considered here may not be considered "avoided" in a strict sense both because they are already built and because they provide benefits not considered in our analysis, it is useful to consider the incremental network benefits they provide in light of their cost.

Also, it is important to note that this comparison is not a "cost-benefit" analysis nor is it intended to be. Recall that our overall objective in this project is to demonstrate a methodology to determine and quantify network benefits of DER, as such network benefits are traditionally excluded from cost-benefit analyses. Thus this discussion does not include the cost of DER projects nor does it include benefits other than network benefits. Because the decision to install a DER project along with the cost burden of that project may lie with a project sponsor, customer, third party project integrator, with the network operator, or some combination, a valid "cost-benefit" analysis must also explicitly state from whose perspective the analysis derives. The practical result of the approach illustrated in this study is that if network benefits of DER have been quantified and priced, and there is a mechanism for the exchange of their associated economic value, they can be included in cost benefit analyses performed from any perspective.

2.4.2. Analytical Results

The network benefits of the Optimal DER Portfolio for the 2002 ("present") and 2005 ("future") portfolios in engineering terms are developed and explained in more detail below.

2.4.2.1. 2002 Optimal DER Portfolio – P and Q Losses

The generation (DG) projects described in Section 2.3 yield a reduction in real power (P) losses in the SVP transmission and distribution systems of 0.289 MW under Summer Peak 2002 conditions. The demand response (DR) projects described in Section 2.3 yield a reduction in losses in the SVP system of 0.101 MW under the same conditions when they are called or dispatched, for a total of .390 MW.

In share terms, these reductions are significant. With the DR projects dispatched, together the DR and DG projects result in a reduction in P losses of about 33%.

The DG projects and DR (when dispatched) also yield a decrease in real power losses in the PG&E system under Summer Peak conditions.

As described in Section 2.3, the Optimal DER Portfolio DR and DG projects are operated differently under different network conditions. It follows that the P loss reduction achieved by these projects would vary for different network conditions. Table 27 summarizes the real power loss benefit of the 2002 Optimal DER Portfolio, with DG and DR projects located and dispatched as described in Section 2.3, under the varying seasonal conditions we considered:

Table 27 2002 DER Portfolio Real Power Loss Benefit (MW)

	SVP System		PG&E System	
	DG	DR	DG	DR
Summer Peak	.289	.101	5.150	1.178
Knee Peak	.279	.031	5.029	.424

Winter Peak	.265	.042	3.216	.509
Minimum Load	.223	.011	1.794	.431

Table 28 shows the impact of the DG projects and DR (when dispatched) in terms of percentage reduction in the system losses of the SVP system with the implementation of recontrols only.

Table 28 2002 DER Portfolio SVP System Percentage Loss Reduction

	DG	DR	Total
Summer Peak	24%	9%	33%
Knee Peak	33%	4%	36%
Winter Peak	30%	5%	35%
Minimum Load	37%	2%	39%

Recall that we considered more DR capacity to be available during the "1% highest hour" Summer Peak conditions. The impact of that is evident in Table 28 in terms of a greater loss benefit for DR under Summer Peak conditions.

It is notable that the P loss benefit from the DR and DG projects actually varies relatively little from season to season. Further, there are loss benefits from these projects even under Minimum Load conditions.

A significant share of the P loss reduction in the SVP system is attributable to an increase in network efficiency. The system's overall loss rate with "recontrols" under Summer Peak conditions is 0.3%. Thus, a reduction in load served through the network of 54.88 MW (due to the DG projects) plus 10.52 MW (due to the DR projects) would explain a P loss reduction of only about .196 MW. However, the loss reductions observed due to the Optimal DER Portfolio and shown here are about twice as great. The difference is entirely the result of increased network efficiency resulting from the placement (location) of the Optimal DER Portfolio projects. As there are only two points of interconnection between the SVP system and the PG&E system, the PG&E system loss reductions are probably purely attributable to a reduction in the SVP load served through the PG&E system.

The DG projects described in Section 2.3 also yield a reduction in reactive power (Q) consumption in the SVP transmission and distribution systems of 11.159 MVAR under Summer Peak 2002 conditions. The DR projects described in Section 2.3 yield a reduction in reactive power consumption in the SVP system of 2.451 MVAR under the same conditions when dispatched, for a total of 13.61 MVAR.

The DG projects and DR (when dispatched) also yield a decrease in reactive power consumption in the PG&E system.

Table 29 summarizes the reactive power consumption benefit of the 2002 Optimal DER Portfolio, with DG and DR projects located and dispatched as described in Section 2.3, under the seasonal conditions we considered:

Table 29 2002 DER Portfolio Reactive Power Consumption Benefit (MVAR)

	SVP System		PG&E System	
	DG	DR	DG	DR
Summer Peak	11.159	2.451	58.007	13.793
Knee Peak	8.800	0.629	59.444	5.204
Winter Peak	9.907	0.819	50.771	8.974
Minimum Load	7.140	1.393	24.485	7.938

Table 30 shows the impact of the DG and DR projects in terms of percentage reduction in the SVP system's reactive power consumption with the implementation of recontrols only.

Table 30 2002 DER Portfolio SVP System Percentage Reactive Power Consumption Reduction

	DG	DR	Total
Summer Peak	23%	5%	28%
Knee Peak	28%	2%	30%
Winter Peak	30%	2%	32%
Minimum Load	37%	7%	45%

It is evident that the DG projects provide a significant benefit in terms of reduced reactive power consumption by providing variable reactive sources closer to their ideal location. Further, this is true regardless of the season. In fact, in the SVP system, the reactive power consumption benefits of the Optimal DER Portfolio are greatest under Winter Peak and Minimum Load conditions.

2.4.2.2. 2002 Optimal DER Portfolio – Voltage Profile and System Stress

Under each of the network conditions we evaluated, the Optimal DER Portfolio projects, if sited and dispatched as described in Section 2.3, make a significant improvement to the voltage profile of the subject system and reduce overall system stress relative to the cases with only recontrols implemented. For Summer Peak 2002 conditions, Table 31 through Table 34 illustrate these contributions, and Figure 16 through Figure 23 illustrate them graphically.

To clarify, the voltage and stress values shown associated with DR projects apply when those projects are dispatched. Further, the values shown associated with DG projects are based on a simulation with DR projects dispatched as well. Since these results reflect conditions in both transmission and distribution portions of the network, voltage is quoted on a per unit (PU) basis.

In general, a flatter voltage profile is more desirable. Figure 16, Figure 18, Figure 20, and Figure 22 show that under each of the seasonal conditions the voltage profile achieved with the addition of the DR and DG projects is significantly flatter, particularly when compared to the "as found" conditions.

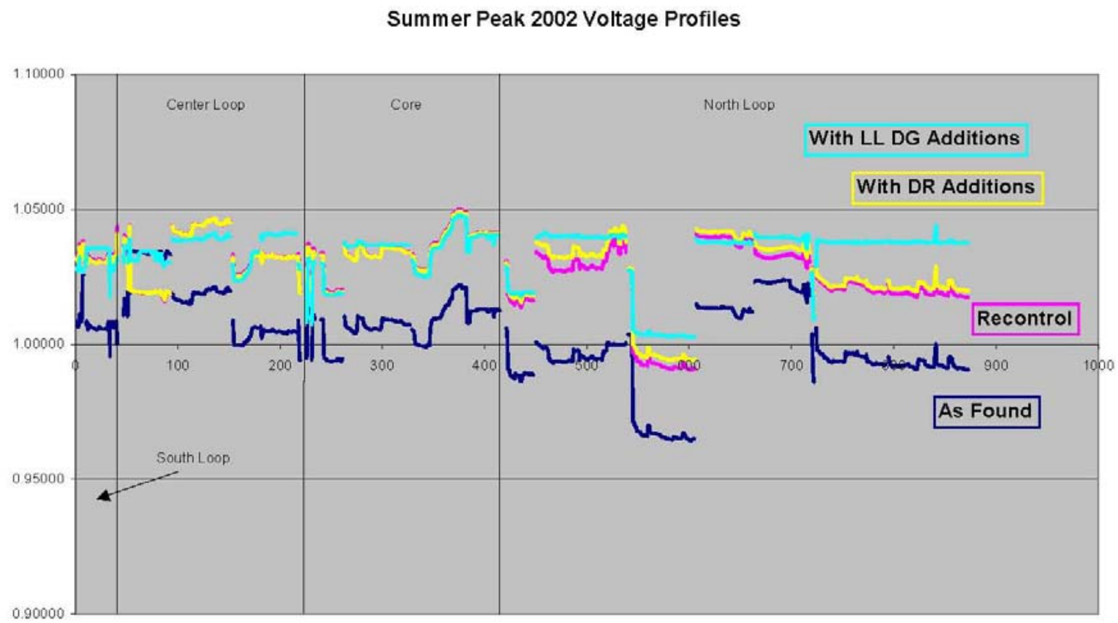

Figure 16 Summer Peak 2002 Voltage Profiles

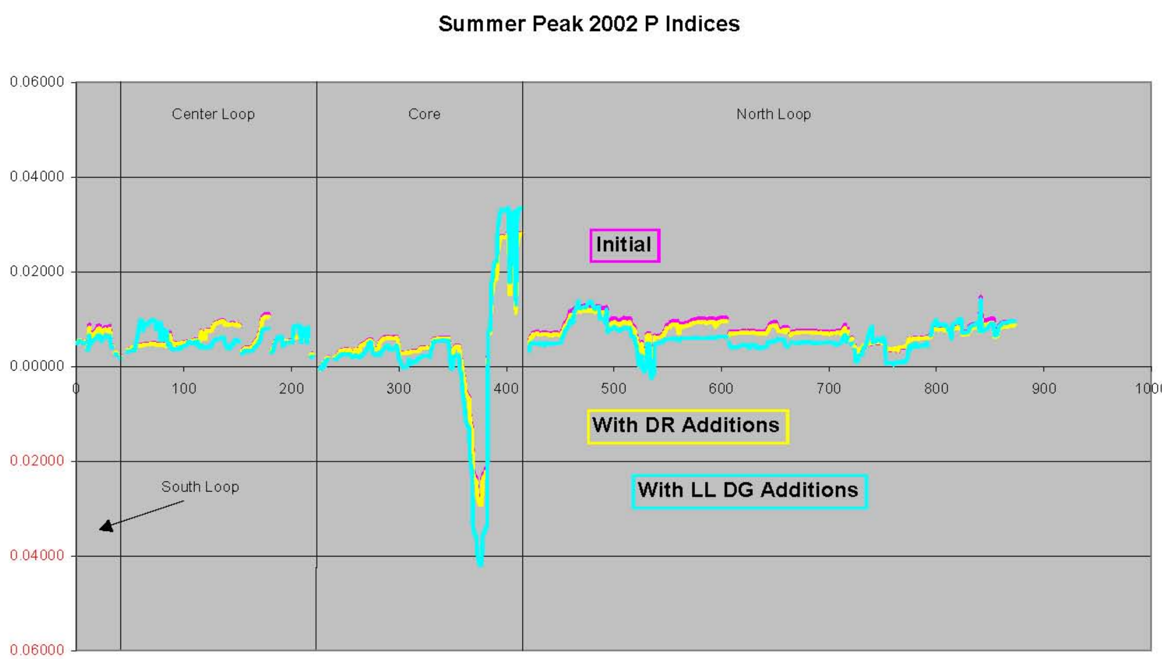

Figure 17 Summer Peak 2002 P Indices

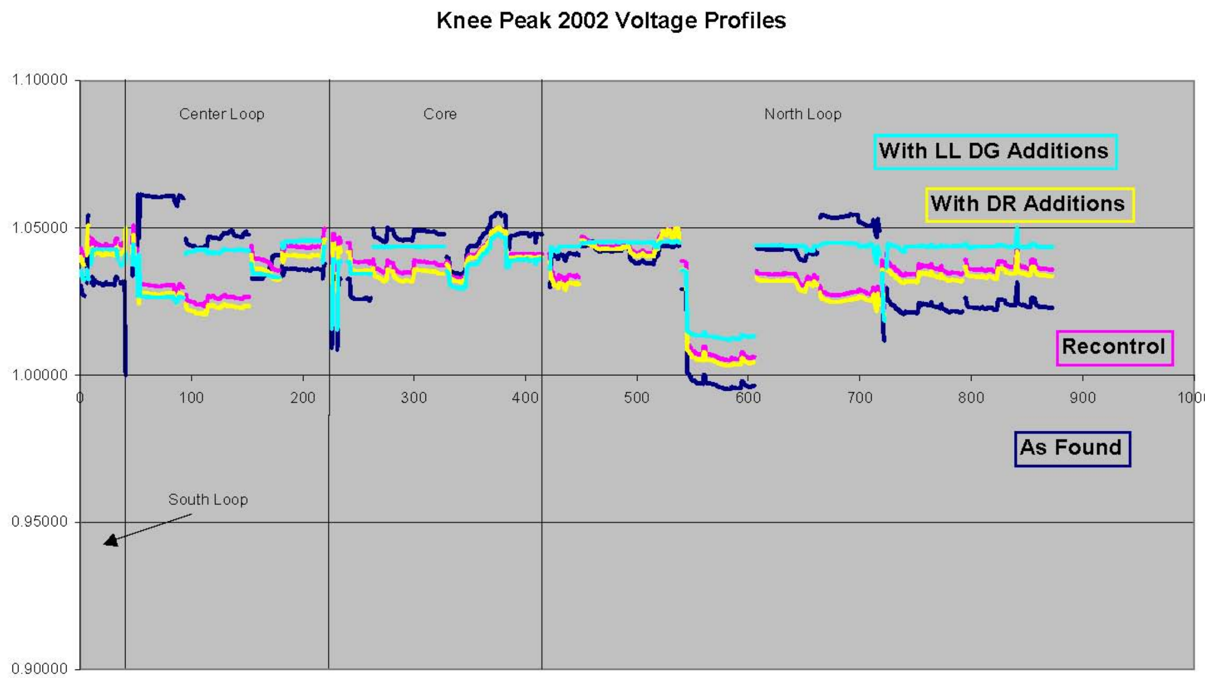

Figure 18 Knee Peak 2002 Voltage Profiles

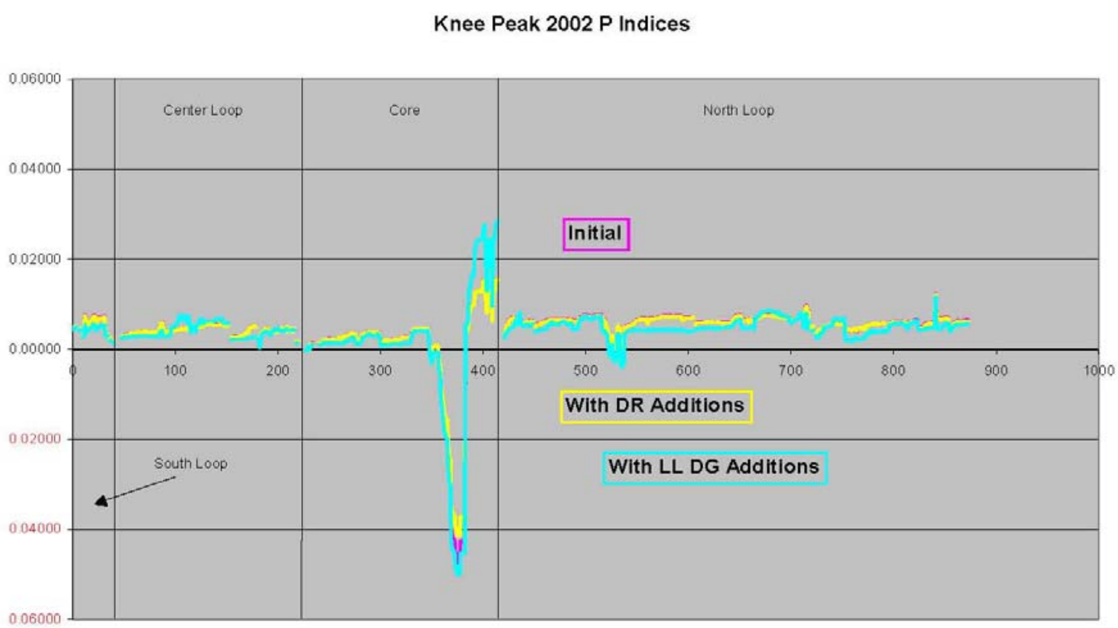

Figure 19 Knee Peak 2002 P Indices

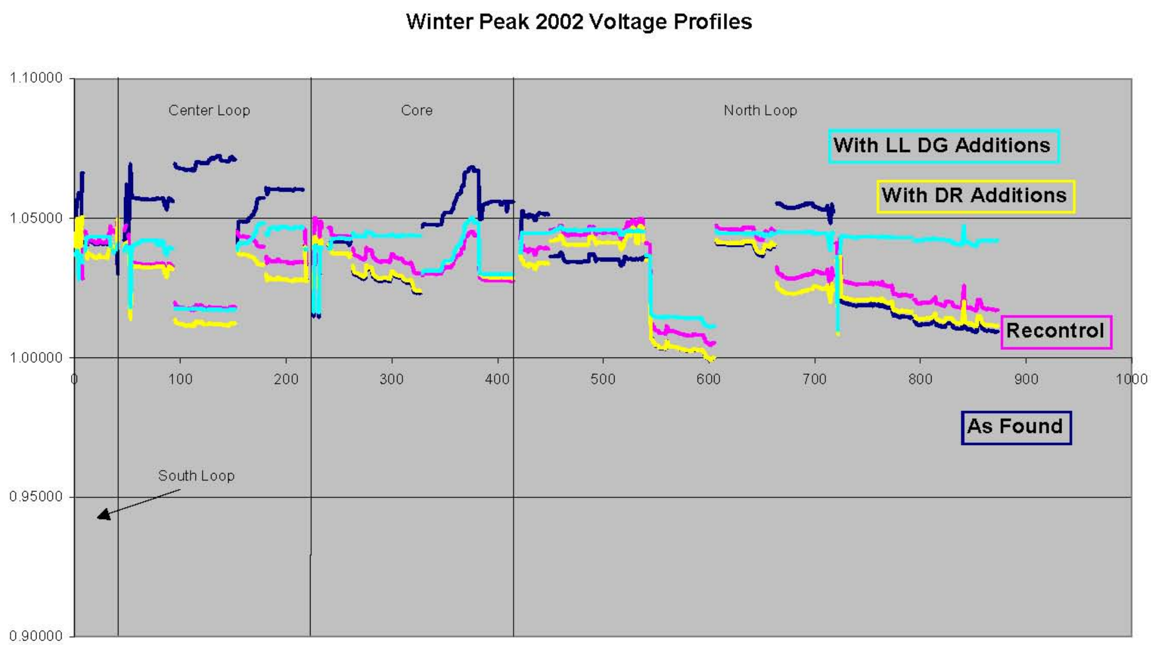

Figure 20 Winter Peak 2002 Voltage Profiles

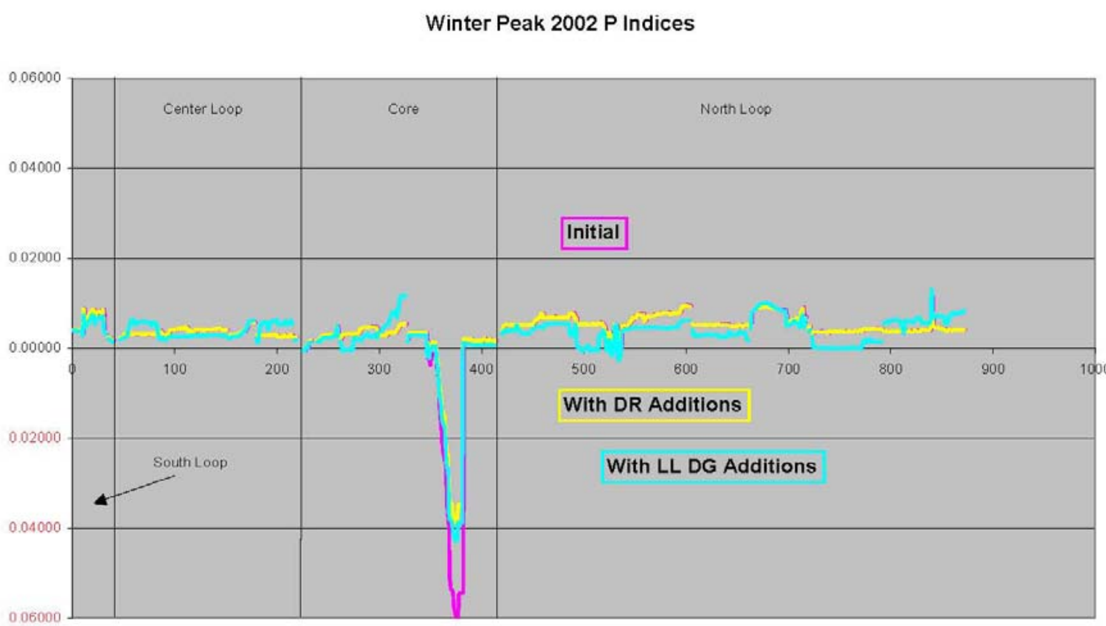

Figure 21 Winter Peak 2002 P Indices

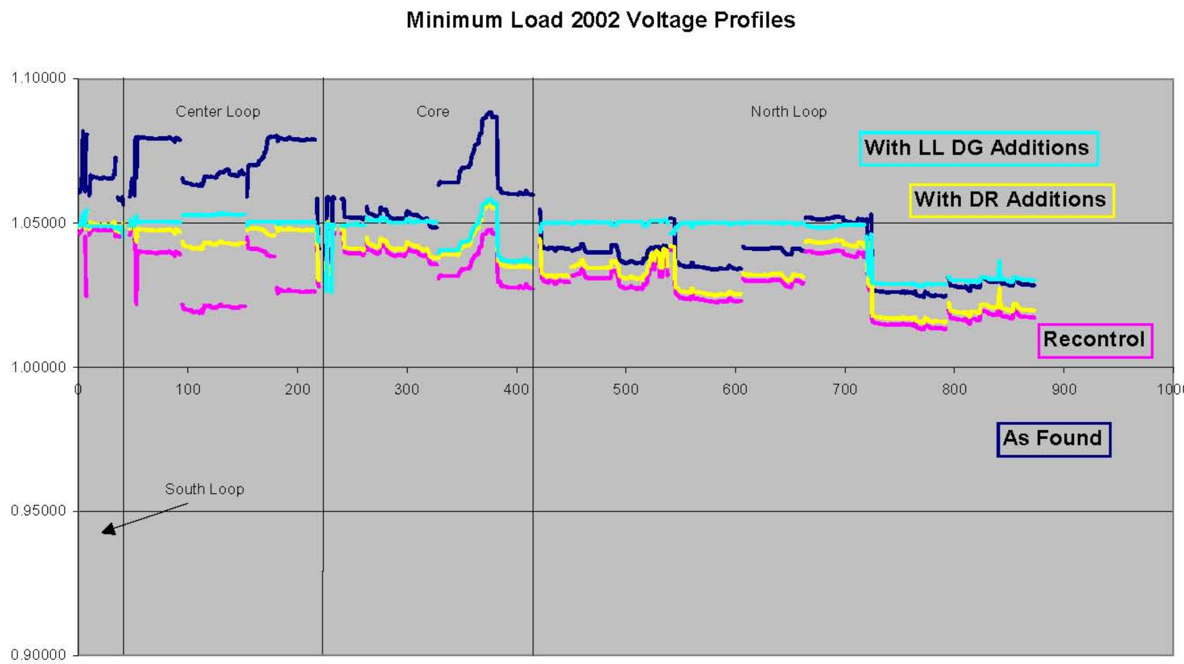

Figure 22 Minimum Load 2002 Voltage Profiles

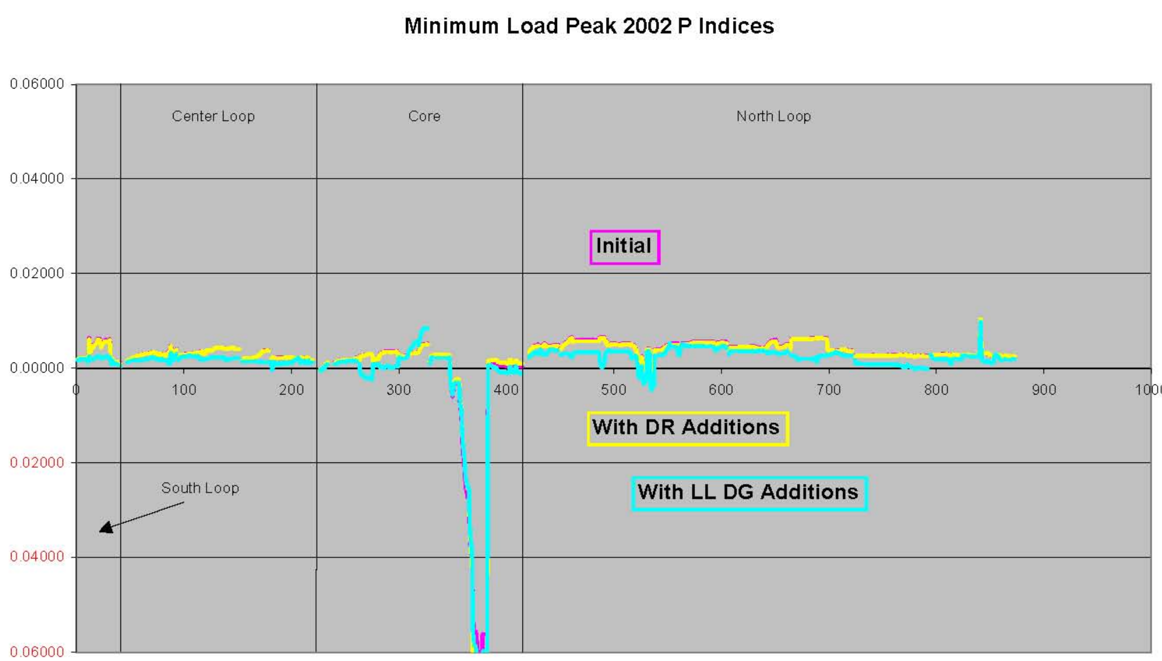

Figure 23 Minimum Load Peak 2002 P Indices

With respect to Figure 17, Figure 19, Figure 21, and Figure 23, again, the deviation of the P Index from a value of zero may be thought of as a measure of the system's P stress at that location. A P Index profile that is closer to zero on an overall basis should be thought of as improved.

With respect to Table 31, Table 32, Table 33, and Table 34, the elimination of high and low-voltage buses and the reduction in overall voltage variation may be thought of as improvements. Recall that in this analysis we set as a "target" voltage 1.05 PU, so the closer the average voltage is to that value may be viewed as a benefit. A reduction in the overall P stress ("Average P Stress") should be thought of as a benefit as well. In some cases there may actually be an increase in the P stress at a particular location, which is acceptable if the overall P stress is not increased.

Table 31 Summer Peak 2002 Voltage Profile and System Stress Results

	With Recontrols	With DR Projects	With DG Projects
Average Voltage (PU)	1.027	1.029	1.033
Min. Voltage	.990	.994	1.002
Max. Voltage	1.050	1.049	1.047
Std. Dev. Voltage	0.013	0.013	0.010
Average P Stress	.007	.007	.007
Max. P Stress	.029	.029	.0041
Std Dev. P Stress	0.005	0.005	0.006

Table 31 shows that under Summer Peak 2002 conditions, with the DR and DG projects together, the low voltage (< 1.0 PU) buses are eliminated, the voltage variability is reduced, and the overall voltage profile is closer to the 1.05 PU target.

Table 32 Knee Peak 2002 Voltage Profile and System Stress Results

	With Recontrols	With DR Projects	With DG Projects
Average Voltage (PU)	1.035	1.032	1.039
Min. Voltage	1.005	1.003	1.012
Max. Voltage	1.051	1.051	1.050
Std. Dev. Voltage	0.009	0.010	0.009
Average P Stress	.006	.006	.006
Max. P Stress	.047	.041	.050
Std Dev. P Stress	0.006	0.005	0.007

Table 32 shows that under Knee Peak 2002 conditions with the DR and DG projects together, high voltage (> 1.05 PU) buses are eliminated, the lowest voltage buses are raised, and the combined network's overall voltage profile is slightly closer to the 1.05 PU target.

Table 33 Winter Peak 2002 Voltage Profile and System Stress Results

	With Recontrols	With DR Projects	With DG Projects
Average Voltage (PU)	1.032	1.027	1.038
Min. Voltage	1.005	0.999	1.010
Max. Voltage	1.050	1.051	1.050
Std. Dev. Voltage	0.011	0.012	0.010
Average P Stress	.006	.005	.005
Max. P Stress	.060	.039	.043
Std Dev. P Stress	0.007	0.005	0.005

It is more evident on the voltage profile plots than in the table, but under Winter Peak conditions one potential issue is high-voltage buses. Table 33 shows that under Winter Peak 2002 conditions with the DR and DG projects together, high voltage (> 1.05 PU) buses are eliminated, the lowest voltage buses are raised, and the overall voltage profile is slightly closer to the 1.05 PU target. There is also visible improvement in the P stress of the system.

Table 34 Minimum Load 2002 Voltage Profile and System Stress Results

	With Recontrols	With DR Projects	With DG Projects
Average Voltage (PU)	1.030	1.035	1.045
Min. Voltage	1.012	1.002	1.025
Max. Voltage	1.051	1.057	1.058
Std. Dev. Voltage	0.010	0.011	0.009
Average P Stress	.005	.005	.004
Max. P Stress	.061	.078	.067
Std Dev. P Stress	0.008	0.009	0.008

As with the Winter Peak case, an issue under Minimum Load conditions is high-voltage buses. Table 34 shows that under Minimum Load 2002 conditions with the DR and DG projects together, overall voltage is moved closer to the 1.05 PU target, but high voltage (> 1.05 PU) buses are not completely eliminated. There is also some visible improvement in the P stress of the system.

2.4.2.3. Attribution of Loss and Voltage Profile Benefits to Groups of Projects

Most of these results presented in this report consider the impact of the Optimal DER Portfolio projects as a group. We know from the analysis presented in Sections 2.2 and 2.3 that the DR and DG projects in the portfolio are ranked in terms of their contribution to the optimization objectives under each set of network conditions. Here we consider whether a subgroup of these projects contributes disproportionately to the overall impact of the portfolio.

AEMPFAST calculates an "objective" value, which is a numerical expression of the state of the simultaneous objectives established for the optimization, for each configuration of the system. Appendix 2.4-1 contains plots showing the cumulative improvement in this objective value, divided by the cumulative additions in kW of DR and DG capacity for the 2002 Optimal DER Portfolio projects, if added in their rank order for each set of conditions. These plots suffer from the "noise" that arises from attempt to discern network improvements from step to step when the changes themselves are close to the solution error of the power flow models.

These plots suggest that for this power delivery network under the Summer Peak conditions those DR and DG projects with rankings among the top 130-140 for these conditions appear to yield a greater share of the benefits than do the remainder.

Under Knee Peak conditions there is almost no discernable difference in the attribution of Knee Peak benefits among the DR projects, but the DG projects with rankings among the top 130 or so for these conditions account for a greater share of the Knee Peak DG benefits.

Under Winter Peak conditions, as with the Knee Peak conditions, there is almost no discernable difference in the attribution of benefits among the DR projects, However, DG projects with rankings among the top 150 or so for these conditions may account for a for a greater share of the Winter Peak DG benefits.

Under Minimum Load conditions these plots are fairly distorted but suggest that there is not much difference in the attribution of Minimum Load benefits among the DR projects, and there may be some greater share of the Minimum Load benefits attributable to DG projects with rankings among the top 140 or so for these conditions.

2.4.2.4. 2002 Optimal DER Portfolio – Increased Load-Serving Capability

By placing the sources of power generation nearer to loads, by adding the capability to reduce load on demand, by reducing reactive power consumption, and by improving the network's voltage profile, the Optimal DER Portfolio projects affect the capability of a given network to serve load under contingency conditions.

With input from SVP we simulated the Summer Peak 2002 network with an outage in the SVP transmission system. We determined the load-serving capability of the network without the Optimal DER Portfolio projects to assess a baseline, then with the projects to determine their impact on load-serving capability.

The 2002 SVP system under Summer Peak conditions with recontrols is capable of serving 466.599 MW (actual load plus losses) under a single outage contingency. With the addition of the DR and light load-limited DG projects located and operated for Summer Peak conditions as described in Section 2.3, the network is capable of serving 584.222 MW under a single-outage contingency. This figure includes the 10.509 MW of demand response that is "served" but also curtailable for network benefits. This represents an increase in load-serving capability due to the 2002 Optimal DER Portfolio projects of about 117.6 MW.

One of the benefits of the Optimal DER Portfolio is the large increase in the degrees of control for network optimization represented by the penetration of DR and DG projects. The approach we used here to assess the increased load-serving capability attributable to the Optimal DER Portfolio projects does not capture that benefit entirely. The ability to re-optimize the network as load increases or if a contingency occurs with the additional operating flexibility of hundreds of variable sources of capacity likely translates to still more load-serving capability.

2.4.2.5. 2002 Optimal DER Portfolio – Capacity Value

Electrical capacity (the reliable *capability* to deliver energy) may be viewed as having standalone value that is distinct from the energy itself. Further, a specified amount of capacity is viewed as required to reliably serve load. The Optimal DER Portfolio projects represent calculable capacity value. Specifically, the DG projects represent a source of physical capacity as well as a source of energy. The DR projects represent capacity in that they reduce demand when called, freeing up physical capacity to serve remaining loads. Both the DG and DR projects in the Optimal DER Portfolio reduce real losses (energy consumption) when they are dispatched, as noted above, also freeing up physical capacity to serve load.

The capacity represented by the Optimal DER projects is physically in the SVP load center – in fact, co-located with load – and thus has no deliverability limitations. The capacity associated with the DG projects is available continuously based on the operating profile of the portfolio, and the capacity of the DR projects is available on a energy-limited basis, but when needed according to our assumption of dispatchability.

The capacity value of the Optimal DER Portfolio projects varies by season, depending on the amount of capacity the portfolio provides and the associated reduction in losses. The capacity value is greatest under Summer Peak conditions when higher levels of DR are available. The capacity value attributable to individual projects differs depending on their seasonal operating profile.

Table 35 and Table 36 summarize the capacity value of the Optimal DER Portfolio projects as a group.

Table 35 Capacity (MW) – DG Projects

	Summer Peak	Knee Peak	Winter Peak	Minimum Load
Projects	317	316	318	315
Capacity (MW)	54.89	54.58	54.76	54.37
Loss Red (MW)	5.439	5.308	3.481	2.017
Total	60.329	59.888	58.241	56.387

Table 36 Capacity (MW) – DR Projects

	Summer Peak	Knee Peak	Winter Peak	Minimum Load
Projects	389	388	389	387
Capacity (MW)	10.52	3.65	3.56	3.63
Loss Red (MW)	1.279	.455	.551	.442
Total	11.799	4.105	4.111	4.072

2.4.2.6. 2005 Optimal DER Portfolio – P and Q Losses

The DG projects described in Section 2.3 for the 2005 Optimal DER Portfolio yield a reduction in P losses in the SVP transmission and distribution systems of 0.683 MW under Summer 2005 conditions. The DR projects described in Section 2.3 yield a reduction in losses in the SVP system of 0.503 MW under the same conditions when dispatched, for a total of 1.186 MW. With the DR projects dispatched, together the DR and DG projects result in a reduction in P losses of about 40%.

The DG projects and DR (when dispatched) also yield a decrease in real power losses in the

PG&E system under these conditions.

Table 37 summarizes the real power loss benefit of the 2005 Optimal DER Portfolio with DG and DR projects located and dispatched as described in Section 2.3:

Table 37 2005 DER Portfolio Real Power Loss Benefit (MW)

	SVP System		PG&E System	
	DG	DR	DG	DR
Summer	.683	0.503	6.025	4.576

Table 38 shows the impact of the DG projects and DR (when dispatched) in terms of percentage reduction in the system losses of the SVP system with the implementation of recontrols only.

Table 38 2005 DER Portfolio SVP System Percentage Loss Reduction

	DG	DR	Total
Summer	23%	17%	40%

Based on the 2002 results presented above, it is reasonable to expect that the 2005 Optimal DER Portfolio would yield P loss reduction benefits under other seasonal conditions following roughly the same profile, and that there would be significant benefits even under Minimum Load conditions. With an assumption of a similar degree of DG project operating flexibility, we can project that the real power loss benefits of the 2005 Optimal DER Portfolio would be about the same in the rest of the summer season as under peak conditions shown here, 65% of this summer peak value during the winter peak, and about 40% of this summer peak value during off-peak conditions.

Also, a significant share of the P loss reduction in the SVP system is attributable to an increase in network efficiency. At the system's overall loss rate with "recontrols" under Summer 2005 conditions of 0.5%, a reduction in load served through the network of 66.66 MW (for the 149 DG projects) plus 25.53 MW (for the 390 DR projects) would explain a P loss reduction of only about 0.470 MW. The loss reductions in the SVP system resulting from the Optimal DER Portfolio projects are nearly three times as great; the difference is purely a result of increased network efficiency resulting from the placement (location) of these projects.

The DG projects described in Section 2.3 for the 2005 system also yield a reduction in reactive power (Q) consumption in the SVP transmission and distribution systems of 16.41 MVAR under Summer 2005 conditions. The DR projects described in Section 2.3 yield an additional reduction in reactive power consumption in the SVP system of 8.731 MVAR under the same conditions when dispatched, for a total of 25.145 MVAR.

The DG projects and DR (when dispatched) also yield a decrease in reactive power consumption in the PG&E system.

Table 39 summarizes the reactive power consumption benefit of the 2005 Optimal DER Portfolio with DG and DR projects located and dispatched as described in Section 2.3:

Table 39 2005 DER Portfolio Reactive Power Consumption Benefit (MVAR)

	SVP System		PG&E System	
	DG	DR	DG	DR
Summer	16.41	8.73	71.487	59.066

Table 40 shows the impact of the DG and DR, in terms of percentage reduction in the SVP system reactive power consumption with the implementation of recontrols only.

Table 40 2005 DER Portfolio SVP System Percentage Reactive Power Consumption Reduction

	DG	DR	Total
Summer	20%	11%	31%

Again, it is evident that the DG projects provide a significant benefit in terms of reduced reactive power consumption by providing variable reactive sources closer to their ideal location. Based on the 2002 results, it is reasonable to expect that these projects would yield the same types of benefits in terms of reduced Q consumption under a variety of seasonal conditions.

2.4.2.7. 2005 Optimal DER Portfolio – Voltage Profile and System Stress

For the 2005 system, the Optimal DER Portfolio projects, if sited and dispatched as described in Section 2.3, make a significant improvement to the voltage profile of the subject system and reduce overall system stress relative to the cases with recontrols implemented. For Summer Peak 2002 conditions, Table 27 illustrates these contributions, and Figure 24 and Figure 25 illustrate them graphically.

Table 41 shows that under Summer 2005 conditions with the DR and DG projects together, the high voltage (> 1.05 PU) buses are eliminated, the voltage variability is reduced, and the overall voltage profile is moved closer to the 1.05 PU target.

Table 41 Summer 2005 Voltage Profile and System Stress Results

	With Recontrols	With DR Projects	With DG Projects
Average Voltage (PU)	1.014	1.020	1.028
Min. Voltage	1.001	1.007	1.010
Max. Voltage	1.051	1.051	1.050
Std. Dev. Voltage	0.011	0.009	0.007
Average P Stress	.008	.008	.006
Max. P Stress	.030	.027	.022
Std Dev. P Stress	0.004	0.004	.003

In Figure 24 it is evident that a significant improvement to the network's voltage profile was achieved through recontrols alone, with further improvement resulting from the DR and DG projects. In Figure 25 there is a visible improvement in P stress in the South Loop of the network resulting from the DR and DG projects.

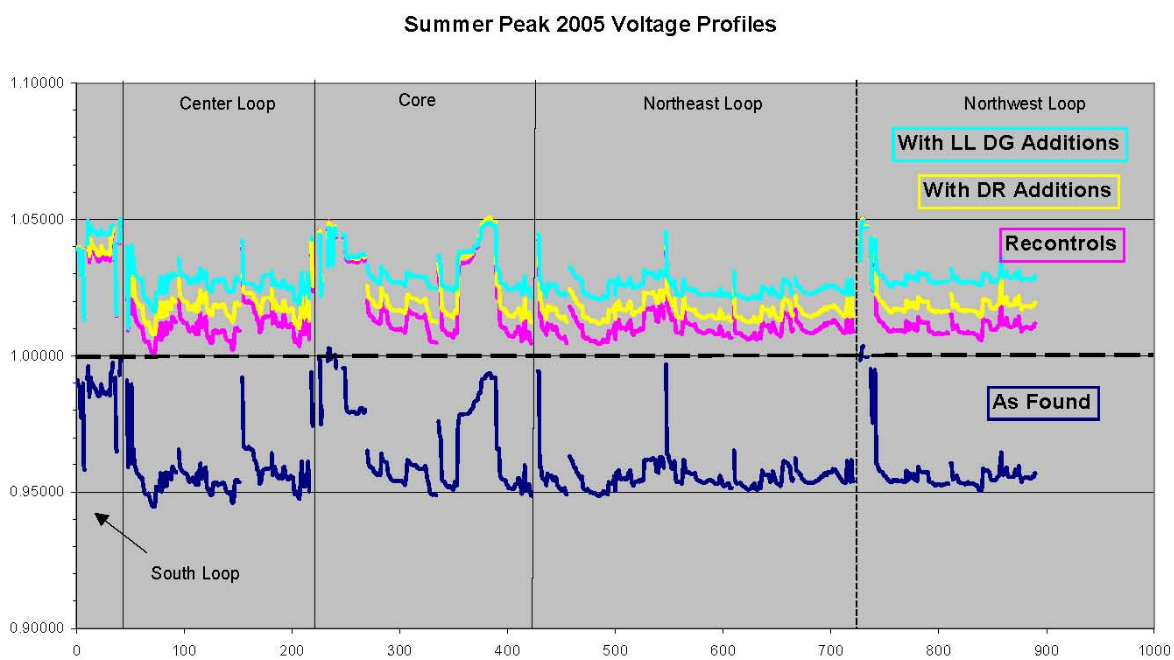

Figure 24 Summer Peak 2005 Voltage Profiles

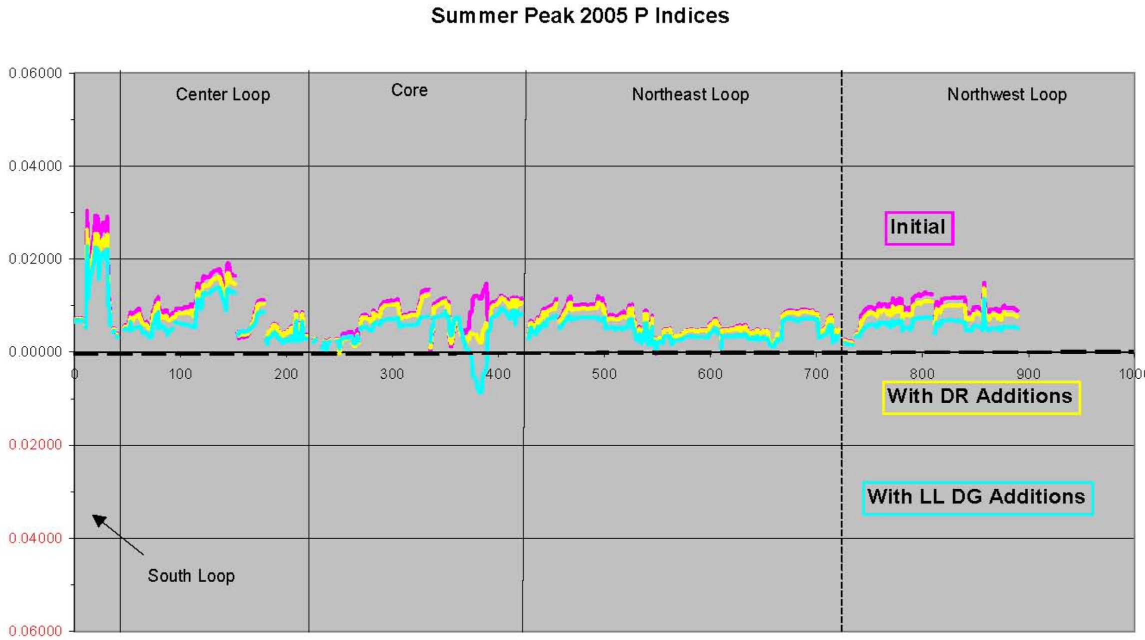

Figure 25 Summer Peak 2005 P Indices

2.4.2.8. Attribution of Loss and Voltage Benefits to Groups of Projects

Plots in Appendix 1 show the cumulative improvement in the objective value divided by the cumulative additions of the DR and DG projects, respectively, under Summer 2005 conditions. These plots show that under these conditions there is relatively little difference among the DR and DG projects in terms of the amount of network performance improvement that can be attributed to individual projects or subgroups.

2.4.2.9. 2005 Optimal DER Portfolio – Increased Load-Serving Capability

By placing the sources of power generation nearer to loads, by adding the capability to reduce load on demand, by reducing reactive power consumption, and by improving the network's voltage profile, the Optimal DER Portfolio projects increase the capability of a given network to serve load under contingency conditions.

The 2005 SVP system (modeled under Summer conditions) with recontrols is capable of serving 823.576 MW (actual load plus losses) under a single outage contingency. With the addition of the DR and light load-limited DG projects located and operated as described in Section 2.3, the network is capable of serving 870. 024 MW under a single-outage contingency. This figure includes the 25.527 MW of demand response that is "served" but also curtailable for network benefits. This represents an increase in load-serving capability due to the 2005 Optimal DER Portfolio projects of about 46.7 MW.

If load-serving capability of the subject network under contingency conditions is a concern or a problem to be addressed with planned capital additions or network improvements, an improvement in load-serving capability from ideally-placed DER projects could defer or eliminate the need for these improvements.

2.4.2.10. 2005 Optimal DER Portfolio – Capacity Value

The following tables summarize the capacity value of the 2005 Optimal DER Portfolio projects.

Table 42 Capacity Value (MW) – DG Projects

	Summer
Projects	149
Capacity (MW)	66.66
Loss Red (MW)	6.708
Total	73.368

Table 43 Capacity Value (MW) – DR Projects

	Summer
Projects	390
Capacity (MW)	25.53
Loss Red (MW)	5.079
Total	30.609

Based on the 2002 results, we can expect the 2005 Optimal DER Portfolio projects represent capacity value under conditions other than the summer peak shown here. Projecting from the 2002 results, we assume that the 2005 Optimal DER Portfolio DG projects represent the same installed capacity in each season. We can also assume that the 2005 Optimal DER Portfolio DR capacity shown here for Summer Peak conditions is about three times the capacity these projects would represent during the balance of the summer season peak, the winter peak, and minimum load conditions.

2.4.2.11. 2005 Optimal DER Portfolio – Comparison with Capital Plan Network Additions

As discussed in Section 2.1, we considered three major transmission-level additions to the SVP power delivery network in our analysis. These are:

- 115 kV Northern Receiving Station, a third transmission receipt point bifurcating the SVP North loop, and related reconfiguration of the SVP 60 kV transmission network.
- 230 kV Northern Receiving Station, a $23 million transformer and transmission line project connecting the Northern Receiving station to PG&E's Los Esteros substation at 230 kV.
- 147 MW PICO Generating Project, a $160 million generating plant rated at 147 MW peak capability, and interconnected to the SVP transmission system between Kifer and Scott substations at 115 kV.

We incorporated the 115 kV Northern Receiving Station in our base 2005 system. The following is an illustration of a side-by side analysis of the 230 kV Northern Receiving Station project, the PICO generating project, and the 2005 Optimal DER Portfolio (both DR and DG projects), using a common set of metrics.

Table 44 below shows power flow results with different network configurations involving these capital projects, after recontrols. In

Table 45 we compare the network benefits of the 2005 Optimal DER Portfolio, the NRS 230 kV project, the PICO generating project, and the NRS 230 kV and PICO projects together, all relative to the 2005 case with recontrols implemented. Again, the 2005 case with recontrols also includes the 115 kV Northern Receiving Station. In each case the network has been recontrolled to maximize performance in each configuration. Network benefits in

Table 45 are for the SVP portion of the network only.

This analysis serves as an illustration of the comparison of disparate types of projects, including both wires projects and non-wires projects, in terms of their network benefits using a common set of metrics. It cannot be considered a full comparison of these projects – in particular, this analysis does not consider possibly over-riding considerations for the NRS 230 kV project or the PICO project, such as tariff savings resulting from imports via a higher-voltage receipt point or the value of the PICO project as an incremental source of capacity or a replacement for other SVP energy resources. It also does not consider the relative cost to SVP of the Optimal DER Portfolio projects and the proposed network upgrades.

Table 44 Summer 2005 System With SVP Capital Additions - Results

	NRS 230 kV	PICO	NRS 230 + PICO
P Losses (MW)	4.106	2.897	3.502
Q Losses (MVAR)	103.519	81.274	98.725
Average Voltage (PU)	1.012	1.013	1.013
Min. Voltage	.997	.977	.998
Max. Voltage	1.050	1.050	1.051
Std. Dev. Voltage	.011	.011	.011
Average P Stress	.006	.006	.006
Max. P Stress	.029	.029	.029
Std Dev. P Stress	.005	.005	.005
SVP Load-Serving Capability (MW)	861.049	862.196	902.536

Table 45 Comparison of SVP Network Benefits of Optimal DER Portfolio and SVP Capital Projects

	2005 Opt DER	NRS 230	PICO	NRS 230 + PICO
Δ P Loss (MW)	-1.186	+1.135	-0.074	+0.531
Δ Q Loss (MVAR)	-25.145	+21.915	-.330	+17.121
Δ Avg Voltage (PU)	+.013	-.003	-.002	-.002
Low buses	No	.997	.977	.998
High buses	No	No	No	1.051
Δ Voltage Var.	-.001	+.003	+.003	+.003
Δ Avg P Stress	-.002	-.002	-.002	-.002
Capacity Value (MW)	93.512		147.074	147.074
Δ Load-serving Capability (MW)	+46.7	+37.5	+38.6	+79.0

It is evident that no combination of the NRS 230 kV project and the PICO project yields the loss reduction, increase in overall system voltage, and reduction in voltage variability of the Optimal DER Portfolio. Each of the alternatives yields an improvement in the average P stress in the network.

A fourth comparison we performed was based on a simulation of the system with the 2005 loads but without the addition of the NRS 115 kV Receiving Station. This presents an opportunity to assess the potential network benefits from DER in a more stressed system and to determine if the improved network performance with the SVP capital plan additions can be achieved entirely through the use of DER additions.

The approach we took was identical to that used to develop the 2005 Optimal DER Portfolio. In this case we identified 385 DR projects representing 24.03 MW, subject to the DR limitations described in Section 2.2, and 154 DG projects representing 64.63 MW, with the "Light Load" feeder limit applied. As before, these projects are in specific locations and dispatched at specified levels.

Table 46 Summer 2005 System without NRS 115 kV DR and DG Additions Results

	With Recontrols	With DR Projects	With DR & DG Projects
P Losses (MW)	3.786	2.995	2.094
Q Losses (MVAR)	104.970	90.500	69.311
Average Voltage (PU)	.999	1.015	1.026
Min. Voltage	.985	1.003	1.012
Max. Voltage	1.050	1.050	1.052
Std. Dev. Voltage	.014	.011	.008
Average P Stress	.011	.010	.008
Max. P Stress	.030	.026	.022
Std Dev. P Stress	.005	.005	.004
SVP Load-Serving Capability (MW)	536.816	N/A	710.243

It is evident first of all that the network in this configuration before the addition of DER resources is more stressed than what we have seen. Unlike the 2005 case incorporating the NRS 115 kV receipt point, in this case recontrols alone were not able to correct a network-wide under-voltage problem. Also, the system in this configuration has a substantially reduced load-serving capability. Under a single contingency the maximum served load is actually less than the total load in the base 2005 cases.

With the addition of the 385 DR and 154 DG projects in their specified locations, real losses were reduced by about 45% and reactive power consumption was reduced by about 34%. Low-voltage buses were eliminated, variability of voltage was reduced, overall voltage was increased, and overall network P stress was reduced. Load-serving capability was also increased by about 173 MW.

Using these metrics, the performance of the network in the configuration without the NRS 115 kV receipt point and with the addition of Optimal DER Portfolio projects was not as good as the base 2005 configuration (which includes the NRS 115 kV receipt point) with the Optimal DER Portfolio projects. However, it does achieve comparable or better network performance than the performance of the network in the other “capital additions” configurations analyzed above. Real and reactive losses are lower, and overall average voltage is closer to the target 1.05 PU and has less variability. There are also no buses with voltage under 1.0 PU. The network configured with the “capital projects” showed lower P stress levels and higher load-serving capability.

2.4.3. Economic Benefits

The network benefits of the Optimal DER Portfolio for the 2002 (“present”) and 2005 (“future”) portfolios in economic terms are developed and explained in more detail below.

2.4.3.1. 2002 Optimal DER Portfolio – P Losses

Reduction of real power losses is a pure network benefit whose value is represented by the cost of energy that would otherwise be purchased. This cost varies seasonally and with time of day.

To value avoided losses for the 2002 Optimal DER Portfolio, we used actual Cal ISO Ex Poste hourly energy prices for Northern California (NP-15) for 12-month period of December 2001 through November 2002. Recall that our "Winter Peak" day was December 20, 2001, our "Minimum Load" day was May 5, 2002, our "Knee Peak" day was September 2, 2002, and our "Summer Peak" day was August 9, 2002.

In applying these prices we considered May through October as the "Summer" season and the period Monday through Saturday, HE (hour ending) 0700 through HE 2200 as the "peak" period. We did not adjust for holidays.

The average price for the top 1% highest-priced Summer season hours was $82.46/MWh. The average price for the remaining Summer season peak hours was $27.86/MWh. The average price for the Winter season peak hours was $33.05/MWh. The average price for the off-peak hours was $19.64/MWh. We considered these periods and their average prices as corresponding, respectively, to the Summer Peak, Knee Peak, Winter Peak, and Minimum Load conditions we modeled.

The DG projects, dispatched as described in Section 2.3, provide varying P loss benefits through the seasonal periods described. Applying these seasonal benefits to the hourly price set, the DG projects yield the following loss benefits in dollar terms, both as a group, and per kW with benefits allocated equally across all projects:

Table 47 Loss Reduction Value ($ per year) – DG Projects

	Summer Peak	Knee Peak	Winter Peak	Minimum Load	Year
DG Portfolio	$38,573	$363,374	$285,222	$147,457	$834,262
Per kW	$.70	$6.66	$5.21	$2.71	$15.28

These benefits are calculated seasonally and are additive for a yearly value.

That there is a loss reduction benefit for these projects during off peak hours becomes significant because these hours represent a large share of the year, and benefits during that period make a meaningful contribution the overall economic value of loss reduction.

2.4.3.2. 2002 Optimal DER Portfolio – Q Consumption Reduction

Reduced reactive power consumption represents reactive capacity that otherwise would have to be injected into the system. Shugar, et. al, in 1990 assigned a value of $41/kVAR for avoided reactive power losses based on the equivalent cost of shunt capacitance on the feeder. We used this to value the reduction in reactive power consumption of the Optimal DER Portfolio projects.

The Optimal DER Portfolio DG projects yield slightly varying amounts of reactive capacity in this sense during the year. On a time-weighted average basis, and again assigning the benefit equally to all DG projects in the portfolio, the value of reactive losses for the 2002 Optimal DER Portfolio DG projects is $37.94/kW.

Determined based on the avoided cost of incremental reactive capacity, this is a one-time value.

2.4.3.3. 2002 Optimal DER Portfolio – Capacity Value

Because California does not have a functioning capacity market, the dollar value of capacity is not transparently visible. The value of capacity is a function of need or shortage, it varies seasonally, and it varies by location. One value for capacity – perhaps the highest, applied to capacity that is needed, located in a load center, and is available when needed with few limitations – is the avoided cost of a combustion turbine, about $500/kW, or about $81/kWyr if annualized using a 10-year 10% present value factor.

As noted earlier, the capacity associated with the Optimal DER Portfolio is located directly in the SVP load center. The capacity associated with the DG projects is available continuously. The capacity associated with the DR projects is available on much more limited basis, but under our assumptions can be dispatched on demand and thus can be called when it is of greatest value.

The valuation of capacity as distinct from energy is a function of the supply and demand of capacity resources having the reliable capability to deliver energy in the location and during the time period specified. The load shape, pool of available resources, cost of new resources, and the revenue opportunity for capacity resources in other (non-capacity) markets are characteristic of a given region. However, the value of capacity in one region is probably sufficiently similar to its value in another region to warrant the use of non region-specific prices in an illustration.

New York ISO Monthly UCAP auction results[14] showed the following capacity values for the 2001-2 year:

Table 48 New York ISO Monthly UCAP auction results 2001-2

	Summer Highest	Summer Avg	Winter Avg
NYC	$9.38/kWmo	$5.83/kWmo	$7.28/kWmo
Rest of State	$0.89/kWmo	$0.44/kWmo	$0.54/kWmo
Avg	$5.14/kWmo	$3.14/kWmo	$3.91/kWmo

These auction results illustrate both the seasonal and locational nature of capacity values. Capacity deliverable in New York City is far more valuable than capacity deliverable in the rest of the state only, and capacity is more valuable during the highest summer month than it is during the remaining summer months or the winter months.

As an illustration, if we use the seasonal values above, averaged between NYC and ROS, as values for capacity, we can value the Optimal DER Portfolio capacity as shown in Table 49 and Table 50. We have associated the highest summer capacity value with the Optimal DER Portfolio's Summer Peak capability, the summer average with the Knee Peak capability, and the winter average with the Winter Peak capability. We have attributed no dollar value to the capacity capability of the portfolio under minimum load conditions. Again, benefits are allocated equally across all projects.

[14] New York ISO, http://www.nyiso.com/markets/icapinfo.html.

Table 49 Capacity Value ($/year) – DG Projects

	Summer Peak	Summer Season	Winter Season
Projects	317	316	318
Capacity (MW)	54.89	54.58	54.76
Loss Red (MW)	5.439	5.308	3.481
Total Capacity (MW)	60.329	59.888	58.241
Capacity Value	$5.14/kWmo	$3.14/kWmo	$3.91/kWmo
Portfolio/season	$310,091	$940, 242	$1,366,334
Per kW	$5.65	$17.23	$24.95

These seasonal values are additive. The DG projects in the Optimal DER Portfolio that are specified to operate year-round provide capacity worth approximately $48/kWyr.

Table 50 Capacity Value ($/year) – DR Projects

	Summer Peak	Summer Season	Winter Season
Projects	389	388	389
Capacity (MW)	10.52	3.65	3.56
Loss Red (MW)	1.279	.455	.551
Total Capacity (MW)	11.799	4.105	4.111
Capacity Value	$5.14/kWmo	$3.14/kWmo	$3.91/kWmo
Portfolio/season	$310,091	$64,448	$96,444
Per kW	$5.76	$17.66	$27.09

Again, these seasonal values are additive. Also, the per-kW capacity value is lower for the summer peak because we have assumed that individual DR projects have greater capability during highest-load-hour summer peak conditions. Accordingly, a DR project specified, based on its location, with a normal capability of 1 kW during winter and summer seasons and a 3 kW capability under highest-load-hour Summer Peak conditions would have a capacity value of a little over $60/kWyr

As with losses, it is evident that capacity may have value in periods other than the summer peak, and the capacity value of the Optimal DER Portfolio projects during those alternative periods makes a meaningful contribution to the economic value these projects represent.

2.4.3.4. 2005 Optimal DER Portfolio – P Losses

To value avoided losses for the 2005 Optimal DER Portfolio, we used a forecast of 2005 hourly energy prices prepared for this project by the Energy Commission[15] based on a scaling of the monthly price forecast prepared for the 2003 IEPR using MarketSym, scaled to hourly based on 1999 PX hourly prices.

[15] Joel Klein, 2004

As with the 2002 prices, in using these prices we considered May through October as the "Summer" season and the period Monday through Saturday, HE (hour ending) 0700 through HE 2200 as the "peak" period. We did not adjust for holidays.

The average price from the forecast for the top 1% highest-priced Summer season hours was $129.50/MWh. The average price for the remaining Summer season peak hours was $34.10/MWh. The average price for the Winter season peak hours was $39.90/MWh. The average price for the off-peak hours was $25.50/MWh.

This price for energy in the top 1% highest-priced Summer season hours is about 60% higher than the comparable 2002 price. The prices for energy in the remaining Summer season peak hours and the Winter season peak hours are about 20% higher than the comparable 2002 prices, and the price for energy during off-peak hours is about the same as the comparable 2002 price.

As shown above, the 2002 Optimal DER Portfolio yields loss benefits during all seasonal conditions. Based on the 2002 results, including the assumption of a similar degree of DG project operating flexibility, we can project that the real power loss benefits of the 2005 Optimal DER Portfolio would be about the same in the summer season as under peak conditions, 65% of the peak value during the winter peak, and about 40% of the peak value during off-peak conditions. With this extrapolation and the hourly forecast price set we can project seasonal and annual values for the real power loss benefits of the DG projects in the 2005 Optimal DER Portfolio:

Table 51 Loss Reduction Value ($ per year) – DG Projects

	Summer Super-Peak	Summer Season Peak	Winter Season Peak	Off-Peak	Year
DG Portfolio	$75,566	$558,049	$428,339	$256,305	$1,318,260
Per kW	$1.13	$8.37	$6.43	$3.84	$19.78

The values are higher than the loss values for the 2002 Optimal DER Portfolio DG projects because there are greater loss benefits (in MW) and the value of the avoided replacement energy is higher.

Again, these seasonal values area additive, and the full annual value would be attributable to projects specified to operate year-round.

With the 2005 DG projects, the higher forecast values for Summer season energy increase the importance of loss reduction during the Summer Super-peak and summer season. However, as with the 2002 Optimal DER Portfolio, there is a meaningful loss reduction value for the 2005 projects for off-peak hours because these hours represent a large share of the year.

2.4.3.5. 2005 Optimal DER Portfolio – Q Consumption Reduction

Reduced reactive power consumption represents reactive capacity that otherwise would have to be injected into the system. As noted above, Shugar, et. al, in 1990 assigned a value of $41/kVAR for avoided reactive power losses based on the equivalent cost of shunt capacitance on the feeder. We used this to value the reduction in reactive power consumption of the 2005 Optimal DER Portfolio projects as with the 2002 projects.

Based on the 2002 results, it is reasonable to expect that the 2005 Optimal DER Portfolio DG projects yield reactive capacity benefits through the year. Thus, we have attributed the same $37.94/kW value for the Q loss reduction of these projects.

2.4.3.6. 2005 Optimal DER Portfolio – Capacity

The New York ISO Monthly UCAP auction results referred to above show the following capacity values[16] for the 2004 summer and 2004-5 winter. These show a similar pattern to the 2001-2 values but reflect the fact that capacity is becoming more valuable in the ROS locality.

Table 52 The New York ISO Monthly UCAP Auction Results 2004 Summer And 2004-5 Winter

	Summer Highest	Summer Avg	Winter Avg
NYC	$11.29/kWmo	$11.23/kWmo	$7.02/kWmo
Rest of State	$1.65/kWmo	$1.39/kWmo	$0.60/kWmo
Avg	$6.47/kWmo	$6.31/kWmo	$3.81/kWmo

Compared to the 2002 values, the Summer Highest capacity value is about 26% higher, the Summer Average is about 100% higher , and the Winter Average is approximately unchanged.

Extrapolating using the 2002 results, we can assume that the 2005 Optimal DER Portfolio DG projects represent the same installed capacity in each season. Using the associated losses projected as described above, we can project the dollar capacity value associated with the 2005 portfolio DG projects using these prices:

Table 53 Capacity Value ($/year) – DG Projects

	Summer Peak	Summer Season	Winter Season
Capacity (MW)	66.66	66.66	66.66
Loss Red (MW)	6.708	6.708	4.360
Total Capacity (MW)	73.368	73.368	71.020
Capacity Value	$6.47/kWmo	$6.31/kWmo	$3.81/kWmo
Portfolio/season	$474,691	$2,314,760	$1,623,517
Per kW	$7.12	$34.72	$24.36

The increased dollar value associated with the Summer Season capacity is evident.

If we assume that, as with the 2002 Optimal DER Portfolio, the DR projects represent about three times the capability during the Summer Peak as they do during the balance of the year and a comparably-scaled level of loss reduction under each season's conditions, we can extrapolate the capacity value of the DR projects:

[16] New York ISO, http://www.nyiso.com/markets/icapinfo.html.

Table 54 Capacity Value ($/year) – DR Projects

	Summer Peak	Summer Season	Winter Season
Capacity (MW)	25.53	8.51	8.51
Loss Red (MW)	5.079	1.693	1.693
Total Capacity (MW)	30.609	10.203	10.203
Capacity Value	$6.47/kWmo	$6.31/kWmo	$3.81/kWmo
Portfolio/season	$198,040	$321,905	$233,241
Per kW	$7.76	$37.83	$27.41

2.4.4. Conclusions

In this section we have proposed a set of metrics for network benefits:

- Local system P and Q loss reduction
- Regional System P and Q loss reduction
- Voltage profile improvement (overall level, low and high-voltage buses, voltage variability)
- P Stress reduction (overall level, high buses, variability)
- Increased load-serving capability under contingency conditions
- Capacity value

In Section 2.3 we showed how developing alternative configurations of DER additions under different network operating conditions allows us to characterize Optimal DER Portfolios for 2002 and 2005 conditions with an operating profile mirroring the range of conditions seen over a year. The Optimal DER Portfolios described in Section 2.3 constitute demand response at nearly every medium and large customer site, but with a limited number of customers capable of providing greater percentage reductions in their demand, and additional demand reduction levels available during the 1% highest-load summer hours. However, these DR projects are also specified for dispatch at different levels at specific locations under different network conditions to gain the maximum network performance benefit.

These portfolios also include onsite generation at specific customer sites, subject to individual project and feeder-level limits. As with the DR projects, these DG projects are dispatched at different real and reactive power output levels at specific locations under different network conditions to gain the maximum network performance benefits.

In this section we have demonstrated how we can extend that analysis to determine what network performance improvements we can expect from these projects over a year's range of conditions, in addition to the Summer Peak conditions.

We have shown that if these DER portfolio projects are operated on a seasonally-varying basis as described in Section 2.3, they yield performance benefits under network conditions ranging from the highest load hour to the minimum load hour, and encompassing summer and winter conditions in-between. We found that for this power delivery network, these benefits are not limited to summer peak conditions; in fact, the contributions are nearly as significant under all conditions.

We have demonstrated that part of the P loss reduction is due to an improvement in system efficiency.

We have characterized the network benefits achieved from the DR projects separate from the DG projects. We have also shown that for this system, under some seasonal conditions a greater share of the overall benefits achieved may be attributed to those projects having rankings in the top 1/3 of the portfolio.

We have also demonstrated how this approach can be used to perform a direct comparison of the potential network benefits of transmission projects, a relatively large transmission-connected generation project, and a portfolio of ideally-placed DER projects. We concluded that the Optimal DER Portfolio's operating flexibility and precise placement of resources where they are needed provides the potential for significant network performance improvement compared to these other measures.

We have demonstrated the valuation of these network benefits in economic terms. We valued avoided real power losses using the prices of replacement energy. For the 2002 portfolio's benefits we used actual historical prices corresponding to the to the seasonal actual load conditions we evaluated. For the 2005 portfolio's benefits we used a forecast of prices that would correspond with the forecast load conditions.

We valued avoided reactive power consumption using a value for the replacement cost of reactive power. We illustrated the valuation of the capacity associated with the Optimal DER Portfolios using prices from a region with a transparently-priced capacity market.

As with the engineering characterization of network benefits, we see economic value for the Optimal DER Portfolio projects in all seasons and under all conditions; the economic value of these network benefits is not limited to a few hours during the year.

We showed how Optimal DER Portfolio projects can improve the load-serving capability of the subject network under contingency conditions. We also that where network improvements have been identified to achieve needed increases in load-serving capability, the avoided costs of these improvements are economic values associated with the DER projects.

Finally, we have demonstrated that one of the most significant benefits of an ideally-placed and flexibly-operated portfolio of DER projects is the improvement in voltage profile and reduced system stress, and the ability to achieve those improvements under a variety of operating conditions. "Improvement in voltage profile" is not a benefit whose economic value is presently easily assessed. However, it has benefits that may include improved power quality, possibly reduced instances of outages, extended equipment life, and improved customer satisfaction. Ultimately these benefits have economic value, and it may be significant.

2.5. Identification of Barriers to Siting of Optimal DER Portfolio Projects

2.5.1. Approach

Knowing the location, size, and operating profile of DER projects that provide network benefits allows us to determine what their siting requirements would be, and to assess whether there are notable barriers to the installation of these projects. It follows that barriers so identified are the most impactful barriers to the most beneficial projects in terms of network benefits. That is the focus of the work described in this Section.

The Optimal DER Portfolio projects for this power delivery network include demand response (DR) and distributed generation projects. We have assumed that there are not regulatory barriers to speak of for demand response projects, and our focus here is on the distributed generation projects.

To evaluate siting requirements and assess barriers, we focused on the 133 highest-ranked (most valuable) generation projects identified for Summer 2002 conditions. These specific projects, their interconnection bus, size, and seasonal operating profile are listed by location in Appendix 2.5-1. This listing also includes information about the host customer, including the customer's class and peak load.

These projects range in size from 7 kW to 1.3 MW, with an average size of about 155 kW. All would interconnect with the network at the distribution level, at 12kV.

In general, the specified operating profile of these projects is a high operation factor. Most (86 projects) would operate year-round, with 16 of those operating at less than a 100% operating factor. The remainder would operate seasonally.

As indicated in Section 2.2, we have assumed for purposes of this study that generation capacity additions have the electrical attributes of synchronous generators. A reasonable variant on this approach would be to consider other types of real power generation sources.

As indicated in Section 2.3, we have assumed for purposes of this study that Optimal DER Portfolio generation projects are natural gas-fired reciprocating engine projects. This assumption is consistent with the attributes for Optimal DER Portfolio generation projects specified above—that is, the capability of high operating factors and the electrical characteristics of synchronous generator capacity sources. Additional results of this assumption are that these units can be fueled (and therefore sited and operated) nearly everywhere; and, as these units offer a great deal of operational flexibility, we are able to define operating profiles based on system conditions rather than operating limitations.

Again, a reasonable variant on this approach would be to consider other types of prime movers. First, a separate analysis may indicate instances where projects in the needed locations with the needed size and operating attributes could in fact be operated on alternative fuels or use non-conventional-fueled prime movers. Moreover, we could use results of the type developed in Section 2.3 to determine those locations where the ideal operating profile of a generation unit is suited to a prime-mover other than a natural gas reciprocating engine. We could also separately determine the locations and attributes of potential renewable projects, then build the Optimal DER Portfolio as demonstrated in this study anticipating the inclusion of those projects first.

The primary reason our assumption that Optimal DER Portfolio generation units were natural gas reciprocating engines was that we felt this would be the most limiting in terms of siting requirements, and would be the most revealing in terms of barriers.

To help project participants visualize a "typical" project of the type we were describing, we identified several manufacturers and models of natural gas reciprocating engines in the 130kW to 150kW size range.

We considered in detail one model, the Kohler 135RZDB. According to information on the packager's website, this unit is rated for up to 130 kW for prime power applications. The prime mover is a Detroit Diesel 260 bhp natural gas-fired lean-burn engine. The generator set has exterior dimensions of about 10′L x 4.2′W x 6.6′H, or roughly the footprint of a small car. The unit is available with exhaust silencers for "critical" or "residential" applications. The manufacturer does not specify whether the engine is certified to meet CARB 2003 emissions standards or the interconnection equipment is certified to meet Rule 21 interconnection standards.

The Kohler® 180RZDB, rated at 160 kW for prime power, is similar, with a 300 bhp Detroit Diesel® engine and slightly larger generator set exterior dimensions of about 11.2′L x 4.2′W x 6.6′H.

Again, this choice is arbitrary. For our purposes, we could have just as easily considered units offered by Cummins®, Caterpillar®, Generac®, or others. [17]

Of the host customers of these Optimal DER Portfolio generation projects listed in Appendix 2.5-1, 7 are small customers (< 200 kVA), 67 are medium customers (200 – 1,000 kVA), and 59 are large customers (> 1,000 kVA).

Using information provided by SVP, we determined the street location of the network bus associated with each of these generation projects. That information was used in our analysis but is not presented here because it includes potentially customer-identifiable information.

For these projects, we surveyed the interconnection requirements that would apply in SVP given their size and interconnection voltage.

We also reviewed the environmental siting requirements that would apply to these projects given their location, size, and operating profile. We also reviewed land use and zoning requirements for and policies affecting these projects based on their location and other factors.

To provide an interesting point of reference, we also reviewed the AQMD 2001 Backup Generator (BUGS) Inventory to determine the extent to which generation units are already installed in locations identified for Optimal DER Portfolio generation projects.

We also developed a questionnaire on DG best practices, which we distributed to industry participants, to assess project experiences and barriers. This questionnaire is provided as Appendix 2.5-2. To expand participation, we solicited contact information from interested parties at the California Alliance for Distributed Energy Resources (CADER) conference in January 2004. A copy of this handout is provided as Appendix 2.5-3.

Having gathered this information, we performed an assessment of the feasibility of siting the Optimal DER Portfolio generation projects listed in Appendix 2.5-1. We also evaluated the interconnection, environmental, and land use requirements for inconsistencies and barriers to successful siting of these projects.

[17] Kohler, Detroit Diesel, Cummins, Caterpillar, and Generac are trademarks of those companies.

2.5.2. Analytical Results

2.5.2.1. Interconnection Requirements

In an effort to streamline the interconnection of distributed generation, particularly those meeting specified criteria for "simplified interconnection," the State of California has adopted standard practices for the interconnection of DER into the distribution systems of the state's investor-owned utilities (IOUs). The California Public Utilities Commission (CPUC) implemented Rule 21, which specifies interconnection, operating, and metering standards for DER resources. The state's three IOUs have revised their former Rule 21 with versions that comply with these standards.

Perhaps the most important feature of Rule 21 is that generators meeting the criteria for "simplified interconnection" do not require interconnection studies and are not responsible for system upgrades. This can significantly reduce the cost and timeframe for interconnection.

In general, under Rule 21 a unit will qualify for simplified interconnection if the interconnection equipment is pre-certified under Rule 21, the generator will not export power, and the generating capacity is small compared to the feeder's peak load.

The constraints described in Section 2.2 that we placed on Optimal DER Portfolio generation projects are intended to avoid the potential for adverse, unanalyzed system impacts. Under our constraints Optimal DER Portfolio generation projects are limited to offsetting the adjacent load and the total generation on a feeder is limited to a share of feeder load. In developing the list of generation projects, we applied as a feeder limit the feeder load under minimum load conditions, rather than the Rule 21 limit of 15% of the feeder's peak load. The limit we used is more permissive than the Rule 21 limit, but it still ensures no export.

We believe the group of generation projects for which we are evaluating siting requirements – the highest-ranked generation projects in the 2002 Optimal DER Portfolio – would very likely be eligible for simplified interconnection under Rule 21 if it applied. Because the 2002 Optimal DER Portfolio was developed using the Light Load feeder non-export limit, lower-ranked – but still beneficial – generation projects, if given a lower siting priority, could exceed Rule 21's 15%-of-feeder-peak limit and thus run a greater risk of being subjected to more costly or time consuming interconnection process.

Rule 21 applies only to the three IOUs of the state; Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. Several municipal utilities in the state have implemented interconnection regulations similar to Rule 21. Silicon Valley Power has drafted interconnection regulations similar to Rule 21, but these regulations had not yet been finalized or implemented as of the time of this research.

One feature of SVP's proposed interconnection regulations is that it provides simplified interconnection for "Residential or Small Commercial Net Energy Metering Customers with Solar or Wind Generating Facilities of 10 Kilowatts or Less." It is likely that few if any of the Optimal DER Portfolio generation projects would qualify under this category even if they were wind or solar projects, both by virtue of the projects' sizes and by virtue of the size of the host customers, which are generally primary distribution customers.

The Federal Energy Regulatory Commission (FERC) has proposed Small Generator Interconnection Procedures (SGIP), also to facilitate the interconnection of distributed generation. FERC has proposed amending the Federal Power Act to require utilities to modify their transmission tariffs to incorporate these procedures. However, the FERC's authority extends only to transmission systems engaged in interstate commerce, not distribution systems, and/or only interconnections involved in interstate commerce. Because the 133 highest-ranked Optimal DER Portfolio generation projects we consider here are all distribution-connected, non-exporting, the FERC SGIP would not apply.

2.5.2.2. Environmental Permitting Requirements

Due to their size, all of the Optimal DER Portfolio generation projects would be subject to local (city or county) siting jurisdiction. As projects of under 50 MW, none of these projects falls within the siting jurisdiction of the California Energy Commission.

Local siting would review these electric power generation facilities for consistency with land use requirements, and, in many cases, compliance with the California Environmental Quality Act, or CEQA (see below). The local agency is also responsible for ensuring that the projects adhere to applicable state and local building codes.

We determined that based on their street addresses, all of the Optimal DER Portfolio generation projects identified lie in districts zoned Industrial or Commercial within the municipal boundaries of the City of Santa Clara. To site these projects, the City of Santa Clara would first have to make a determination on whether the proposed use – electric power generation, is a permitted use, a conditional use, a prohibited use, or not designated for the applicable zoning designation.

Our understanding – and a key finding – is that none of the land use zones within the City of Santa Clara identifies electrical power generation *per se* as a permitted use (that is, a use that does not require issuance of a conditional use permit). In Santa Clara's Heavy Industrial zones, "public utility" uses, having presumably similar impacts, are permitted uses, and the planning commission has fairly broad latitude to find other uses as permitted uses. Also, Santa Clara's Heavy Industrial, Light Industrial, and Planned Industrial zones all allow as permitted uses "accessory uses necessary for an existing permitted use," while in some zones applying to space limitations and screening requirements.[18]

Thus, for Optimal DER Portfolio generation projects located in these industrial zones, there is the chance that the projects could be found to be a permitted use if they are viewed by city planners as having similar impacts to public utility uses or necessary for an existing permitted use. In every other case, city approval, in the form a conditional use permit, would be required. This, in turn, would trigger review of the project under CEQA (see below), with the city serving as the lead reviewing agency.

The applicable zoning designation also includes the relevant requirements for noise and aesthetics. In general, power generation facilities in Industrial and Commercial zoned areas are more compatible with existing land uses and subjected to less restrictive noise and aesthetic requirements than they would in be, say, Residential zoned areas. The City of Santa Clara's zoning ordinance is relatively open to interpretation; e.g., it does not specify what noise levels or visual impacts are "objectionable or detrimental to adjacent properties." However, according to the City of Santa Clara's general plan, noise levels of 70 dBA Ldn and 65 dBA Ldn are

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[18] Santa Clara City Code Title 18, Chapters 18.46, 18.48, 18.50.

"compatible" with industrial and commercial uses, respectively.[19] These levels should not create a significant problem for power generation equipment. Also, the units we are considering here are small enough to be located behind walls or enclosures or in buildings.

According to the AQMD BUGS Inventory there were in 2001 44 onsite (backup) power generation units *already* installed and operational in Santa Clara. These generation units range in size from 300 kW to 2,500 kW and average 835 kW. Most of these (all but five) are on streets served by feeders we modeled in detail in this study. Moreover, 18 of these generation units are actually already located at the locations of Optimal DER Portfolio generation projects listed in Appendix 2.5-1.

Air Permits

In 2001, as a result of the passage of Senate Bill 1298, the California Air Resources Board (CARB) implemented an order establishing a certification program for distributed generation units that are otherwise exempt from local air district permitting, and established guidelines for air districts for the permitting of electrical generating technologies (CARB, 2002). Under the certification program, a manufacturer whose units are demonstrated as meeting specified emissions rates on a lb/MWh basis are certified for use in California.

This program was intended to streamline air permitting for small generation projects meeting its stringent emissions standards. If a generation project uses equipment certified for low emissions under the CARB program and is small enough that it is not subject to local air district jurisdiction no air permit is required. Where it applies, this is a significant benefit, both because of the avoided project-specific Best Available Control Technology showing and also because the issuance of an air permit triggers review under CEQA.

Because the CARB DG certification program, now that it is in place, requires that all distributed generation units installed in the state meet the applicable emission standards, it is reasonable to assume that all the Optimal DER Portfolio generation projects would meet these standards. Based on conversations with vendors, we also believe that equipment capable of meeting the 2003 CARB standards is generally available, even though the units we identified for illustration purposes are not listed as certified on the CARB website.

However, the jurisdiction of the Bay Area Air Quality Management District, the local air permitting district for the Optimal DER Portfolio generation projects due to their location in Santa Clara, extends to projects of 50 hp or greater, or roughly 35 kW. Therefore – and a key finding – essentially all of the Optimal DER Portfolio generation projects remain subject to case-by-case demonstrations of the use of Best Available Control Technology (BACT) and issuance of an air permit by the BAAQMD. The CARB emissions standards would serve as "guidance" for BACT emission levels, but even a project using a CARB-certified engine must still go through the air district's BACT determination process. Further, the issuance of an air permit by BAAQMD is a discretionary government agency action that would also subject the Optimal

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[19] City of Santa Clara 200-2010 General Plan, Chapter 5 (Environmental Element). http://www.ci.santa-clara.ca.us/pdf/collateral/3081-GeneralPlan-Chapter5.pdf. "dB Ldn" is the day-night average sound level at the property line with 10 dB added to measured readings for the hours 10 PM to 7AM to account for night time sensitivity.

DER Portfolio generation project to review under CEQA (see below), with the BAAQMD serving as the lead reviewing agency.

The CARB certification program also limits the use of Continuous Emissions Monitoring Systems (CEMS) for NOx, CO, and VOC to units larger than 2.9 MW and NOx only to units rated at 1,000 hp or more and operated at more than two million bhp-hr per calendar year (this is equivalent to a generation unit of approximately 745 kW or more with an operation factor of 22% or more). Accordingly, many Optimal DER Portfolio generation projects would not be required to install CEMS by virtue of their size if BAAQMD were to follow the CARB guidance. This is a benefit as CEMS systems can be prohibitively expensive for small projects.

CEQA

In the event that a state, regional, or local agency must grant discretionary approval for a power generation facility, such as rezoning or the issuance of a conditional use permit, or the issuance of an air permit, that decision and the related project is subject to review under CEQA.

A cogeneration project under 50 MW may qualify for a categorical exemption from CEQA under Article 19 Section 15329 if it meets certain emissions, noise, and other criteria. Optimal DER Portfolio generation projects may qualify for other categorical exemptions, depending on the each project's characteristics.

CEQA review consists of an Initial Study, which assesses the project's impacts relative to a variety of environmental factors. In general, power generation projects at existing industrial or commercial facilities will not involve significant impacts in most categories; the most likely areas of impact would be aesthetics, noise, air quality, and land use/planning.

Based on the Initial Study and the project's anticipated level of impact on the environment, the local agency will generally determine that:

a. there are no significant environmental impacts and issue a Negative Declaration;

b. there are significant environmental impacts that can be mitigated to less than significant levels, and direct the preparation of a Mitigated Negative Declaration (MND); or

c. there are significant environmental impacts that cannot be mitigated to less than significant levels, and direct the preparation of an Environmental Impact Report (EIR).

A study prepared by the California Energy Commission in 2000[20] found that in the limited sample available, most onsite generation projects had been reviewed under CEQA, due to the need for a conditional use permit. Further, most reviews involved the preparation of an MND, and none involved an EIR. If it is required, an EIR requires a much longer review timeframe.

CEQA also requires the consideration of cumulative impacts. In other words, the reviewing agency may consider impacts of projects or activities other than those of the applicant or the

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[20] Mignon Marks, "Distributed Generation: CEQA Review and Permit Streamlining;" December, 2000; P700-00-019; http://www.energy.ca.gov/reports/2000-12-21_700-00-019.PDF

applicant's project. One type of cumulative impact might be the emissions of several on-site power projects in an industrial area. However, because of the small size of most of the Optimal DER Portfolio generation projects, their emissions impacts will be fairly localized, and may not result in significant cumulative impacts.

2.5.2.3. Siting Assessment

We know from prior analyses that the Optimal DER Portfolio generation projects for this power delivery network lie in specific locations, are of a certain size range, and have specific operating profiles. We have determined that all are located in industrial or commercial zoned districts within the city of Santa Clara. We have also determined that at some of the locations identified Optimal DER Portfolio generation projects there are comparably-sized backup generation projects already installed.

As noted above, we presume that Optimal DER Portfolio generation projects use equipment that can meet CARB 2003 DG emissions standards. We also presume that these projects use interconnection equipment certified under Rule 21. We also presume these projects can meet applicable noise and visual screening requirements.

We can project the following for Optimal DER Portfolio generation based on this limited analysis:

1. Most projects will require, but can receive, an air permit from the BAAQMD.
2. Some projects may be considered permitted uses, but most will require a conditional use permit with attendant notice and hearing requirements. In general, most or all projects should be able to meet the requirements imposed by local zoning.
3. Most projects will require review under CEQA leading to an MND. An EIR is not likely to be required.
4. If SVP adopts rules similar to Rule 21, and accepts Rule 21 equipment certification, most projects will not require detailed system studies or incur costs for system upgrades.

Based on this, it is fair to conclude that the Optimal DER Portfolio generation projects can be sited in the sizes and locations specified, and operated with the operating profiles specified. However, real barriers remain; these are discussed more thoroughly below.

2.5.2.4. Barriers

Anecdotal Barriers

The following is a list of barriers to the type of generation projects of the Optimal DER Portfolio identified in one or more anecdotal examples by members of the DER industry, staff at an interviewed planning department, or from a member of a DER committee of a local government during our research:

The building identified as an optimal site under the "Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energynet" is under ownership/management of a party who is unaware of the deployment of this technology. The barrier is that the building owner has little sense of this opportunity and if they are interested in on-site generation would not know how to choose among the different types of on site power production.

This person (the decision-maker) is not prepared to purchase or lease the generation equipment and go through the steps to have the equipment approved and installed. The barrier is that the industry has not yet marketed to this sector and explained the value of the equipment to this customer.

This decision-maker and the vendor providing the equipment have very low levels of certainty regarding the cost-effectiveness of the equipment, and approval of the system and equipment. The value proposition is "iffy" and approval process is likely to be complicated and not straight -forward. This market has too any unknowns and hidden costs and each project has characteristics of a "demonstration" program – thus maybe not be worthy of the limited time to invest in developing the market or procedures which govern applicants.

The agencies responsible for approval, poorly understand the equipment requested and therefore move slowly to expedite. The barriers include lack of information on the equipment and lack of time to understand the technologies and the relative impacts. The impacts and the environmental conditions associated with the permitting of the equipment are poorly understood.

Local governments as the lead agency when asked to approve the siting of the DER equipment (as well as the utility for the inter-connection) lack a single point of information for assistance.

The local government, generally under-staffed to undertake the development of these procedures and faced with the request to approve the DER equipment, responds to such requests with one of the following responses:

- Permitted – the equipment and its impact is well known, understood and can be approved in a uniform manner and in a predicable amount of time and cost.
- Conditional – the equipment would be approved if the applicant were able to demonstrate to the jurisdiction and approving agencies that the equipment meets certain provisions including air quality, noise, odor, storage of materials and appearance.
- Not allowed.
- Subject to delay
- Subject to requests for special studies

Barriers Specific to the City of Santa Clara

The Optimal DER Portfolio generation projects, located in Santa Clara, share some of the same barriers to development that have been identified for DER projects in other locations. However, Santa Clara also presents certain barriers that are more area-specific. As noted elsewhere, DER projects in Santa Clara would interconnect with the Silicon Valley Power (SVP) system rather than to one of the state's IOU systems. SVP is not subject to the same provisions as the IOUs, such as Rule 21 and the Self Generation Incentive Program (described in Section 2.6). SVP is in the process of implementing regulations similar to Rule 21, but it does not offer the same incentive programs as required for the IOUs. SVP's electricity prices are also generally lower than the IOUs, and reliability on the SVP system is higher than the IOUs (Owens, 2004). Less financial incentives, higher reliability, and lower energy prices tend to make DER somewhat less attractive in Santa Clara than in other areas of the state.

Additionally, Santa Clara is located within the jurisdictional area of the BAAQMD, which has some of the most strict air quality permitting requirements in the state, and which has established jurisdiction to projects small enough to include most of the Optimal DER Portfolio generation projects. Although not unique to Santa Clara, Santa Clara Planning Department Staff have stated that they have not seen any DER projects come in to their department for permitting other than solar (Riley, 2004). This lack of experience can cause delays in the process; however, the lack of experience at the Planning Department is somewhat offset by the fact that the City has its own utility staff (SVP) with experience in power generation and transmission issues.

Some of the themes in the two sections above are repeated in the discussion of additional barriers below.

Local Land Use Policies do not Address DER

One of the barriers identified by the CEC (CEC, 2000) is that local land use policies do not specifically address DER projects. If land use planners receive little or no guidance from their existing policies on how to handle DER projects, they must apply judgment to assess the impacts of a given project, and apply interpretations to existing policies to determine whether a project is a permitted use, an accessory use, a conditional use, or a prohibited use.

Noted above as a key finding, we found that this was exactly the case with the land use policies that would apply to the Optimal DER Portfolio generation projects in the City of Santa Clara. Clearly small onsite power generation projects were not specifically identified as either permitted or conditional uses. Conceivably these projects could be classified as either permitted or conditional uses, but the planning staff would have to apply judgment to reach that conclusion.

Based on our research, now taken place four years after the CEC's comprehensive study, we find still that relatively few California cities have reported that they have adopted policies that aid the applicant in the approval process for small scale distributed generation (including those in the size of the 130 KW to 150 kW range). For those that have adopted DER policies and procedures, each city appears to have written policies along lines that reflect local input, but with little degree of support by information sharing and the broader DER industry.

To the extent that cities have adopted DER policies, these generally are a broad statement of support for solar energy. Few deal with or address on-site natural gas generation in the arrangement contemplated by the Optimal DER Portfolio.

Based on our research, few cities have achieved a point in which they have made the process for the approval of DER "user –friendly " in terms that would be needed to achieve the penetration of DER postulated here. Only a few have clearly stated procedures at the building counter, making the requirements equivalent to other types of equipment with respect to noise and visual impact, and helping the applicant save time and money in finding out about requirements, time between application, review and inspections.

Lack of Familiarity at the Local Level

Another of the barriers to distributed generation projects that was identified by the CEC (CEC, 2000) is that local planning staffers may not be familiar with onsite generation projects and technologies. Where this is the case, it compounds the prior barrier. Where planners are unfamiliar with distributed generation technologies, they may not be as well equipped to assess the impacts of a given generation project, or even to determine what information they need to make such an assessment, as they would be for another project involving industrial equipment.

Statewide financial incentive programs for distributed generation have precipitated a standard set of filing requirements, some of which must be submitted at various points in the local permitting process. These standard filing requirements could contribute to consistency across jurisdictions and facilitate permitting of onsite generation plants of the type in the Optimal DER Portfolio. However, our research found that most local agencies have not been informed or educated on these requirements or provided with relevant literature; thus, they are ill-equipped to provide information to applicants, process these forms, or efficiently integrate these filings with their own requirements. One notable exception is the San Diego Regional Energy Office, which administers statewide incentive programs at the local level.

Air Permit Requirements

Noted above as a key finding, even Optimal DER Portfolio generation projects using equipment capable of meeting (or certificated to meet) emissions standards established by CARB would likely be subjected to the local BAAQMD process for issuance of an air permit. In this respect, the CARB DG emissions certification program has been incompletely successful in streamlining the permit process for distributed generation projects that meet the CARB standards, and this would directly affect the siting of Optimal DER Portfolio generation projects.

CEQA Review

As noted above, an Optimal DER Portfolio generation project may be subject to review under CEQA either due to the need for a conditional use permit or rezoning, or due to the need for a local district-issued air permit – that is, as a procedural matter rather than based on the anticipated impacts of the project. Therefore, a generation project of this type may be subject to a more costly and time-consuming siting and environmental review process than would another piece of industrial machinery such as a large boiler, compressor, or HVAC system. However, the CEC study found no instance where a full Environmental Impact Report was required for an onsite generation facility (CEC, 2000). The CEC study goes on to observe that the applicant can bypass the Intial Study phase and complete an MND within six months under a state guidelines, and may in fact be exposed to little risk that an EIR requiring a year will be required.

Vendor-Provided Information

The CARB DG emissions certification program and the Rule 21 interconnection equipment certification programs are both intended to encourage standardization for equipment performance and reward it with streamlined siting requirements. However, it appears that few vendors have made the effort (or incurred the expense) to complete these certification processes. In particular, an entity seeking to develop one of the Optimal DER Portfolio generation projects will not find a vendor of a natural gas reciprocating engine in this size range among those listed as certified on the CARB web site[21] or the CEC's Rule 21 web site.[22] As a result, an applicant seeking to permit a generation project of this type must still enter the permit process to determine what performance information is required, approach the vendor directly to obtain that information, and serve as the go-between to ensure all of the needed information is available and sufficient.

Our research also revealed, anecdotally, that the incidence of installation of generation projects in the 130-150kW size range for high operating-factor duty is uncommon, and that units of this size are normally specified for backup service with diesel fuel. This raises the suggestion that the Optimal DER Portfolio generation projects may lie in a class that is underserved by vendors.

2.5.3. Conclusions

We have demonstrated the use of this methodology to make a reasonable assessment of the siting requirements that would apply to the installation of a set of onsite generation projects that would enhance the performance of the SVP power delivery network, and the feasibility of siting that set of projects.

We can fairly conclude that most of these projects would be subject to the issuance of a conditional use permit by the City of Santa Clara, an air permit by the BAAQMD, and review under CEQA leading to a mitigated negative declaration. City of Santa Clara land use regulations do not specify environmental standards for these particular types of projects, so the planning department will have to exercise judgment in evaluating their impacts. Before doing this the staff will have to familiarize themselves with the technologies proposed. With few exceptions these projects would be subject to the full BAAQMD and CEQA processes even if they use CARB-certified equipment. Pre-certification of interconnection equipment under Rule 21 is not of direct benefit for these projects, but there is a good possibility that these projects as presently configured would receive some benefit in terms of simplified interconnection if SVP adopts interconnection rules similar to Rule 21.

We have also demonstrated the ability to use the Optimal DER Portfolio project specification to identify regulatory and institutional barriers that particularly affect this group of beneficial projects. For example, for this power delivery network, its Optimal DER Portfolio generation projects are specified for location in areas where they are likely to be compatible with existing land uses. However, the treatment of onsite power generation facilities in industrial and commercial districts is not specified in Santa Clara's zoning ordinance, and the siting of these projects would require the application of judgment and interpretation on the part of planning staff, who may not be well-acquainted with these technologies or their impacts and have indicted that they have seen few projects of these types. In our judgment, the planning regulations that would apply to these generation projects are more open to interpretation than they would be in communities that have made an specific effort to facilitate onsite power

[21] http://www.arb.ca.gov/energy/dg/dg.htm, downloaded January, 2005.

[22] http://www.energy.ca.gov/distgen/interconnection/certification.html, downloaded January 2005.

generation, and these projects would be subjected to more extensive review than would projects having similar impact but involving other types of industrial equipment.

Also, for this power delivery network, Optimal DER Portfolio generation projects are of a size that subjects them to BAAQMD jurisdiction whether or not they can meet (or are certified to meet) CARB 2003 DG emissions levels; the CARB DG emissions certification program provides only partial streamlining for this set of projects.

Also, Optimal DER Portfolio generation projects would likely qualify for "simplified interconnection," avoiding costly system studies and upgrade costs, under Rule 21 in IOU-jurisdictional networks. However, located in Santa Clara, these projects fall outside Rule 21's applicability, and whether these particular projects would receive these benefits depends on the rules adopted by SVP.

Further, if Optimal DER Portfolio generation projects for this network are to be developed using natural gas reciprocating engine prime movers, they are of a size for which equipment that is pre-certified under CARB and Rule 21 standards is not readily available. Also, this network's Optimal DER Portfolio generation projects are in a size range where high operating-factor/prime power onsite power generation units appear to be rare. Focus among existing vendors industry may be on units that are smaller or larger than those specified for this network's Optimal DER Portfolio.

We also demonstrated that the generation projects identified for the Optimal DER Portfolio are not likely to benefit from certain programs intended to benefit DER. For example, for this system, Optimal DER Portfolio generation projects are not in the size or class that will qualify under SVP's draft "Application for Interconnecting Residential or Small Commercial Net Energy Metering Customers with Solar or Wind Electric Generating Facilities of 10 Kilowatts or Less." Also, the FERC SGIPs are not likely to apply directly to Optimal DER Portfolio generation projects because these projects are largely distribution-connected and non-exporting.

2.6. Incentives

2.6.1. Approach

One of our main focuses was on actions local agencies (cities, towns, and counties) could or do take to promote the development of DER projects generally, or specifically those that provide grid benefits. We met with or gained input from a variety of local agencies, including the City of San Jose, the City of San Diego, the City of Pleasanton, and the City of Santa Clara.

We also developed a questionnaire that was distributed to local agencies to assess existing local policies or practices to promote the development of distributed generation. A copy of this questionnaire was included in Appendix 2.5-2. To expand participation, we solicited contact information from interested parties at the California Alliance for Distributed Energy Resources (CADER) conference in January 2004. A copy of this handout was provided as Appendix 2.5-3.

In addition, we investigated in some detail the policies and procedures of eight cities or agencies that have taken the first step in making consistent an approach to guide the approval of DER. These cities or agencies are:

- Pleasanton, California
- San Jose, California

- Clark County, Nevada
- San Diego, California
- The San Diego Regional Energy Office, California
- Santa Monica, California
- Santa Clara, California
- Air districts, California

In addition to local initiatives, we investigated statewide non-financial initiatives to facilitate deployment of distributed generation, including the CARB emission certification program and Rule 21. We also investigated initiatives of the Federal Energy Regulatory Commission to expedite interconnection of small generation facilities. These are discussed in Section 2.5.

We also reviewed publications of others (CEC, 2000,[23] Starrs and Wenger, 1999[24]) that have identified barriers to and recommended incentives for expanded penetration of DER.

Finally, we performed an assessment of our results for their energy, environmental, and land use policy implications and interplay with other Silicon Valley Manufacturing Group (SVMG) member-driven initiatives.

2.6.2. Analytical Results

2.6.2.1. Existing Local Government Initiatives

In our research, we found that concerns over energy reliability have prompted a few local governments to invest the time to develop and enact policies to facilitate the development of DER as part of the energy supply of the future. However, as noted in the Section 2.5, these policies have been developed apparently without the benefit of support or input from the broader DER industry. We found that few local entities have clearly stated procedures "at the building or planning counters" that make the requirements for electric power generation projects equivalent to other types of equipment with similar noise and visual impacts.

The generation projects we have identified through this methodology for the Optimal DER Portfolio fall within a relatively narrow band of what could be considered distributed generation. Where DER policies have been adopted, we found that they typically are not oriented specifically toward relatively small, high load factor, conventional-fueled generation projects identified for the Optimal DER Portfolio for this network. We actually found that one issue in facilitating the development of these projects involves a mismatch between very ambitious ordinances intended to foster many types of distributed generation projects and the specific needs of the 130-150 kW high operating-factor, conventional fueled projects we have identified in this study and the specific types of customers that would host them.

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[23] Mignon Marks, "Distributed Generation: CEQA Review and Permit Streamlining;" December, 2000; P700-00-019; http://www.energy.ca.gov/reports/2000-12-21_700-00-019.PDF

[24] Starrs & Wenger, "Policies to Support a Distributed Energy System;" May, 1999; http://solstice.crest.org/repp_pubs/articles/pv/3/3.html

For example specific requirements have been adopted in the following communities for the following types of DER projects:

Table 55 DER Projects

Entity		Solar	Wind	Natural Gas/Co-Gen	Fuel cell	Other
Pleasanton		Yes	Yes	Yes	Yes	Yes
San Jose		Yes				
Clark County		Yes	Yes	Yes	Yes	Yes
San Diego						
San Diego Regional Energy Office		Yes	Yes	Yes	Yes	
Santa Monica		Yes				
Santa Clara						Yes

It is evident that some of these DER policies do not address generating projects of the type we have identified for the Optimal DER Portfolio at all, particularly if they are not cogeneration facilities. Further, to yield the anticipated system benefits, this Optimal DER Portfolio contemplates deployment of many projects within a local area. We found that even with entities that have adopted DER policies a large number of such projects would precipitate additional reviews and conditions.

Nonetheless, the requirements established by these local agencies with respect to DER represent the first stage of pro-actively planning for greater DER penetration.

We found that cities are better prepared to review DER projects where they have:

- Enacted a policy in the General Plan that anticipates and invites distributed generation
- Adopted a specific DER Ordinance that anticipates the variety and types of systems and sizes and locations for permitted use
- A clear procedure for the review of conditional use of DER
- An established "punch list" for the review of a DER application
- A process for single point application, well-established internal inter-departmental review and a timeline to complete the initial review by all departments
- A specific form for the applicant to complete for the DER project
- A line for DER in their overview permit application
- Published standards for each criterion

- An established coordination with the Air District for these systems
- CEQA review for a certain threshold number of DER units in the community
- CEQA review for a set of pre-approved systems types
- Become familiar with the technologies and are able to assist the applicant
- Established a goal for a certain amount of DER by a certain date

Some of the local entities we surveyed had adopted specific requirements for DER projects:

Table 56 Specific Requirements for DER Projects

Entity	Air Quality Requirements Defined for Projects	DER Set Backs Defined by Zoning	DER Noise Requirements by Zoning	DER Review Process	DER Size Cut-Offs
Pleasanton	Yes	Yes	Yes	Yes	Yes
San Jose	No			Yes	
Clark County	No	Yes	Yes	Yes	Yes
San Diego	No			Yes	
San Diego Regional Energy Office	No			yes	Yes
Santa Monica	No				
Santa Clara	No				

These elements all help to make information requirements clearer earlier in the process, highlight potential issues early on, and reduce the risk in siting generation projects for project sponsors.

2.6.2.2. Existing State and Local Financial Incentives

An overarching finding in our research is that, not surprisingly, we found no existing financial incentive programs for DER that are designed specifically to promote the deployment of projects in the locations and having the size and operating attributes that enhance power delivery network performance.

We did find that the protocols for financial incentives for DER from state agencies and utilities under state law provide a good pathway for unraveling the "paperwork" in place by which DER project both seek approval and obtain value from financial incentives. Notably, these procedures have been the subject of working groups, utility coordination staff, DER stakeholders, and together present the more advanced characteristics of the DER community success in standardization and simplification of procedures. These standards, now in place, can serve as an example for future adoption of simplified DER approval procedures at the local level.

Existing financial incentives for DER from state agencies and utilities generally fall in to the following categories:

- Financial incentives
- Standby rate waivers
- Net metering
- CRS exemption
- Waived or reduced interconnection process fees

Under California's AB970 and legislation that followed, programs administered by the IOUs and by the California Energy Commission are implemented to provide direct capital cost buydown payments or waivers of payments for self-generation projects. Among the incentives legislated and offered to DER projects are funds for certain types of projects, including micro-turbines operating on non-renewable fuels up to 1.5 MW, cogeneration systems with 60% efficiency as well as funds for PV's.

Another special financial incentive, adopted by the State legislation, provides for waiving and exemptions of standby charges in certain size categories and types of DER projects.

Onsite generation projects of certain sizes and prime mover technologies (typically wind and solar) qualify for net metering. The specific projects we have identified for the Optimal DER Portfolio for this power deliver network would generally not qualify for net metering. However, if some Optimal DER Portfolio generation projects were developed as renewable projects, they could qualify for this benefit.

Additional waivers of payments involve the payments otherwise due under the customer responsibility surcharge (CRS) exemption, with fees charged for "departing load". Some if not all Optimal DER Portfolio projects would be eligible for this exemption.

While it is likely that some of the generation projects identified for the Optimal DER Portfolio would qualify for some share of these incentives, none of these programs is designed for or oriented toward a set of projects whose key attribute is the benefit to network performance these projects provide. At best the eligibility of Optimal DER Portfolio generation projects would be inconsistent.

Also, it is worth noting that while benefits of these programs may well more than cover their costs, payments under these programs are not funded directly from the benefits these projects create.

Further, according to our research, these programs, and their requirements are not well known to local planning staffs "at the counter." Local staffs are not in a position to inform applicants of the existence of these programs or help them determine if their projects may qualify. Also, local procedures are not set up to directly utilize and leverage information applicants must prepare for these statewide programs.

Finally, most of these programs are sponsored by or applicable in IOU service territories. They could apply in instances were this methodology is being applied in those areas. However, they would not apply to the Optimal DER Portfolio generation projects identified in this study as they are located in the service territory of a municipal/non-CPUC jurisdictional utility.

2.6.3. Recommendations for Incentives

2.6.3.1. Non-financial Incentives

This research has revealed that the generation projects identified for the Optimal DER Portfolio face a relatively complex – but not impossible – siting process. We recommend a more straightforward land use and siting application process for onsite power generation projects, with procedures and conditions consistent with non-power generation equipment having similar impacts. For deployment of onsite power generation to become as commonplace as suggested by the Optimal DER Portfolio, procedures for siting these facilities should align with those for more commonplace industrial equipment.

As noted above, procedures and standards developed in connection with statewide DER financial incentives have been developed with extensive DER industry and stakeholder input, and provide a model for streamlined evaluation and siting of large numbers of onsite generation projects. We also view the existing DER policies adopted by cities as the present examples of "best practices." We note further that cities that have adopted DER policies did so expecting a rush of these types of projects. Now, with the number of applications – other than for solar PV – far reduced, this is an excellent time to review these ordinances.

In particular, we found the DER ordinances adopted by the City of Pleasanton, CA, and Clark County, NV, as important steps toward streamlined evaluation and siting of onsite generation projects so as to facilitate the deployment of projects that could enhance power delivery network performance. The City of Pleasanton ordinance, for example, identifies distributed generation projects of under 1,000 kW as "small" electric generator facilities. It also enumerates a set of criteria for allowed fuels, emissions, visual impacts, noise, and odors for these facilities that will ensure that they have minimal impacts. Projects meeting these criteria are classified as "permitted" uses in agricultural, office, commercial, industrial, and institutional districts, and as "conditional" uses in residential districts. Such an ordinance if applicable would treat nearly all of the generating projects identified for the Optimal DER Portfolio as permitted uses provided they meet the environmental criteria, greatly facilitating their siting.

Appendix 2.6-1 includes a model resolution leading to a DER ordinance that could be adopted by local agencies seeking to facilitate the deployment of DER projects of the type identified for the Optimal DER Portfolio at a penetration level that could yield grid benefits. Appendix 2.6-2 provides a copy of the City of Pleasanton ordinance.

In concert, we encourage the DER industry and stakeholders to work to ensure that the footprint and impacts of generation projects that can yield power network benefits are no worse or even better than other types of equipment that is presently accepted as "permitted" uses.

This research shows that pre-certification programs established for Rule 21 and the CARB distributed generation emission program are both under-utilized by vendors, and that benefits of these programs are attenuated for Optimal DER Portfolio generation projects due to the continued applicability of local air permit review.

BAAQMD Regulation 2-3-301 requires a Best Available Control Technology (BACT) demonstration for any source whose emissions could exceed 10 tons per day of a regulated pollutant. Onsite generation projects up to 1,000 kW would be well under that level, with CO likely the controlling pollutant. Accordingly, it seems reasonable to consider exempting projects under 1,000 kW from review by BAAQMD provided they use equipment that has been certified under the CARB program. This would remove one barrier for developers and owners of generation projects. Such a rule change would greatly simplify the permitting of many of the Optimal DER Portfolio generation projects for project owners and developers. It would also provide an added incentive for industry participants to embrace the CARB certification process.

As noted above, CEQA provides for a categorical exemption for certain cogeneration projects. We suggest as well a categorical exemption for generation projects of any type under 1,000 kW that are located in industrial, commercial, or institutional zones, use equipment with CARB emissions certification, and satisfy local requirements for noise and visual impacts. Projects meeting these requirements are very unlikely to have significant environmental impacts, and arguably can be adequately evaluated under the local land use process without the additional burden of the CEQA review.

The results of the analysis described in Section 2.2 also suggest that the Rule 21 15%-of-peak-load feeder limit may be so restrictive that it prevents the full realization of potential network benefits from ideally-placed distributed generation. With the ability to directly assess impacts of distributed generation and identify beneficial locations demonstrated in this study, perhaps that limit should be re-evaluated.

As noted in Section 2.5, their location in Santa Clara places some specific burdens on Optimal DER Portfolio generation projects. Stricter air quality requirements and lack of incentives from SVP will require financial incentives from some other source to offset these constraints and allow the network benefits of the Optimal DER Portfolio to be realized. The

Table 57 lists potential barriers and potential approaches to overcome those barriers, based on the previous studies cited in this report and barriers specific to Santa Clara.

Table 57 Potential Barriers And Potential Approaches

Barrier	Potential Solutions
Planning and building department staff with limited experience on DER projects	Rely on SVP staff for support; applicants prepare detailed description of the project and identify potential environment impacts associated with DER projects
Potential for community concern and opposition due to lack of exposure to DERs	Applicants prepare and conduct a community outreach program to educate the local residents
Current zoning does not address DERs	Applicants work closely with planning department staff to inform of potential land use impact through the conditional use and CEQA processes
Local codes likely do not address DER technology	Applicant to work closely with building department in plan review process; as necessary, hire third party consultant experienced in DERs to conduct plan check for the City
Potential for cumulative air quality impacts from multiple DER project in close proximity	Site DERs sufficiently far apart to minimize potential for cumulative impacts; approach CEC and air district about rule modification to more aggressively account for energy benefits from DERs
Strict air quality requirements, low system electricity costs, lack of incentives from SVP	Approach CEC regarding potential for other financial incentives to offset project costs and be competitive

2.6.3.2. Financial Incentives

The economic value of the network benefits created by Optimal DER Portfolio projects can serve as a source of funding for value-sharing rather than cost-shifting incentives. The dollar value of incentives paid could be limited to a share of the value derived from network benefits. Also, the payment of incentives could be directed to projects with attributes demonstrated to contribute to the posited network benefits, and, ultimately, in amounts commensurate with that project's contribution.

This would require a highly locational program design, and an acceptance by all that offering different incentives at different locations is based on objective analysis, not discrimination.

Demand Response

It is generally accepted that demand response projects have value in a general sense in terms of reduced energy consumption. It is becoming more widely accepted that demand response (as distinct from energy efficiency) has additional value in providing reserve capacity under high demand conditions.

As summarized in Section 2.4, we determined that demand response at most customer locations would provide benefits to the power delivery network if only in terms of loss reduction due to less served load.

However, a more important conclusion is that we determined that demand response at specific locations had particularly high value in enhancing network performance. Further, under different operating conditions, the beneficial locations for demand response may also be different. Moreover, in some locations, demand response always has high value, where in other locations demand response has high value only under certain conditions. It is notable that we also determined that the value of demand response in this context is not limited to projects of large energy users, and is nearly equally valuable in winter peak or minimum load conditions as it is in summer peak conditions.

In other words, through the methodology of this study, we can identify demand response projects in particular locations and having particular dispatch characteristics as having particular value to enhanced network performance.

This study suggests a new approach for demand response incentives, one that is location-specific, that includes specification of general and seasonal dispatch characteristics, that crosses those customer classes where sophisticated metering and telecommunications are available or could be justified, and that compensates customers based on the value their demand response provides. A locational approach to demand response – calling for reductions only where and when they have the most value – has the twin benefits of improved network performance and reduced impact on customers.

Such an approach is inherent in the Energynet notion of an intelligent power system, where among other things load is responsive to network conditions.

Some features of location-specific demand response are already incorporated in traditional demand response programs. Customer-level demand response projects are by their nature implemented at the individual customer level. Demand response measures are also enacted at the individual customer level, whether by telephone request, price signal, or an automatic connection to the customer's Energy Management System.

To incent beneficial DR projects on a value-sharing basis, a network operator could offer an incentive similar to that described for DG below for customer-sponsored demand response based on the estimated monetary value derived from DR projects from an analysis of the type described in this study. The analysis would identify those customer locations where higher levels of demand response yield additional value; these could be targeted for more intensive development or sophisticated energy management systems to achieve higher demand response levels. Further, the analysis would identify those locations where the value of higher levels of demand response is limited to particular seasons or network conditions. For example, Section 2.3 identifies two large customers on Core1 Feeder 205 and North6 Feeder 202 that are specified for the highest (15%) demand reduction during 2002 Summer Peak conditions but that are specified for the lowest (2%) demand response under all other conditions. The network operator or DR program sponsor could offer well-founded assurances to customers that their demand reductions will only be called during those limited periods, possibly gaining greater customer participation.

Because the real and reactive loss benefits of DR are intermittent, the easily-priced network benefits of DR considered in this section are limited to capacity value, only a portion of which is location-specific. The greatest value of demand response in terms of network performance benefits may lie in the areas of voltage profile improvement and stress reduction, particularly given the operational flexibility of a locational demand response program. The inability to directly value these benefits makes the implementation of a value-sharing locational demand response incentive more difficult.

Distributed Generation

As with demand response, we have determined in this study that for the subject power delivery network, power generation at specific locations can be shown to have particularly high value in enhancing network performance. These locational differences are particularly pronounced when limitations are imposed on the overall penetration of power generation in the distribution system to ensure non-export.

Further, we found that under different operating conditions, these power generation units should be operated at different levels of VAR output, and some should be curtailed to allow generation at other locations under the feeder penetration limits. Again, we found that the value of generation in this context is not limited to projects at the sites of large energy users, and is nearly equally valuable in winter peak or minimum load conditions as it is in summer peak conditions.

This suggests that financial incentives for onsite generation that provides network benefits should be location specific and conditioned upon the availability of certain operational flexibility and possibly limited operational control.

An examination of the list of generation projects in Appendix 2.5-1 indicates that such a program must be highly location-specific. For example, the generation projects on Core1 Feeder 305 and North 2 Feeder 202 are all highly valuable to the network as indicated by their rankings. That they have sequential rankings suggests that projects at any of the identified locations on each feeder have about equal value as a practical matter (with the exception of the 43 kW project on Bus 5191 of Core1 Feeder 305). An incentive program could offer equal payments at any one of these points.

Conversely, the generation projects on North6 Feeder 205 are much more differentiated. The 288 kW project on Bus 5052 is more valuable than the others on the feeder; the two projects on Buses 5273 and 8592 are about equal in value; and the 72 kW project on Bus 5053 is less valuable than the others. Physically, all four of these locations are on the same street (actually a circle with two street names) within ½ mile of each other. Further, there are three other customer sites on this same circle that were not identified among the 133 most valuable generation projects at all. An incentive program could and should offer different payments each of these points even though they are physically close.

To illustrate, an analysis as demonstrated in this study might identify a set of hypothetical Optimal DER Portfolio DG projects that is found to yield network benefits (loss reduction, reduced VAR consumption, capacity, and avoided network upgrades) of $450/kW. The network operator could offer an incentive of, say, $250/kW to customers in the beneficial locations identified in the study. To qualify for the incentive, these customers would need to develop project having the following, fairly light-handed characteristics:

- Size comparable to that assumed in the study.
- VAR output dispatchable by the utility within the rated range of the generator.
- Rights to the wholesale capacity value of the unit remain with the utility.

If an individual project were one of the 1/3 of the DG projects that must follow a specified operating profile according to the analysis, that would be specified as well. However, this specification could be as simple as the agreement to turn down the unit on request during off-peak hours or in some cases during a particular season. For the remaining units eligible for the incentive it would be sufficient for the owner to agree to operate the unit as available during peak daytime hours.

The utility could offer this incentive preferentially for individual projects identified as particularly high-ranking, or could tailor the incentive using a sliding scale to further incent projects in groups identified as contributing a greater share of network benefits

If the projects are successfully developed, the utility benefits by retaining a share of the predicted network benefits, now realized. As the penetration of real projects evolves, the utility can easily refresh the analysis under the method demonstrated here to incorporate actual projects, and restate the incentives for incoming projects to more accurately reflect both the needed characteristics and benefits of the remaining projects.

The availability of such financial incentives would allow customers and their advisors to economic assessments of potential generation projects to combine network benefits with customer economic benefits and other benefits. The benefits to multiple stakeholders are combined in a single decision – those projects offering *both* network benefits and customer benefits would become the most feasible as customer-sponsored projects.

The approach developed in this study would also permit the network operator to identify those DG projects with significant network benefits but that are unlikely to be developed under customer initiatives. These projects are ideal candidates for utility development as a cost-effective element of power delivery network improvement.

2.6.4. Policy Implications

Greater penetration of DER is well established as a policy priority in California. This study establishes that there are additional potential benefits from DER in terms of enhanced performance of the power delivery network, suggesting that if anything, DER should receive even higher priority as a resource where a specific portfolio of "beneficial" DER projects has been identified. At the same time, by its nature, the development of DER requires more direct involvement of electricity customers as project hosts or even as project sponsors; it is not a strategy that can be carried out by utilities unilaterally.

The discussion in Section 2.5 identifies regulatory barriers to Optimal DER Portfolio generation projects. While permitting these generation projects is demonstrably feasible, we have established that it would involve multiple processes (local, BAAQMD, CEQA), is likely to be subjective (interpretation leading to a conditional use permit), and may be new to the reviewer and the applicant both.

The discussion in Section 2.5 also identifies technology and vendor barriers. The identified Optimal DER Portfolio generation projects lie in a class where vendors have not sought equipment pre-certifications to facilitate project development. They may also lie in a class that is not widely supported by vendors. Among the anecdotal examples there are indications that these projects are perceived by project sponsors as challenging, partly due to the lack of certain assurances or information from vendors.

We know that the host customer population for the 133 highest-ranked Optimal DER Portfolio generation projects considered for the siting analysis in Section 2.5 includes a mix of customers, many of whom have rated loads of under 1,000 kVA or even under 200 kVA. In other words, at least for this power delivery network, the most beneficial projects are for the most part not those at the sites of the extremely large, sophisticated heavy industrial facilities with dedicated onsite energy/engineering staffs.

Input to SVMG from end-use customers fitting the profile of hosts for Optimal DER Portfolio generation projects indicates that they will commit their capital or staff time to what they may perceive to be a project that is ancillary to their businesses only if there are compelling benefits. Risk and procedural uncertainty can be a significant disincentive. We can infer that the regulatory and technology barriers identified here will have an even greater impact on the particular customer group associated with these Optimal DER Portfolio generation projects.

The profile of host generation customers identified by this analysis suggests that if Optimal DER Portfolio generation projects are to be sponsored by customers rather than the utility, there is significant benefit to further streamlining of siting requirements and to making equipment in this size range easier to buy, permit, install, and operate.

This also suggests an institutional barrier – or opportunity – in the need for value-added project integrators with specialized expertise to manage these project issues, thereby facilitating the development of these beneficial projects.

Finally, it raises the question of whether at this stage in the development of onsite power generation, a strategy of deploying onsite power generation at sufficient penetration levels to improve network performance might be best carried out by the utility itself.

2.6.5. Conclusions

This research shows that, at least for the power delivery network that is the subject of this study, to fully realize the potential benefits to power network performance that DER could provide would require the ability to site many onsite generation units in specific locations. We can make several conclusions from this Section and Section 2.5. These are summarized as follows.

Though it may be the case, it is not readily apparent that equipment pre-certified to meet statewide emission and interconnection standards is available with the size and operating characteristics needed for the Optimal DER Portfolio. Moreover, even if pre-certified equipment is available and proposed for use, the Optimal DER Portfolio generation projects will still be subjected to relatively complex local, CEQA, and BAAQMD permitting processes. Also, onsite generation projects of the type – especially the size and operating duty – identified for the Optimal DER Portfolio are perceived as new and uncertain both by electricity customers as potential project sponsors and equipment vendors.

Also, existing financial incentives for DER would apply to these projects at best unevenly. Some projects would benefit and some would not, irrespective of their contribution to power delivery network performance. Existing local DER policies we have reviewed are an important first step. However, these remain rare, and those that exist could be further refined to meet the specific objective of facilitating deployment of generation projects that provide power network benefits.

We have illustrated how financial incentives that emphasize and are built upon the locational benefits of specific DER projects could be developed and implemented using this methodology. We have also recommended a model resolution leading to a DER ordinance that encourages and relies upon standardization to streamline the local permitting process for onsite power generation projects.

In addition to the foregoing, we have also highlighted again that many of the Optimal DER Portfolio generation projects – those projects that yield the greatest network benefit – are located at sites of customers with relatively modest loads, and by inference, modest on-site technical staffs and the resources to take on challenging projects ancillary to their core businesses. This suggests significant value in further measures to make these generation projects "easy," and raises institutional questions about how best to carry out a strategy to use onsite generation to improve power network performance.

3.0 Project Results

The overall goal of this project was to demonstrate an analytical methodology that can identify:

Where a DER project or group of projects, including distribution-connected DER, can provide specific T&D network benefits;

The value of those network benefits in engineering and economic terms;

A suggested set of financial and non-financial incentives to facilitate the development of DER projects, including locational pricing of energy and real and reactive capacity; and

Value-sharing, rather than cost-shifting incentives for DER projects that are beneficial to the operation of the T&D network, as well as targeted policy initiatives that will facilitate the recognition and development of beneficial DER projects.

This project addresses the need for an objective, systematic way to assess the grid benefits of DER. The first two bullets of the goal above – determination where in the network such projects can provide benefits and quantification of those benefits – are a measure of the analytical rigor of the methodology. The second two bullets – development of incentives based on these results – are one measure of the usefulness of the methodology.

The 2002 and 2005 Optimal DER Portfolios derived as discussed in this report represent sets of projects that demonstrably enhance the performance of the SVP T&D system. These portfolios include both demand response (DR) and distributed generation projects. Nearly all of these are connected to the system at customer sites in the distribution portion of the system. These Optimal DER Portfolio projects are characterized in terms of their location in the network – that is, they pinpoint the locations in the network where resources if added would yield benefits in terms of network performance. They are also characterized in terms of their size, and operating profile to address a range of system conditions based on actual conditions observed over the course of a particular year.

These projects provide quantified network benefits in terms of real power loss reduction, reduced reactive power consumption, improved voltage profile, reduced system stress, increased load-serving capability, and incremental system capacity. Some of these network benefits can also be quantified in dollar terms, and we have illustrated now these values could be used to for incentives for beneficial projects based on a sharing of the economic value of their benefits. Thus, the overall goal of this project has been achieved.

This project had as its objective to develop and demonstrate this methodology to place a value on DER as a core component of a T&D network through a study incorporating specific components or elements. Each of these elements of the project's objective, and how the results obtained in this project address those elements are discussed individually below.

3.1. Integration of T&D into a Single Model

One element of the goal of this project was verification that an Energynet dataset for a utility network can integrate distribution with transmission in a single model, that that model can simulate dispatchable demand response and embedded generation in the network and assess their impacts, and that such a model can be used both by AEMFAST and GE's PSLF power system analytical software. This element represented the key technical risk in the project.

In Section 2.1 we showed the capability to collect, error-check, and integrate distribution detail with transmission data into a single analytical model of a power system. We also showed that both AEMPFAST and PSLF could achieve solutions using such a model, and that the power flow results were confirming. We also demonstrated the ability to exchange modeled system data between the two environments.

The use of both analytical packages is important not only as a check, but also because we wanted to demonstrate the interoperability of these detailed Energynet models with PSLF, a widely-used, legacy tool in the utility industry.

We demonstrated the development of detailed load data both from actual recorded results, SCADA in this case, and from a conventional utility load forecast. We were able to develop estimates of seasonally-varying real and reactive loads at the individual customer level without the use of sensitive customer-specific load data.

We developed cases characterizing this integrated network "as found" under a seasonal range of actual, recorded load conditions and topology, specifically, for dates in December, 2001, and May, August, and September 2002. We also developed cases characterizing this integrated network in Summer 2005, incorporating anticipated changes in network topology and projected loads. The Base Case or "as found" power flow results from both PSLF and AEMPFAST are shown in Table 1 and repeated in Table 58.

Table 58 Base Case Load Flow Results

Summer Peak 2002 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	397.598	209.076	397.598	209.076
Net Interchange	-366.519	-70.868	-366.56	-69.725
Losses	1.248	51.313	1.262	50.943

Knee Peak 2002 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	329.095	184.226	329.095	184.226
Net Interchange	-297.952	-19.250	-297.954	-19.488
Losses	0.888	32.735	0.895	32.425

Winter Peak 2001-02 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	336.971	181.565	336.971	181.565
Net Interchange	-304.439	-11.853	-304.44	-9.75
Losses	0.908	35.917	0.909	33.102

Minimum Load 2002 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	254.521	141.075	254.521	141.075
Net Interchange	-221.651	-27.925	-221.652	-28.147
Losses	0.610	18.287	0.611	18.089

Summer 2005 Base Case Load Flow Results

	PSLF – SVP Control Area		AEMPFAST LF	
	P (MW)	Q (MVAR)	P (MW)	Q (MVAR)
Actual Load	581.999	348.747	581.999	348.747
Net Interchange	-552.792	-260.904	-552.86	-261.57
Losses	3.09	92.049	3.17	92.56

3.2. Characterization of Subject System Prior to DER Additions

Another element of the goal of this project was characterization of the condition of the subject network before the addition of DER resources under seasonally-varying "present" conditions and “future” conditions. In implementation, we characterized the condition of the network both “as found” and after optimization of existing network controls. We also characterized the network in terms of its initial P stress, a measure of the network’s condition with recontrols implemented.

3.2.1. “As Found” Conditions

The “as found“ power flow results and overall losses of the SVP system are summarized above in Table 58. The seasonally-varying “as found” voltage profiles of the 2002 network are shown in Figure 3 and repeated below in Figure 26 “As Found” Energynet Voltage Profiles. The “As Found” voltage profile of the 2005 network is shown in Figure 4 and repeated below in Figure 27. Figure 26 “As Found” Energynet Voltage Profiles and Figure 27 are “Voltage Profile” plots which show the per-unit voltage at each of the approximately 850 points or buses in the network. Those buses arranged roughly according to network topology and by transmission loop to reveal variation in voltage along individual feeders and in different regions in the network.

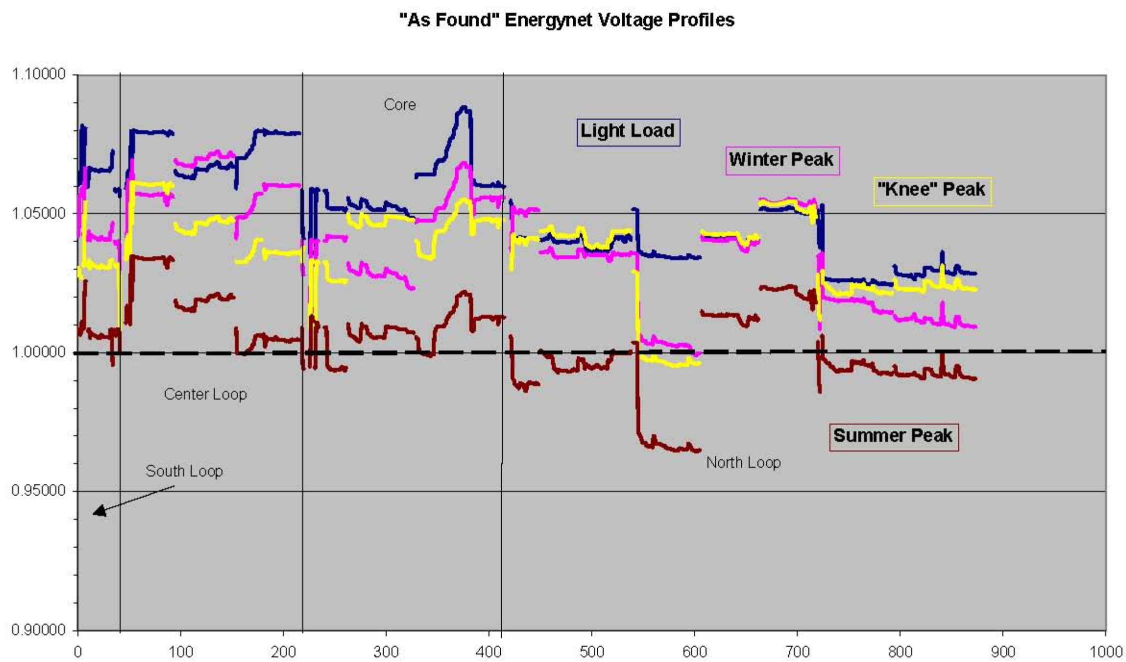

Figure 26 “As Found” Energynet Voltage Profiles

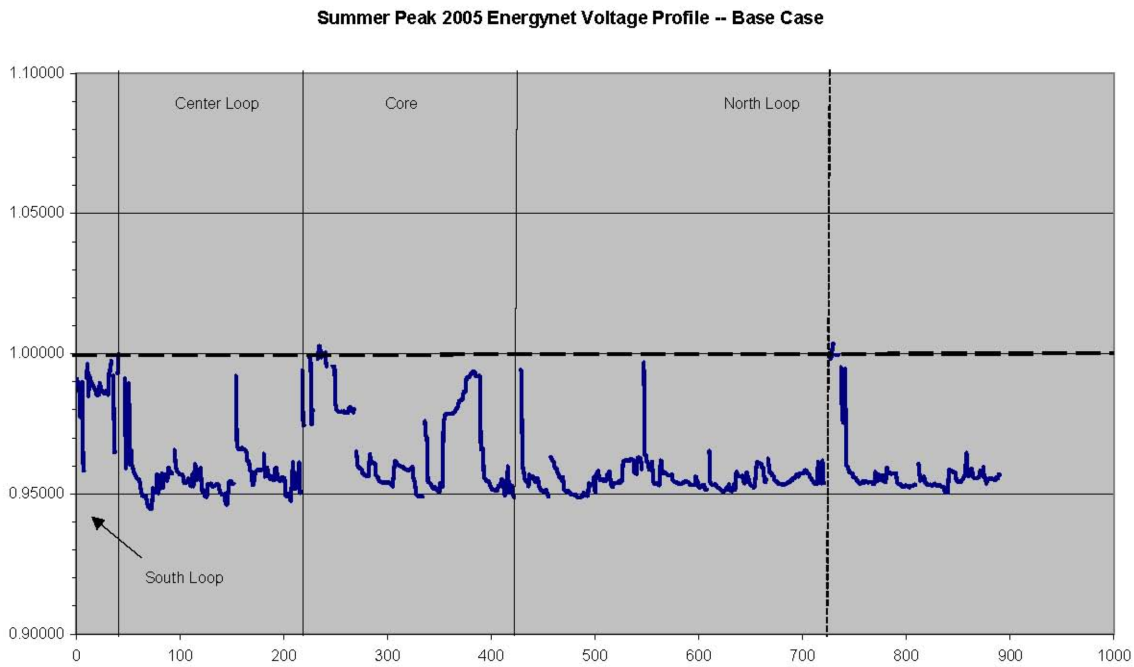

Figure 27 Summer Peak 2005 Energynet Voltage Profile – Base Case

An assessment of the "As Found" voltage profile of the 2002 and 2005 networks is presented in tabular form in Table 3 and repeated below in Table 59.

Table 59 Voltage Profile Comparison

Summer 2002 Case Voltage per-unit (PU)		
	Transmission Only (65 buses)	Distribution and Transmission (833 buses)
Average	1.00	1.00
High	1.034	1.035
Low	.97	.96
Variation (std dev)	.012	.015
Summer 2005 Case Voltage per-unit (PU)		
	Transmission Only (80 buses)	Distribution and Transmission (848 buses)
Average	.98	.96
High	1.003	1.003
Low	.96	.94
Variation (std dev)	.015	.013

These results illustrate that these detailed models with distribution-level components discretely depicted reveal the condition of the network in a great deal of detail – far detail than would be available in a transmission-only view such as that shown in Figure 28 below, repeated from Figure 1.

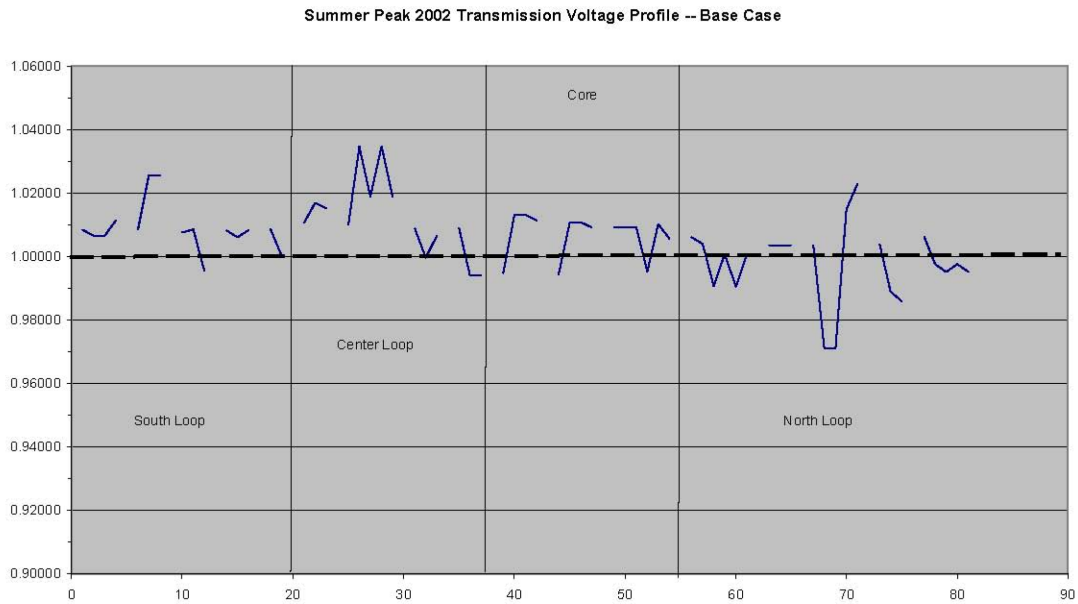

Figure 28 Summer Peak 2002 Transmission Voltage Profile – Base Case

Moreover, while we found a lightly-loaded network with no flow limits exceeded, the integrated Energynet model revealed a greater level of voltage variability and low- and high-voltage buses in the distribution portion of the system, particularly in 2002 conditions other than the Summer Peak, as evident in Figure 26. The 2005 case with significantly higher loads had notably lower voltages in the distribution system, as shown in Figure 27. As discussed in Section 2.1, we concluded that while stability should not be a concern for this network, the low voltages of individual buses revealed in the integrated network model might be.

As discussed in Section 2.1.2.4, power flow results for the integrated datasets also revealed locations within the distribution system where voltage variation was high, where voltage levels were outside the desired range (both high and low), and where real and reactive flows opposed each other. Such locations also suggest sites where addition of real or reactive capacity as DER would mitigate adverse flows or low voltage. Again, the existence of these conditions and the precise locations where they occur would all be invisible in a transmission-only characterization of the network.

3.2.2. "Recontrols"

We intended to optimize control settings to the extent possible – i.e., also before adding any incremental DER capacity – primarily to avoid attributing the associated benefits to DER additions. However, we found using AEMPFAST that for this network, resetting available network controls alone made a meaningful improvement in network performance in most cases. Moreover, we found that while the recontrol steps were localized, their impacts extended across the network. This was particularly evident in the 2005 network. Section 2.2 discusses how we determined which control variables we would consider available for recontrol.

The impact of recontrols on the Summer Peak 2002 case is shown in Figure 5 and repeated below as Figure 29.The impact of recontrols on the Summer 2005 system is shown in Figure 9 and repeated below as Figure 30.

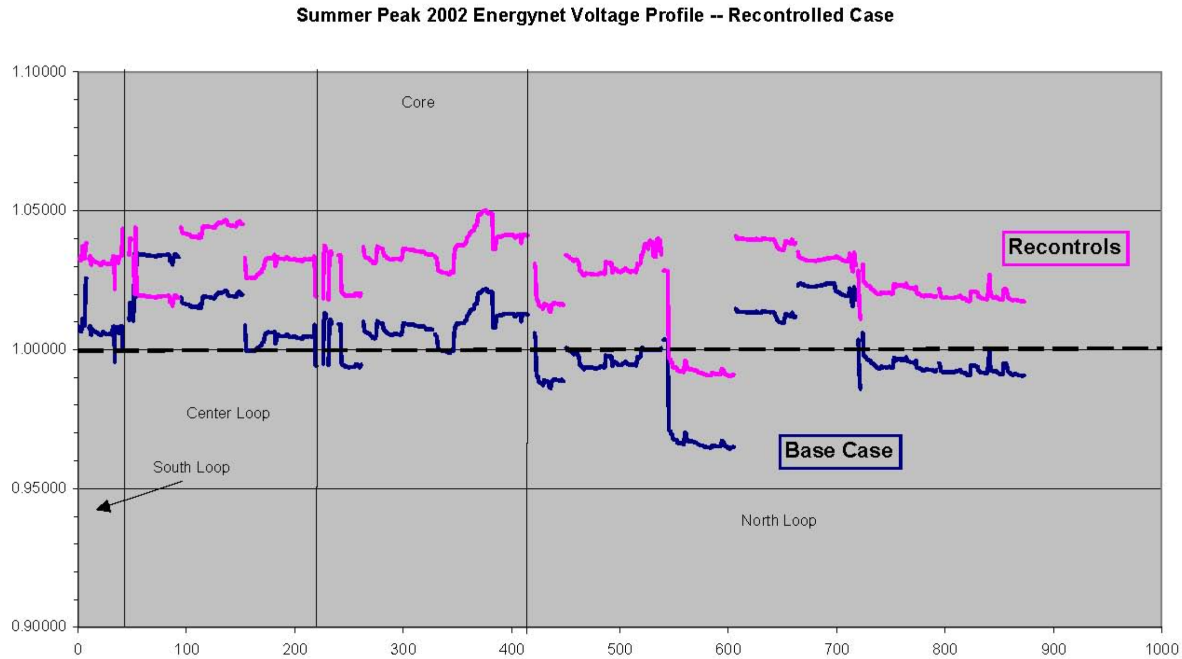

Figure 29 Summer Peak 2002 Energynet Voltage Profile - Recontrolled Case

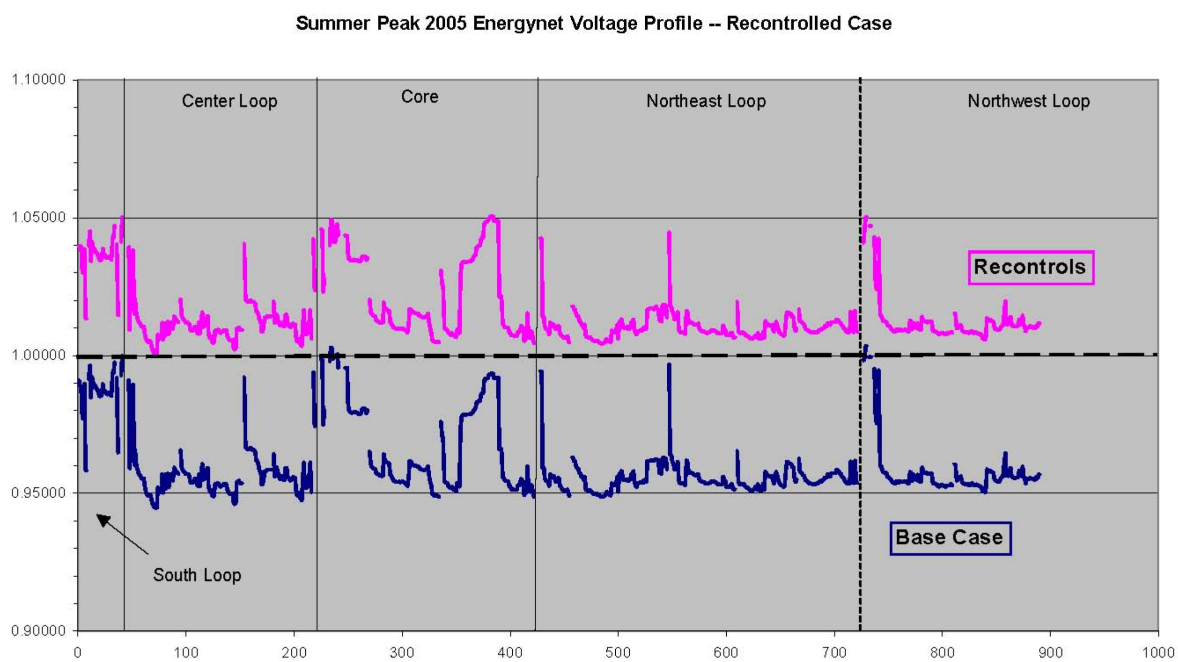

Figure 30 Summer Peak 2005 Energynet Voltage Profile - Recontrolled Case

3.2.3. "P Stress"

One of the fundamental capabilities of AEMPFAST is to directly calculate the impact of addition of real (P) or reactive (Q) resources at each point in the modeled network would have on a given objective under a given set of conditions. These values – the P index and Q index at each location – may also be interpreted as the amount of P or Q "stress" at that location. The further from zero the P index is at a location, the more that location is stressed – or, the less optimized the amount of P resource is at that location – relative to the optimization objective.

Initial P and Q indices are determined for networks after recontrols. We determined initial P and Q indices for all the cases we simulated. For the Summer Peak 2002 case, we found that the maximum P stress value is about 0.028, the average network-wide P stress is about 0.0073, and the standard deviation (a measure of the variability of the stress across the system) is about 0.0049. For the Summer 2005 case the maximum P stress value is about 0.03, the average network-wide P stress is about 0.008, and the standard deviation is about 0.0044. According to Optimal, these levels of P stress are low. Further, we believe the overall level of P stress and the variability of P stress are more significant indicators of network condition than is the maximum P stress at a particular point.

Figure 6 shows the initial P index of the Summer Peak 2002 case with specific areas of high P stress annotated. This is repeated below as Figure 31. Figure 10 shows the initial P index of the Summer 2005 case; this is repeated below as Figure 32.

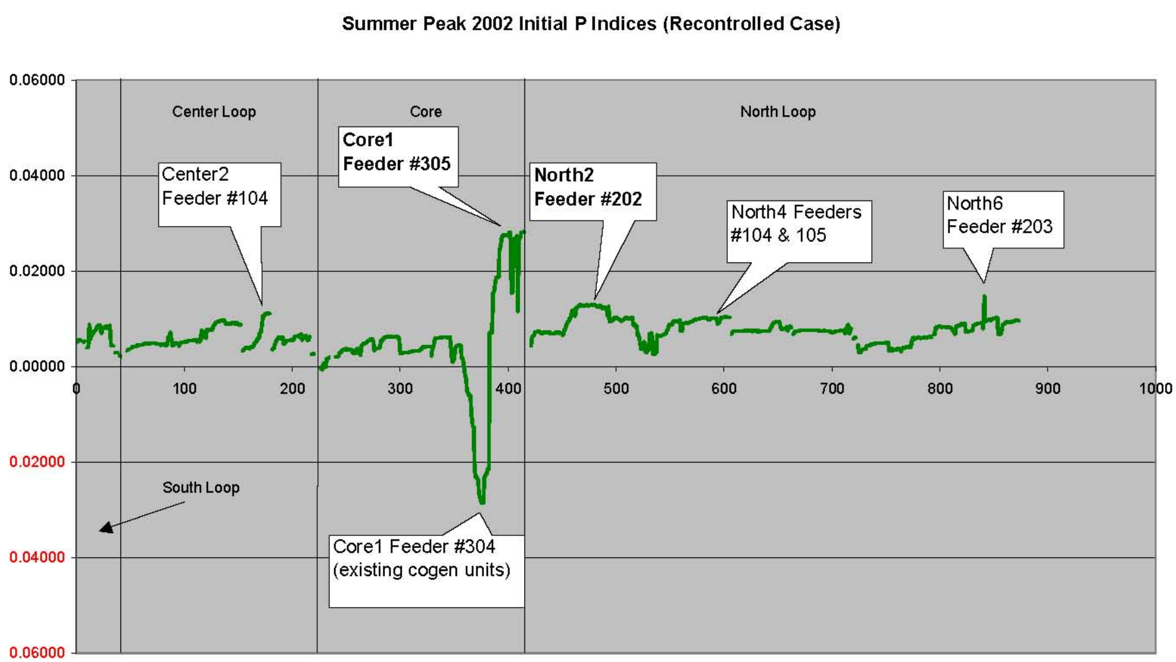

Figure 31 Summer Peak 2002 Initial P Indices (Recontrolled Case)

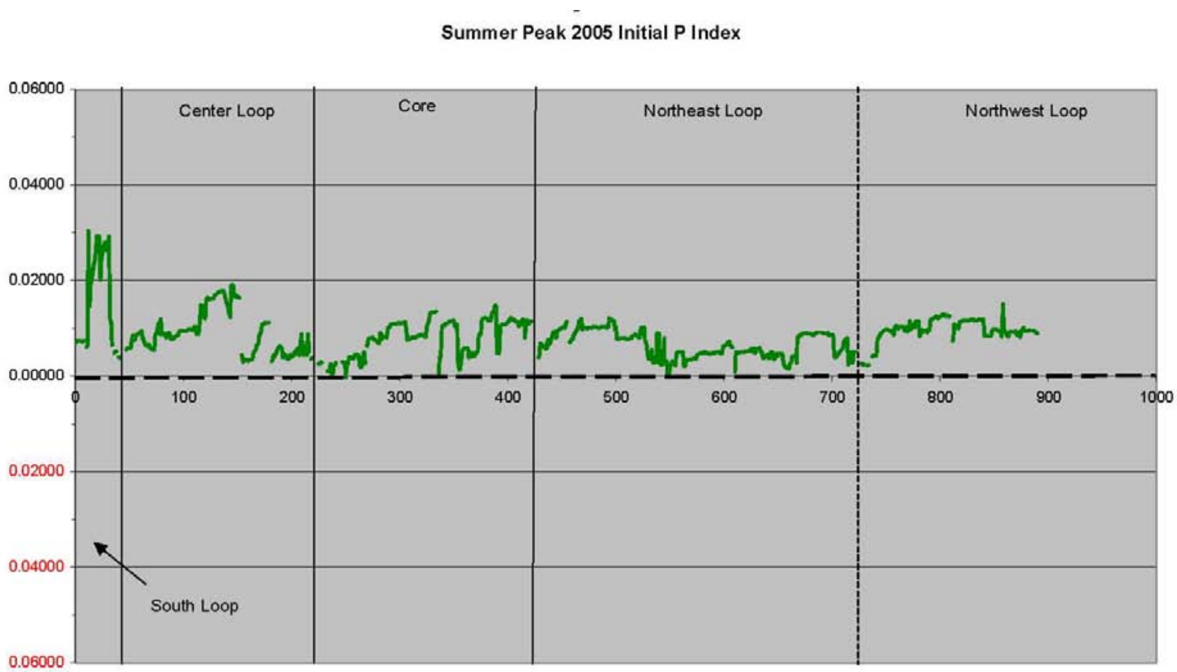

Figure 32 Summer Peak 2005 Initial P Index

3.3. Identification of DER Additions to Improve Network Performance

Another element of the goal of this project was characterization of two sets of DER capacity additions that demonstrably improve network performance. These additions were to be characterized by type, size, and location, and ranked in terms of their contribution to network performance. The two sets of DER capacity additions were to improve performance under Summer Peak 2002 and Summer 2005 conditions, respectively.

We used AEMPFAST as the primary tool to identify beneficial locations for capacity additions. In doing so, established as the objective for the optimization the simultaneous minimization of real power losses, reactive power consumption and voltage variability, with a target voltage of 1.05 PU.

Using AEMPFAST, we developed a list of capacity additions that would improve network performance relative to the foregoing objective under each of the different conditions we simulated. These were subject to external limitations consistent with DR and DG projects, and rank ordered by AEMPFAST. We developed the set of DR additions first, starting with the network assuming the implementation of recontrols. We developed the set of DG additions afterwards, starting with the network with recontrols and DR additions implemented and dispatched.

We evaluated the Summer Peak 2002 network using AEMPFAST and determined that were no additions of reactive capacity alone that would improve network performance. We next identified 389 individual, rank-ordered locations where demand response would benefit network performance. These are listed individually, with their locations, in rank order in Appendix 2.2-1.

We next identified and rank-ordered individual locations where distributed (DG) capacity additions would benefit network performance over and above the benefit provided by these DR additions. Under the constraint that total DG capacity on a feeder would be limited to 15% of that feeder's peak demand, we identified 111 beneficial locations. Under the constraint that total DG capacity on a feeder would be limited to that feeder's total demand under minimum load conditions, we identified 317 beneficial locations. These are also listed individually, with their locations, in rank order in Appendix 2.1-1.

Table 5 lists the top-ranked 133 DR projects for the Summer Peak 2002 case in terms of the distribution feeders with the highest-ranking DR locations. Table 6 lists the top-ranked 133 DG projects under the Light Load feeder limit in terms of the distribution feeders with the highest-ranking DG locations. Core1 Feeder 305, North4 Feeder 204, and North2 Feeder 202 were notable for highly-ranked DR locations. North2 Feeder 202, Center2 Feeder 104, and Core1 Feeder 305 were notable for highly-ranked DG locations. These areas are consistent with those identified in the initial P index plot above.

We conducted essentially identical analyses for the "present" system under Knee Peak, Winter Peak, and Minimum Load conditions, identifying rank-ordered DR and DG capacity additions to identify any of the DER sites identified under Summer Peak conditions that could have adverse network impacts under different network conditions. Through this process, we identified one DG site identified as beneficial to network performance under Summer Peak conditions but potentially adverse under other conditions; thus, any capacity at that location would have to be curtailed.

We completed a similar study of the 2005 network. We evaluated the 2005 network using AEMPFAST and determined that there were no additions of reactive capacity that would improve network performance.

We next identified 390 individual, rank-ordered locations where DR would benefit network performance. These are listed individually with their locations in rank order in Appendix 2.1-1.

We next identified and rank-ordered individual locations where DG capacity additions would benefit network performance over and above the benefit provided by these DR additions. Under the constraint that total DG capacity on a feeder would be limited to 15% of that feeder's peak demand, we identified 114 beneficial locations. Under the constraint that total DG capacity on a feeder would be limited to that feeder's total demand under minimum load conditions, we identified 149 beneficial locations. These are listed individually with their locations in rank order in Appendix 2.1-1.

Table 7 lists the top-ranked 99 DR projects for the Summer 2005 case in terms of the distribution feeders with the highest-ranking DR locations. Table 8 lists the top-ranked 100 DG projects under the Light Load feeder limit in terms of the distribution feeders with the highest-ranking DG locations. South3 Feeder 104, Core1 Feeder 205, and Center3 Feeder 303 were notable for highly-ranked DR project sites. Center3 Feeder 303, Core1 Feeder 305, and South3 Feeder 104 were notable for highly-ranked DG project sites.

3.4. Establish Optimal DER Portfolios

Another element of the goal of this project was to use these results to establish "Optimal DER Portfolios," or sets of DER projects, characterized in terms of specific technical and operational attributes, that could measurably improve the performance of the network relative to the network's "as found" conditions.

3.4.1. 2002 Optimal DER Portfolio

The 2002 Optimal DER Portfolio for this network includes DR at essentially all of the 390 eligible (over 200 kVA) customer locations. The size of these projects in terms of the percentage reduction in the customer's load varies according to customer capability (we assume a function of their size) and these projects are dispatched or called individually at different levels depending on network conditions. They are also ranked according to their value in terms of network benefits under each of the conditions we analyzed. Under the "highest 1% hour" Summer Peak conditions these projects represent 10.52 MW, or 2.6% of load, and under more typical summer seasonal conditions these projects represent 3.65 MW or 1.1% load.

Again, to achieve maximum network benefits, these DR projects are dispatched by location at different levels of demand reduction depending on customer capability and network conditions. Of the DR projects at the 130 large (> 1,000 kVA) customer sites, a portion is dispatchable at two levels under conditions other that the "1% highest hour" summer peak. The locations of the preferred sites for higher levels of dispatch under these conditions are specified. Of the large customer projects, only 61 are preferred locations for higher levels of dispatch under both summer and winter seasons and minimum load conditions as well. These projects are listed by location inTable 9. The remainder of the large customer DR projects could be made available for higher levels of dispatch on a limited seasonal basis only without compromising network performance. The large customer DR projects that are preferred locations for a higher level of dispatch under the 99th percentile summer peak (Knee Peak) conditions only and both summer and winter peak conditions are listed in Table 10 The large customer DR projects that are preferred locations for a higher level of dispatch under Winter Peak conditions only are listed in Table 11. The large customer DR projects that are preferred locations for a higher level of dispatch under minimum load conditions as well as one or more seasonal conditions are also identified in Table 10 and Table 11. Large customer DR projects that are preferred locations for a higher level of dispatch under minimum load conditions only are listed in Table 12.

Under just the "1% highest hour" summer peak conditions, a portion of both the medium customer (200 kVA – 1,000 kVA) and large customer DR projects is dispatchable at the highest DR level. Those large customer DR projects that are preferred locations for the highest level of dispatch under the 1% highest hour summer peak condition are identified in Table 9, Table 10, Table 11, Table 12, and Table 13. Those medium customer DR projects that are preferred locations for the higher level of dispatch under Summer Peak conditions are listed in Table 13.

The 2002 Optimal DER Portfolio for this network consists of DG projects at 380 of the 419 eligible customer locations (not including the existing embedded generators in the network). As with DR, these projects are dispatched individually at different levels depending on network conditions, and they are ranked according to their value in terms of network benefits under each of the conditions we analyzed. These projects average 160 kW in size, with the largest 8.9 MW. They total 60.73 MW on a nameplate basis, and dispatched as specified would represent 54.88 MW, or 13.8% of the system's load, under Summer Peak conditions. We found that the majority (60%) of the portfolio generation projects would not need to vary their real power output in response to changing network conditions to maintain network performance, and could operate on a base load basis for the customer. These DG projects are listed individually by location with their operating profiles in Table 14.

3.4.2. 2005 Optimal DER Portfolio

The 2005 Optimal DER Portfolio for this network includes DR at all of the 390 eligible customer sites. These projects are ranked according to their value in terms of network benefits. They are also scaled according to customer capability and are dispatched individually at different levels on network conditions. These projects represent 25.53 MW, or 4.4% of load under 1% highest hour summer peak conditions.

As with the 2002 portfolio, under the 1% highest hour Summer 2005 conditions we modeled, a portion of the medium customer (200 kVA – 1,000 kVA) and large customer projects is dispatchable at higher levels, and the preferred locations for these projects, based on their network benefits, are specified. The locations of the preferred sites for higher levels of DR dispatch under these conditions are listed, by location, in Tables 2.3-8 and 2.3-9. While we did not perform a seasonal analysis as with the 2002 cases, it is reasonable to expect that the seasonal dispatch specification of the 2005 portfolio DR projects would be comparable. A seasonal analysis would identify the preferred dispatch of each project by location.

The 2005 Optimal DER Portfolio for this network consists of DG projects at 149 of the of the 419 eligible customer locations (not including the existing embedded generators in the network). As with the DR projects, these generation projects are ranked according to their value in terms of network benefits under the conditions we analyzed. These projects would be dispatched individually at different levels depending on network conditions. These projects average 447 kW in size with the largest 14.3 MW. They total 66.66 MW or 11.5% of the system's load as dispatched under Summer Peak conditions.

This set of DG projects is derived from an analysis of the 2005 network's summer peak conditions only. Extrapolating from the 2002 results, we believe it is reasonable that there are additional projects, perhaps 20% of this group in terms of size or number, that would yield network benefits if operated during periods other than the summer peak. We also believe the operating profile of the DG projects as a group would be comparable to the 2002 portfolio DG projects – that is, that the majority of the portfolio generation projects would not need to vary their real power output in response to changing network conditions to maintain network performance, and could operate on a base load basis for the host customer. The 2005 Optimal DER Portfolio DG projects are listed individually by location in Table 18.

With the Optimal DER Portfolio projects described above in place, the SVP network includes about 390 individually-dispatchable demand response resources. It also includes 380 embedded generation resources (or 149 in the case of the 2005 network) each of which represents, at a minimum, a variable source of reactive power dispatchable by the network operator. Per our assumptions noted in Section 2.2, all 100 capacitors are also individually dispatchable. Conceivably actual voltage and real and reactive power flow could be monitored at all 390 dispatchable DR sites through advanced power quality metering, as could MW and MVAR output from each of the embedded generation units. Compared to a typical power delivery network of today this is a highly flexible network with many degrees of operational freedom.

This is the very picture of an advanced Energynet power delivery infrastructure, with related technologies to monitor and coordinate these devices. At the same time, it is not far-fetched. According to the 2001 AQMD Public Back Up Generation System Inventory, there were 44 onsite power generation units at customer sites in the City of Santa Clara, 16 of which are actually at locations identified in this study as generation sites. Also, as noted in Section 2.2, monitoring and control capabilities of the type described here have in many cases already been demonstrated. Such a system is highly flexible, and through the use of advanced analytics such as AEMPFAST could be operated to achieve the elevated levels of network performance described below under varying operating conditions.

3.5. Quantifiable Improvement in Network Performance

Another element of the goal of this project was to quantify the operational benefits enabled by the Optimal DER Portfolio projects in both engineering and financial terms.

The Optimal DER Portfolio projects, as a group, located and dispatched as specified, yielded quantifiable improvements. We confirmed this result, obtained from AEMPFAST, with solutions from PSLF. As indicated above, Optimal DER Portfolio projects are ranked in terms of their network benefits under different network conditions. We found that under some seasonal conditions projects with higher rankings accounted for a greater share of the portfolio's benefit than the remaining projects.

3.5.1. Network Performance Improvement

The network benefits yielded by Optimal DER Portfolio projects include:

- Real power loss reduction within the SVP system
- Reactive power consumption reduction within the SVP system
- Real power loss reduction within the PG&E system
- Reactive power consumption reduction within the PG&E system
- SVP system voltage profile improvement
- SVP system P stress reduction
- Increase in load-serving capability under contingency conditions
- Capacity value

The contributions in each of these areas of Optimal DER Portfolio projects quantified in engineering terms are summarized below for the 2002 and 2005 systems. All of these results assume the Optimal DER Portfolio projects are installed and operated as specified in this report. The development of these results is discussed in detail in Section 2.4.

For the 2005 system, we also compared the network performance improvement achieved with the 2005 Optimal DER Portfolio with the network performance improvement that would be achieved with specific transmission-level network upgrades using these same metrics. We also developed a characterization of the 2005 network with the heavier forecast loads but without planned network improvements to evaluate the potential network benefits of DER in a very stressed network.

3.5.1.1. 2002 Optimal DER Portfolio

- **Real Power Loss Reduction**

Table 60 Loss Reduction (MWh per hour) – DG Projects

	Summer Peak	Knee Peak	Winter Peak	Minimum Load
SVP System	.289	.279	.265	.223
PG&E System	5.150	5.029	3.216	1.794
Total	5.439	5.308	3.481	2.017

Table 61 Loss Reduction (MWh per hour when called) – DR Projects

	Summer Peak	Knee Peak	Winter Peak	Minimum Load
SVP System	.101	.031	.042	.011
PG&E System	1.178	.424	.509	.431
Total	1.279	.455	.551	.442

Table 62 2002 DER Portfolio SVP System Percentage Loss Reduction
(reduction relative to "recontrols" only)

	DG	DR	Total
Summer Peak	24%	9%	33%
Knee Peak	33%	4%	36%
Winter Peak	30%	5%	35%
Minimum Load	37%	2%	39%

Because the SVP system is lightly loaded, the loss reduction within the SVP system is small in absolute terms. However, it is significant in percentage terms. Also, it is notable that the real power loss benefit from the Optimal DER Portfolio DR and DG projects actually varies relatively little from season to season. Further, there are loss benefits from these projects even under Minimum Load conditions.

- **Reduced Reactive Power Consumption**

Table 63 Reduced Reactive Power Consumption (MVAR) – DG Projects

	Summer Peak	Knee Peak	Winter Peak	Minimum Load
SVP System	11.159	8.800	9.907	7.140
PG&E System	58.007	59.444	50.771	24.485
Total	69.166	68.244	60.678	31.625

Table 64 Reduced Reactive Power Consumption (MVAR) – DR Projects (when called)

	Summer Peak	Knee Peak	Winter Peak	Minimum Load

SVP System	2.451	.629	.819	1.393
PG&E System	13.793	5.204	8.974	7.938
Total	16.244	5.833	9.793	9.331

Table 65 2002 DER Portfolio SVP System Percentage Reactive Power Consumption Reduction (reduction relative to "recontrols" only)

	DG	DR	Total
Summer Peak	23%	5%	28%
Knee Peak	28%	2%	30%
Winter Peak	30%	2%	32%
Minimum Load	37%	7%	45%

- **Voltage Profile Improvement and P Stress Reduction**

Table 66 Voltage Profile and P Stress with DR and DG Projects

	Summer Peak	Knee Peak	Winter Peak	Minimum Load
Avg Voltage (PU)	1.033	1.039	1.038	1.045
Low buses	No	No	No	No
High buses	No	No	No	Yes
Voltage Var.	0.010	0.009	0.010	0.009
Avg P Stress	.007	.006	.005	.004

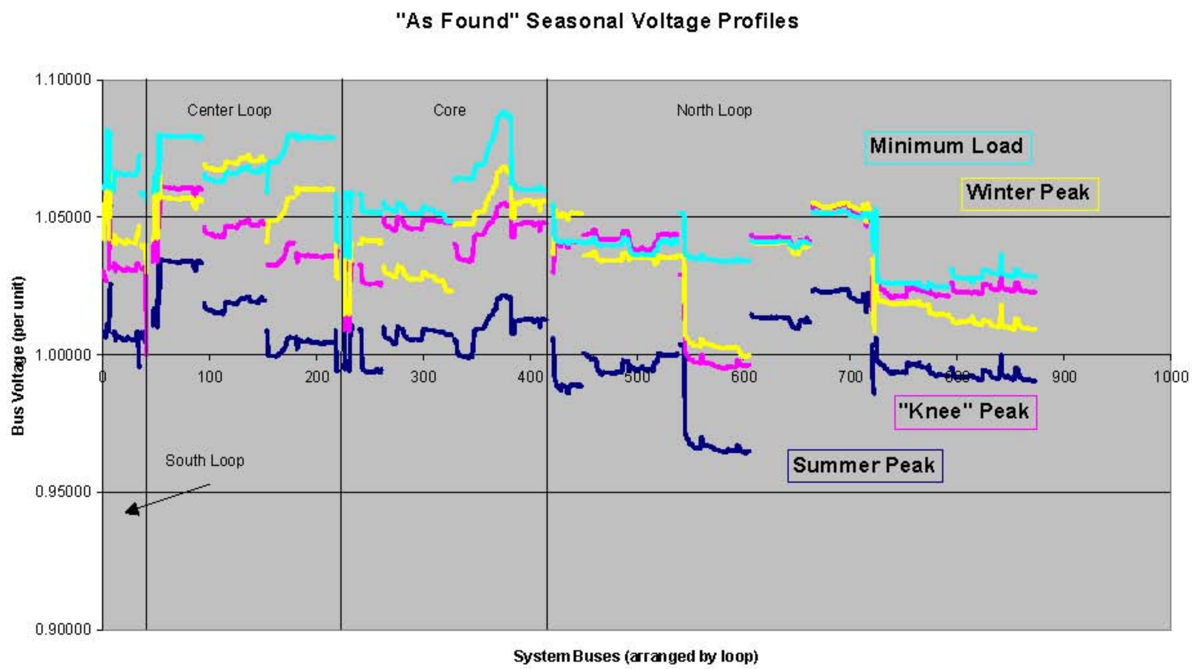

Figure 33 "As Found" Seasonal Voltage Profiles

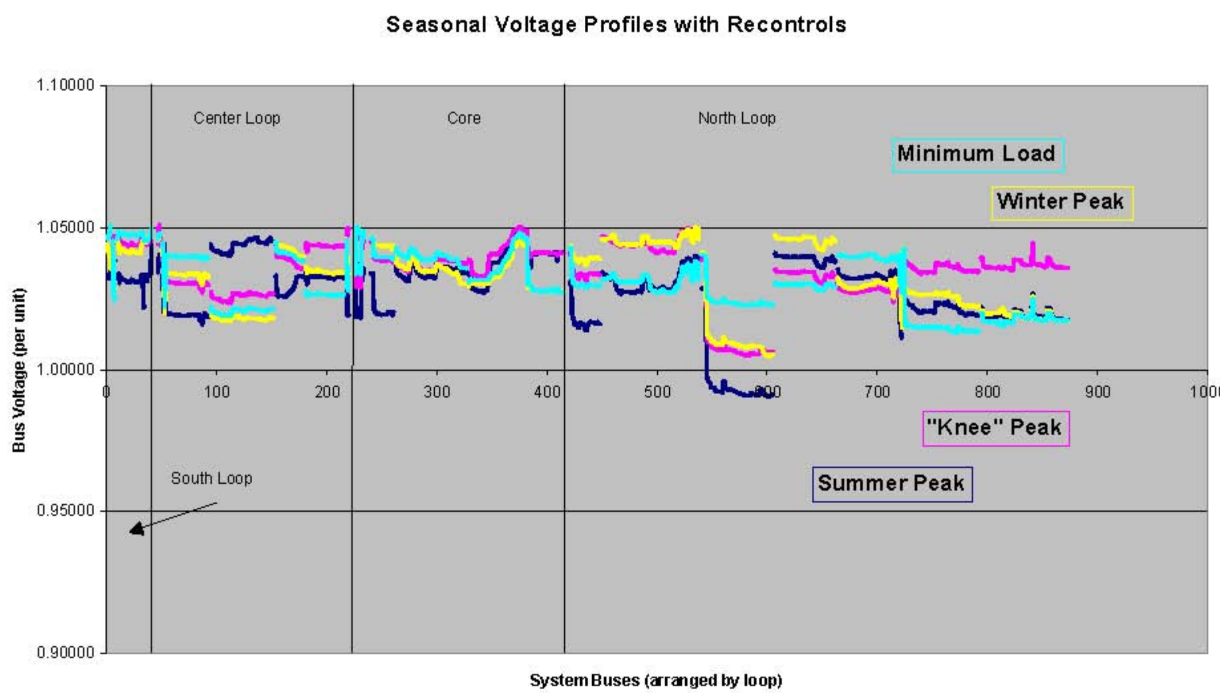

Figure 34 Seasonal Voltage Profiles with Recontrols

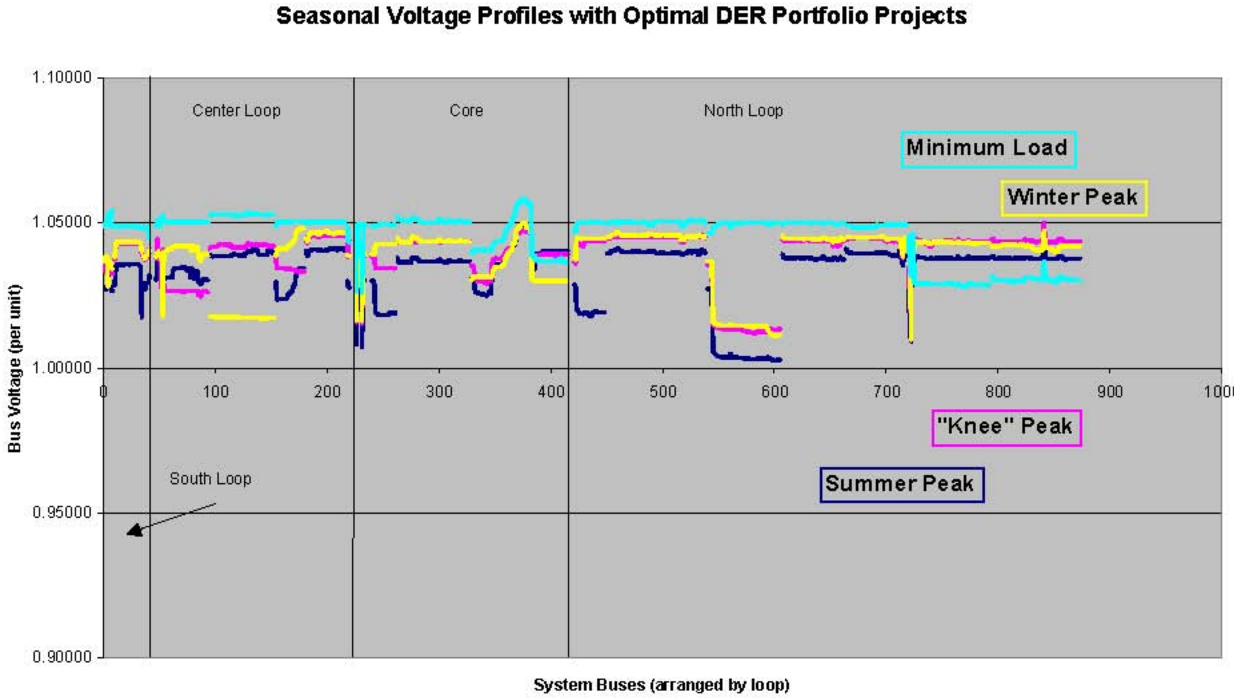

Figure 35 Seasonal Voltage Profiles with Optimal DER Portfolio Projects

Note that with the cumulative effects of DG and DR projects, the voltage profiles in all seasons are very flat compared to the "as found" voltage profiles, and low and high voltage buses are eliminated, in all seasonal conditions.

- Increased Load-Serving Capability: 117.6 MW under top 1% highest hour peak loads and single contingency conditions.
- Capacity Value

Table 67 Capacity Value (MW) – DG Projects

	Summer Peak	Knee Peak	Winter Peak	Minimum Load
Projects	317	316	318	315
Capacity (MW)	54.89	54.58	54.76	54.37
Loss Red (MW)	5.439	5.308	3.481	2.017
Total	60.329	59.888	58.241	56.387

Table 68 Capacity Value (MW) – DR Projects

	Summer Peak	Knee Peak	Winter Peak	Minimum Load
Projects	389	388	389	387
Capacity (MW)	10.52	3.65	3.56	3.63
Loss Red (MW)	1.279	.455	.551	.442
Total	11.799	4.105	4.111	4.072

3.5.1.2. 2005 Optimal DER Portfolio

- **Real Power Loss Reduction**

Table 69 Loss Reduction (MWh per hour) – DG Projects

	Summer
SVP System	.683
PG&E System	6.025
Total	6.708

Table 70 Loss Reduction (MWh per hour when called) – DR Projects

	Summer
SVP System	.503
PG&E System	4.576
Total	5.079

Table 71 2005 DER Portfolio SVP System Percentage Loss Reduction
(reduction relative to "recontrols" only)

	DG	DR	Total
Summer	23%	17%	40%

- **Reduced Reactive Power Consumption**

Table 72 Reduced Reactive Power Consumption (MVAR) – DG Projects

	Summer
SVP System	16.41
PG&E System	71.487
Total	87.897

Table 73 Reduced Reactive Power Consumption (MVAR) – DR Projects (when called)

	Summer
SVP System	8.73
PG&E System	59.066
Total	67.796

Table 74 2005 DER Portfolio SVP System Percentage Reactive Power Consumption Reduction (reduction relative to "recontrols" only)

	DG	DR	Total
Summer	20%	11%	31%

- **Voltage Profile Improvement and P Stress Reduction**

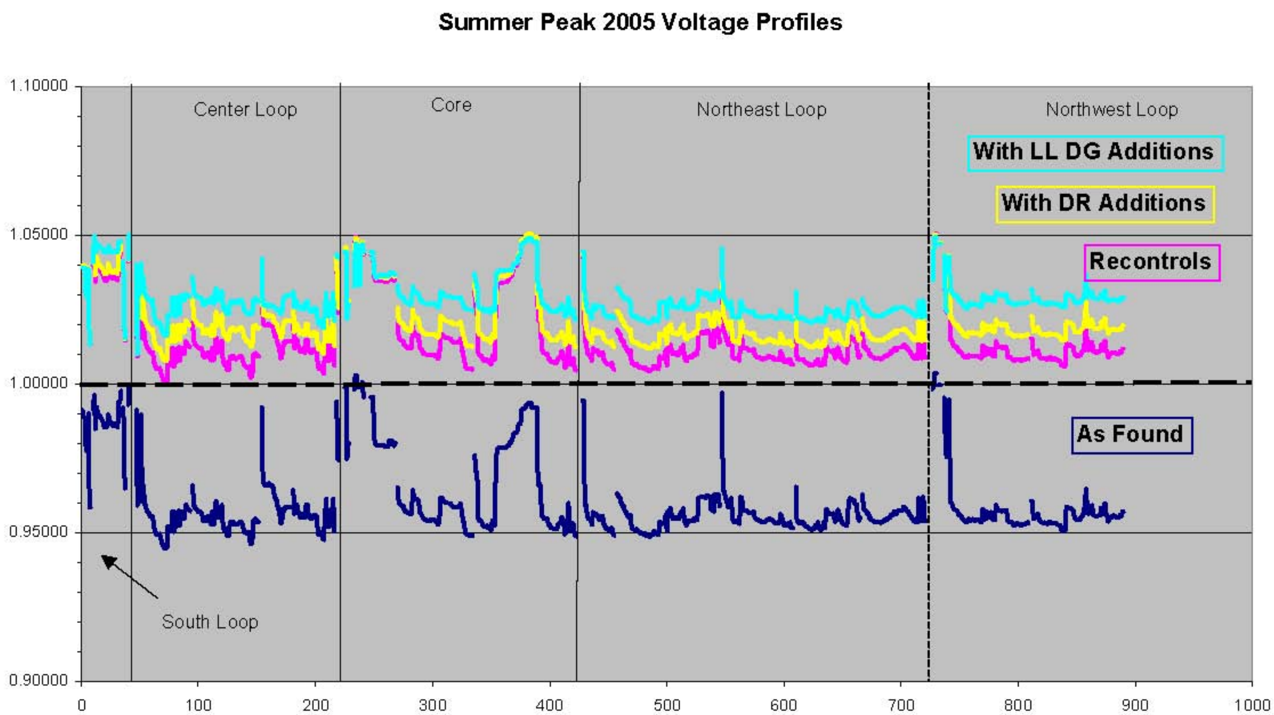

Figure 36 Summer Peak 2005 Voltage Profiles

Note that the recontrol step for the 2005 system made a significant, far-reaching improvement in voltage profile. The addition of DR and DG projects yielded further improvement, and with their cumulative effects all low and high voltage buses are eliminated.

Table 75 Voltage Profile and P Stress with DR and DG Projects

	Summer
Avg Voltage (PU)	1.028
Low buses	No
High buses	No
Voltage Var.	0.007
Avg P Stress	.006

- **Increased Load-Serving Capability: 46.727 MW under peak loads and single contingency conditions.**
- **Capacity Value**

Table 76 Capacity Value (MW) – DG Projects

	Summer Peak
Projects	149
Capacity (MW)	66.66
Loss Red (MW)	6.708
Total	73.368

Table 77 Capacity Value (MW) – DR Projects

	Summer Peak
Projects	390
Capacity (MW)	25.53
Loss Red (MW)	5.079
Total	30.609

- **Comparison of Optimal DER Portfolio with Network Additions**

Table 78 below (repeated from Table 44) summarizes the performance of the network with specified network additions incorporated. Table 79 (repeated from

Table 45) compares the network benefits of these additions with network benefits achieved by the Optimal DER Portfolio projects.

Table 78 Summer 2005 System With SVP Capital Additions - Results

	NRS 230 kV	PICO	NRS 230 + PICO
P Losses (MW)	4.106	2.897	3.502
Q Losses (MVAR)	103.519	81.274	98.725
Average Voltage (PU)	1.012	1.013	1.013
Min. Voltage	.997	.977	.998
Max. Voltage	1.050	1.050	1.051
Std. Dev. Voltage	.011	.011	.011
Average P Stress	.006	.006	.006
Max. P Stress	.029	.029	.029
Std Dev. P Stress	.005	.005	.005
SVP Load-Serving Capability (MW)	861.049	862.196	902.536

Table 79 Comparison of SVP Network Benefits of Optimal DER Portfolio and SVP Capital Additions

	2005 Opt DER	NRS 230	PICO	NRS 230 + PICO
Δ P Loss (MW)	-1.186	+1.135	-0.074	+0.531
Δ Q Loss (MVAR)	-25.145	+21.915	-.330	+17.121
Δ Avg Voltage (PU)	+.013	-.003	-.002	-.002
Low buses	No	.997	.977	.998
High buses	No	No	No	1.051
Δ Voltage Var.	-.001	+.003	+.003	+.003
Δ Avg P Stress	-.002	-.002	-.002	-.002
Capacity Value (MW)	93.512		147.074	147.074
Δ Load-serving Capability (MW)	+46.7	+37.5	+38.6	+79.0

It is evident that no combination of the NRS 230 kV project and the PICO project yields the loss reduction, increase in overall system voltage, and reduction in voltage variability of the Optimal DER Portfolio. Each of the alternatives yields an improvement in the average P stress in the network.

Table 80 (repeated from

Table 46) shows the network benefits of an Optimal DER Portfolio developed using the same approach, but for a network hypothesized as having the loads of the 2005 network but none of the network improvements incorporated in the 2005 cases above. In this case the Optimal DER Portfolio consists of 385 DR projects representing 24.03 MW, subject to the DR limitations described in Section 2.2, and 154 DG projects representing 64.63 MW, with the "Light Load" feeder limit applied. As before, these projects are in specific locations and dispatched at specified levels.

Table 80 Summer 2005 System without NRS 115 kV

	With Recontrols	With DR Projects	With DR & DG Projects
P Losses (MW)	3.786	2.995	2.094
Q Losses (MVAR)	104.970	90.500	69.311
Average Voltage (PU)	.999	1.015	1.026
Min. Voltage	.985	1.003	1.012
Max. Voltage	1.050	1.050	1.052
Std. Dev. Voltage	.014	.011	.008
Average P Stress	.011	.010	.008
Max. P Stress	.030	.026	.022
Std Dev. P Stress	.005	.005	.004
SVP Load-Serving Capability (MW)	536.816	N/A	710.243

The system in this configuration has a substantially reduced load-serving capability. Under a single contingency the maximum served load is actually a reduction from the total load in the base 2005 cases. With the addition of the 385 DR and 154 DG projects in their specified locations, real losses were reduced by about 45% and reactive power consumption was reduced by about 34%. Low-voltage buses were eliminated, variability of voltage was reduced, overall voltage was increased, and overall network P stress was reduced. Load-serving capability of the network was also increased by about 173 MW.

3.5.2. Value of Network Improvement

The network benefits yielded by these projects, particularly real power loss reduction and reduced reactive power consumption and capacity, can be readily priced in economic terms. Others, including voltage profile improvement, the elimination of low-and high-voltage buses, reduced system stress, and increased load-serving capability, are more difficult to price though may still be significantly valuable. The contributions of the Optimal DER Portfolios are quantified in economic terms below. Economic values are expressed in terms of the portfolio in aggregate and on a per-kW of portfolio capacity with benefits allocated equally across the portfolio projects.

The development of these values is discussed in detail in Section 2.4.

3.5.2.1. 2002 Optimal DER Portfolio

- **Loss Reduction Value ($ per year) – DG Projects:**

Table 81 Loss Reduction Value

	Summer Peak	Knee Peak	Winter Peak	Minimum Load	Year
DG Portfolio	$38,573	$363,374	$285,222	$147,457	$834,262
Per kW	$.70	$6.66	$5.21	$2.71	$15.28

- **Reactive Power Value – DG Projects: $37.94/kW**
- **Capacity Value**

Table 82 DG Projects ($/year)

	Summer Peak	Summer Season	Winter Season
Capacity (MW)	60.329	59.888	58.241
Portfolio	$310,091	$940, 242	$1,366,334
Per kW	$5.65	$17.23	$24.95

These seasonal values are additive, and for projects providing capacity during all seasons the value approaches $50/kWyr

Table 83 DR Projects ($/year)

	Summer Peak	Summer Season	Winter Season
Capacity (MW)	11.799	4.105	4.111
Portfolio	$60,647	$64,448	$96,444
Per kW	$5.76	$17.66	$27.09

Again, these seasonal values are additive. A DR project specified, based on its location, with a normal capability of 1 kW during winter and summer seasons and a 3 kW capability under highest-load-hour conditions would have a capacity value of a little over $60/kWyr.

These illustrate how economic value could be derived using the results of this methodology. Compiling these results we have network benefits for the 2002 Optimal Portfolio DG projects yield in the neighborhood of $40/kW for avoided reactive capacity, $15/kWyr for real loss reduction, and $50/kW year for capacity. If the loss reduction and capacity values are brought to the present using a 10-year, 10% discount factor, the total value is nearly $450/kW.

In addition, where the increased load-serving capability from a portfolio of DER projects defers or eliminates the need for otherwise planned capital upgrades, the avoided cost of those upgrades is a quantifiable economic benefit that should be attributed to the DER projects.

3.5.2.2. 2005 Optimal DER Portfolio

- **Loss Reduction Value ($ per year) – DG Projects:**

Table 84 Loss Reduction Value ($ per year) – DG Projects

	Summer Super-Peak	Summer Season Peak	Winter Season Peak	Off-Peak	Year
DG Portfolio	$75,566	$558,049	$428,339	$256,305	$1,318,260
Per kW	$1.13	$8.37	$6.43	$3.84	$19.78

- **Reactive Power Value – DG Projects: $37.94/kW**
- **Capacity Value**

Table 85 Capacity Value ($/year) – DG Projects

	Summer Peak	Summer Season	Winter Season
Total Capacity (MW)	73.368	73.368	71.020
Portfolio/season	$474,691	$2,314,760	$1,623,517
Per kW	$7.12	$34.72	$24.36

Table 86 Capacity Value ($/year) – DR Projects

	Summer Peak	Summer Season	Winter Season
Total Capacity (MW)	30.609	10.203	10.203
Portfolio/season	$198,040	$321,905	$233,241
Per kW	$7.76	$37.83	$27.41

For the 2005 Optimal DER Portfolio, capacity values and loss benefits of the portfolio projects are extrapolated from the summer conditions analyzed based on results for the 2002 portfolio. Real power losses are valued based on a forecast of 2005 energy prices, and capacity is valued based on actual capacity prices for the 2004-5 year.

3.6. Guided Policies and Targeted Incentives based on Optimal DER Portfolios

Another element of the goal of this project was to determine how the Optimal DER Portfolio can be used to guide policies and design incentives to facilitate the development of real DER projects that enhance T&D network performance.

As discussed in more detail in Sections 2.5 and 2.6, we used the detailed characterization generation projects identified for the Optimal DER Portfolio – i.e., their location, size, and operating profile – to evaluate the siting requirements that would apply and to consider how these projects would benefit from existing incentives. This establishes an assessment of existing barriers and incentives specific to projects demonstrated to enhance T&D network performance for this particular power delivery network. We then considered non-financial incentives (policy initiatives) and financial incentives that would specifically address these barriers and/or directly promote projects having the attributes of the Optimal DER Portfolio projects and thus achieve improved network performance.

3.6.1. Nonfinancial Incentives

As discussed in Section 2.5, we evaluated the siting requirements and feasibility of the 133 highest-ranked (most valuable) Optimal DER Portfolio generation projects identified for Summer 2002 conditions. These specific projects, their location (interconnection bus), size, and seasonal operating profile are listed by location in Appendix 2.5-1. This listing also includes information about the host customer, including the customer's class and peak load.

These projects range in size from 7 kW to 1.3 MW, with an average size of about 155 kW. Their interconnection bus also specified their street address. All would interconnect with the network at the distribution level, at 12kV. In general, the specified operating profile of these projects is a high operation factor. Most (86 projects) would operate at some level year-round, with only 16 of those operating at less than a 100% operating factor. The remainder would operate seasonally.

We found that these projects could very likely be sited under city-granted conditional use permits, primarily because they are all located in commercial or industrial districts of the city. However, we also found specific permitting issues that are of particular concern for these projects, especially in light of their relatively small size, the size of their host customers, and the number of projects anticipated in the Optimal DER Portfolio.

The City of Santa Clara's zoning ordinance does not provide specific guidance for non-utility on-site power generation facilities. Power generation other than utility facilities is not identified as a permitted use under any zoning category, and the criteria for approval of such facilities as a conditional use are not specified. This does not preclude the siting of these units, particularly given that using presently available equipment these projects would likely satisfy any reasonable criteria imposed. However, it does place the burden on the planning staff to understand the project and its technology and make interpretations of zoning requirements to determine if a particular project is permissible. The siting of projects in the number contemplated in the Optimal DER Portfolio would ideally be much more routine.

Even if these generation projects use equipment pre-certified by CARB as ultra-low emission, most will still be subject to a full review, demonstration of use of "Best Available Control Technology," and air permit issuance. This is because the Bay Area Air Quality Management District, the local air quality management district for Santa Clara, extends its jurisdiction down to very small stationary engines of 50 hp or greater. CARB certification was intended to streamline permitting for demonstrably low-emission distributed generation projects. However, in the case of these projects, it provides relatively little benefit in terms of permit simplification.

Even if these projects meet all applicable emission, noise, and visual impact standard, they will still likely be subject to review under the California Environmental Quality Act CEQA), through either an Environmental Impact Report (EIR), or a Mitigated Negative Declaration. In general, CEQA review is required if there is a discretionary government action; in the case of these projects CEQA review would be triggered by the issuance of a conditional use permit by the city or an air permit by the BAAQMD. CEQA has exemptions for certain types of facilities, including certain power generation facilities, but there is no exemption that would cover all or most of the Optimal DER Portfolio generation projects.

The Optimal DER Portfolio for this network contemplates a high penetration of relatively small, high load-factor DG units. In light of that, we judge these barriers to be particularly impactful for Optimal DER Portfolio generation projects, especially if these projects are sponsored by their host customers – primarily medium commercial and small industrial facilities. Therefore, we suggest the following policy initiatives to address these barriers; we believe such initiatives represent meaningful non-financial incentives for generation projects that would yield performance benefits this power delivery network.

We believe a local planning ordinance for the City of Santa Clara that specifically anticipates onsite generation and establishes objective standards would be a valuable non-financial incentive for Optimal DER Portfolio generation projects. For example, the City of Pleasanton ordinance identifies distributed generation projects of under 1,000 kW as "small" electric generator facilities. It also enumerates a specific set of criteria for allowed fuels, emissions, visual impacts, noise, and odors for these facilities that will ensure that they have minimal impacts. Projects meeting these criteria are classified as "permitted" uses in agricultural, office, commercial, industrial, and institutional districts, and as "conditional" uses in residential districts. If such an ordinance were applicable to the Optimal DER Portfolio generation projects for this network, nearly all of these projects would be handled as "permitted" uses provided they meet the stated environmental criteria. This would reduce the burden on planning staff and avoid the need to issue a conditional use permit, greatly facilitating siting of these projects. Further, with these criteria pre-determined and published, it becomes an easy matter for vendors and developers or host customers to determine if they can be met – a significant benefit for a medium-sized commercial or industrial customer considering installation of onsite power generation as an adjunct to its regular business.

Appendix 2.6-1 includes a model resolution leading to a DER ordinance that could be adopted by a local agency with local land use jurisdiction (such as Santa Clara in this case) seeking to facilitate the deployment of DER projects of the type identified for the Optimal DER Portfolio at a penetration level that could yield grid benefits.

While this lies outside Santa Clara's jurisdiction, we also believe that it is reasonable to consider exempting projects under 1,000 kW from review by BAAQMD provided they use equipment that has been pre-certified under the CARB program. This would remove another barrier for developers and owners of generation projects. Such a rule change would greatly simplify the permitting of many of the Optimal DER Portfolio generation projects for project owners and developers and would be a valuable non-financial incentive. It would also provide an added incentive for industry participants to embrace the CARB certification process.

We also suggest a categorical exemption from CEQA for generation projects of any type under 1,000 kW that use equipment with CARB emissions certification, that are located in industrial, commercial, or institutional zones, and that satisfy local requirements for noise and visual impacts. Projects that meet these requirements are very unlikely to have significant environmental impacts, and arguably can be adequately evaluated under the local land use process without the additional burden of the CEQA review. Removal of the CEQA step would be an important non-financial incentive.

These policy changes would also give additional encouragement to DG industry participants and vendors to embrace the pre-certification processes that have been established in California. Ultimately permits for the installation of an onsite generation facility should be as straightforward as those for other industrial equipment with comparable impacts.

3.6.2. DR Financial Incentives

This study suggests a new approach for demand response program incentives, one that is location-specific, that includes specification of general and seasonal dispatch characteristics, that extends to full participation within those customer classes where sophisticated metering and telecommunications are available or could be justified, and that compensates customers based on the value their demand response provides. A locational approach to demand response – calling for reductions only where and when they have the most value – has the twin benefits of improved network performance and reduced impact on customers.

Such an approach is inherent in the Energynet notion of an intelligent power system, where among other things load is responsive to network conditions.

Some features of location-specific demand response are already incorporated in traditional demand response programs. Customer-level demand response projects are by their nature implemented at the individual customer level. Demand response measures once implemented are also engaged at the individual customer level, whether by telephone request, price signal, or an automatic signal to the customer's Energy Management System.

To incent beneficial DR projects on a value-sharing basis, a network operator could offer a per-kW incentive for customer-sponsored demand response in specific locations in the network based on the estimated monetary value derived from DR projects from an analysis of the type described in this study.

For example, an analysis as demonstrated in this study might identify a set of specific Optimal DER Portfolio DR projects that is found to yield network benefits in terms of capacity and voltage profile improvement. The analysis might also establish that the capacity component associated with these DR projects is worth $400/kW. Accordingly, the network operator could offer an incentive of, say, $250/kW to customers in the specific locations identified in the study for beneficial projects. To qualify for the incentive, these customers would simply need to develop projects having the following characteristics:

- Verifiable demand reduction as a percent of load and in absolute terms comparable to that assumed in the study.
- Specified dispatchability.
- Related telecommunications capability.
- Rights to the wholesale capacity value of the project remain with the utility.

If an individual DR project is shown through the analysis to have value only under certain network conditions or time periods, the plan sponsor or network operator can offer assurances that the demand response will be called on a limited basis, possibly gaining additional customer participation or levels of response.

The utility could offer this incentive preferentially for individual projects identified by this methodology as particularly high-ranking in terms of network benefits, or could tailor the incentive using a sliding scale to further incent projects in groups identified as contributing a greater share of network benefits

Because the real and reactive loss benefits of DR are intermittent, the easily-priced network benefits of DR considered in this section are limited to capacity value, only a portion of which is location-specific. The greatest value of demand response in terms of network performance benefits may lie in the areas of voltage profile improvement and stress reduction, particularly given the operational flexibility of a locational demand response program. The inability to directly value these benefits makes the implementation of a value-sharing locational demand response incentive more difficult.

3.6.3. DG Financial Incentives

As with demand response, this study suggest that financial incentives for onsite generation that provides network benefits should be location specific and conditioned upon the availability of certain operational flexibility and possibly limited operational control.

As indicated in Section 2.6, such a program must be highly location-specific. In some instances an incentive program may offer the same incentive for projects near each other, and in others the incentive may be different; both conclusions are justifiable as the result of rigorous analysis.

As an illustration of such an incentive, an analysis as demonstrated in this study might identify a set of Optimal DER Portfolio DG projects that is found to yield network benefits (loss reduction, reduced VAR consumption, capacity, and avoided network upgrades) of $450/kW. The network operator could offer an incentive of, say, $250/kW to customers in the beneficial locations identified in the study. To qualify for the incentive, these customers would need to develop projects having the following, fairly light-handed characteristics:

- Size comparable to that assumed in the study.
- VAR output dispatchable by the utility within the rated range of the generator.
- Rights to the wholesale capacity value of the unit remain with the utility.

If an individual project were one of the 1/3 of the DG projects that must follow a specified operating profile according to the analysis, that requirement would be specified as well. However, this specification could be as simple as an agreement to turn down the unit on request during off-peak hours or in some cases during a particular season. For the remaining units eligible for the incentive it would be sufficient for the owner to agree to operate the unit as available during peak daytime hours.

The utility could offer this incentive preferentially for individual projects identified through the methodology as particularly high-ranking in terms of network benefits, or could tailor the incentive using a sliding scale to further incent projects in groups identified as contributing a greater share of network benefits

If the projects are successfully developed, the utility benefits by retaining a share of the predicted network benefits, now realized. As the penetration of real projects evolves, the utility can easily refresh the analysis under the method demonstrated here to incorporate actual projects, and restate the incentives for yet-to-be-developed projects to more accurately reflect both the needed characteristics and projected benefits of those projects.

The availability of such financial incentives would allow customers and their advisors to make economic assessments of potential generation projects that combine network benefits with customer economic benefits and other benefits. Thus the benefits to multiple stakeholders are combined in a single decision – those projects offering *both* network benefits and customer benefits would become the most feasible as customer-sponsored projects.

The approach developed in this study would also permit the network operator to identify those DG projects with significant network benefits but that are unlikely to be developed under customer initiatives. These projects are ideal candidates for utility development as a cost-effective element of power delivery network improvement.

4.0 Conclusions and Recommendations

4.1. Conclusions

4.1.1. Optimal DER Portfolios

In general, we conclude unequivocally from these results that DER can provide network benefits, provided these projects are in the right locations and have the right characteristics, and we can determine those locations and characteristics in a systematic way. Section 2.3 presents Optimal DER Portfolios for the subject system for 2002 and 2005 conditions. These portfolios constitute individual DER projects, identified by type (DR or DG in this case), location, size, and operating profile appropriate for a range of network conditions. Section 2.3 also shows the improved performance of the network with these DER projects located and dispatched as proposed under these different operating conditions. The results using the AEMPFAST network model are confirmed using PSLF. From this we conclude that this methodology is an effective way to determine the locations and characteristics of DER projects that enhance network performance.

The results in Sections 2.2 and 2.3 clearly show that the location of DER projects is very important in their ability to enhance (or, by inference, compromise) network performance.

Based on the results presented 2.3, we conclude that there is value in terms of network performance in different levels of demand response individually called for at different customer locations as the network passes through different conditions. This flexibility is reflected in the characterization of the Optimal DER Portfolio DER projects.

From the results in Sections 2.2 and 2.3 we conclude that, at least for this network, DG projects at or near transmission buses or substations offer less in terms of network benefits than do more electrically remote projects out on the distribution feeders. This conclusion is supported analytically by the AEMPFAST rankings. However, it also makes intuitive sense, as adding support at a well-supported location should be expected to provide less incremental benefit than adding the same support at a less-well-supported location.

From the results of Sections 2.2 and 2.3, we conclude that, at least for this network, the amount of redispatch required for beneficial DG units to maintain network benefits under seasonally-varying conditions is actually relatively modest -- the majority of DG projects require no redispatch of real power output. At the same time, the variation in reactive power output from these units is much more pervasive and the ability is very valuable.

From a methodological standpoint we can conclude from the results in Section 2.1, 2.2, and 2.3 that by incorporating off-summer-peak cases based on actual recorded network conditions in our 2002 analysis, we (a) gained important insights into the network's condition outside the summer peak, (b) were able to infer a seasonally-varying operating profile for Optimal DER Portfolio projects, and (c) gained greater insight into the annualized value of network benefits these projects provide. We note that we gained these insights with the development of only three additional cases.

4.1.2. Quantifiable Improvement in Network Performance

From the results presented in Section 2.4, we conclude that the Optimal DER Portfolio projects, located and operated as specified by this methodology, have the potential to yield significant, quantifiable network benefits in terms a predetermined set of metrics, listed below. In Section 2.4 we showed how the impact of the Optimal DER Portfolio projects under these metrics varies under seasonal conditions. We also showed how these metrics can be used to compare the network benefits of the Optimal DER Portfolio projects with the network benefits of traditional network expansion projects on an "apples-to-apples" basis.

- Local system P and Q loss reduction
- Regional System P and Q loss reduction
- Voltage profile improvement (overall level, low and high-voltage buses, voltage variability)
- P Stress reduction (overall level, high buses, variability)
- Increased load-serving capability under contingency conditions
- Capacity value

We also conclude that at least for this network, the network benefits of the Optimal DER Portfolio projects are not limited to Summer Peak conditions; on the contrary, the benefits are nearly as great under all the conditions considered, including the Minimum Load case.

From the results presented in Section 2.4 we also conclude that this methodology identifies potential network benefits from DER that can be valued in dollar terms. We also conclude that some of the network benefits with possibly the greatest potential value are not easily priced.

4.1.3. Integration of T&D Into a Single Model

As shown in Section 2.1, we determined that the nature of the data required to simulate a distribution system within an integrated distribution and transmission model using a transmission-oriented power flow model is readily obtained from engineering drawings of the form used by SVP. Gathered in a systematic way, these data are fairly easily checked and put in a form for integration into a regional transmission dataset. With methods we developed we were able to integrate these data and achieve initial power flow solutions using a legacy tool, GE's PSLF, as well as a new tool, AEMPFAST, achieving confirming results in the two analytical environments. Based on this experience we conclude that the creation and use of datasets integrating distribution and transmission is not only feasible, but practical.

The results discussed in Sections 2.1 and 2.2 illustrate that a load flow solution using an integrated dataset incorporating distribution and transmission gives visibility into system conditions and opportunities for improvement that would be invisible using the traditional approaches of modeling transmission only or distribution feeders individually. This is particularly true when actual seasonally-varying network data are incorporated in the model. Even the system that is the subject of this study, lightly loaded, with no obvious concerns, revealed localized areas where capacity additions could potentially enhance network performance. From this we conclude that the true network-wide impacts of distribution-connected DER can only be assessed using a model that combines transmission and distribution into a single dataset.

4.1.4. Guided Policies and Targeted Incentives based on Optimal DER Portfolios

From the results presented in Sections 2.5 and 2.6, we conclude that this method's specification of individual projects within the Optimal DER Portfolio by location, size, and operating profile permits us to determine what permitting and other requirements are relevant to projects that offer the potential of improved network performance. This information is important in assessing barriers specific to those DER projects that enhance T&D network performance and designing incentives to facilitate their development.

From the results presented in Sections 2.5 and 2.6, we conclude that the absence in Santa Clara's zoning ordinance of specific guidance for small electric power generation projects in commercial and industrial districts, local air district review even for projects using equipment that is state pre-certified for low emissions, and temporary lack of a simplified interconnection rule for the SVP system are the barriers that would have the greatest impact on the types of DG projects with the potential to enhance the performance of the SVP network. We also conclude that there are existing policies and incentives that would encourage beneficial DER projects either only indirectly or not at all.

We conclude from the results presented in Sections 2.5 and 2.6 that additional policies to streamline permitting of the types of projects identified the Optimal DER Portfolios for SVP would still be effective non-financial incentives for such projects. In addition, we conclude that financial incentives to promote such projects should be highly locational in their design.

We also conclude from the results presented in Sections 2.5 and 2.6 that the relatively small size of the generation projects identified for the Optimal DER Portfolio and the relatively small loads of their host customers make the barriers noted above particularly impactful, as customers in this size range are not prepared to deal with uncertain projects outside the size focus of some vendors.

4.1.5. Characterization of Subject System Prior to DER Additions

As noted above, we conclude from the results in Section 2.1, 2.2, and 2.3 that by incorporating the Summer Peak, Winter Peak, Minimum Load, Knee Peak "present" cases and the Summer 2005 "future" in our analysis, we gained important insights into the network's condition outside the summer peak.

The results presented in Section 2.2 also indicate that even a few, localized control variables can have a significant, non-localized impact on overall network performance. Further, these control settings alone can go a long way to improve network performance under seasonally-varying conditions.

4.1.6. Identification of DER Additions to Improve Network Performance

From the results presented in Section 2.2, we are able to conclude that DER resource additions, in the right locations, can demonstrably improve network performance, and that those locations can be identified in a systematic way. We were also able to conclude that, at least for this network, the initial P index for the system is a good indicator of the locations that will ultimately emerge as the highest-ranked locations for resource additions.

As shown in Section 2.2, AEMPFAST has the ability to make distinctions among the benefits of alternative potential sites for DER capacity additions at a very fine level – down to individual adjacent buses. While a hand analysis of power flow results from an integrated model can identify a number of "good" locations for capacity additions, the "best" locations for capacity additions may not be visible except with a tool such as AEMPFAST. The reliability of these results in this application was supported by this project's TAC. From this we conclude that AEMPFAST is a tool that is very useful in assessing the relative merits of hundreds or thousands of potential sites for DER capacity additions.

One implication of this conclusion is that the approach presented here of using integrated datasets to identify beneficial DER locations in the distribution system creates its own problem of the need to evaluate a great many potential sites for capacity additions. In contrast, the analysis of potential sites for central-station power plants in a transmission system would offer far fewer choices. Again, we conclude that the use of a tool such as AEMPFAST that can draw fine distinctions among a large number of potential capacity addition locations is very valuable in this application.

From the results of Section 2.2, we also conclude that the Rule 21 limit on DG at 15% of a feeder's peak load is a restrictive limit. Relaxing that limit to the feeder's load under minimum load conditions would also prevent export, but would also permit distributed generation to contribute more in terms of network benefits.

4.2. Recommendations

In general, this study shows that this methodology offers the analytical tool sought to assess and quantify the benefits of DER to a power delivery network, providing the location and other characteristics of projects that provide these benefits. As such, this methodology is a practical and valuable tool for network planning and policy guidance. It permits the inclusion of DER as a key component in a power delivery network, and thus meets the overarching goal of this project.

4.2.1. Optimal DER Portfolios

This project shows that the approach presented here is a viable analytical tool for systematically determining the location and characteristics of DER projects that would enhance network performance. This information would be useful for utilities seeking to assess their systems either in anticipation of growth in customer-sponsored DER projects or as part of a utility DER initiative.

Further, as these results show that the ability of DER projects to enhance network performance is highly dependent on their locations, this project suggests that any blanket plan or policy concerning DER is problematic, and such plans and policies should be developed with the benefit of a network assessment of this type.

Demand response is presently developed and implemented on an individual customer site basis. However, programs to encourage demand response and measures to call for demand response are presently not highly locational, in fact, they may be state wide. This project shows that if DR were promoted and called or dispatched on a locational basis, it could yield additional value in the form of network benefits.

These results show that there is significant value in the inclusion of all DG units in a network operator scheme to maintain network performance. At the same time, these results show that such a scheme need not necessarily burden the unit for the use of the customer. In fact, it may be sufficient in the majority of cases to leave dispatch control with the customer as long as the network operator can control the unit's reactive power output within the specified operating range of the unit's generator.

Perhaps more importantly, incorporating seasonal analyses based on historical loads in a network assessment of this type permits the specification of operating requirements for beneficial DER projects ahead of time. This would allow the network operator to achieve the desired results without unnecessarily burdening or inconveniencing customers. This in turn could yield greater and more valuable customer participation in both DR and DG programs designed to enhance network performance.

More fundamentally, this study demonstrates the network benefits of ideally-placed DER whose operation is coordinated and the benefits of optimized control settings. It also demonstrates the practicality of planning of tools such as this methodology and the AEMPFAST network optimization tool. These suggest significant network performance value in an Energynet power delivery infrastructure that incorporates much more extensive monitoring and control, particularly at the distribution level, intelligently coordinated operation of distributed devices, and analytically-guided operational decisionmaking.

4.2.2. Quantifiable Improvement in Network Performance

The methodology presented here offers the ability to systematically quantify the potential benefits of DER to the performance of a power delivery network, using a set of metrics that can also be used for traditional network expansion projects, fulfilling the basic goal of this project. Moreover, the network benefits are shown to be considerable, and impacts of DER are shown to be comparable in some respects to traditional transmission upgrades at least for this network. Accordingly, DER should receive more attention as a measure for achieving network performance improvements and increased load-serving capability alongside traditional “wires” measures. With this methodology DER can be beneficially incorporated as a core component of a T&D network.

Improvement in voltage profile, elimination of low- and high-voltage buses, reduction in reactive power consumption, and reduction in system stress are network benefits not traditionally associated with DER. At the same time, these issues are receiving increasing attention in the industry. Voltage support and reactive sources were the first “near term industry action” identified by the North American Electric Reliability Council following the Northeast blackout of 2003.[25] This project shows the ability of DER to provide these benefits if properly sited and operated, and it shows the ability of this methodology to determine how and quantify how much. The inability to put dollar values on network benefits of this type is a challenge that should be addressed. In the meantime, the ways to incorporate these benefits – and resources that provide them – in system planning should continue to developed and implemented when ready.

DER, particularly DR should not be thought of as purely a peak-reduction strategy; this project shows that the true potential network benefits of DER are year-round, and achieved through a diverse set of projects flexibly managed over a variety of conditions.

4.2.3. Integration of T&D Into a Single Model

This project has demonstrated both the practicality and value of “Energynet” datasets integrating distribution and transmission in a single network model. These results suggest that this platform could be expanded to uses other than simply the ideal placement of DER in a

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[25] D. Nevius, D. Cook, et al, *FERC and Regional Efforts to Ensure Reliability*, p. 15

power system. Certainly, any DER planning and assessment should be performed using an integrated Energynet T&D model.

4.2.4. Guided Policies and Targeted Incentives based on Optimal DER Portfolios

This project shows that the Optimal DER Portfolio approach offers an important input in assessing the practicality of DER as a measure for network performance improvement. This study shows how identification of the individual project characteristics of beneficial projects permits an assessment of their feasibility even on a hypothetical project level. If DER projects cannot be sited or operated as needed to deliver network benefits, they are not really a viable alternative to traditional network upgrades.

This project has shown that identification of Optimal DER Portfolio projects, according to the method of this study, permits the identification of siting barriers having the greatest impact on DER projects that provide network benefits as well as customer benefits – the most valuable DER projects. This perspective would provide important guidance to policy initiatives seeking to make DG easier to implement.

This project shows that this methodology and its results can be extended to developing financial incentives for DER that share the value these projects create rather than simply shift costs. Such incentives would facilitate the exchange of value between the multiple stakeholders in a DER project and lead to more economically rational decision-making. However, this study also indicates that financial incentives for DER that are based on a sharing of network benefits must be highly locational. Policy makers would have to accept the analytical results that justify different treatment for different projects.

Through this study we developed three specific recommendations that relate to the Optimal DER Projects we identified for the SVP system. These are:

1. Adopt a local distributed generation ordinance that establishes requirements for small (< 1,000 kW) DG projects that ensure their impacts are minimal, but then allows their siting as a "permitted use" in appropriate districts.
2. Allow an exemption from local air board permitting for projects of under 1,0000 kW that use equipment pre-certified for emissions under the CARB program.
3. Allow an exemption from CEQA review for any generation project using CARB-certified equipment and that meets all local noise, visual, and other requirements.

Our motivation is to move the mechanism for ensuring minimal impacts away from project-specific review to pre-established standards. This would facilitate the siting of onsite generation projects in the numbers that appear warranted to yield grid benefits as a fairly routine matter. The purpose of these recommendations within this project is to illustrate how this methodology can be used to identify and guide policies specifically to promote grid-beneficial projects for a given system. However, we believe this project's results support actually implementing these recommendations.

If the experience of this network is repeated, a focus on DG with network benefits will raise the importance of comparatively large numbers of relatively small power generation units located at electrically-remote sites of customers with modest sized-loads. Because the siting of such units is presently still far more involved than the siting of other industrial equipment, this raises number of related implications.

Chief among these is the suggestion that deploying onsite generation for network benefits may not simply be a question of financial incentives. For example, further standardization of permitting requirements such as through the recommendations above, may be a requirement to the emergence of grid-beneficial DG projects. Increased vendor support for units in smaller sizes may also be a key factor.

Siting onsite generation projects under the present requirements described in Section 2.5 is somewhat specialized and requires expertise likely not found with many of the relatively small host customers identified in this study. Accordingly, the deployment of DER for network benefits could depend on capable third-party project integrators, or the network operators themselves.

4.2.5. Characterization of Subject System Prior to DER Additions

This project suggests that network analysis using actual historical loads, particularly seasonally-varying data, may yield important insights that, while based on a backcast, have value in planning.

This project also demonstrates that the re-optimization of available network controls has the potential to yield significant benefits on its own, even before consideration of resource additions. Accordingly, the optimization of control settings in power delivery systems, and the use of tools such as AEMPFAST that provide such results, should receive far more attention. Also, more extensive operational controls might be justifiable.

Further, dynamically operable controls, or the ability to refine the adjustment of controls on a more continuous basis, could have significant value in accomodating varying network conditions while maintaining high network performance. Remotely dispatched, variable-output capacitors are a good example of such dynamically-operable controls.

4.2.6. Identification of DER Additions to Improve Network Performance

As noted above, and in Section 2.2, it appears that the Rule 21 limit on DG penetration for simplified interconnection could restrict the deployment of beneficial projects. With the availability of more sophisticated tools that identify DG projects that yield network benefits on a system-wide basis rather than through individual project analysis (and also, by inference, DG projects that may compromise network performance), the Rule 21 limit on DG penetration at 15% of the feeder's peak load should be reconsidered.

4.3. Commercialization Potential

The method demonstrated in this study shows potential as a valuable tool for network operators to assess their system requirements in anticipation of customer or third-party sponsored distributed generation or as a tool to employ DER to improve network performance alongside traditional network upgrades. The potential is significant, as this study shows that at least for some systems DER may be able to provide network performance improvement that is comparable or superior to the gains that would be achieved through network upgrades

This method could also be used to extract additional value – in the of network performance improvement – from existing DER sites and existing programs to promote DER.

Network operators could also use this tool, working with regional planners policy makers, to develop policies and tariffs to promote the development of beneficial DER projects (and discourage the development of DER projects that are not beneficial).

The next step in the development of this approach is to implement it in a major utility system with a much larger distribution component, and, ideally, one where there is a known need to assess and resolve network deficiencies. The suite of DER alternatives considered could be expanded to include storage devices and generator types other than synchronous generators. Also, our ability to directly observe the impact of changes in the distribution system on the entire network, including transmission, suggests the assessment of distribution measures other than DER, such as variable topology through automated or remote switching.

4.4. Benefits to California

California's final Energy Action Plan[26] establishes as its goal:

- Ensure that adequate, reliable, and reasonably-priced electrical power and
- Natural gas supplies, including prudent reserves, are achieved and provided
- Through policies, strategies, and actions that are cost-effective and
- Environmentally sound for California's consumers and taxpayers.

The Action Plan proposes six specific means to accomplish its goal. These include Optimizing Resource Conservation and Energy Efficiency (I), Upgrading and Expanding The Electricity Transmission and Distribution Infrastructure (IV), and Promoting Utility-owned and Customer-Owned Distributed Generation (V). The Action Plan also envisions a "loading order" of energy resources under which needs for new generation are met first by renewable energy resources and distributed generation.

Through this project we have demonstrated a methodology that can rigorously and systematically determine the characteristics (location, size, and operating profile) of distributed energy resources that enhance the performance of a given power delivery network. Network benefit s associated with DER are additive to their value as energy resources, and this methodology, which identifies and helps capture these benefits, adds to the value of DER as a means to achieve California's energy policy goal. The ability to assess and quantify these benefits, to design incentives based on a sharing of these benefits, and to focus policies on removing barriers specific to these beneficial projects all will contribute to realizing the Action Plan's preference for distributed generation.

The network benefits of Optimal DER Projects, once quantified under this methodology, themselves contribute to the means identified to achieve the Action Plan's goal. Greater efficiency in the operation of the power delivery system through reduced losses may be a significant – and presently largely untapped – source of energy efficiency. The ability to serve additional load with greater power quality from the existing power delivery infrastructure

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[26] State of California Energy Action Plan, April 2003, http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.

using DER deployed under this methodology contributes directly to the Action Plan's objectives with respect to the transmission and distribution system.

This project demonstrates a systematic, objective analytical tool through which DER can be a core, *contributing* component of power delivery network – at the transmission level, and at the distribution level. With this methodology DER can be considered directly as an element in power system planning alongside "wires" alternatives. Moreover, using this approach, DER can enhance the network's performance in addition to providing incremental resources to its customers.

This project also demonstrates the feasibility of a platform – the integrated Energynet dataset – that directly captures the impacts of measures in either transmission or distribution on both transmission and distribution. This platform may have analysis and planning uses that go well beyond simply the ideal placement of DER.

REFERENCES

References are included in the footnotes.

GLOSSARY

Specific terms and acronyms used throughout this work statement are defined as follows:

Acronym	Definition
AEMPFAST*	Advanced Energy Management and Power Flow Analysis System Technology
Commission	California Energy Commission
DER	Distributed Energy Resources
Energynet	A power transmission and distribution network, treated as an integrated whole, with embedded generation and loads responsive to dispatch or system conditions.
GE PSLF**	General Electric Positive Sequence Load Flow
kVA	Kilovolt-Ampere, a unit of transformer output rating, equals kW at unity power factor.
MVAR	MegaVAR, a unit of rate of reactive power delivery
MW	MegaWatt, a unit of rate of power delivery
MWh	MegaWatt-hour, a unit of energy
PIER	Public Interest Energy Research
PU	Voltage, expressed as a ratio of actual to rated
SVMG	Silicon Valley Manufacturing Group
SVP	Silicon Valley Power
T&D	Transmission and distribution.
TAC	Technical Advisory Committee

* AEMPFAST is Optimal's proprietary advanced software for analysis and optimization of complex electric power systems. According to Optimal Technologies, Inc., Aempfast software is a set of power optimization and management tools that thoroughly and intelligently solves for competing objectives relating to the real physical nature of the power grid. It simultaneously addresses system security, voltage profile, reliability, congestion, minimum loss, minimum generation cost, minimum emissions, and minimum maintenance. Taking into account all of these parameters, Aempfast optimizes, analyzes, and manages generation and network resources to provide the optimum solution within the limitations of the resources currently available.

The AEMPFAST Analyzer provides load-flow solutions giving the steady-state condition of the network. The AEMPFAST Optimizer will be used in this study to identify the optimal control settings and/or modifications or additions that optimize performance of the network.

** GE PSLF is the load-flow component of the GE power systems analysis package for power systems modeling. The GE PSLF load flow database describes the positive sequence network, and the GE PSLF load-flow solution gives the steady state condition of the network as described by the database. According to GE, load-flow solutions provided by GE PSLF can adjust tap changers, static Var devices, generators, and direct current inverters to control bus voltages.

APPENDICES

2.2-1 DER CAPACITY ADDITIONS APPENDIX

Appendix 2.2-1
DER Capacity Additions

Summer 2002 Rank-Ordered DR Capacity Additions

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	Demand Response (MW)	DR % of Peak Load
1	524	Core1	Feeder 305	Over 1,000 kVA	0.192	0.02875	15%
2	5163	Core1	Feeder 305	200-1,000 kVA	0.014	0.00216	15%
3	8205	Core1	Feeder 305	200-1,000 kVA	0.024	0.00359	15%
4	9129	Core1	Feeder 305	200-1,000 kVA	0.048	0.00719	15%
5	8701	Core1	Feeder 305	Over 1,000 kVA	0.072	0.01078	15%
6	8923	Core1	Feeder 305	200-1,000 kVA	0.024	0.00359	15%
7	8404	Core1	Feeder 305	200-1,000 kVA	0.024	0.00359	15%
8	7285	Core1	Feeder 305	200-1,000 kVA	0.011	0.00162	15%
9	8661	North2	Feeder 202	Over 1,000 kVA	0.372	0.05576	15%
10	5185	North2	Feeder 202	200-1,000 kVA	0.248	0.03717	15%
11	503	North2	Feeder 202	Over 1,000 kVA	0.991	0.14869	15%
12	8313	North2	Feeder 202	200-1,000 kVA	0.124	0.01859	15%
13	5178	North2	Feeder 202	200-1,000 kVA	0.124	0.01859	15%
14	8630	North2	Feeder 202	200-1,000 kVA	0.074	0.01115	15%
15	8662	North2	Feeder 202	Over 1,000 kVA	0.372	0.05576	15%
16	5225	North2	Feeder 202	200-1,000 kVA	0.074	0.01115	15%
17	5028	North2	Feeder 202	200-1,000 kVA	0.124	0.01859	15%
18	8271	North2	Feeder 202	200-1,000 kVA	0.074	0.01115	15%
19	8690	North2	Feeder 202	200-1,000 kVA	0.186	0.02788	15%
20	8314	North2	Feeder 202	200-1,000 kVA	0.124	0.01859	15%
21	8250	North2	Feeder 202	200-1,000 kVA	0.056	0.00836	15%
22	8514	North2	Feeder 202	Over 1,000 kVA	0.372	0.05576	15%
23	8890	North2	Feeder 202	Over 1,000 kVA	0.496	0.07434	15%
24	8204	North2	Feeder 202	200-1,000 kVA	0.124	0.01859	15%
25	7697	North2	Feeder 202	200-1,000 kVA	0.124	0.01859	15%
26	8689	North2	Feeder 202	200-1,000 kVA	0.186	0.02788	15%
27	8303	North2	Feeder 202	200-1,000 kVA	0.186	0.02788	15%
28	8388	North2	Feeder 202	200-1,000 kVA	0.056	0.00836	15%
29	8854	Center2	Feeder 104	200-1,000 kVA	0.508	0.07623	15%
30	8228	North4	Feeder 105	200-1,000 kVA	0.231	0.0346	15%
31	504	North2	Feeder 203	Over 1,000 kVA	0.776	0.11647	15%
32	7736	North4	Feeder 105	200-1,000 kVA	0.092	0.01384	15%
33	7645	North6	Feeder 203	200-1,000 kVA	0.08	0.01199	15%
34	8527	North4	Feeder 104	200-1,000 kVA	0.035	0.0052	15%
35	8161	North4	Feeder 105	Over 1,000 kVA	0.461	0.06919	15%
36	5176	North4	Feeder 104	200-1,000 kVA	0.026	0.0039	15%
37	7654	North6	Feeder 203	200-1,000 kVA	0.08	0.01199	15%
38	7668	North4	Feeder 104	200-1,000 kVA	0.035	0.0052	15%
39	5113	North2	Feeder 203	Over 1,000 kVA	0.388	0.05823	15%
40	8283	North4	Feeder 104	200-1,000 kVA	0.058	0.00866	15%
41	7662	North6	Feeder 203	200-1,000 kVA	0.08	0.01199	15%
42	5148	North4	Feeder 104	Over 1,000 kVA	0.231	0.03463	15%
43	5034	North4	Feeder 105	Over 1,000 kVA	0.615	0.09226	15%
44	9048	North4	Feeder 104	200-1,000 kVA	0.115	0.01732	15%
45	8401	North6	Feeder 203	200-1,000 kVA	0.178	0.02664	15%
46	8341	North4	Feeder 104	200-1,000 kVA	0.058	0.00866	15%
47	5248	North2	Feeder 203	200-1,000 kVA	0.097	0.01456	15%
48	8411	North4	Feeder 104	200-1,000 kVA	0.115	0.01732	15%
49	9011	North2	Feeder 203	200-1,000 kVA	0.097	0.01456	15%
50	5118	North4	Feeder 104	200-1,000 kVA	0.058	0.00866	15%
51	8126	North2	Feeder 203	200-1,000 kVA	0.097	0.01456	15%
52	8787	North6	Feeder 203	200-1,000 kVA	0.178	0.02664	15%
53	7495	North4	Feeder 105	200-1,000 kVA	0.154	0.02306	15%
54	8497	North4	Feeder 104	200-1,000 kVA	0.087	0.01299	15%
55	5205	North2	Feeder 203	200-1,000 kVA	0.146	0.02184	15%
56	8269	North4	Feeder 105	200-1,000 kVA	0.092	0.01384	15%
57	7449	North6	Feeder 203	200-1,000 kVA	0.107	0.01599	15%
58	8698	North4	Feeder 104	Over 1,000 kVA	0.173	0.02598	15%
59	7557	North6	Feeder 203	200-1,000 kVA	0.178	0.02664	15%

Summer 2002 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	Demand Response (MW)	DR % of Peak Load
60	8633	North4	Feeder 104	200-1,000 kVA	0.115	0.01732	15%
61	5226	North4	Feeder 101	Over 1,000 kVA	0.312	0.0468	15%
62	5052	North6	Feeder 205	Over 1,000 kVA	0.48	0.07198	15%
63	9087	North4	Feeder 104	Over 1,000 kVA	0.173	0.02598	15%
64	8595	North2	Feeder 203	Over 1,000 kVA	0.291	0.04368	15%
65	8517	North6	Feeder 203	Over 1,000 kVA	0.533	0.07993	15%
66	8131	North4	Feeder 104	200-1,000 kVA	0.115	0.01732	15%
67	5144	North2	Feeder 203	Over 1,000 kVA	0.388	0.05823	15%
68	8417	North4	Feeder 104	200-1,000 kVA	0.058	0.00866	15%
69	531	North4	Feeder 203	Over 1,000 kVA	0.604	0.09064	15%
70	5273	North6	Feeder 205	200-1,000 kVA	0.054	0.0081	15%
71	9093	North4	Feeder 101	Over 1,000 kVA	0.187	0.02808	15%
72	8594	North2	Feeder 203	Over 1,000 kVA	0.291	0.04368	15%
73	5027	North6	Feeder 203	200-1,000 kVA	0.178	0.02664	15%
74	9091	North4	Feeder 101	Over 1,000 kVA	0.187	0.02808	15%
75	8038	North2	Feeder 203	Over 1,000 kVA	0.291	0.04368	15%
76	515	North6	Feeder 203	Over 1,000 kVA	1.421	0.21314	15%
77	9090	North4	Feeder 101	Over 1,000 kVA	0.187	0.02808	15%
78	8893	North4	Feeder 203	Over 1,000 kVA	0.302	0.04532	15%
79	541	Center3	Feeder 303	Over 1,000 kVA	0.436	0.06544	15%
80	9088	North4	Feeder 101	Over 1,000 kVA	0.187	0.02808	15%
81	5168	North2	Feeder 203	Over 1,000 kVA	0.291	0.04368	15%
82	8592	North6	Feeder 205	Over 1,000 kVA	0.36	0.05399	15%
83	8905	North4	Feeder 104	Over 1,000 kVA	0.231	0.03463	15%
84	5169	Center3	Feeder 303	Over 1,000 kVA	0.164	0.02454	15%
85	8904	North4	Feeder 203	Over 1,000 kVA	0.302	0.04532	15%
86	8973	North2	Feeder 203	Over 1,000 kVA	0.388	0.05823	15%
87	5053	North6	Feeder 205	200-1,000 kVA	0.12	0.018	15%
88	8658	North4	Feeder 104	200-1,000 kVA	0.115	0.00231	2%
89	8044	North6	Feeder 205	200-1,000 kVA	0.12	0.0024	2%
90	5256	Center3	Feeder 303	200-1,000 kVA	0.055	0.00109	2%
91	5255	Center3	Feeder 303	200-1,000 kVA	0.109	0.00218	2%
92	5250	Center3	Feeder 303	200-1,000 kVA	0.055	0.00109	2%
93	517	North6	Feeder 205	Over 1,000 kVA	0.96	0.14397	15%
94	9130	Center3	Feeder 303	200-1,000 kVA	0.109	0.00218	2%
95	530	North4	Feeder 203	Over 1,000 kVA	0.604	0.09064	15%
96	8501	North4	Feeder 104	200-1,000 kVA	0.058	0.00115	2%
97	506	South3	Feeder 104	Over 1,000 kVA	0.859	0.12884	15%
98	8342	North4	Feeder 104	200-1,000 kVA	0.058	0.00115	2%
99	505	North2	Feeder 204	Over 1,000 kVA	2.235	0.33528	15%
100	6837	North6	Feeder 201	200-1,000 kVA	0.173	0.00345	2%
101	534	North4	Feeder 304	Over 1,000 kVA	2.033	0.30488	15%
102	6879	North6	Feeder 201	200-1,000 kVA	0.069	0.00138	2%
103	5115	North4	Feeder 104	Over 1,000 kVA	0.231	0.03463	15%
104	8413	North4	Feeder 105	200-1,000 kVA	0.308	0.00615	2%
105	8363	North6	Feeder 202	200-1,000 kVA	0.041	0.00082	2%
106	8155	North6	Feeder 205	200-1,000 kVA	0.072	0.00144	2%
107	5097	North6	Feeder 201	Over 1,000 kVA	0.46	0.06907	15%
108	8227	North4	Feeder 104	200-1,000 kVA	0.087	0.00173	2%
109	7465	North4	Feeder 104	200-1,000 kVA	0.026	0.00052	2%
110	8412	North4	Feeder 104	200-1,000 kVA	0.115	0.00231	2%
111	5172	North6	Feeder 202	200-1,000 kVA	0.041	0.00082	2%
112	7266	North6	Feeder 205	200-1,000 kVA	0.12	0.0024	2%
113	8445	North6	Feeder 202	200-1,000 kVA	0.041	0.00082	2%
114	9086	North6	Feeder 202	Over 1,000 kVA	0.275	0.04119	15%
115	8164	North6	Feeder 205	Over 1,000 kVA	0.36	0.05399	15%
116	532	North4	Feeder 204	Over 1,000 kVA	1.608	0.24113	15%
117	526	North4	Feeder 101	Over 1,000 kVA	0.499	0.07488	15%
118	514	North6	Feeder 202	Over 1,000 kVA	0.732	0.10983	15%
119	8037	North4	Feeder 101	200-1,000 kVA	0.062	0.00125	2%

Summer 2002 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	Demand Response (MW)	DR % of Peak Load
120	5051	South3	Feeder 104	Over 1,000 kVA	0.429	0.06442	15%
121	8659	North6	Feeder 205	Over 1,000 kVA	0.36	0.05399	15%
122	533	North4	Feeder 205	Over 1,000 kVA	0.908	0.13616	15%
123	5060	North6	Feeder 201	200-1,000 kVA	0.052	0.00104	2%
124	5181	North6	Feeder 201	200-1,000 kVA	0.115	0.0023	2%
125	8225	North6	Feeder 202	Over 1,000 kVA	0.366	0.05492	15%
126	5198	North6	Feeder 201	Over 1,000 kVA	0.345	0.0518	15%
127	5254	South3	Feeder 104	200-1,000 kVA	0.215	0.00429	2%
128	7619	North6	Feeder 205	200-1,000 kVA	0.12	0.0024	2%
129	7198	North6	Feeder 201	200-1,000 kVA	0.115	0.0023	2%
130	5304	North6	Feeder 201	Over 1,000 kVA	0.46	0.06907	15%
131	8730	South3	Feeder 104	200-1,000 kVA	0.161	0.00322	2%
132	8542	South3	Feeder 104	Over 1,000 kVA	0.322	0.04831	15%
133	535	North4	Feeder 305	Over 1,000 kVA	1.893	0.28402	15%
134	9140	North6	Feeder 201	200-1,000 kVA	0.173	0.00345	2%
135	9012	North6	Feeder 201	200-1,000 kVA	0.173	0.00345	2%
136	8352	North6	Feeder 201	200-1,000 kVA	0.173	0.00345	2%
137	8829	North6	Feeder 202	200-1,000 kVA	0.055	0.0011	2%
138	5123	North6	Feeder 201	200-1,000 kVA	0.173	0.00345	2%
139	8924	North6	Feeder 201	200-1,000 kVA	0.173	0.00345	2%
140	8229	North4	Feeder 205	200-1,000 kVA	0.17	0.0034	2%
141	5253	North6	Feeder 201	200-1,000 kVA	0.23	0.0046	2%
142	7758	North6	Feeder 201	200-1,000 kVA	0.115	0.0023	2%
143	540	Center3	Feeder 303	Over 1,000 kVA	0.436	0.06544	15%
144	8792	North6	Feeder 201	200-1,000 kVA	0.115	0.0023	2%
145	5268	North4	Feeder 204	200-1,000 kVA	0.09	0.00181	2%
146	8703	North4	Feeder 204	200-1,000 kVA	0.09	0.00181	2%
147	8365	Center3	Feeder 303	200-1,000 kVA	0.109	0.00218	2%
148	5302	Center3	Feeder 303	Over 1,000 kVA	0.164	0.02454	15%
149	8827	South3	Feeder 104	200-1,000 kVA	0.064	0.00129	2%
150	8726	North4	Feeder 204	200-1,000 kVA	0.201	0.00402	2%
151	7671	Center3	Feeder 303	200-1,000 kVA	0.055	0.00109	2%
152	5135	South3	Feeder 104	200-1,000 kVA	0.048	0.00097	2%
153	5016	South3	Feeder 104	200-1,000 kVA	0.107	0.00215	2%
154	8710	North4	Feeder 204	200-1,000 kVA	0.121	0.00241	2%
155	8187	North4	Feeder 301	200-1,000 kVA	0.114	0.00228	2%
156	7690	North4	Feeder 301	Over 1,000 kVA	0.171	0.02567	15%
157	7563	North6	Feeder 201	200-1,000 kVA	0.052	0.00104	2%
158	525	North4	Feeder 101	Over 1,000 kVA	0.499	0.07488	15%
159	5054	North4	Feeder 301	200-1,000 kVA	0.057	0.00114	2%
160	8281	North4	Feeder 301	Over 1,000 kVA	0.171	0.02567	15%
161	5324	North4	Feeder 303	Over 1,000 kVA	0.453	0.0679	15%
162	7702	North4	Feeder 301	200-1,000 kVA	0.114	0.00228	2%
163	8190	North4	Feeder 301	200-1,000 kVA	0.114	0.00228	2%
164	5094	North4	Feeder 301	200-1,000 kVA	0.086	0.00171	2%
165	8894	North4	Feeder 201	Over 1,000 kVA	0.055	0.00826	15%
166	7986	North4	Feeder 303	200-1,000 kVA	0.226	0.00453	2%
167	7689	North4	Feeder 301	Over 1,000 kVA	0.171	0.02567	15%
168	7763	North4	Feeder 201	200-1,000 kVA	0.006	0.00012	2%
169	8132	North4	Feeder 201	200-1,000 kVA	0.021	0.00041	2%
170	8748	North4	Feeder 201	200-1,000 kVA	0.014	0.00027	2%
171	7612	North4	Feeder 301	200-1,000 kVA	0.114	0.00228	2%
172	5366	North4	Feeder 201	200-1,000 kVA	0.021	0.00041	2%
173	9098	North4	Feeder 201	200-1,000 kVA	0.021	0.00041	2%
174	8541	North4	Feeder 301	Over 1,000 kVA	0.171	0.02567	15%
175	8284	North4	Feeder 201	200-1,000 kVA	0.014	0.00027	2%
176	8591	North4	Feeder 201	Over 1,000 kVA	0.041	0.00619	15%
177	7973	North6	Feeder 201	200-1,000 kVA	0.23	0.0046	2%
178	527	North4	Feeder 103	Over 1,000 kVA	1.448	0.21727	15%
179	8282	North4	Feeder 201	200-1,000 kVA	0.014	0.00027	2%

Summer 2002 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	Demand Response (MW)	DR % of Peak Load
180	528	North4	Feeder 201	Over 1,000 kVA	0.11	0.01651	15%
181	9092	North4	Feeder 202	Over 1,000 kVA	0.209	0.0313	15%
182	7970	North4	Feeder 201	200-1,000 kVA	0.021	0.00041	2%
183	8191	Center3	Feeder 303	200-1,000 kVA	0.055	0.00109	2%
184	500	North2	Feeder 102	Over 1,000 kVA	1.158	0.17363	15%
185	5098	North4	Feeder 301	Over 1,000 kVA	0.228	0.03423	15%
186	8623	North4	Feeder 201	200-1,000 kVA	0.021	0.00041	2%
187	5096	North4	Feeder 301	200-1,000 kVA	0.086	0.00171	2%
188	8700	North4	Feeder 202	Over 1,000 kVA	0.209	0.0313	15%
189	8311	North4	Feeder 201	200-1,000 kVA	0.021	0.00041	2%
190	7755	North4	Feeder 301	200-1,000 kVA	0.057	0.00114	2%
191	8903	North4	Feeder 201	200-1,000 kVA	0.028	0.00055	2%
192	8522	North4	Feeder 303	200-1,000 kVA	0.226	0.00453	2%
193	8133	North4	Feeder 202	200-1,000 kVA	0.104	0.00209	2%
194	538	Center3	Feeder 203	Over 1,000 kVA	2.21	0.3315	15%
195	7656	North4	Feeder 201	200-1,000 kVA	0.006	0.00012	2%
196	7094	North4	Feeder 201	200-1,000 kVA	0.006	0.00012	2%
197	5190	North4	Feeder 202	Over 1,000 kVA	0.209	0.0313	15%
198	5147	North4	Feeder 201	200-1,000 kVA	0.014	0.00027	2%
199	8277	North4	Feeder 303	200-1,000 kVA	0.17	0.00339	2%
200	8189	North4	Feeder 201	200-1,000 kVA	0.028	0.00055	2%
201	5222	South3	Feeder 104	200-1,000 kVA	0.064	0.00129	2%
202	5191	Core1	Feeder 305	Over 1,000 kVA	0.072	0.01078	15%
203	5311	North4	Feeder 303	200-1,000 kVA	0.226	0.00453	2%
204	529	North4	Feeder 201	Over 1,000 kVA	0.11	0.01651	15%
205	8907	North4	Feeder 202	200-1,000 kVA	0.07	0.00139	2%
206	502	North2	Feeder 105	Over 1,000 kVA	0.773	0.11591	15%
207	8127	North2	Feeder 102	200-1,000 kVA	0.145	0.00289	2%
208	7965	North2	Feeder 104	Over 1,000 kVA	0.637	0.09558	15%
209	5130	North2	Feeder 102	Over 1,000 kVA	0.434	0.06511	15%
210	501	North2	Feeder 105	Over 1,000 kVA	0.773	0.04636	6%
211	8506	North6	Feeder 201	200-1,000 kVA	0.115	0.0023	2%
212	5149	North2	Feeder 104	Over 1,000 kVA	0.85	0.05098	6%
213	5201	North4	Feeder 303	Over 1,000 kVA	0.34	0.02037	6%
214	8499	South3	Feeder 104	200-1,000 kVA	0.161	0.00322	2%
215	9010	North2	Feeder 104	200-1,000 kVA	0.319	0.00637	2%
216	8128	North2	Feeder 104	200-1,000 kVA	0.212	0.00425	2%
217	8682	North2	Feeder 205	Over 1,000 kVA	0.538	0.03228	6%
218	7655	North6	Feeder 202	200-1,000 kVA	0.041	0.00082	2%
219	8524	North6	Feeder 202	200-1,000 kVA	0.183	0.00366	2%
220	8504	North2	Feeder 105	200-1,000 kVA	0.097	0.00193	2%
221	8444	North6	Feeder 202	200-1,000 kVA	0.041	0.00082	2%
222	8420	North2	Feeder 105	200-1,000 kVA	0.097	0.00193	2%
223	8248	North2	Feeder 105	200-1,000 kVA	0.058	0.00116	2%
224	7761	North6	Feeder 201	200-1,000 kVA	0.115	0.0023	2%
225	7613	North6	Feeder 202	200-1,000 kVA	0.041	0.00082	2%
226	8656	North6	Feeder 202	200-1,000 kVA	0.183	0.00366	2%
227	5116	North6	Feeder 202	200-1,000 kVA	0.092	0.00183	2%
228	8125	Center3	Feeder 303	200-1,000 kVA	0.055	0.00109	2%
229	8587	North6	Feeder 105	Over 1,000 kVA	0.237	0.01424	6%
230	6481	Core1	Feeder 204	200-1,000 kVA	0.181	0.00363	2%
231	7272	Center2	Feeder 203	200-1,000 kVA	0.06	0.00121	2%
232	9050	Center2	Feeder 203	200-1,000 kVA	0.121	0.00241	2%
233	8621	Center2	Feeder 203	200-1,000 kVA	0.091	0.00181	2%
234	5158	Core1	Feeder 204	200-1,000 kVA	0.091	0.00181	2%
235	8199	North6	Feeder 105	200-1,000 kVA	0.079	0.00158	2%
236	8304	Center2	Feeder 203	200-1,000 kVA	0.121	0.00241	2%
237	8157	Core1	Feeder 204	200-1,000 kVA	0.181	0.00363	2%
238	8036	North6	Feeder 105	200-1,000 kVA	0.079	0.00158	2%
239	520	Core1	Feeder 204	Over 1,000 kVA	0.726	0.04356	6%

Summer 2002 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	Demand Response (MW)	DR % of Peak Load
240	7550	North6	Feeder 105	200-1,000 kVA	0.079	0.00158	2%
241	7067	North6	Feeder 105	200-1,000 kVA	0.158	0.00316	2%
242	8431	Core1	Feeder 204	200-1,000 kVA	0.136	0.00272	2%
243	7705	North6	Feeder 105	200-1,000 kVA	0.158	0.00316	2%
244	7627	North6	Feeder 105	200-1,000 kVA	0.079	0.00158	2%
245	522	Core1	Feeder 302	Over 1,000 kVA	0.852	0.05112	6%
246	8725	Core1	Feeder 204	200-1,000 kVA	0.091	0.00181	2%
247	8162	North6	Feeder 105	Over 1,000 kVA	0.237	0.01424	6%
248	516	North6	Feeder 204	Over 1,000 kVA	0.005	0.00029	6%
249	7988	North6	Feeder 105	200-1,000 kVA	0.119	0.00237	2%
250	7737	Core1	Feeder 204	200-1,000 kVA	0.054	0.00109	2%
251	8589	Center2	Feeder 203	Over 1,000 kVA	0.181	0.01087	6%
252	8350	North6	Feeder 105	200-1,000 kVA	0.119	0.00237	2%
253	7765	Center3	Feeder 303	200-1,000 kVA	0.055	0.00109	2%
254	8768	North6	Feeder 105	Over 1,000 kVA	0.316	0.01898	6%
255	5204	Core1	Feeder 302	200-1,000 kVA	0.16	0.00319	2%
256	5197	Center2	Feeder 203	200-1,000 kVA	0.091	0.00181	2%
257	8705	Core1	Feeder 302	200-1,000 kVA	0.048	0.00096	2%
258	8426	North6	Feeder 105	200-1,000 kVA	0.119	0.00237	2%
259	5188	Center2	Feeder 203	200-1,000 kVA	0.121	0.00241	2%
260	7439	Core1	Feeder 204	Over 1,000 kVA	0.272	0.01634	6%
261	7463	North6	Feeder 105	200-1,000 kVA	0.079	0.00158	2%
262	9051	Core1	Feeder 302	200-1,000 kVA	0.213	0.00426	2%
263	7610	Core1	Feeder 302	200-1,000 kVA	0.16	0.00319	2%
264	8853	Core1	Feeder 302	200-1,000 kVA	0.048	0.00096	2%
265	8252	Core1	Feeder 302	200-1,000 kVA	0.048	0.00096	2%
266	8590	Center3	Feeder 303	Over 1,000 kVA	0.164	0.00982	6%
267	539	Center3	Feeder 204	Over 1,000 kVA	1.31	0.07862	6%
268	8429	Core1	Feeder 203	200-1,000 kVA	0.271	0.00541	2%
269	513	North6	Feeder 105	Over 1,000 kVA	0.633	0.03797	6%
270	5121	Core1	Feeder 203	200-1,000 kVA	0.18	0.00361	2%
271	7275	Core1	Feeder 203	200-1,000 kVA	0.18	0.00361	2%
272	5183	Center3	Feeder 302	Over 1,000 kVA	0.399	0.02393	6%
273	5301	Center2	Feeder 203	200-1,000 kVA	0.091	0.00181	2%
274	5182	Center3	Feeder 302	Over 1,000 kVA	0.399	0.02393	6%
275	5171	North6	Feeder 101	Over 1,000 kVA	0.284	0.01702	6%
276	9049	Center2	Feeder 203	200-1,000 kVA	0.121	0.00241	2%
277	9041	Center2	Feeder 203	200-1,000 kVA	0.091	0.00181	2%
278	9196	Center2	Feeder 203	Over 1,000 kVA	0.181	0.01087	6%
279	5224	Core1	Feeder 203	200-1,000 kVA	0.108	0.00217	2%
280	7255	Core1	Feeder 204	Over 1,000 kVA	0.454	0.02722	6%
281	9085	Center2	Feeder 203	200-1,000 kVA	0.121	0.00241	2%
282	9053	Center2	Feeder 203	200-1,000 kVA	0.121	0.00241	2%
283	9038	Center2	Feeder 203	200-1,000 kVA	0.027	0.00054	2%
284	8764	Center3	Feeder 302	200-1,000 kVA	0.1	0.00199	2%
285	8349	Center3	Feeder 302	200-1,000 kVA	0.15	0.00299	2%
286	8280	North6	Feeder 101	Over 1,000 kVA	0.284	0.01702	6%
287	5187	Center3	Feeder 302	200-1,000 kVA	0.199	0.00399	2%
288	8226	Center3	Feeder 302	200-1,000 kVA	0.15	0.00299	2%
289	6093	Core1	Feeder 203	200-1,000 kVA	0.081	0.00162	2%
290	5088	North6	Feeder 101	200-1,000 kVA	0.095	0.00189	2%
291	5087	North6	Feeder 101	200-1,000 kVA	0.095	0.00189	2%
292	8660	Core1	Feeder 203	Over 1,000 kVA	0.541	0.03248	6%
293	5142	North6	Feeder 101	200-1,000 kVA	0.057	0.00113	2%
294	5170	North6	Feeder 101	Over 1,000 kVA	0.284	0.01702	6%
295	5154	North6	Feeder 101	200-1,000 kVA	0.043	0.00085	2%
296	5155	North6	Feeder 101	200-1,000 kVA	0.043	0.00085	2%
297	7760	Center3	Feeder 302	200-1,000 kVA	0.1	0.00199	2%
298	5133	North6	Feeder 101	200-1,000 kVA	0.043	0.00085	2%
299	8351	North6	Feeder 101	200-1,000 kVA	0.142	0.00284	2%

Summer 2002 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	Demand Response (MW)	DR % of Peak Load
300	9044	Center3	Feeder 302	200-1,000 kVA	0.06	0.0012	2%
301	8525	North6	Feeder 101	200-1,000 kVA	0.189	0.00378	2%
302	7673	Center3	Feeder 302	200-1,000 kVA	0.15	0.00299	2%
303	5289	North6	Feeder 101	200-1,000 kVA	0.095	0.00189	2%
304	8747	Center3	Feeder 302	200-1,000 kVA	0.1	0.00199	2%
305	6821	Center3	Feeder 302	200-1,000 kVA	0.06	0.0012	2%
306	8605	North6	Feeder 101	200-1,000 kVA	0.043	0.00085	2%
307	8528	North2	Feeder 205	200-1,000 kVA	0.081	0.00161	2%
308	8699	Center3	Feeder 204	Over 1,000 kVA	0.491	0.02948	6%
309	7711	Center3	Feeder 302	200-1,000 kVA	0.06	0.0012	2%
310	5247	North6	Feeder 101	200-1,000 kVA	0.095	0.00189	2%
311	5305	Core1	Feeder 203	Over 1,000 kVA	0.722	0.04331	6%
312	7674	Center3	Feeder 202	200-1,000 kVA	0.033	0.00066	2%
313	7445	Center3	Feeder 202	200-1,000 kVA	0.022	0.00044	2%
314	5122	Center3	Feeder 202	200-1,000 kVA	0.033	0.00066	2%
315	8406	Center3	Feeder 202	200-1,000 kVA	0.044	0.00088	2%
316	8887	Center3	Feeder 204	200-1,000 kVA	0.328	0.00655	2%
317	8158	Center3	Feeder 202	200-1,000 kVA	0.044	0.00088	2%
318	8274	Center3	Feeder 202	200-1,000 kVA	0.033	0.00066	2%
319	8041	Center3	Feeder 202	Over 1,000 kVA	0.066	0.00394	6%
320	5186	Center3	Feeder 202	200-1,000 kVA	0.044	0.00088	2%
321	512	North6	Feeder 104	Over 1,000 kVA	1.954	0.11722	6%
322	8049	Core1	Feeder 203	Over 1,000 kVA	0.722	0.04331	6%
323	7637	Center3	Feeder 202	200-1,000 kVA	0.013	0.00026	2%
324	5132	Center2	Feeder 203	Over 1,000 kVA	0.181	0.01087	6%
325	5011	Center3	Feeder 202	200-1,000 kVA	0.01	0.0002	2%
326	7759	Center3	Feeder 202	200-1,000 kVA	0.022	0.00044	2%
327	536	Center3	Feeder 202	Over 1,000 kVA	0.175	0.01052	6%
328	7418	Center3	Feeder 202	200-1,000 kVA	0.01	0.0002	2%
329	7753	North6	Feeder 101	200-1,000 kVA	0.043	0.00085	2%
330	8665	Center3	Feeder 204	200-1,000 kVA	0.328	0.00655	2%
331	537	Center3	Feeder 202	Over 1,000 kVA	0.175	0.01052	6%
332	8306	Core1	Feeder 203	200-1,000 kVA	0.361	0.00722	2%
333	7974	Center3	Feeder 202	200-1,000 kVA	0.033	0.00066	2%
334	7554	Center3	Feeder 202	200-1,000 kVA	0.01	0.0002	2%
335	7969	Center3	Feeder 202	200-1,000 kVA	0.033	0.00066	2%
336	8826	Center3	Feeder 204	200-1,000 kVA	0.098	0.00197	2%
337	8646	Center3	Feeder 202	200-1,000 kVA	0.01	0.0002	2%
338	8666	North6	Feeder 103	200-1,000 kVA	0.269	0.00539	2%
339	507	South3	Feeder 105	Over 1,000 kVA	0.24	0.0144	6%
340	8972	North6	Feeder 103	Over 1,000 kVA	0.539	0.03233	6%
341	8278	North6	Feeder 103	Over 1,000 kVA	0.404	0.02425	6%
342	523	Core1	Feeder 302	Over 1,000 kVA	0.852	0.05112	6%
343	511	North6	Feeder 103	Over 1,000 kVA	1.078	0.06466	6%
344	36612	North1	Substation	Over 1,000 kVA (Xmsn level)	14.878	0.8922	6%
345	521	Core1	Feeder 205	Over 1,000 kVA	0.251	0.01507	6%
346	8971	Core1	Feeder 205	Over 1,000 kVA	0.126	0.00753	6%
347	7971	Core1	Feeder 205	Over 1,000 kVA	0.094	0.00565	6%
348	7493	Center2	Feeder 104	200-1,000 kVA	0.508	0.01016	2%
349	8516	Core1	Feeder 205	Over 1,000 kVA	0.094	0.00565	6%
350	8767	Core1	Feeder 205	Over 1,000 kVA	0.126	0.00753	6%
351	5062	Core1	Feeder 304	200-1,000 kVA	0.462	0.00925	2%
352	508	North6	Feeder 102	Over 1,000 kVA	0.573	0.03436	6%
353	510	North6	Feeder 102	Over 1,000 kVA	0.573	0.03436	6%
354	8627	North6	Feeder 102	200-1,000 kVA	0.107	0.00215	2%
355	8732	North6	Feeder 101	200-1,000 kVA	0.142	0.00284	2%
356	5276	North6	Feeder 102	200-1,000 kVA	0.143	0.00286	2%
357	8523	Core1	Feeder 204	200-1,000 kVA	0.181	0.00363	2%
358	7747	Core1	Feeder 204	200-1,000 kVA	0.041	0.00082	2%
359	6881	Core1	Feeder 204	200-1,000 kVA	0.054	0.00109	2%

Summer 2002 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	Demand Response (MW)	DR % of Peak Load
360	8355	Core1	Feeder 204	200-1,000 kVA	0.136	0.00272	2%
361	519	Core1	Feeder 103	Over 1,000 kVA	1.166	0.06996	6%
362	8857	Core1	Feeder 102	Over 1,000 kVA	0.248	0.01489	6%
363	509	North6	Feeder 102	Over 1,000 kVA	0.573	0.03436	6%
364	8340	North6	Feeder 102	200-1,000 kVA	0.072	0.00143	2%
365	542	Center2	Feeder 201	Over 1,000 kVA	2.424	0.14546	6%
366	8886	Core1	Feeder 102	200-1,000 kVA	0.124	0.00248	2%
367	8885	Core1	Feeder 102	200-1,000 kVA	0.124	0.00248	2%
368	8188	North6	Feeder 102	200-1,000 kVA	0.143	0.00286	2%
369	8629	Core1	Feeder 102	200-1,000 kVA	0.037	0.00074	2%
370	8526	Core1	Feeder 102	200-1,000 kVA	0.037	0.00074	2%
371	7448	North2	Feeder 205	200-1,000 kVA	0.081	0.00161	2%
372	8631	Core1	Feeder 102	200-1,000 kVA	0.124	0.00248	2%
373	8385	Core1	Feeder 205	200-1,000 kVA	0.014	0.00028	2%
374	5306	Core1	Feeder 205	Over 1,000 kVA	0.126	0.00753	6%
375	5013	Core1	Feeder 205	200-1,000 kVA	0.014	0.00028	2%
376	8203	Core1	Feeder 205	200-1,000 kVA	0.031	0.00063	2%
377	8272	Core1	Feeder 205	200-1,000 kVA	0.019	0.00038	2%
378	8604	Core1	Feeder 205	200-1,000 kVA	0.014	0.00028	2%
379	518	Core1	Feeder 102	Over 1,000 kVA	0.496	0.02978	6%
380	9099	Core1	Feeder 205	200-1,000 kVA	0.047	0.00094	2%
381	6943	Core1	Feeder 205	200-1,000 kVA	0.031	0.00063	2%
382	9005	Core1	Feeder 205	200-1,000 kVA	0.031	0.00063	2%
383	5020	Core1	Feeder 205	200-1,000 kVA	0.031	0.00063	2%
384	8186	Core1	Feeder 205	200-1,000 kVA	0.031	0.00063	2%
385	5258	Core1	Feeder 205	200-1,000 kVA	0.031	0.00063	2%
386	6525	Core1	Feeder 205	200-1,000 kVA	0.014	0.00028	2%
387	36650	Center1	Substation	Over 1,000 kVA (Xmsn level)	7.783	0.46698	6%
388	8795	North2	Feeder 205	200-1,000 kVA	0.135	0.00269	2%
389	36622	South1	Substation	Over 1,000 kVA (Xmsn level)	7.819	0.46914	6%
Total						10.51597	

Summer 2002 Rank-Ordered DG Capacity Additions (Light Load Fdr Limit)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG (MW)	DG % of Peak Load
1	524	Core1	Feeder 305	Over 1,000 kVA	0.192	0.115	60%
2	5163	Core1	Feeder 305	200-1,000 kVA	0.014	0.008	57%
3	8205	Core1	Feeder 305	200-1,000 kVA	0.024	0.014	58%
4	9129	Core1	Feeder 305	200-1,000 kVA	0.048	0.029	60%
5	8701	Core1	Feeder 305	Over 1,000 kVA	0.072	0.043	60%
6	8923	Core1	Feeder 305	200-1,000 kVA	0.024	0.014	58%
7	8404	Core1	Feeder 305	200-1,000 kVA	0.024	0.014	58%
8	7285	Core1	Feeder 305	200-1,000 kVA	0.011	0.007	64%
9	8661	North2	Feeder 202	Over 1,000 kVA	0.372	0.223	60%
10	8313	North2	Feeder 202	200-1,000 kVA	0.124	0.074	60%
11	5185	North2	Feeder 202	200-1,000 kVA	0.248	0.149	60%
12	503	North2	Feeder 202	Over 1,000 kVA	0.991	0.595	60%
13	8890	North2	Feeder 202	Over 1,000 kVA	0.496	0.029	6%
14	8854	Center2	Feeder 104	200-1,000 kVA	0.508	0.305	60%
15	7606	North4	Feeder 105	Under 200 kVA	0.034	0.02	59%
16	8228	North4	Feeder 105	200-1,000 kVA	0.231	0.139	60%
17	8527	North4	Feeder 104	200-1,000 kVA	0.035	0.021	60%
18	504	North2	Feeder 203	Over 1,000 kVA	0.776	0.466	60%
19	7687	North4	Feeder 104	Under 200 kVA	0.013	0.008	62%
20	7645	North6	Feeder 203	200-1,000 kVA	0.08	0.048	60%
21	9048	North4	Feeder 104	200-1,000 kVA	0.115	0.069	60%
22	5176	North4	Feeder 104	200-1,000 kVA	0.026	0.016	62%
23	8161	North4	Feeder 105	Over 1,000 kVA	0.461	0.277	60%
24	7654	North6	Feeder 203	200-1,000 kVA	0.08	0.048	60%
25	8283	North4	Feeder 104	200-1,000 kVA	0.058	0.035	60%
26	541	Center3	Feeder 303	Over 1,000 kVA	0.436	0.262	60%
27	5148	North4	Feeder 104	Over 1,000 kVA	0.231	0.139	60%
28	7662	North6	Feeder 203	200-1,000 kVA	0.08	0.048	60%
29	8401	North6	Feeder 203	200-1,000 kVA	0.178	0.107	60%
30	5226	North4	Feeder 101	Over 1,000 kVA	0.312	0.187	60%
31	5113	North2	Feeder 203	Over 1,000 kVA	0.388	0.233	60%
32	7668	North4	Feeder 104	200-1,000 kVA	0.035	0.021	60%
33	5169	Center3	Feeder 303	Over 1,000 kVA	0.164	0.098	60%
34	531	North4	Feeder 203	Over 1,000 kVA	0.604	0.362	60%
35	8233	North6	Feeder 203	Under 200 kVA	0.04	0.024	60%
36	8411	North4	Feeder 104	200-1,000 kVA	0.115	0.069	60%
37	5052	North6	Feeder 205	Over 1,000 kVA	0.48	0.288	60%
38	5256	Center3	Feeder 303	200-1,000 kVA	0.055	0.033	60%
39	5255	Center3	Feeder 303	200-1,000 kVA	0.109	0.065	60%
40	8341	North4	Feeder 104	200-1,000 kVA	0.058	0.035	60%
41	7557	North6	Feeder 203	200-1,000 kVA	0.178	0.107	60%
42	5034	North4	Feeder 105	Over 1,000 kVA	0.615	0.369	60%
43	8633	North4	Feeder 104	200-1,000 kVA	0.115	0.069	60%
44	5248	North2	Feeder 203	200-1,000 kVA	0.097	0.058	60%
45	8787	North6	Feeder 203	200-1,000 kVA	0.178	0.107	60%
46	9130	Center3	Feeder 303	200-1,000 kVA	0.109	0.065	60%
47	506	South3	Feeder 104	Over 1,000 kVA	0.859	0.515	60%
48	9091	North4	Feeder 101	Over 1,000 kVA	0.187	0.112	60%
49	5144	North2	Feeder 203	Over 1,000 kVA	0.388	0.233	60%
50	8497	North4	Feeder 104	200-1,000 kVA	0.087	0.052	60%
51	6837	North6	Feeder 201	200-1,000 kVA	0.173	0.104	60%
52	5250	Center3	Feeder 303	200-1,000 kVA	0.055	0.033	60%
53	505	North2	Feeder 204	Over 1,000 kVA	2.235	1.341	60%
54	8698	North4	Feeder 104	Over 1,000 kVA	0.173	0.104	60%
55	8517	North6	Feeder 203	Over 1,000 kVA	0.533	0.32	60%
56	534	North4	Feeder 304	Over 1,000 kVA	2.033	0.13	6%
57	9093	North4	Feeder 101	Over 1,000 kVA	0.187	0.112	60%
58	9011	North2	Feeder 203	200-1,000 kVA	0.097	0.058	60%
59	532	North4	Feeder 20[illegible]	Over 1,000 kVA	1.608	0.69	43%

Summer 2002 Rank-Ordered DG Capacity Additions (Light Load Fdr Limit) (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG (MW)	DG % of Peak Load
60	9087	North4	Feeder 104	Over 1,000 kVA	0.173	0.104	60%
61	8893	North4	Feeder 203	Over 1,000 kVA	0.302	0.181	60%
62	6879	North6	Feeder 201	200-1,000 kVA	0.069	0.041	59%
63	5240	North2	Feeder 203	Under 200 kVA	0.022	0.013	59%
64	5205	North2	Feeder 203	200-1,000 kVA	0.146	0.088	60%
65	5097	North6	Feeder 201	Over 1,000 kVA	0.46	0.276	60%
66	9090	North4	Feeder 101	Over 1,000 kVA	0.187	0.112	60%
67	8126	North2	Feeder 203	200-1,000 kVA	0.097	0.058	60%
68	5118	North4	Feeder 104	200-1,000 kVA	0.058	0.035	60%
69	533	North4	Feeder 205	Over 1,000 kVA	0.908	0.545	60%
70	5273	North6	Feeder 205	200-1,000 kVA	0.054	0.032	59%
71	8156	North4	Feeder 104	Under 200 kVA	0.012	0.007	58%
72	5168	North2	Feeder 203	Over 1,000 kVA	0.291	0.175	60%
73	8592	North6	Feeder 205	Over 1,000 kVA	0.36	0.216	60%
74	8131	North4	Feeder 104	200-1,000 kVA	0.115	0.069	60%
75	7736	North4	Feeder 105	200-1,000 kVA	0.092	0.055	60%
76	5051	South3	Feeder 104	Over 1,000 kVA	0.429	0.257	60%
77	8363	North6	Feeder 202	200-1,000 kVA	0.041	0.025	61%
78	9088	North4	Feeder 101	Over 1,000 kVA	0.187	0.112	60%
79	7449	North6	Feeder 203	200-1,000 kVA	0.107	0.064	60%
80	8905	North4	Feeder 104	Over 1,000 kVA	0.231	0.139	60%
81	8595	North2	Feeder 203	Over 1,000 kVA	0.291	0.175	60%
82	8904	North4	Feeder 203	Over 1,000 kVA	0.302	0.181	60%
83	5172	North6	Feeder 202	200-1,000 kVA	0.041	0.025	61%
84	7495	North4	Feeder 105	200-1,000 kVA	0.154	0	0%
85	515	North6	Feeder 203	Over 1,000 kVA	1.421	0.608	43%
86	540	Center3	Feeder 303	Over 1,000 kVA	0.436	0.262	60%
87	535	North4	Feeder 305	Over 1,000 kVA	1.893	0.52	27%
88	8417	North4	Feeder 104	200-1,000 kVA	0.058	0.035	60%
89	8038	North2	Feeder 203	Over 1,000 kVA	0.291	0.175	60%
90	9133	South3	Feeder 104	Under 200 kVA	0.024	0.014	58%
91	8658	North4	Feeder 104	200-1,000 kVA	0.115	0.069	60%
92	526	North4	Feeder 101	Over 1,000 kVA	0.499	0.234	47%
93	5304	North6	Feeder 201	Over 1,000 kVA	0.46	0.276	60%
94	5254	South3	Feeder 104	200-1,000 kVA	0.215	0.129	60%
95	8501	North4	Feeder 104	200-1,000 kVA	0.058	0.035	60%
96	8365	Center3	Feeder 303	200-1,000 kVA	0.109	0.065	60%
97	7690	North4	Feeder 301	Over 1,000 kVA	0.171	0.103	60%
98	530	North4	Feeder 203	Over 1,000 kVA	0.604	0.335	55%
99	8594	North2	Feeder 203	Over 1,000 kVA	0.291	0.175	60%
100	5191	Core1	Feeder 305	Over 1,000 kVA	0.072	0.043	60%
101	8227	North4	Feeder 104	200-1,000 kVA	0.087	0.031	36%
102	7986	North4	Feeder 303	200-1,000 kVA	0.226	0.136	60%
103	8445	North6	Feeder 202	200-1,000 kVA	0.041	0.025	61%
104	7671	Center3	Feeder 303	200-1,000 kVA	0.055	0.033	60%
105	5302	Center3	Feeder 303	Over 1,000 kVA	0.164	0.098	60%
106	9086	North6	Feeder 202	Over 1,000 kVA	0.275	0.165	60%
107	8894	North4	Feeder 201	Over 1,000 kVA	0.055	0.033	60%
108	8187	North4	Feeder 301	200-1,000 kVA	0.114	0.068	60%
109	8730	South3	Feeder 104	200-1,000 kVA	0.161	0.097	60%
110	8973	North2	Feeder 203	Over 1,000 kVA	0.388	0.225	58%
111	538	Center3	Feeder 203	Over 1,000 kVA	2.21	0.85	38%
112	8542	South3	Feeder 104	Over 1,000 kVA	0.322	0.193	60%
113	9012	North6	Feeder 201	200-1,000 kVA	0.173	0.104	60%
114	5016	South3	Feeder 104	200-1,000 kVA	0.107	0.064	60%
115	8827	South3	Feeder 104	200-1,000 kVA	0.064	0.038	59%
116	5135	South3	Feeder 104	200-1,000 kVA	0.048	0.029	60%
117	7412	South3	Feeder 104	Under 200 kVA	0.024	0.014	58%
118	5222	South3	Feeder 104	200-1,000 kVA	0.064	0.038	59%
119	8499	South3	Feeder 104	200-1,000 kVA	0.161	0.097	60%

Summer 2002 Rank-Ordered DG Capacity Additions (Light Load Fdr Limit) (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG (MW)	DG % of Peak Load
120	527	North4	Feeder 103	Over 1,000 kVA	1.448	0.53	37%
121	500	North2	Feeder 102	Over 1,000 kVA	1.158	0.695	60%
122	7702	North4	Feeder 301	200-1,000 kVA	0.114	0.068	60%
123	8190	North4	Feeder 301	200-1,000 kVA	0.114	0.068	60%
124	5054	North4	Feeder 301	200-1,000 kVA	0.057	0.034	60%
125	8281	North4	Feeder 301	Over 1,000 kVA	0.171	0.103	60%
126	7689	North4	Feeder 301	Over 1,000 kVA	0.171	0.103	60%
127	5094	North4	Feeder 301	200-1,000 kVA	0.086	0.052	60%
128	7612	North4	Feeder 301	200-1,000 kVA	0.114	0.068	60%
129	8541	North4	Feeder 301	Over 1,000 kVA	0.171	0.103	60%
130	5098	North4	Feeder 301	Over 1,000 kVA	0.228	0.11	48%
131	5053	North6	Feeder 205	200-1,000 kVA	0.12	0.072	60%
132	9092	North4	Feeder 202	Over 1,000 kVA	0.209	0.125	60%
133	5123	North6	Feeder 201	200-1,000 kVA	0.173	0.104	60%
134	5324	North4	Feeder 303	Over 1,000 kVA	0.453	0.272	60%
135	7682	North4	Feeder 303	Under 200 kVA	0.025	0.015	60%
136	8522	North4	Feeder 303	200-1,000 kVA	0.226	0.108	48%
137	517	North6	Feeder 205	Over 1,000 kVA	0.96	0.542	56%
138	8587	North6	Feeder 105	Over 1,000 kVA	0.237	0.142	60%
139	7965	North2	Feeder 104	Over 1,000 kVA	0.637	0.382	60%
140	502	North2	Feeder 105	Over 1,000 kVA	0.773	0.464	60%
141	5171	North6	Feeder 101	Over 1,000 kVA	0.284	0.17	60%
142	8191	Center3	Feeder 303	200-1,000 kVA	0.055	0.033	60%
143	9140	North6	Feeder 201	200-1,000 kVA	0.173	0.104	60%
144	7272	Center2	Feeder 203	200-1,000 kVA	0.06	0.036	60%
145	8284	North4	Feeder 201	200-1,000 kVA	0.014	0.008	57%
146	6481	Core1	Feeder 204	200-1,000 kVA	0.181	0.109	60%
147	8621	Center2	Feeder 203	200-1,000 kVA	0.091	0.055	60%
148	7198	North6	Feeder 201	200-1,000 kVA	0.115	0.069	60%
149	5190	North4	Feeder 202	Over 1,000 kVA	0.209	0.125	60%
150	8748	North4	Feeder 201	200-1,000 kVA	0.014	0.008	57%
151	7763	North4	Feeder 201	200-1,000 kVA	0.006	0.004	67%
152	5366	North4	Feeder 201	200-1,000 kVA	0.021	0.013	62%
153	8132	North4	Feeder 201	200-1,000 kVA	0.021	0.013	62%
154	9050	Center2	Feeder 203	200-1,000 kVA	0.121	0.073	60%
155	501	North2	Feeder 105	Over 1,000 kVA	0.773	0.464	60%
156	7550	North6	Feeder 105	200-1,000 kVA	0.079	0.047	59%
157	8924	North6	Feeder 201	200-1,000 kVA	0.173	0.104	60%
158	7656	North4	Feeder 201	200-1,000 kVA	0.006	0.004	67%
159	9098	North4	Feeder 201	200-1,000 kVA	0.021	0.013	62%
160	8199	North6	Feeder 105	200-1,000 kVA	0.079	0.047	59%
161	514	North6	Feeder 202	Over 1,000 kVA	0.732	0.361	49%
162	5088	North6	Feeder 101	200-1,000 kVA	0.095	0.057	60%
163	7627	North6	Feeder 105	200-1,000 kVA	0.079	0.047	59%
164	522	Core1	Feeder 302	Over 1,000 kVA	0.852	0.04	5%
165	5181	North6	Feeder 201	200-1,000 kVA	0.115	0.059	51%
166	5158	Core1	Feeder 204	200-1,000 kVA	0.091	0.055	60%
167	8282	North4	Feeder 201	200-1,000 kVA	0.014	0.008	57%
168	8682	North2	Feeder 205	Over 1,000 kVA	0.538	0.323	60%
169	9010	North2	Feeder 104	200-1,000 kVA	0.319	0.191	60%
170	8304	Center2	Feeder 203	200-1,000 kVA	0.121	0.073	60%
171	5108	North2	Feeder 205	Under 200 kVA	0.02	0.012	60%
172	8591	North4	Feeder 201	Over 1,000 kVA	0.041	0.025	61%
173	6633	North2	Feeder 104	Under 200 kVA	0.048	0.029	60%
174	520	Core1	Feeder 204	Over 1,000 kVA	0.726	0.436	60%
175	8157	Core1	Feeder 204	200-1,000 kVA	0.181	0.109	60%
176	8431	Core1	Feeder 204	200-1,000 kVA	0.136	0.082	60%
177	7725	Core1	Feeder 204	Under 200 kVA	0.02	0.012	60%
178	7737	Core1	Feeder 204	200-1,000 kVA	0.054	0.032	59%
179	8531	Core1	Feeder 204	Under 200 kVA	0.02	0.012	60%

Summer 2002 Rank-Ordered DG Capacity Additions (Light Load Fdr Limit) (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG (MW)	DG % of Peak Load
180	8725	Core1	Feeder 204	200-1,000 kVA	0.091	0.055	60%
181	7614	Core1	Feeder 204	Under 200 kVA	0.02	0.012	60%
182	7575	Core1	Feeder 204	Under 200 kVA	0.02	0.012	60%
183	7439	Core1	Feeder 204	Over 1,000 kVA	0.272	0.163	60%
184	8125	Center3	Feeder 303	200-1,000 kVA	0.055	0.033	60%
185	528	North4	Feeder 201	Over 1,000 kVA	0.11	0.066	60%
186	8589	Center2	Feeder 203	Over 1,000 kVA	0.181	0.109	60%
187	8128	North2	Feeder 104	200-1,000 kVA	0.212	0.127	60%
188	5130	North2	Feeder 102	Over 1,000 kVA	0.434	0.175	40%
189	8504	North2	Feeder 105	200-1,000 kVA	0.097	0.058	60%
190	5197	Center2	Feeder 203	200-1,000 kVA	0.091	0.055	60%
191	539	Center3	Feeder 204	Over 1,000 kVA	1.31	0.786	60%
192	5166	North2	Feeder 105	Under 200 kVA	0.022	0.013	59%
193	5149	North2	Feeder 104	Over 1,000 kVA	0.85	0.36	42%
194	8429	Core1	Feeder 203	200-1,000 kVA	0.271	0.163	60%
195	8420	North2	Feeder 105	200-1,000 kVA	0.097	0.058	60%
196	7765	Center3	Feeder 303	200-1,000 kVA	0.055	0.033	60%
197	529	North4	Feeder 201	Over 1,000 kVA	0.11	0.066	60%
198	8229	North4	Feeder 205	200-1,000 kVA	0.17	0.055	32%
199	5188	Center2	Feeder 203	200-1,000 kVA	0.121	0.073	60%
200	8248	North2	Feeder 105	200-1,000 kVA	0.058	0.035	60%
201	5183	Center3	Feeder 302	Over 1,000 kVA	0.399	0.239	60%
202	7255	Core1	Feeder 204	Over 1,000 kVA	0.454	0.272	60%
203	7970	North4	Feeder 201	200-1,000 kVA	0.021	0.013	62%
204	8590	Center3	Feeder 303	Over 1,000 kVA	0.164	0.098	60%
205	8623	North4	Feeder 201	200-1,000 kVA	0.021	0.013	62%
206	5301	Center2	Feeder 203	200-1,000 kVA	0.091	0.055	60%
207	9049	Center2	Feeder 203	200-1,000 kVA	0.121	0.073	60%
208	9041	Center2	Feeder 203	200-1,000 kVA	0.091	0.055	60%
209	9196	Center2	Feeder 203	Over 1,000 kVA	0.181	0.057	31%
210	8903	North4	Feeder 201	200-1,000 kVA	0.028	0.017	61%
211	5121	Core1	Feeder 203	200-1,000 kVA	0.18	0.108	60%
212	7094	North4	Feeder 201	200-1,000 kVA	0.006	0.004	67%
213	5182	Center3	Feeder 302	Over 1,000 kVA	0.399	0.239	60%
214	8349	Center3	Feeder 302	200-1,000 kVA	0.15	0.09	60%
215	8764	Center3	Feeder 302	200-1,000 kVA	0.1	0.06	60%
216	5187	Center3	Feeder 302	200-1,000 kVA	0.199	0.119	60%
217	8226	Center3	Feeder 302	200-1,000 kVA	0.15	0.09	60%
218	7760	Center3	Feeder 302	200-1,000 kVA	0.1	0.06	60%
219	9044	Center3	Feeder 302	200-1,000 kVA	0.06	0.036	60%
220	7673	Center3	Feeder 302	200-1,000 kVA	0.15	0.09	60%
221	8747	Center3	Feeder 302	200-1,000 kVA	0.1	0.06	60%
222	6821	Center3	Feeder 302	200-1,000 kVA	0.06	0.036	60%
223	7711	Center3	Feeder 302	200-1,000 kVA	0.06	0.036	60%
224	8189	North4	Feeder 201	200-1,000 kVA	0.028	0.017	61%
225	8907	North4	Feeder 202	200-1,000 kVA	0.07	0.029	41%
226	8426	North6	Feeder 105	200-1,000 kVA	0.119	0.071	60%
227	5147	North4	Feeder 201	200-1,000 kVA	0.014	0.008	57%
228	7275	Core1	Feeder 203	200-1,000 kVA	0.18	0.108	60%
229	5224	Core1	Feeder 203	200-1,000 kVA	0.108	0.065	60%
230	6093	Core1	Feeder 203	200-1,000 kVA	0.081	0.049	60%
231	8660	Core1	Feeder 203	Over 1,000 kVA	0.541	0.325	60%
232	5305	Core1	Feeder 203	Over 1,000 kVA	0.722	0.433	60%
233	7705	North6	Feeder 105	200-1,000 kVA	0.158	0.095	60%
234	7067	North6	Feeder 105	200-1,000 kVA	0.158	0.095	60%
235	8351	North6	Feeder 101	200-1,000 kVA	0.142	0.073	51%
236	7674	Center3	Feeder 202	200-1,000 kVA	0.033	0.02	61%
237	8699	Center3	Feeder 204	Over 1,000 kVA	0.491	0.295	60%
238	7445	Center3	Feeder 202	200-1,000 kVA	0.022	0.013	59%
239	5122	Center3	Feeder 202	200-1,000 kVA	0.033	0.02	61%

Summer 2002 Rank-Ordered DG Capacity Additions (Light Load Fdr Limit) (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG (MW)	DG % of Peak Load
240	8406	Center3	Feeder 202	200-1,000 kVA	0.044	0.026	59%
241	8274	Center3	Feeder 202	200-1,000 kVA	0.033	0.02	61%
242	8158	Center3	Feeder 202	200-1,000 kVA	0.044	0.026	59%
243	8041	Center3	Feeder 202	Over 1,000 kVA	0.066	0.04	61%
244	8036	North6	Feeder 105	200-1,000 kVA	0.079	0.047	59%
245	7637	Center3	Feeder 202	200-1,000 kVA	0.013	0.008	62%
246	7988	North6	Feeder 105	200-1,000 kVA	0.119	0.071	60%
247	8350	North6	Feeder 105	200-1,000 kVA	0.119	0.071	60%
248	8162	North6	Feeder 105	Over 1,000 kVA	0.237	0.142	60%
249	7463	North6	Feeder 105	200-1,000 kVA	0.079	0.047	59%
250	8768	North6	Feeder 105	Over 1,000 kVA	0.316	0.19	60%
251	513	North6	Feeder 105	Over 1,000 kVA	0.633	0.285	45%
252	512	North6	Feeder 104	Over 1,000 kVA	1.954	1.172	60%
253	8666	North6	Feeder 103	200-1,000 kVA	0.269	0.161	60%
254	7759	Center3	Feeder 202	200-1,000 kVA	0.022	0.013	59%
255	537	Center3	Feeder 202	Over 1,000 kVA	0.175	0.105	60%
256	8887	Center3	Feeder 204	200-1,000 kVA	0.328	0.197	60%
257	507	South3	Feeder 105	Over 1,000 kVA	0.24	0.04	17%
258	536	Center3	Feeder 202	Over 1,000 kVA	0.175	0.105	60%
259	8665	Center3	Feeder 204	200-1,000 kVA	0.328	0.197	60%
260	8278	North6	Feeder 103	Over 1,000 kVA	0.404	0.242	60%
261	8972	North6	Feeder 103	Over 1,000 kVA	0.539	0.323	60%
262	5186	Center3	Feeder 202	200-1,000 kVA	0.044	0.026	59%
263	8049	Core1	Feeder 203	Over 1,000 kVA	0.722	0.433	60%
264	5011	Center3	Feeder 202	200-1,000 kVA	0.01	0.006	60%
265	7974	Center3	Feeder 202	200-1,000 kVA	0.033	0.02	61%
266	7554	Center3	Feeder 202	200-1,000 kVA	0.01	0.006	60%
267	7969	Center3	Feeder 202	200-1,000 kVA	0.033	0.02	61%
268	8826	Center3	Feeder 204	200-1,000 kVA	0.098	0.059	60%
269	7418	Center3	Feeder 202	200-1,000 kVA	0.01	0.006	60%
270	8646	Center3	Feeder 202	200-1,000 kVA	0.01	0.006	60%
271	7102	Center3	Feeder 202	Under 200 kVA	0.005	0.003	60%
272	8528	North2	Feeder 205	200-1,000 kVA	0.081	0.049	60%
273	521	Core1	Feeder 205	Over 1,000 kVA	0.251	0.151	60%
274	8971	Core1	Feeder 205	Over 1,000 kVA	0.126	0.076	60%
275	7493	Center2	Feeder 104	200-1,000 kVA	0.508	0.265	52%
276	7971	Core1	Feeder 205	Over 1,000 kVA	0.094	0.056	60%
277	36612	North1	Substation	Over 1,000 kVA (Xmsn level)	14.878	8.927	60%
278	519	Core1	Feeder 103	Over 1,000 kVA	1.166	0.7	60%
279	508	North6	Feeder 102	Over 1,000 kVA	0.573	0.344	60%
280	8857	Core1	Feeder 102	Over 1,000 kVA	0.248	0.149	60%
281	542	Center2	Feeder 201	Over 1,000 kVA	2.424	1.11	46%
282	8516	Core1	Feeder 205	Over 1,000 kVA	0.094	0.056	60%
283	8885	Core1	Feeder 102	200-1,000 kVA	0.124	0.074	60%
284	7747	Core1	Feeder 204	200-1,000 kVA	0.041	0.025	61%
285	511	North6	Feeder 103	Over 1,000 kVA	1.078	0.647	60%
286	8523	Core1	Feeder 204	200-1,000 kVA	0.181	0.109	60%
287	8629	Core1	Feeder 102	200-1,000 kVA	0.037	0.022	59%
288	8886	Core1	Feeder 102	200-1,000 kVA	0.124	0.074	60%
289	8526	Core1	Feeder 102	200-1,000 kVA	0.037	0.022	59%
290	8355	Core1	Feeder 204	200-1,000 kVA	0.136	0.082	60%
291	5040	Core1	Feeder 102	Under 200 kVA	0.014	0.008	57%
292	8767	Core1	Feeder 205	Over 1,000 kVA	0.126	0.076	60%
293	6881	Core1	Feeder 204	200-1,000 kVA	0.054	0.032	59%
294	8306	Core1	Feeder 203	200-1,000 kVA	0.361	0.177	49%
295	5062	Core1	Feeder 304	200-1,000 kVA	0.462	0.277	60%
296	8385	Core1	Feeder 205	200-1,000 kVA	0.014	0.008	57%
297	9099	Core1	Feeder 205	200-1,000 kVA	0.047	0.028	60%
298	5306	Core1	Feeder 205	Over 1,000 kVA	0.126	0.076	60%
299	36650	Center1	Substation	Over 1,000 kVA (Xmsn level)	7.783	4.67	60%

Summer 2002 Rank-Ordered DG Capacity Additions (Light Load Fdr Limit) (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG (MW)	DG % of Peak Load
300	510	North6	Feeder 102	Over 1,000 kVA	0.573	0.344	60%
301	5234	Core1	Feeder 103	Under 200 kVA	0.022	0.013	59%
302	8604	Core1	Feeder 205	200-1,000 kVA	0.014	0.008	57%
303	509	North6	Feeder 102	Over 1,000 kVA	0.573	0.344	60%
304	6525	Core1	Feeder 205	200-1,000 kVA	0.014	0.008	57%
305	8232	Core1	Feeder 205	Under 200 kVA	0.007	0.004	57%
306	8272	Core1	Feeder 205	200-1,000 kVA	0.019	0.011	58%
307	8369	Core1	Feeder 205	Under 200 kVA	0.007	0.004	57%
308	5258	Core1	Feeder 205	200-1,000 kVA	0.031	0.019	61%
309	5013	Core1	Feeder 205	200-1,000 kVA	0.014	0.008	57%
310	8627	North6	Feeder 102	200-1,000 kVA	0.107	0.064	60%
311	8203	Core1	Feeder 205	200-1,000 kVA	0.031	0.019	61%
312	5276	North6	Feeder 102	200-1,000 kVA	0.143	0.044	31%
313	7496	Core1	Feeder 205	Under 200 kVA	0.007	0.004	57%
314	6943	Core1	Feeder 205	200-1,000 kVA	0.031	0.019	61%
315	7448	North2	Feeder 205	200-1,000 kVA	0.081	0.049	60%
316	9005	Core1	Feeder 205	200-1,000 kVA	0.031	0.019	61%
317	8186	Core1	Feeder 205	200-1,000 kVA	0.031	0.019	61%

Summer 2002 Rank-Ordered DG Capacity Additions (15% Fdr Limit)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG (MW)	DG % of Peak Load
1	524	Core1	Feeder 305	Over 1,000 kVA	0.192	0.07	36%
2	8661	North2	Feeder 202	Over 1,000 kVA	0.372	0.223	60%
3	5185	North2	Feeder 202	200-1,000 kVA	0.248	0.149	60%
4	503	North2	Feeder 202	Over 1,000 kVA	0.991	0.298	30%
5	8854	Center2	Feeder 104	200-1,000 kVA	0.508	0.15	30%
6	8228	North4	Feeder 105	200-1,000 kVA	0.231	0.139	60%
7	8527	North4	Feeder 104	200-1,000 kVA	0.035	0.021	60%
8	504	North2	Feeder 203	Over 1,000 kVA	0.776	0.466	60%
9	7687	North4	Feeder 104	Under 200 kVA	0.013	0.008	62%
10	9048	North4	Feeder 104	200-1,000 kVA	0.115	0.069	60%
11	7645	North6	Feeder 203	200-1,000 kVA	0.08	0.048	60%
12	8161	North4	Feeder 105	Over 1,000 kVA	0.461	0.161	35%
13	5176	North4	Feeder 104	200-1,000 kVA	0.026	0.016	62%
14	7654	North6	Feeder 203	200-1,000 kVA	0.08	0.048	60%
15	7668	North4	Feeder 104	200-1,000 kVA	0.035	0.021	60%
16	5148	North4	Feeder 104	Over 1,000 kVA	0.231	0.139	60%
17	541	Center3	Feeder 303	Over 1,000 kVA	0.436	0.262	60%
18	7662	North6	Feeder 203	200-1,000 kVA	0.08	0.048	60%
19	5113	North2	Feeder 203	Over 1,000 kVA	0.388	0.064	16%
20	5226	North4	Feeder 101	Over 1,000 kVA	0.312	0.187	60%
21	8401	North6	Feeder 203	200-1,000 kVA	0.178	0.107	60%
22	8341	North4	Feeder 104	200-1,000 kVA	0.058	0.035	60%
23	5169	Center3	Feeder 303	Over 1,000 kVA	0.164	0.038	23%
24	531	North4	Feeder 203	Over 1,000 kVA	0.604	0.27	45%
25	8411	North4	Feeder 104	200-1,000 kVA	0.115	0.052	45%
26	8233	North6	Feeder 203	Under 200 kVA	0.04	0.024	60%
27	5052	North6	Feeder 205	Over 1,000 kVA	0.48	0.288	60%
28	7557	North6	Feeder 203	200-1,000 kVA	0.178	0.107	60%
29	9091	North4	Feeder 101	Over 1,000 kVA	0.187	0.112	60%
30	8787	North6	Feeder 203	200-1,000 kVA	0.178	0.078	44%
31	506	South3	Feeder 104	Over 1,000 kVA	0.859	0.37	43%
32	505	North2	Feeder 204	Over 1,000 kVA	2.235	0.34	15%
33	6837	North6	Feeder 201	200-1,000 kVA	0.173	0.104	60%
34	534	North4	Feeder 304	Over 1,000 kVA	2.033	0.3	15%
35	9093	North4	Feeder 101	Over 1,000 kVA	0.187	0.021	11%
36	532	North4	Feeder 204	Over 1,000 kVA	1.608	0.32	20%
37	6879	North6	Feeder 201	200-1,000 kVA	0.069	0.041	59%
38	5273	North6	Feeder 205	200-1,000 kVA	0.054	0.032	59%
39	8363	North6	Feeder 202	200-1,000 kVA	0.041	0.025	61%
40	5097	North6	Feeder 201	Over 1,000 kVA	0.46	0.276	60%
41	533	North4	Feeder 205	Over 1,000 kVA	0.908	0.16	18%
42	8592	North6	Feeder 205	Over 1,000 kVA	0.36	0.15	42%
43	5172	North6	Feeder 202	200-1,000 kVA	0.041	0.025	61%
44	8445	North6	Feeder 202	200-1,000 kVA	0.041	0.025	61%
45	9086	North6	Feeder 202	Over 1,000 kVA	0.275	0.165	60%
46	535	North4	Feeder 305	Over 1,000 kVA	1.893	0.28	15%
47	5304	North6	Feeder 201	Over 1,000 kVA	0.46	0.119	26%
48	8187	North4	Feeder 301	200-1,000 kVA	0.114	0.068	60%
49	7986	North4	Feeder 303	200-1,000 kVA	0.226	0.136	60%
50	514	North6	Feeder 202	Over 1,000 kVA	0.732	0.081	11%
51	8894	North4	Feeder 201	Over 1,000 kVA	0.055	0.033	60%
52	7690	North4	Feeder 301	Over 1,000 kVA	0.171	0.103	60%
53	527	North4	Feeder 103	Over 1,000 kVA	1.448	0.22	15%
54	9092	North4	Feeder 202	Over 1,000 kVA	0.209	0.12	57%
55	8132	North4	Feeder 201	200-1,000 kVA	0.021	0.013	62%
56	8281	North4	Feeder 301	Over 1,000 kVA	0.171	0.079	46%
57	7763	North4	Feeder 201	200-1,000 kVA	0.006	0.004	67%
58	8748	North4	Feeder 201	200-1,000 kVA	0.014	0.008	57%
59	9098	North4	Feeder 202	200-1,000 kVA	0.021	0.013	62%

Summer 2002 Rank-Ordered DG Capacity Additions (15% Fdr Limit) (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG (MW)	DG % of Peak Load
60	8284	North4	Feeder 201	200-1,000 kVA	0.014	0.008	57%
61	5366	North4	Feeder 201	200-1,000 kVA	0.021	0.011	52%
62	5324	North4	Feeder 303	Over 1,000 kVA	0.453	0.114	25%
63	500	North2	Feeder 102	Over 1,000 kVA	1.158	0.26	22%
64	7965	North2	Feeder 104	Over 1,000 kVA	0.637	0.31	49%
65	502	North2	Feeder 105	Over 1,000 kVA	0.773	0.27	35%
66	538	Center3	Feeder 203	Over 1,000 kVA	2.21	0.33	15%
67	8682	North2	Feeder 205	Over 1,000 kVA	0.538	0.13	24%
68	7272	Center2	Feeder 203	200-1,000 kVA	0.06	0.036	60%
69	8587	North6	Feeder 105	Over 1,000 kVA	0.237	0.142	60%
70	8621	Center2	Feeder 203	200-1,000 kVA	0.091	0.055	60%
71	6481	Core1	Feeder 204	200-1,000 kVA	0.181	0.109	60%
72	9050	Center2	Feeder 203	200-1,000 kVA	0.121	0.073	60%
73	522	Core1	Feeder 302	Over 1,000 kVA	0.852	0.36	42%
74	7550	North6	Feeder 105	200-1,000 kVA	0.079	0.047	59%
75	5158	Core1	Feeder 204	200-1,000 kVA	0.091	0.055	60%
76	8304	Center2	Feeder 203	200-1,000 kVA	0.121	0.073	60%
77	8199	North6	Feeder 105	200-1,000 kVA	0.079	0.047	59%
78	7705	North6	Feeder 105	200-1,000 kVA	0.158	0.095	60%
79	520	Core1	Feeder 204	Over 1,000 kVA	0.726	0.237	33%
80	8589	Center2	Feeder 203	Over 1,000 kVA	0.181	0.024	13%
81	7627	North6	Feeder 105	200-1,000 kVA	0.079	0.038	48%
82	539	Center3	Feeder 204	Over 1,000 kVA	1.31	0.38	29%
83	5171	North6	Feeder 101	Over 1,000 kVA	0.284	0.17	60%
84	8429	Core1	Feeder 203	200-1,000 kVA	0.271	0.163	60%
85	5183	Center3	Feeder 302	Over 1,000 kVA	0.399	0.239	60%
86	5088	North6	Feeder 101	200-1,000 kVA	0.095	0.057	60%
87	5121	Core1	Feeder 203	200-1,000 kVA	0.18	0.108	60%
88	5182	Center3	Feeder 302	Over 1,000 kVA	0.399	0.051	13%
89	8351	North6	Feeder 101	200-1,000 kVA	0.142	0.083	58%
90	7275	Core1	Feeder 203	200-1,000 kVA	0.18	0.108	60%
91	7674	Center3	Feeder 202	200-1,000 kVA	0.033	0.02	61%
92	512	North6	Feeder 104	Over 1,000 kVA	1.954	0.29	15%
93	7445	Center3	Feeder 202	200-1,000 kVA	0.022	0.013	59%
94	8660	Core1	Feeder 203	Over 1,000 kVA	0.541	0.101	19%
95	5122	Center3	Feeder 202	200-1,000 kVA	0.033	0.02	61%
96	8406	Center3	Feeder 202	200-1,000 kVA	0.044	0.026	59%
97	8274	Center3	Feeder 202	200-1,000 kVA	0.033	0.02	61%
98	8158	Center3	Feeder 202	200-1,000 kVA	0.044	0.021	48%
99	8666	North6	Feeder 103	200-1,000 kVA	0.269	0.161	60%
100	507	South3	Feeder 105	Over 1,000 kVA	0.24	0.04	17%
101	8972	North6	Feeder 103	Over 1,000 kVA	0.539	0.179	33%
102	521	Core1	Feeder 205	Over 1,000 kVA	0.251	0.151	60%
103	36612	North1	Substation	Over 1,000 kVA (Xmsn level)	14.878	2.23	15%
104	508	North6	Feeder 102	Over 1,000 kVA	0.573	0.33	58%
105	8971	Core1	Feeder 205	Over 1,000 kVA	0.126	0.019	15%
106	519	Core1	Feeder 103	Over 1,000 kVA	1.166	0.18	15%
107	8857	Core1	Feeder 102	Over 1,000 kVA	0.248	0.149	60%
108	542	Center2	Feeder 201	Over 1,000 kVA	2.424	0.36	15%
109	8885	Core1	Feeder 102	200-1,000 kVA	0.124	0.031	25%
110	5062	Core1	Feeder 304	200-1,000 kVA	0.462	0.21	45%
111	36650	Center1	Substation	Over 1,000 kVA (Xmsn level)	7.783	1.17	15%

Summer 2005 Rank-Ordered DR Capacity Additions

Rank	Bus ID	Demand Response (MW)	Peak Load (MW)	Substation	Feeder	Customer Class	DR % of Peak Load
1	506	0.55558	3.704	South3	Feeder 104	Over 1,000 kVA	15%
2	5051	0.27779	1.852	South3	Feeder 104	Over 1,000 kVA	15%
3	5254	0.13889	0.926	South3	Feeder 104	200-1,000 kVA	15%
4	8542	0.20834	1.389	South3	Feeder 104	Over 1,000 kVA	15%
5	8730	0.10417	0.694	South3	Feeder 104	200-1,000 kVA	15%
6	8827	0.04167	0.278	South3	Feeder 104	200-1,000 kVA	15%
7	5135	0.03125	0.208	South3	Feeder 104	200-1,000 kVA	15%
8	5016	0.06945	0.463	South3	Feeder 104	200-1,000 kVA	15%
9	5222	0.04167	0.278	South3	Feeder 104	200-1,000 kVA	15%
10	8499	0.10417	0.694	South3	Feeder 104	200-1,000 kVA	15%
11	541	0.51346	3.423	Center3	Feeder 303	Over 1,000 kVA	15%
12	5169	0.19255	1.284	Center3	Feeder 303	Over 1,000 kVA	15%
13	540	0.51346	3.423	Center3	Feeder 303	Over 1,000 kVA	15%
14	9130	0.12837	0.856	Center3	Feeder 303	200-1,000 kVA	15%
15	5302	0.19255	1.284	Center3	Feeder 303	Over 1,000 kVA	15%
16	8365	0.12837	0.856	Center3	Feeder 303	200-1,000 kVA	15%
17	7671	0.06418	0.428	Center3	Feeder 303	200-1,000 kVA	15%
18	5250	0.06418	0.428	Center3	Feeder 303	200-1,000 kVA	15%
19	521	0.16948	1.13	Core1	Feeder 205	Over 1,000 kVA	15%
20	5255	0.12837	0.856	Center3	Feeder 303	200-1,000 kVA	15%
21	8971	0.08474	0.565	Core1	Feeder 205	Over 1,000 kVA	15%
22	7971	0.06356	0.424	Core1	Feeder 205	Over 1,000 kVA	15%
23	8191	0.06418	0.428	Center3	Feeder 303	200-1,000 kVA	15%
24	8516	0.06356	0.424	Core1	Feeder 205	Over 1,000 kVA	15%
25	7627	0.03456	0.23	North6	Feeder 105	200-1,000 kVA	15%
26	8767	0.08474	0.565	Core1	Feeder 205	Over 1,000 kVA	15%
27	7988	0.05183	0.346	North6	Feeder 105	200-1,000 kVA	15%
28	7067	0.06911	0.461	North6	Feeder 105	200-1,000 kVA	15%
29	8036	0.03456	0.23	North6	Feeder 105	200-1,000 kVA	15%
30	8350	0.05183	0.346	North6	Feeder 105	200-1,000 kVA	15%
31	8199	0.03456	0.23	North6	Feeder 105	200-1,000 kVA	15%
32	8162	0.10367	0.691	North6	Feeder 105	Over 1,000 kVA	15%
33	5256	0.06418	0.428	Center3	Feeder 303	200-1,000 kVA	15%
34	8587	0.10367	0.691	North6	Feeder 105	Over 1,000 kVA	15%
35	7705	0.06911	0.461	North6	Feeder 105	200-1,000 kVA	15%
36	8768	0.13822	0.921	North6	Feeder 105	Over 1,000 kVA	15%
37	8125	0.06418	0.428	Center3	Feeder 303	200-1,000 kVA	15%
38	7463	0.03456	0.23	North6	Feeder 105	200-1,000 kVA	15%
39	513	0.27644	1.843	North6	Feeder 105	Over 1,000 kVA	15%
40	9129	0.13238	0.883	Core1	Feeder 305	200-1,000 kVA	15%
41	8205	0.06619	0.441	Core1	Feeder 305	200-1,000 kVA	15%
42	8701	0.19857	1.324	Core1	Feeder 305	Over 1,000 kVA	15%
43	5204	0.09928	0.662	Core1	Feeder 302	200-1,000 kVA	15%
44	524	0.52952	3.53	Core1	Feeder 305	Over 1,000 kVA	15%
45	507	0.55558	3.704	South3	Feeder 105	Over 1,000 kVA	15%
46	7550	0.03456	0.23	North6	Feeder 105	200-1,000 kVA	15%
47	6879	0.01945	0.13	North6	Feeder 201	200-1,000 kVA	15%
48	6837	0.04862	0.324	North6	Feeder 201	200-1,000 kVA	15%
49	8303	0.05109	0.341	North2	Feeder 202	200-1,000 kVA	15%
50	5097	0.12965	0.864	North6	Feeder 201	Over 1,000 kVA	15%
51	8705	0.02979	0.199	Core1	Feeder 302	200-1,000 kVA	15%
52	8426	0.05183	0.346	North6	Feeder 105	200-1,000 kVA	15%
53	7765	0.06418	0.428	Center3	Feeder 303	200-1,000 kVA	15%
54	502	0.36638	2.443	North2	Feeder 105	Over 1,000 kVA	15%
55	8506	0.03241	0.216	North6	Feeder 201	200-1,000 kVA	15%
56	7761	0.03241	0.216	North6	Feeder 201	200-1,000 kVA	15%
57	7973	0.06482	0.432	North6	Feeder 201	200-1,000 kVA	15%
58	7563	0.01459	0.097	North6	Feeder 201	200-1,000 kVA	15%
59	508	0.27644	1.843	North6	Feeder 102	Over 1,000 kVA	15%

Summer 2005 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Demand Response (MW)	Peak Load (MW)	Substation	Feeder	Customer Class	DR % of Peak Load
60	8890	0.13624	0.908	North2	Feeder 202	Over 1,000 kVA	15%
61	8689	0.05109	0.341	North2	Feeder 202	200-1,000 kVA	15%
62	6481	0.04237	0.282	Core1	Feeder 204	200-1,000 kVA	15%
63	5304	0.12965	0.864	North6	Feeder 201	Over 1,000 kVA	15%
64	5060	0.01459	0.097	North6	Feeder 201	200-1,000 kVA	15%
65	5123	0.04862	0.324	North6	Feeder 201	200-1,000 kVA	15%
66	5011	0.01726	0.115	Center3	Feeder 202	200-1,000 kVA	15%
67	8923	0.06619	0.441	Core1	Feeder 305	200-1,000 kVA	15%
68	5181	0.03241	0.216	North6	Feeder 201	200-1,000 kVA	15%
69	8924	0.04862	0.324	North6	Feeder 201	200-1,000 kVA	15%
70	5198	0.09724	0.648	North6	Feeder 201	Over 1,000 kVA	15%
71	9051	0.13238	0.883	Core1	Feeder 302	200-1,000 kVA	15%
72	8590	0.19255	1.284	Center3	Feeder 303	Over 1,000 kVA	15%
73	510	0.27644	1.843	North6	Feeder 102	Over 1,000 kVA	15%
74	520	0.16948	1.13	Core1	Feeder 204	Over 1,000 kVA	15%
75	9012	0.04862	0.324	North6	Feeder 201	200-1,000 kVA	15%
76	5163	0.03971	0.265	Core1	Feeder 305	200-1,000 kVA	15%
77	7610	0.09928	0.662	Core1	Feeder 302	200-1,000 kVA	15%
78	8627	0.05183	0.346	North6	Feeder 102	200-1,000 kVA	15%
79	522	0.52952	3.53	Core1	Feeder 302	Over 1,000 kVA	15%
80	9140	0.04862	0.324	North6	Feeder 201	200-1,000 kVA	15%
81	5276	0.06911	0.461	North6	Feeder 102	200-1,000 kVA	15%
82	8854	0.00184	0.092	Center2	Feeder 104	200-1,000 kVA	2%
83	8725	0.00283	0.141	Core1	Feeder 204	200-1,000 kVA	2%
84	5253	0.00864	0.432	North6	Feeder 201	200-1,000 kVA	2%
85	8853	0.00397	0.199	Core1	Feeder 302	200-1,000 kVA	2%
86	8157	0.00565	0.282	Core1	Feeder 204	200-1,000 kVA	2%
87	8431	0.00424	0.212	Core1	Feeder 204	200-1,000 kVA	2%
88	5158	0.00283	0.141	Core1	Feeder 204	200-1,000 kVA	2%
89	7737	0.00169	0.085	Core1	Feeder 204	200-1,000 kVA	2%
90	7439	0.06356	0.424	Core1	Feeder 204	Over 1,000 kVA	15%
91	7637	0.00307	0.153	Center3	Feeder 202	200-1,000 kVA	2%
92	501	0.36638	2.443	North2	Feeder 105	Over 1,000 kVA	15%
93	5170	0.10367	0.691	North6	Feeder 101	Over 1,000 kVA	15%
94	8252	0.00397	0.199	Core1	Feeder 302	200-1,000 kVA	2%
95	503	0.27248	1.817	North2	Feeder 202	Over 1,000 kVA	15%
96	8280	0.10367	0.691	North6	Feeder 101	Over 1,000 kVA	15%
97	8404	0.00883	0.441	Core1	Feeder 305	200-1,000 kVA	2%
98	7285	0.00397	0.199	Core1	Feeder 305	200-1,000 kVA	2%
99	5225	0.00273	0.136	North2	Feeder 202	200-1,000 kVA	2%
100	5154	0.00207	0.104	North6	Feeder 101	200-1,000 kVA	2%
101	5087	0.00461	0.23	North6	Feeder 101	200-1,000 kVA	2%
102	5183	0.25673	1.712	Center3	Feeder 302	Over 1,000 kVA	15%
103	7697	0.00454	0.227	North2	Feeder 202	200-1,000 kVA	2%
104	5028	0.00454	0.227	North2	Feeder 202	200-1,000 kVA	2%
105	8271	0.00273	0.136	North2	Feeder 202	200-1,000 kVA	2%
106	5155	0.00207	0.104	North6	Feeder 101	200-1,000 kVA	2%
107	5142	0.00276	0.138	North6	Feeder 101	200-1,000 kVA	2%
108	8792	0.00432	0.216	North6	Feeder 201	200-1,000 kVA	2%
109	8314	0.00454	0.227	North2	Feeder 202	200-1,000 kVA	2%
110	8204	0.00454	0.227	North2	Feeder 202	200-1,000 kVA	2%
111	8250	0.00204	0.102	North2	Feeder 202	200-1,000 kVA	2%
112	8313	0.00454	0.227	North2	Feeder 202	200-1,000 kVA	2%
113	5088	0.00461	0.23	North6	Feeder 101	200-1,000 kVA	2%
114	505	0.27248	1.817	North2	Feeder 204	Over 1,000 kVA	15%
115	8630	0.00273	0.136	North2	Feeder 202	200-1,000 kVA	2%
116	7255	0.10593	0.706	Core1	Feeder 204	Over 1,000 kVA	15%
117	5182	0.25673	1.712	Center3	Feeder 302	Over 1,000 kVA	15%
118	8690	0.00681	0.341	North2	Feeder 202	200-1,000 kVA	2%
119	5185	0.00908	0.454	North2	Feeder 202	200-1,000 kVA	2%

Summer 2005 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Demand Response (MW)	Peak Load (MW)	Substation	Feeder	Customer Class	DR % of Peak Load
120	5178	0.00454	0.227	North2	Feeder 202	200-1,000 kVA	2%
121	5133	0.00207	0.104	North6	Feeder 101	200-1,000 kVA	2%
122	8388	0.00204	0.102	North2	Feeder 202	200-1,000 kVA	2%
123	8514	0.10218	0.681	North2	Feeder 202	Over 1,000 kVA	15%
124	8248	0.00366	0.183	North2	Feeder 105	200-1,000 kVA	2%
125	8190	0.00894	0.447	North4	Feeder 301	200-1,000 kVA	2%
126	7758	0.00432	0.216	North6	Feeder 201	200-1,000 kVA	2%
127	7612	0.00894	0.447	North4	Feeder 301	200-1,000 kVA	2%
128	5094	0.00671	0.335	North4	Feeder 301	200-1,000 kVA	2%
129	5171	0.10367	0.691	North6	Feeder 101	Over 1,000 kVA	15%
130	8661	0.10218	0.681	North2	Feeder 202	Over 1,000 kVA	15%
131	8420	0.00611	0.305	North2	Feeder 105	200-1,000 kVA	2%
132	8662	0.10218	0.681	North2	Feeder 202	Over 1,000 kVA	15%
133	509	0.27644	1.843	North6	Feeder 102	Over 1,000 kVA	15%
134	7689	0.10059	0.671	North4	Feeder 301	Over 1,000 kVA	15%
135	8504	0.00611	0.305	North2	Feeder 105	200-1,000 kVA	2%
136	8340	0.00461	0.23	North6	Feeder 102	200-1,000 kVA	2%
137	5096	0.00671	0.335	North4	Feeder 301	200-1,000 kVA	2%
138	8659	0.09724	0.648	North6	Feeder 205	Over 1,000 kVA	15%
139	8352	0.00648	0.324	North6	Feeder 201	200-1,000 kVA	2%
140	8541	0.10059	0.671	North4	Feeder 301	Over 1,000 kVA	15%
141	7759	0.00511	0.256	Center3	Feeder 202	200-1,000 kVA	2%
142	5098	0.13412	0.894	North4	Feeder 301	Over 1,000 kVA	15%
143	514	0.2593	1.729	North6	Feeder 202	Over 1,000 kVA	15%
144	8281	0.10059	0.671	North4	Feeder 301	Over 1,000 kVA	15%
145	7702	0.00894	0.447	North4	Feeder 301	200-1,000 kVA	2%
146	7965	0.13739	0.916	North2	Feeder 104	Over 1,000 kVA	15%
147	7198	0.00432	0.216	North6	Feeder 201	200-1,000 kVA	2%
148	5247	0.00461	0.23	North6	Feeder 101	200-1,000 kVA	2%
149	5054	0.00447	0.224	North4	Feeder 301	200-1,000 kVA	2%
150	7753	0.00207	0.104	North6	Feeder 101	200-1,000 kVA	2%
151	5187	0.01712	0.856	Center3	Feeder 302	200-1,000 kVA	2%
152	8764	0.00856	0.428	Center3	Feeder 302	200-1,000 kVA	2%
153	8225	0.12965	0.864	North6	Feeder 202	Over 1,000 kVA	15%
154	8188	0.00921	0.461	North6	Feeder 102	200-1,000 kVA	2%
155	8349	0.01284	0.642	Center3	Feeder 302	200-1,000 kVA	2%
156	8226	0.01284	0.642	Center3	Feeder 302	200-1,000 kVA	2%
157	8829	0.00259	0.13	North6	Feeder 202	200-1,000 kVA	2%
158	511	0.27644	1.843	North6	Feeder 103	Over 1,000 kVA	15%
159	8187	0.00894	0.447	North4	Feeder 301	200-1,000 kVA	2%
160	7755	0.00447	0.224	North4	Feeder 301	200-1,000 kVA	2%
161	8605	0.00207	0.104	North6	Feeder 101	200-1,000 kVA	2%
162	5149	0.18319	1.221	North2	Feeder 104	Over 1,000 kVA	15%
163	7690	0.10059	0.671	North4	Feeder 301	Over 1,000 kVA	15%
164	9086	0.09724	0.648	North6	Feeder 202	Over 1,000 kVA	15%
165	517	0.2593	1.729	North6	Feeder 205	Over 1,000 kVA	15%
166	8660	0.06356	0.424	Core1	Feeder 203	Over 1,000 kVA	15%
167	512	0.27644	1.843	North6	Feeder 104	Over 1,000 kVA	15%
168	7760	0.00856	0.428	Center3	Feeder 302	200-1,000 kVA	2%
169	5289	0.00461	0.23	North6	Feeder 101	200-1,000 kVA	2%
170	8972	0.13822	0.921	North6	Feeder 103	Over 1,000 kVA	15%
171	7673	0.01284	0.642	Center3	Feeder 302	200-1,000 kVA	2%
172	9044	0.00513	0.257	Center3	Feeder 302	200-1,000 kVA	2%
173	8747	0.00856	0.428	Center3	Feeder 302	200-1,000 kVA	2%
174	7619	0.00432	0.216	North6	Feeder 205	200-1,000 kVA	2%
175	7554	0.0023	0.115	Center3	Feeder 202	200-1,000 kVA	2%
176	6821	0.00513	0.257	Center3	Feeder 302	200-1,000 kVA	2%
177	8592	0.09724	0.648	North6	Feeder 205	Over 1,000 kVA	15%
178	8525	0.00921	0.461	North6	Feeder 101	200-1,000 kVA	2%
179	7711	0.00513	0.257	Center3	Feeder 302	200-1,000 kVA	2%

Summer 2005 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Demand Response (MW)	Peak Load (MW)	Substation	Feeder	Customer Class	DR % of Peak Load
180	5053	0.00432	0.216	North6	Feeder 205	200-1,000 kVA	2%
181	8682	0.13624	0.908	North2	Feeder 205	Over 1,000 kVA	15%
182	8155	0.00259	0.13	North6	Feeder 205	200-1,000 kVA	2%
183	8044	0.00432	0.216	North6	Feeder 205	200-1,000 kVA	2%
184	8732	0.00691	0.346	North6	Feeder 101	200-1,000 kVA	2%
185	7266	0.00432	0.216	North6	Feeder 205	200-1,000 kVA	2%
186	8164	0.09724	0.648	North6	Feeder 205	Over 1,000 kVA	15%
187	7418	0.0023	0.115	Center3	Feeder 202	200-1,000 kVA	2%
188	515	0.2593	1.729	North6	Feeder 203	Over 1,000 kVA	15%
189	8445	0.00195	0.097	North6	Feeder 202	200-1,000 kVA	2%
190	8278	0.10367	0.691	North6	Feeder 103	Over 1,000 kVA	15%
191	8203	0.00283	0.141	Core1	Feeder 205	200-1,000 kVA	2%
192	5306	0.08474	0.565	Core1	Feeder 205	Over 1,000 kVA	15%
193	7654	0.00195	0.097	North6	Feeder 203	200-1,000 kVA	2%
194	7645	0.00195	0.097	North6	Feeder 203	200-1,000 kVA	2%
195	7662	0.00195	0.097	North6	Feeder 203	200-1,000 kVA	2%
196	8272	0.00169	0.085	Core1	Feeder 205	200-1,000 kVA	2%
197	8401	0.00432	0.216	North6	Feeder 203	200-1,000 kVA	2%
198	8787	0.00432	0.216	North6	Feeder 203	200-1,000 kVA	2%
199	8666	0.00921	0.461	North6	Feeder 103	200-1,000 kVA	2%
200	5052	0.12965	0.864	North6	Feeder 205	Over 1,000 kVA	15%
201	7449	0.00259	0.13	North6	Feeder 203	200-1,000 kVA	2%
202	8355	0.00424	0.212	Core1	Feeder 204	200-1,000 kVA	2%
203	5013	0.00127	0.064	Core1	Feeder 205	200-1,000 kVA	2%
204	7974	0.00767	0.383	Center3	Feeder 202	200-1,000 kVA	2%
205	5027	0.00432	0.216	North6	Feeder 203	200-1,000 kVA	2%
206	516	0.2593	1.729	North6	Feeder 204	Over 1,000 kVA	15%
207	8604	0.00127	0.064	Core1	Feeder 205	200-1,000 kVA	2%
208	6881	0.00169	0.085	Core1	Feeder 204	200-1,000 kVA	2%
209	5172	0.00195	0.097	North6	Feeder 202	200-1,000 kVA	2%
210	7969	0.00767	0.383	Center3	Feeder 202	200-1,000 kVA	2%
211	536	0.30677	2.045	Center3	Feeder 202	Over 1,000 kVA	15%
212	5324	0.13412	0.894	North4	Feeder 303	Over 1,000 kVA	15%
213	504	0.27248	1.817	North2	Feeder 203	Over 1,000 kVA	15%
214	8523	0.00565	0.282	Core1	Feeder 204	200-1,000 kVA	2%
215	538	0.30677	2.045	Center3	Feeder 203	Over 1,000 kVA	15%
216	8385	0.00127	0.064	Core1	Feeder 205	200-1,000 kVA	2%
217	9099	0.00424	0.212	Core1	Feeder 205	200-1,000 kVA	2%
218	8351	0.00691	0.346	North6	Feeder 101	200-1,000 kVA	2%
219	6943	0.00283	0.141	Core1	Feeder 205	200-1,000 kVA	2%
220	8363	0.00195	0.097	North6	Feeder 202	200-1,000 kVA	2%
221	9005	0.00283	0.141	Core1	Feeder 205	200-1,000 kVA	2%
222	7747	0.00127	0.064	Core1	Feeder 204	200-1,000 kVA	2%
223	5020	0.00283	0.141	Core1	Feeder 205	200-1,000 kVA	2%
224	5305	0.08474	0.565	Core1	Feeder 203	Over 1,000 kVA	15%
225	8186	0.00283	0.141	Core1	Feeder 205	200-1,000 kVA	2%
226	5273	0.00195	0.097	North6	Feeder 205	200-1,000 kVA	2%
227	537	0.30677	2.045	Center3	Feeder 202	Over 1,000 kVA	15%
228	5205	0.00681	0.341	North2	Feeder 203	200-1,000 kVA	2%
229	8049	0.08474	0.565	Core1	Feeder 203	Over 1,000 kVA	15%
230	5258	0.00283	0.141	Core1	Feeder 205	200-1,000 kVA	2%
231	7986	0.00894	0.447	North4	Feeder 303	200-1,000 kVA	2%
232	5248	0.00454	0.227	North2	Feeder 203	200-1,000 kVA	2%
233	9011	0.00454	0.227	North2	Feeder 203	200-1,000 kVA	2%
234	8517	0.09724	0.648	North6	Feeder 203	Over 1,000 kVA	15%
235	8306	0.00565	0.282	Core1	Feeder 203	200-1,000 kVA	2%
236	8126	0.00454	0.227	North2	Feeder 203	200-1,000 kVA	2%
237	5113	0.13624	0.908	North2	Feeder 203	Over 1,000 kVA	15%
238	8699	0.11504	0.767	Center3	Feeder 204	Over 1,000 kVA	15%
239	8646	0.0023	0.115	Center3	Feeder 202	200-1,000 kVA	2%

Summer 2005 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Demand Response (MW)	Peak Load (MW)	Substation	Feeder	Customer Class	DR % of Peak Load
240	5168	0.10218	0.681	North2	Feeder 203	Over 1,000 kVA	15%
241	5144	0.0545	0.908	North2	Feeder 203	Over 1,000 kVA	6%
242	6525	0.00127	0.064	Core1	Feeder 205	200-1,000 kVA	2%
243	8038	0.04087	0.681	North2	Feeder 203	Over 1,000 kVA	6%
244	8656	0.00864	0.432	North6	Feeder 202	200-1,000 kVA	2%
245	8973	0.0545	0.908	North2	Feeder 203	Over 1,000 kVA	6%
246	7557	0.00432	0.216	North6	Feeder 203	200-1,000 kVA	2%
247	5116	0.00432	0.216	North6	Feeder 202	200-1,000 kVA	2%
248	539	0.12271	2.045	Center3	Feeder 204	Over 1,000 kVA	6%
249	8228	0.00593	0.297	North4	Feeder 105	200-1,000 kVA	2%
250	8595	0.04087	0.681	North2	Feeder 203	Over 1,000 kVA	6%
251	8594	0.04087	0.681	North2	Feeder 203	Over 1,000 kVA	6%
252	6093	0.00127	0.064	Core1	Feeder 203	200-1,000 kVA	2%
253	8887	0.01023	0.511	Center3	Feeder 204	200-1,000 kVA	2%
254	8665	0.01023	0.511	Center3	Feeder 204	200-1,000 kVA	2%
255	5224	0.00169	0.085	Core1	Feeder 203	200-1,000 kVA	2%
256	7655	0.00195	0.097	North6	Feeder 202	200-1,000 kVA	2%
257	8524	0.00864	0.432	North6	Feeder 202	200-1,000 kVA	2%
258	8444	0.00195	0.097	North6	Feeder 202	200-1,000 kVA	2%
259	7613	0.00195	0.097	North6	Feeder 202	200-1,000 kVA	2%
260	7736	0.00237	0.119	North4	Feeder 105	200-1,000 kVA	2%
261	8826	0.00307	0.153	Center3	Feeder 204	200-1,000 kVA	2%
262	9010	0.00916	0.458	North2	Feeder 104	200-1,000 kVA	2%
263	7275	0.00283	0.141	Core1	Feeder 203	200-1,000 kVA	2%
264	5121	0.00283	0.141	Core1	Feeder 203	200-1,000 kVA	2%
265	8128	0.00611	0.305	North2	Feeder 104	200-1,000 kVA	2%
266	7495	0.00395	0.198	North4	Feeder 105	200-1,000 kVA	2%
267	8429	0.00424	0.212	Core1	Feeder 203	200-1,000 kVA	2%
268	8269	0.00237	0.119	North4	Feeder 105	200-1,000 kVA	2%
269	5034	0.04745	0.791	North4	Feeder 105	Over 1,000 kVA	6%
270	5062	0.00883	0.441	Core1	Feeder 304	200-1,000 kVA	2%
271	5186	0.01023	0.511	Center3	Feeder 202	200-1,000 kVA	2%
272	8161	0.03558	0.593	North4	Feeder 105	Over 1,000 kVA	6%
273	5130	0.05496	0.916	North2	Feeder 102	Over 1,000 kVA	6%
274	7617	0.01765	0.883	Core1	Feeder 304	200-1,000 kVA	2%
275	8127	0.00611	0.305	North2	Feeder 102	200-1,000 kVA	2%
276	8158	0.01023	0.511	Center3	Feeder 202	200-1,000 kVA	2%
277	8041	0.04602	0.767	Center3	Feeder 202	Over 1,000 kVA	6%
278	7763	0.00157	0.079	North4	Feeder 201	200-1,000 kVA	2%
279	8274	0.00767	0.383	Center3	Feeder 202	200-1,000 kVA	2%
280	8277	0.00671	0.335	North4	Feeder 303	200-1,000 kVA	2%
281	500	0.14655	2.443	North2	Feeder 102	Over 1,000 kVA	6%
282	8748	0.00349	0.175	North4	Feeder 201	200-1,000 kVA	2%
283	5366	0.00524	0.262	North4	Feeder 201	200-1,000 kVA	2%
284	8522	0.00894	0.447	North4	Feeder 303	200-1,000 kVA	2%
285	8589	0.05988	0.998	Center2	Feeder 203	Over 1,000 kVA	6%
286	8894	0.0419	0.698	North4	Feeder 201	Over 1,000 kVA	6%
287	8132	0.00524	0.262	North4	Feeder 201	200-1,000 kVA	2%
288	8406	0.01023	0.511	Center3	Feeder 202	200-1,000 kVA	2%
289	5188	0.01331	0.665	Center2	Feeder 203	200-1,000 kVA	2%
290	5197	0.00998	0.499	Center2	Feeder 203	200-1,000 kVA	2%
291	5226	0.05931	0.988	North4	Feeder 101	Over 1,000 kVA	6%
292	8284	0.00349	0.175	North4	Feeder 201	200-1,000 kVA	2%
293	534	0.1073	1.788	North4	Feeder 304	Over 1,000 kVA	6%
294	8528	0.00273	0.136	North2	Feeder 205	200-1,000 kVA	2%
295	535	0.1073	1.788	North4	Feeder 305	Over 1,000 kVA	6%
296	9091	0.03558	0.593	North4	Feeder 101	Over 1,000 kVA	6%
297	9098	0.00524	0.262	North4	Feeder 201	200-1,000 kVA	2%
298	5148	0.04745	0.791	North4	Feeder 104	Over 1,000 kVA	6%
299	9090	0.03558	0.593	North4	Feeder 101	Over 1,000 kVA	6%

Summer 2005 Rank-Ordered DR Capacity Additions (cont.)

Rank	Bus ID	Demand Response (MW)	Peak Load (MW)	Substation	Feeder	Customer Class	DR % of Peak Load
300	9093	0.03558	0.593	North4	Feeder 101	Over 1,000 kVA	6%
301	8341	0.00395	0.198	North4	Feeder 104	200-1,000 kVA	2%
302	8283	0.00395	0.198	North4	Feeder 104	200-1,000 kVA	2%
303	5191	0.07943	1.324	Core1	Feeder 305	Over 1,000 kVA	6%
304	9048	0.00791	0.395	North4	Feeder 104	200-1,000 kVA	2%
305	8411	0.00791	0.395	North4	Feeder 104	200-1,000 kVA	2%
306	8282	0.00349	0.175	North4	Feeder 201	200-1,000 kVA	2%
307	5122	0.00767	0.383	Center3	Feeder 202	200-1,000 kVA	2%
308	5118	0.00395	0.198	North4	Feeder 104	200-1,000 kVA	2%
309	7970	0.00524	0.262	North4	Feeder 201	200-1,000 kVA	2%
310	9088	0.03558	0.593	North4	Feeder 101	Over 1,000 kVA	6%
311	528	0.08381	1.397	North4	Feeder 201	Over 1,000 kVA	6%
312	8623	0.00524	0.262	North4	Feeder 201	200-1,000 kVA	2%
313	7668	0.00237	0.119	North4	Feeder 104	200-1,000 kVA	2%
314	7445	0.00511	0.256	Center3	Feeder 202	200-1,000 kVA	2%
315	8497	0.00593	0.297	North4	Feeder 104	200-1,000 kVA	2%
316	8591	0.03143	0.524	North4	Feeder 201	Over 1,000 kVA	6%
317	7674	0.00767	0.383	Center3	Feeder 202	200-1,000 kVA	2%
318	7094	0.00157	0.079	North4	Feeder 201	200-1,000 kVA	2%
319	8903	0.00698	0.349	North4	Feeder 201	200-1,000 kVA	2%
320	8633	0.00791	0.395	North4	Feeder 104	200-1,000 kVA	2%
321	8311	0.00524	0.262	North4	Feeder 201	200-1,000 kVA	2%
322	7656	0.00157	0.079	North4	Feeder 201	200-1,000 kVA	2%
323	9087	0.03558	0.593	North4	Feeder 104	Over 1,000 kVA	6%
324	8189	0.00698	0.349	North4	Feeder 201	200-1,000 kVA	2%
325	8698	0.03558	0.593	North4	Feeder 104	Over 1,000 kVA	6%
326	5147	0.00349	0.175	North4	Feeder 201	200-1,000 kVA	2%
327	5301	0.00998	0.499	Center2	Feeder 203	200-1,000 kVA	2%
328	529	0.08381	1.397	North4	Feeder 201	Over 1,000 kVA	6%
329	523	0.21181	3.53	Core1	Feeder 302	Over 1,000 kVA	6%
330	8893	0.0419	0.698	North4	Feeder 203	Over 1,000 kVA	6%
331	5176	0.00178	0.089	North4	Feeder 104	200-1,000 kVA	2%
332	8413	0.00791	0.395	North4	Feeder 105	200-1,000 kVA	2%
333	8417	0.00395	0.198	North4	Feeder 104	200-1,000 kVA	2%
334	5311	0.00894	0.447	North4	Feeder 303	200-1,000 kVA	2%
335	8527	0.00237	0.119	North4	Feeder 104	200-1,000 kVA	2%
336	8904	0.0419	0.698	North4	Feeder 203	Over 1,000 kVA	6%
337	8131	0.00791	0.395	North4	Feeder 104	200-1,000 kVA	2%
338	519	0.17158	2.86	Core1	Feeder 103	Over 1,000 kVA	6%
339	7272	0.00665	0.333	Center2	Feeder 203	200-1,000 kVA	2%
340	8621	0.00998	0.499	Center2	Feeder 203	200-1,000 kVA	2%
341	531	0.08381	1.397	North4	Feeder 203	Over 1,000 kVA	6%
342	530	0.08381	1.397	North4	Feeder 203	Over 1,000 kVA	6%
343	9050	0.01331	0.665	Center2	Feeder 203	200-1,000 kVA	2%
344	8133	0.00524	0.262	North4	Feeder 202	200-1,000 kVA	2%
345	533	0.08381	1.397	North4	Feeder 205	Over 1,000 kVA	6%
346	8304	0.01331	0.665	Center2	Feeder 203	200-1,000 kVA	2%
347	8229	0.00524	0.262	North4	Feeder 205	200-1,000 kVA	2%
348	8629	0.00429	0.214	Core1	Feeder 102	200-1,000 kVA	2%
349	5201	0.04024	0.671	North4	Feeder 303	Over 1,000 kVA	6%
350	8885	0.0143	0.715	Core1	Feeder 102	200-1,000 kVA	2%
351	5132	0.05988	0.998	Center2	Feeder 203	Over 1,000 kVA	6%
352	9041	0.00998	0.499	Center2	Feeder 203	200-1,000 kVA	2%
353	5190	0.03143	0.524	North4	Feeder 202	Over 1,000 kVA	6%
354	8526	0.00429	0.214	Core1	Feeder 102	200-1,000 kVA	2%
355	9196	0.05988	0.998	Center2	Feeder 203	Over 1,000 kVA	6%
356	9092	0.03143	0.524	North4	Feeder 202	Over 1,000 kVA	6%
357	9038	0.00299	0.15	Center2	Feeder 203	200-1,000 kVA	2%
358	7493	0.00184	0.092	Center2	Feeder 104	200-1,000 kVA	2%
359	9049	0.01331	0.665	Center2	Feeder 203	200-1,000 kVA	2%

Summer 2005 Rank-Ordered DR Capacity Additions
(cont.)

Rank	Bus ID	Demand Response (MW)	Peak Load (MW)	Substation	Feeder	Customer Class	DR % of Peak Load
360	8658	0.00791	0.395	North4	Feeder 104	200-1,000 kVA	2%
361	8907	0.00349	0.175	North4	Feeder 202	200-1,000 kVA	2%
362	8905	0.04745	0.791	North4	Feeder 104	Over 1,000 kVA	6%
363	36612	1.4346	23.91	North1	Substation	Over 1,000 kVA (Xmsn Level)	6%
364	8700	0.03143	0.524	North4	Feeder 202	Over 1,000 kVA	6%
365	8501	0.00395	0.198	North4	Feeder 104	200-1,000 kVA	2%
366	36622	0.4926	8.21	South1	Substation	Over 1,000 kVA (Xmsn Level)	6%
367	36650	0.6642	11.07	Center1	Substation	Over 1,000 kVA (Xmsn Level)	6%
368	8342	0.00395	0.198	North4	Feeder 104	200-1,000 kVA	2%
369	8631	0.0143	0.715	Core1	Feeder 102	200-1,000 kVA	2%
370	7465	0.00178	0.089	North4	Feeder 104	200-1,000 kVA	2%
371	7448	0.00273	0.136	North2	Feeder 205	200-1,000 kVA	2%
372	8227	0.00593	0.297	North4	Feeder 104	200-1,000 kVA	2%
373	8886	0.0143	0.715	Core1	Feeder 102	200-1,000 kVA	2%
374	8412	0.00791	0.395	North4	Feeder 104	200-1,000 kVA	2%
375	5115	0.04745	0.791	North4	Feeder 104	Over 1,000 kVA	6%
376	9053	0.01331	0.665	Center2	Feeder 203	200-1,000 kVA	2%
377	9085	0.01331	0.665	Center2	Feeder 203	200-1,000 kVA	2%
378	526	0.0949	1.582	North4	Feeder 101	Over 1,000 kVA	6%
379	8857	0.08579	1.43	Core1	Feeder 102	Over 1,000 kVA	6%
380	542	0.15968	2.661	Center2	Feeder 201	Over 1,000 kVA	6%
381	532	0.08381	1.397	North4	Feeder 204	Over 1,000 kVA	6%
382	8037	0.00395	0.198	North4	Feeder 101	200-1,000 kVA	2%
383	525	0.0949	1.582	North4	Feeder 101	Over 1,000 kVA	6%
384	8795	0.00454	0.227	North2	Feeder 205	200-1,000 kVA	2%
385	518	0.17158	2.86	Core1	Feeder 102	Over 1,000 kVA	6%
386	527	0.0949	1.582	North4	Feeder 103	Over 1,000 kVA	6%
387	8710	0.00209	0.105	North4	Feeder 204	200-1,000 kVA	2%
388	8726	0.00349	0.175	North4	Feeder 204	200-1,000 kVA	2%
389	8703	0.00157	0.079	North4	Feeder 204	200-1,000 kVA	2%
390	5268	0.00157	0.079	North4	Feeder 204	200-1,000 kVA	2%

2005 Rank-Ordered DG Capacity Additions (Light Load Fdr Limit)

Rank	Bus ID	Substation	Feeder	Customer Class	DG Capacity (MW)	Peak Load (MW)	DG % of Peak Load
1	506	South3	Feeder 104	Over 1,000 kVA	1.84	3.704	50%
2	541	Center3	Feeder 303	Over 1,000 kVA	1.66	3.423	48%
3	521	Core1	Feeder 205	Over 1,000 kVA	0.678	1.13	60%
4	8971	Core1	Feeder 205	Over 1,000 kVA	0.339	0.565	60%
5	8205	Core1	Feeder 305	200-1,000 kVA	0.265	0.441	60%
6	7627	North6	Feeder 105	200-1,000 kVA	0.138	0.23	60%
7	9129	Core1	Feeder 305	200-1,000 kVA	0.135	0.883	15%
8	8199	North6	Feeder 105	200-1,000 kVA	0.138	0.23	60%
9	7971	Core1	Feeder 205	Over 1,000 kVA	0.254	0.424	60%
10	8036	North6	Feeder 105	200-1,000 kVA	0.138	0.23	60%
11	7988	North6	Feeder 105	200-1,000 kVA	0.208	0.346	60%
12	5204	Core1	Feeder 302	200-1,000 kVA	0.04	0.662	6%
13	8587	North6	Feeder 105	Over 1,000 kVA	0.415	0.691	60%
14	507	South3	Feeder 105	Over 1,000 kVA	0.04	3.704	1%
15	8516	Core1	Feeder 205	Over 1,000 kVA	0.254	0.424	60%
16	7067	North6	Feeder 105	200-1,000 kVA	0.277	0.461	60%
17	502	North2	Feeder 105	Over 1,000 kVA	1.38	2.443	56%
18	8162	North6	Feeder 105	Over 1,000 kVA	0.087	0.691	13%
19	8854	Center2	Feeder 104	200-1,000 kVA	0.055	0.092	60%
20	8767	Core1	Feeder 205	Over 1,000 kVA	0.339	0.565	60%
21	5011	Center3	Feeder 202	200-1,000 kVA	0.069	0.115	60%
22	8303	North2	Feeder 202	200-1,000 kVA	0.205	0.341	60%
23	6879	North6	Feeder 201	200-1,000 kVA	0.078	0.13	60%
24	7761	North6	Feeder 201	200-1,000 kVA	0.13	0.216	60%
25	5097	North6	Feeder 201	Over 1,000 kVA	0.518	0.864	60%
26	6481	Core1	Feeder 204	200-1,000 kVA	0.169	0.282	60%
27	508	North6	Feeder 102	Over 1,000 kVA	1.106	1.843	60%
28	7612	North4	Feeder 301	200-1,000 kVA	0.268	0.447	60%
29	520	Core1	Feeder 204	Over 1,000 kVA	0.678	1.13	60%
30	7637	Center3	Feeder 202	200-1,000 kVA	0.092	0.153	60%
31	8689	North2	Feeder 202	200-1,000 kVA	0.205	0.341	60%
32	8190	North4	Feeder 301	200-1,000 kVA	0.268	0.447	60%
33	8506	North6	Feeder 201	200-1,000 kVA	0.13	0.216	60%
34	7725	Core1	Feeder 204	Under 200 kVA	0.019	0.032	59%
35	8890	North2	Feeder 202	Over 1,000 kVA	0.545	0.908	60%
36	503	North2	Feeder 202	Over 1,000 kVA	0.116	1.817	6%
37	8531	Core1	Feeder 204	Under 200 kVA	0.019	0.032	59%
38	5094	North4	Feeder 301	200-1,000 kVA	0.201	0.335	60%
39	7973	North6	Feeder 201	200-1,000 kVA	0.259	0.432	60%
40	8725	Core1	Feeder 204	200-1,000 kVA	0.085	0.141	60%
41	8431	Core1	Feeder 204	200-1,000 kVA	0.127	0.212	60%
42	5096	North4	Feeder 301	200-1,000 kVA	0.143	0.335	43%
43	5304	North6	Feeder 201	Over 1,000 kVA	0.125	0.864	14%
44	505	North2	Feeder 204	Over 1,000 kVA	1.09	1.817	60%
45	5170	North6	Feeder 101	Over 1,000 kVA	0.3	0.691	43%
46	510	North6	Feeder 102	Over 1,000 kVA	0.034	1.843	2%
47	8157	Core1	Feeder 204	200-1,000 kVA	0.169	0.282	60%
48	5183	Center3	Feeder 302	Over 1,000 kVA	1.027	1.712	60%
49	7614	Core1	Feeder 204	Under 200 kVA	0.019	0.032	59%
50	7575	Core1	Feeder 204	Under 200 kVA	0.019	0.032	59%
51	7439	Core1	Feeder 204	Over 1,000 kVA	0.254	0.424	60%
52	7759	Center3	Feeder 202	200-1,000 kVA	0.154	0.256	60%
53	5158	Core1	Feeder 204	200-1,000 kVA	0.085	0.141	60%
54	7737	Core1	Feeder 204	200-1,000 kVA	0.051	0.085	60%
55	7255	Core1	Feeder 204	Over 1,000 kVA	0.424	0.706	60%
56	7965	North2	Feeder 104	Over 1,000 kVA	0.55	0.916	60%
57	5182	Center3	Feeder 302	Over 1,000 kVA	0.373	1.712	22%
58	5324	North4	Feeder 303	Over 1,000 kVA	0.53	0.894	59%
59	514	North6	Feeder 202	Over 1,000 kVA	0.6	1.729	35%

2005 Rank-Ordered DG Capacity Additions (Light Load Fdr Limit) (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	DG Capacity (MW)	Peak Load (MW)	DG % of Peak Load
60	7418	Center3	Feeder 202	200-1,000 kVA	0.069	0.115	60%
61	5149	North2	Feeder 104	Over 1,000 kVA	0.54	1.221	44%
62	8659	North6	Feeder 205	Over 1,000 kVA	0.389	0.648	60%
63	5108	North2	Feeder 205	Under 200 kVA	0.02	0.034	59%
64	512	North6	Feeder 104	Over 1,000 kVA	1.106	1.843	60%
65	8660	Core1	Feeder 203	Over 1,000 kVA	0.254	0.424	60%
66	8682	North2	Feeder 205	Over 1,000 kVA	0.42	0.908	46%
67	536	Center3	Feeder 202	Over 1,000 kVA	0.367	2.045	18%
68	8355	Core1	Feeder 204	200-1,000 kVA	0.001	0.212	0%
69	5306	Core1	Feeder 205	Over 1,000 kVA	0.339	0.565	60%
70	511	North6	Feeder 103	Over 1,000 kVA	1.106	1.843	60%
71	7606	North4	Feeder 105	Under 200 kVA	0.026	0.044	59%
72	504	North2	Feeder 203	Over 1,000 kVA	1.09	1.817	60%
73	5062	Core1	Feeder 304	200-1,000 kVA	0.265	0.441	60%
74	8272	Core1	Feeder 205	200-1,000 kVA	0.051	0.085	60%
75	8604	Core1	Feeder 205	200-1,000 kVA	0.038	0.064	59%
76	8228	North4	Feeder 105	200-1,000 kVA	0.178	0.297	60%
77	7496	Core1	Feeder 205	Under 200 kVA	0.019	0.032	59%
78	8203	Core1	Feeder 205	200-1,000 kVA	0.085	0.141	60%
79	6943	Core1	Feeder 205	200-1,000 kVA	0.085	0.141	60%
80	515	North6	Feeder 203	Over 1,000 kVA	1.037	1.729	60%
81	9005	Core1	Feeder 205	200-1,000 kVA	0.085	0.141	60%
82	5013	Core1	Feeder 205	200-1,000 kVA	0.038	0.064	59%
83	5305	Core1	Feeder 203	Over 1,000 kVA	0.339	0.565	60%
84	5248	North2	Feeder 203	200-1,000 kVA	0.136	0.227	60%
85	9099	Core1	Feeder 205	200-1,000 kVA	0.105	0.212	50%
86	8699	Center3	Feeder 204	Over 1,000 kVA	0.46	0.767	60%
87	7736	North4	Feeder 105	200-1,000 kVA	0.071	0.119	60%
88	9011	North2	Feeder 203	200-1,000 kVA	0.136	0.227	60%
89	517	North6	Feeder 205	Over 1,000 kVA	0.761	1.729	44%
90	8049	Core1	Feeder 203	Over 1,000 kVA	0.339	0.565	60%
91	5168	North2	Feeder 203	Over 1,000 kVA	0.409	0.681	60%
92	8126	North2	Feeder 203	200-1,000 kVA	0.136	0.227	60%
93	8306	Core1	Feeder 203	200-1,000 kVA	0.169	0.282	60%
94	539	Center3	Feeder 204	Over 1,000 kVA	1.227	2.045	60%
95	5144	North2	Feeder 203	Over 1,000 kVA	0.223	0.908	25%
96	7495	North4	Feeder 105	200-1,000 kVA	0.119	0.198	60%
97	8972	North6	Feeder 103	Over 1,000 kVA	0.553	0.921	60%
98	5130	North2	Feeder 102	Over 1,000 kVA	0.55	0.916	60%
99	6093	Core1	Feeder 203	200-1,000 kVA	0.038	0.064	59%
100	5224	Core1	Feeder 203	200-1,000 kVA	0.051	0.085	60%
101	8269	North4	Feeder 105	200-1,000 kVA	0.071	0.119	60%
102	8666	North6	Feeder 103	200-1,000 kVA	0.062	0.461	13%
103	5226	North4	Feeder 101	Over 1,000 kVA	0.593	0.988	60%
104	7275	Core1	Feeder 203	200-1,000 kVA	0.085	0.141	60%
105	7662	North6	Feeder 203	200-1,000 kVA	0.058	0.097	60%
106	538	Center3	Feeder 203	Over 1,000 kVA	0.85	2.045	42%
107	5034	North4	Feeder 105	Over 1,000 kVA	0.394	0.791	50%
108	5121	Core1	Feeder 203	200-1,000 kVA	0.085	0.141	60%
109	7645	North6	Feeder 203	200-1,000 kVA	0.058	0.097	60%
110	5027	North6	Feeder 203	200-1,000 kVA	0.13	0.216	60%
111	534	North4	Feeder 304	Over 1,000 kVA	0.13	1.788	7%
112	8429	Core1	Feeder 203	200-1,000 kVA	0.127	0.212	60%
113	7654	North6	Feeder 203	200-1,000 kVA	0.058	0.097	60%
114	8127	North2	Feeder 102	200-1,000 kVA	0.183	0.305	60%
115	7449	North6	Feeder 203	200-1,000 kVA	0.078	0.13	60%
116	8787	North6	Feeder 203	200-1,000 kVA	0.06	0.216	28%
117	9091	North4	Feeder 101	Over 1,000 kVA	0.277	0.593	47%
118	8665	Center3	Feeder 204	200-1,000 kVA	0.307	0.511	60%
119	500	North2	Feeder 102	Over 1,000 kVA	0.137	2.443	6%

2005 Rank-Ordered DG Capacity Additions (Light Load Fdr Limit) (cont.)

Rank	Bus ID	Substation	Feeder	Customer Class	DG Capacity (MW)	Peak Load (MW)	DG % of Peak Load
120	8341	North4	Feeder 104	200-1,000 kVA	0.119	0.198	60%
121	8887	Center3	Feeder 204	200-1,000 kVA	0.307	0.511	60%
122	519	Core1	Feeder 103	Over 1,000 kVA	0.79	2.86	28%
123	535	North4	Feeder 305	Over 1,000 kVA	0.52	1.788	29%
124	8283	North4	Feeder 104	200-1,000 kVA	0.119	0.198	60%
125	8826	Center3	Feeder 204	200-1,000 kVA	0.092	0.153	60%
126	8589	Center2	Feeder 203	Over 1,000 kVA	0.599	0.998	60%
127	5148	North4	Feeder 104	Over 1,000 kVA	0.475	0.791	60%
128	7493	Center2	Feeder 104	200-1,000 kVA	0.055	0.092	60%
129	7763	North4	Feeder 201	200-1,000 kVA	0.047	0.079	59%
130	8748	North4	Feeder 201	200-1,000 kVA	0.105	0.175	60%
131	5118	North4	Feeder 104	200-1,000 kVA	0.119	0.198	60%
132	5197	Center2	Feeder 203	200-1,000 kVA	0.111	0.499	22%
133	8411	North4	Feeder 104	200-1,000 kVA	0.237	0.395	60%
134	8629	Core1	Feeder 102	200-1,000 kVA	0.128	0.214	60%
135	5366	North4	Feeder 201	200-1,000 kVA	0.157	0.262	60%
136	9048	North4	Feeder 104	200-1,000 kVA	0.092	0.395	23%
137	8885	Core1	Feeder 102	200-1,000 kVA	0.222	0.715	31%
138	8132	North4	Feeder 201	200-1,000 kVA	0.02	0.262	8%
139	8893	North4	Feeder 203	Over 1,000 kVA	0.419	0.698	60%
140	8904	North4	Feeder 203	Over 1,000 kVA	0.419	0.698	60%
141	8133	North4	Feeder 202	200-1,000 kVA	0.157	0.262	60%
142	533	North4	Feeder 205	Over 1,000 kVA	0.6	1.397	43%
143	36650	Center1	Substation	Over 1,000 kVA (Xmsn Level)	6.642	11.07	60%
144	36612	North1	Substation	Over 1,000 kVA (Xmsn Level)	14.346	23.91	60%
145	530	North4	Feeder 203	Over 1,000 kVA	0.222	1.397	16%
146	5190	North4	Feeder 202	Over 1,000 kVA	0.123	0.524	23%
147	542	Center2	Feeder 201	Over 1,000 kVA	1.11	2.661	42%
148	532	North4	Feeder 204	Over 1,000 kVA	0.69	1.397	49%
149	527	North4	Feeder 103	Over 1,000 kVA	0.53	1.582	34%

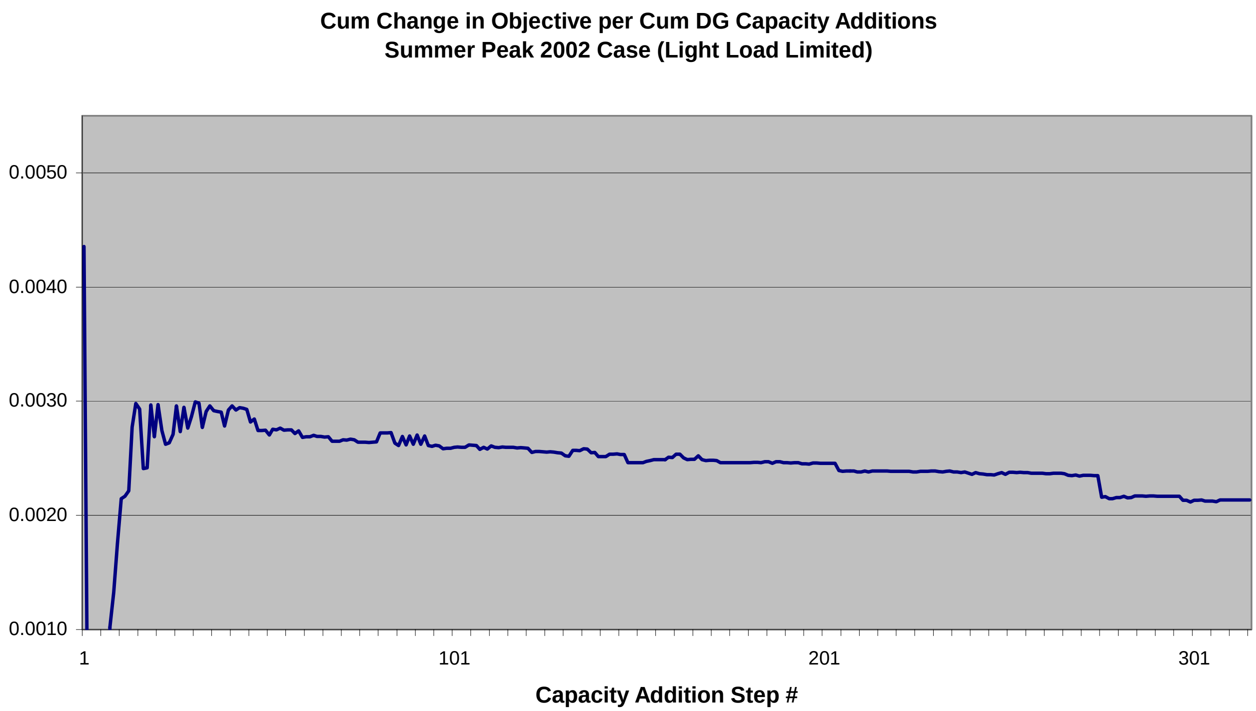
2005 Rank-Ordered DG Capacity Additions (15% Fdr Limit)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG Capacity (MW)	DG % of Peak Load
1	506	South3	Feeder 104	Over 1,000 kVA	3.704	1.6	43%
2	541	Center3	Feeder 303	Over 1,000 kVA	3.423	2.054	60%
3	5169	Center3	Feeder 303	Over 1,000 kVA	1.284	0.316	25%
4	521	Core1	Feeder 205	Over 1,000 kVA	1.13	0.678	60%
5	8971	Core1	Feeder 205	Over 1,000 kVA	0.565	0.092	16%
6	8205	Core1	Feeder 305	200-1,000 kVA	0.441	0.265	60%
7	7627	North6	Feeder 105	200-1,000 kVA	0.23	0.138	60%
8	9129	Core1	Feeder 305	200-1,000 kVA	0.883	0.53	60%
9	8199	North6	Feeder 105	200-1,000 kVA	0.23	0.138	60%
10	8036	North6	Feeder 105	200-1,000 kVA	0.23	0.138	60%
11	8701	Core1	Feeder 305	Over 1,000 kVA	1.324	0.536	40%
12	7988	North6	Feeder 105	200-1,000 kVA	0.346	0.208	60%
13	8587	North6	Feeder 105	Over 1,000 kVA	0.691	0.415	60%
14	507	South3	Feeder 105	Over 1,000 kVA	3.704	0.56	15%
15	7067	North6	Feeder 105	200-1,000 kVA	0.461	0.054	12%
16	5204	Core1	Feeder 302	200-1,000 kVA	0.662	0.397	60%
17	502	North2	Feeder 105	Over 1,000 kVA	2.443	0.86	35%
18	8854	Center2	Feeder 104	200-1,000 kVA	0.092	0.03	33%
19	8303	North2	Feeder 202	200-1,000 kVA	0.341	0.205	60%
20	5092	Core1	Feeder 302	Under 200 kVA	0.099	0.059	60%
21	6879	North6	Feeder 201	200-1,000 kVA	0.13	0.078	60%
22	5042	Core1	Feeder 302	Under 200 kVA	0.099	0.059	60%
23	7761	North6	Feeder 201	200-1,000 kVA	0.216	0.13	60%
24	8705	Core1	Feeder 302	200-1,000 kVA	0.199	0.119	60%
25	8506	North6	Feeder 201	200-1,000 kVA	0.216	0.13	60%
26	5097	North6	Feeder 201	Over 1,000 kVA	0.864	0.518	60%
27	6481	Core1	Feeder 204	200-1,000 kVA	0.282	0.169	60%
28	8689	North2	Feeder 202	200-1,000 kVA	0.341	0.205	60%
29	522	Core1	Feeder 302	Over 1,000 kVA	3.53	0.875	25%
30	5011	Center3	Feeder 202	200-1,000 kVA	0.115	0.069	60%
31	508	North6	Feeder 102	Over 1,000 kVA	1.843	1.05	57%
32	7612	North4	Feeder 301	200-1,000 kVA	0.447	0.268	60%
33	520	Core1	Feeder 204	Over 1,000 kVA	1.13	0.461	41%
34	8190	North4	Feeder 301	200-1,000 kVA	0.447	0.268	60%
35	8890	North2	Feeder 202	Over 1,000 kVA	0.908	0.545	60%
36	7637	Center3	Feeder 202	200-1,000 kVA	0.153	0.092	60%
37	7973	North6	Feeder 201	200-1,000 kVA	0.432	0.164	38%
38	5094	North4	Feeder 301	200-1,000 kVA	0.335	0.201	60%
39	503	North2	Feeder 202	Over 1,000 kVA	1.817	0.276	15%
40	5096	North4	Feeder 301	200-1,000 kVA	0.335	0.201	60%
41	5170	North6	Feeder 101	Over 1,000 kVA	0.691	0.415	60%
42	7689	North4	Feeder 301	Over 1,000 kVA	0.671	0.032	5%
43	8280	North6	Feeder 101	Over 1,000 kVA	0.691	0.325	47%
44	505	North2	Feeder 204	Over 1,000 kVA	1.817	0.27	15%
45	5183	Center3	Feeder 302	Over 1,000 kVA	1.712	1.027	60%
46	7759	Center3	Feeder 202	200-1,000 kVA	0.256	0.154	60%
47	7965	North2	Feeder 104	Over 1,000 kVA	0.916	0.45	49%
48	5182	Center3	Feeder 302	Over 1,000 kVA	1.712	0.213	12%
49	8660	Core1	Feeder 203	Over 1,000 kVA	0.424	0.254	60%
50	514	North6	Feeder 202	Over 1,000 kVA	1.729	0.76	44%
51	5324	North4	Feeder 303	Over 1,000 kVA	0.894	0.5	56%
52	5108	North2	Feeder 205	Under 200 kVA	0.034	0.02	59%
53	8682	North2	Feeder 205	Over 1,000 kVA	0.908	0.2	22%
54	7418	Center3	Feeder 202	200-1,000 kVA	0.115	0.069	60%
55	512	North6	Feeder 104	Over 1,000 kVA	1.843	0.28	15%
56	8659	North6	Feeder 205	Over 1,000 kVA	0.648	0.389	60%
57	511	North6	Feeder 103	Over 1,000 kVA	1.843	0.59	32%
58	5305	Core1	Feeder 203	Over 1,000 kVA	0.565	0.116	21%
59	536	Center3	Feeder 202	Over 1,000 kVA	2.045	1.037	51%

2005 Rank-Ordered DG Capacity Additions (15% Fdr Limit)

Rank	Bus ID	Substation	Feeder	Customer Class	Peak Load (MW)	DG Capacity (MW)	DG % of Peak Load
60	504	North2	Feeder 203	Over 1,000 kVA	1.817	1.09	60%
61	5062	Core1	Feeder 304	200-1,000 kVA	0.441	0.2	45%
62	5248	North2	Feeder 203	200-1,000 kVA	0.227	0.136	60%
63	7606	North4	Feeder 105	Under 200 kVA	0.044	0.026	59%
64	517	North6	Feeder 205	Over 1,000 kVA	1.729	0.451	26%
65	8228	North4	Feeder 105	200-1,000 kVA	0.297	0.178	60%
66	9011	North2	Feeder 203	200-1,000 kVA	0.227	0.024	11%
67	538	Center3	Feeder 203	Over 1,000 kVA	2.045	0.31	15%
68	515	North6	Feeder 203	Over 1,000 kVA	1.729	0.56	32%
69	516	North6	Feeder 204	Over 1,000 kVA	1.729	0.26	15%
70	7736	North4	Feeder 105	200-1,000 kVA	0.119	0.071	60%
71	8699	Center3	Feeder 204	Over 1,000 kVA	0.767	0.46	60%
72	539	Center3	Feeder 204	Over 1,000 kVA	2.045	0.14	7%
73	7495	North4	Feeder 105	200-1,000 kVA	0.198	0.104	53%
74	5130	North2	Feeder 102	Over 1,000 kVA	0.916	0.55	60%
75	8127	North2	Feeder 102	200-1,000 kVA	0.305	0	0%
76	5226	North4	Feeder 101	Over 1,000 kVA	0.988	0.593	60%
77	8589	Center2	Feeder 203	Over 1,000 kVA	0.998	0.599	60%
78	7763	North4	Feeder 201	200-1,000 kVA	0.079	0.047	59%
79	534	North4	Feeder 304	Over 1,000 kVA	1.788	0.27	15%
80	8748	North4	Feeder 201	200-1,000 kVA	0.175	0.105	60%
81	5197	Center2	Feeder 203	200-1,000 kVA	0.499	0.299	60%
82	535	North4	Feeder 305	Over 1,000 kVA	1.788	0.27	15%
83	5366	North4	Feeder 201	200-1,000 kVA	0.262	0.157	60%
84	9091	North4	Feeder 101	Over 1,000 kVA	0.593	0.356	60%
85	5188	Center2	Feeder 203	200-1,000 kVA	0.665	0.399	60%
86	8341	North4	Feeder 104	200-1,000 kVA	0.198	0.119	60%
87	519	Core1	Feeder 103	Over 1,000 kVA	2.86	0.44	15%
88	8283	North4	Feeder 104	200-1,000 kVA	0.198	0.119	60%
89	5148	North4	Feeder 104	Over 1,000 kVA	0.791	0.475	60%
90	8132	North4	Feeder 201	200-1,000 kVA	0.262	0.157	60%
91	8894	North4	Feeder 201	Over 1,000 kVA	0.698	0.419	60%
92	5301	Center2	Feeder 203	200-1,000 kVA	0.499	0.123	25%
93	9048	North4	Feeder 104	200-1,000 kVA	0.395	0.237	60%
94	8633	North4	Feeder 104	200-1,000 kVA	0.395	0.237	60%
95	8629	Core1	Feeder 102	200-1,000 kVA	0.214	0.128	60%
96	5118	North4	Feeder 104	200-1,000 kVA	0.198	0.044	22%
97	8284	North4	Feeder 201	200-1,000 kVA	0.175	0.105	60%
98	9093	North4	Feeder 101	Over 1,000 kVA	0.593	0.061	10%
99	8885	Core1	Feeder 102	200-1,000 kVA	0.715	0.429	60%
100	7094	North4	Feeder 201	200-1,000 kVA	0.079	0.047	59%
101	529	North4	Feeder 201	Over 1,000 kVA	1.397	0.042	3%
102	8893	North4	Feeder 203	Over 1,000 kVA	0.698	0.419	60%
103	36612	North1	Substation	Over 1,000 kVA (Xmsn Level)	23.91	3.59	15%
104	36650	Center1	Substation	Over 1,000 kVA (Xmsn Level)	11.07	1.66	15%
105	8904	North4	Feeder 203	Over 1,000 kVA	0.698	0.211	30%
106	8133	North4	Feeder 202	200-1,000 kVA	0.262	0.157	60%
107	8526	Core1	Feeder 102	200-1,000 kVA	0.214	0.128	60%
108	533	North4	Feeder 205	Over 1,000 kVA	1.397	0.25	18%
109	542	Center2	Feeder 201	Over 1,000 kVA	2.661	0.4	15%
110	5190	North4	Feeder 202	Over 1,000 kVA	0.524	0.143	27%
111	5040	Core1	Feeder 102	Under 200 kVA	0.08	0.048	60%
112	8631	Core1	Feeder 102	200-1,000 kVA	0.715	0.316	44%
113	532	North4	Feeder 204	Over 1,000 kVA	1.397	0.27	19%
114	527	North4	Feeder 103	Over 1,000 kVA	1.582	0.24	15%

2.4-1 CUMULATIVE CHANGE IN OBJECTIVE PER CUMULATIVE DG CAPACITY ADDITION APPENDIX


Cum Change in Objective per Cum DG Capacity Additions
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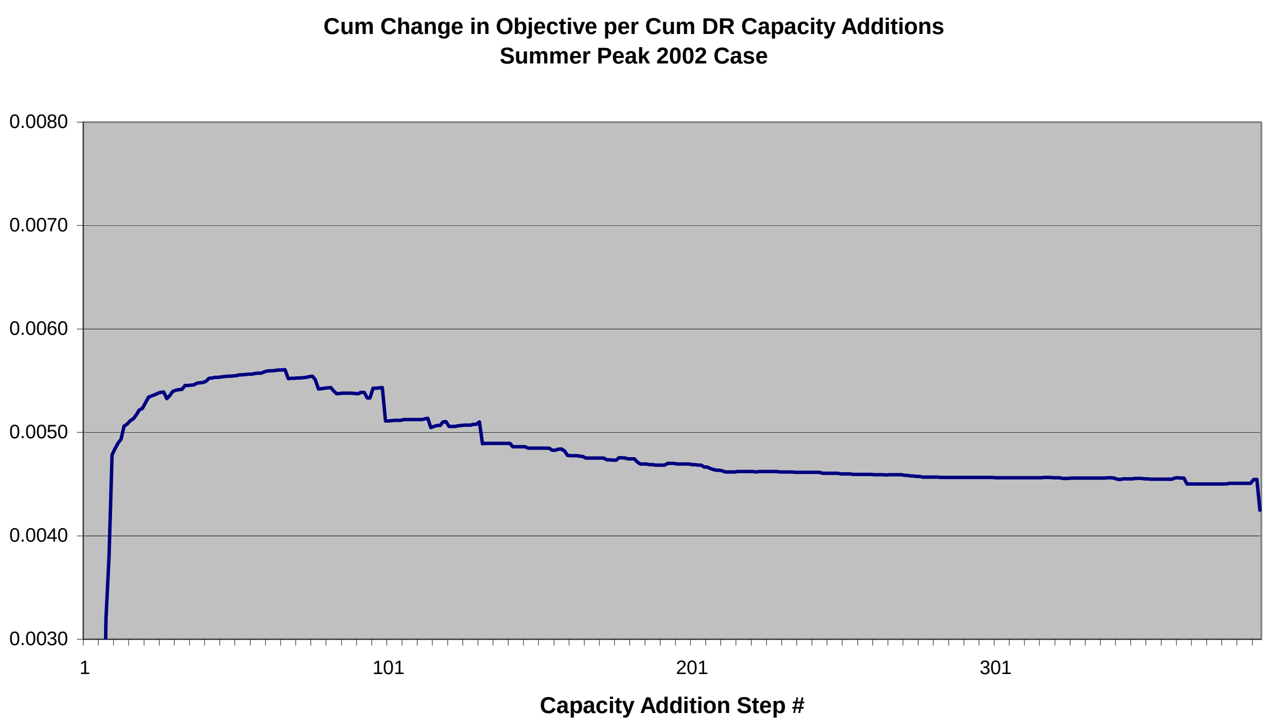
201
301
Capacity Addition Step #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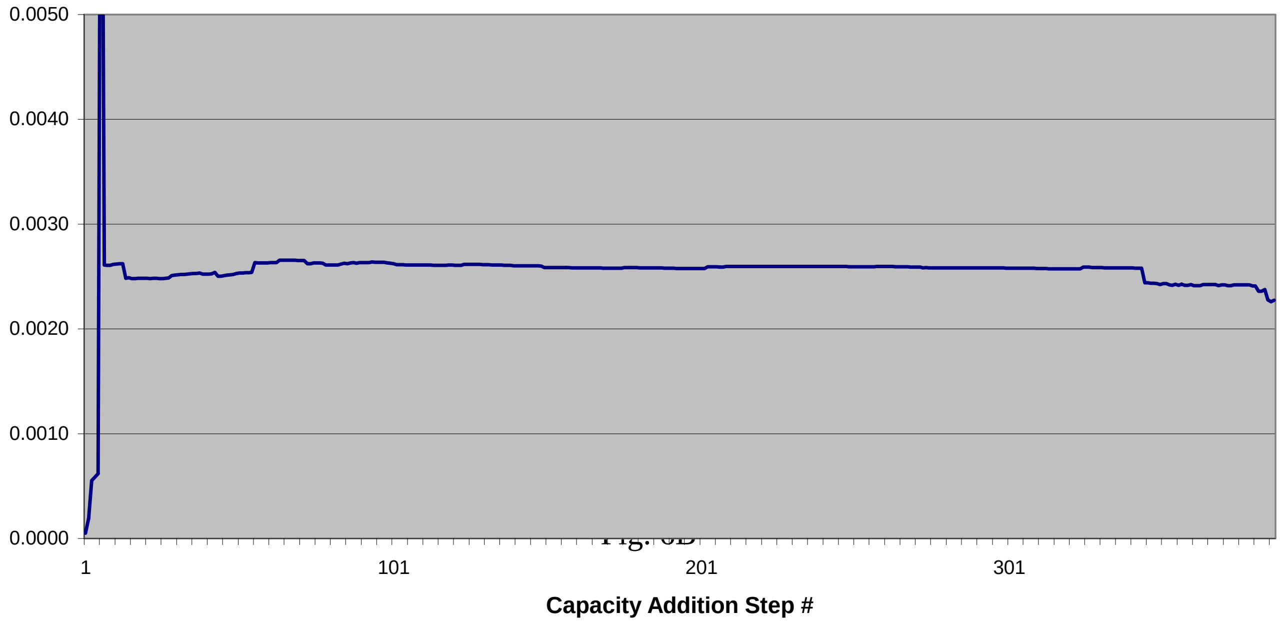
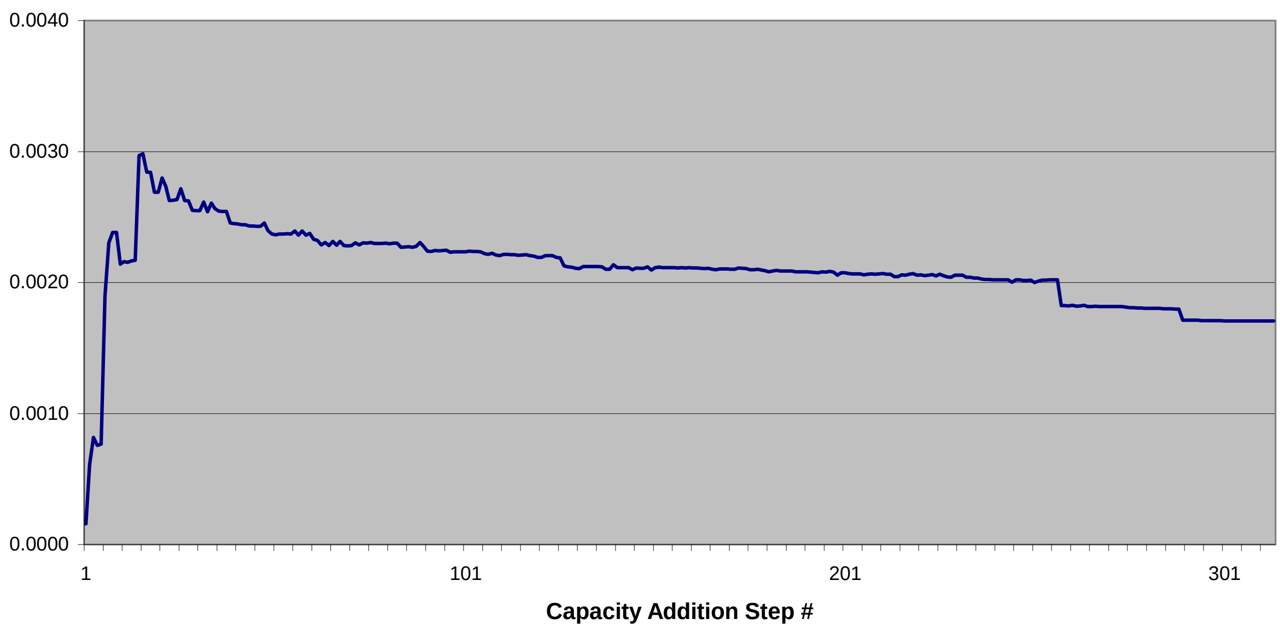
101
201
301
Capacity Addition Step #

Cum Change in Objective per Cum DR Capacity Additions
Knee Peak 2002 Case



Cum Change in Objective per Cum DG Capacity Additions
Knee Peak 2002 Case (Light Load Limited)



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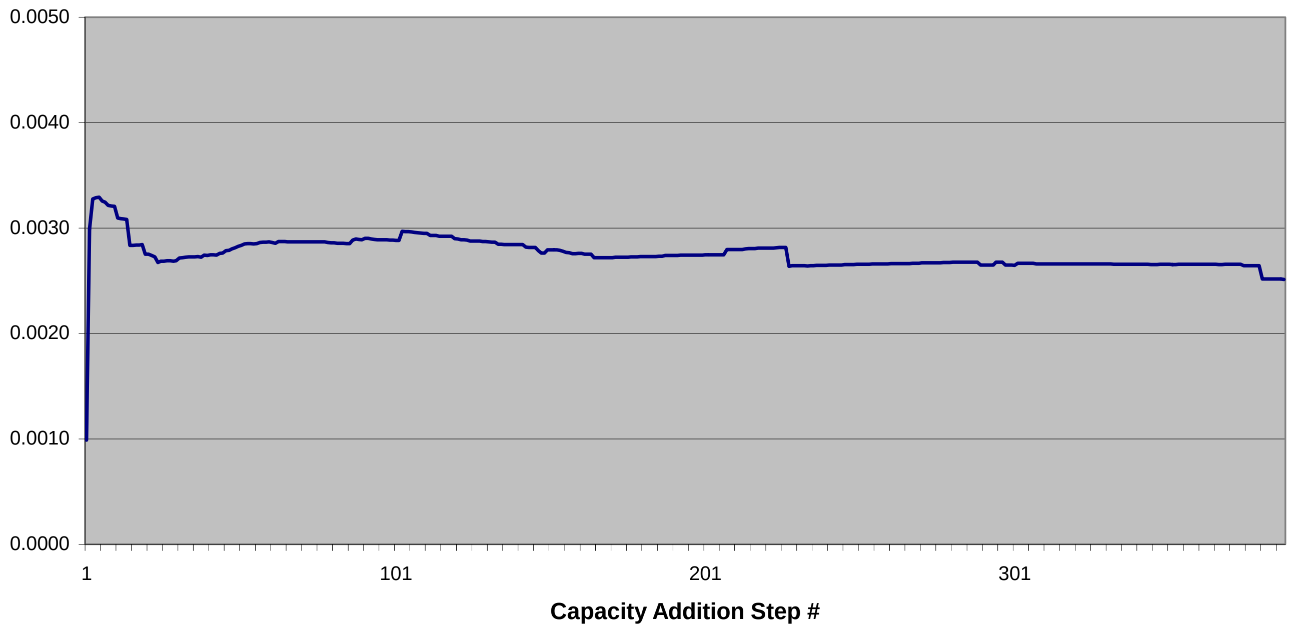
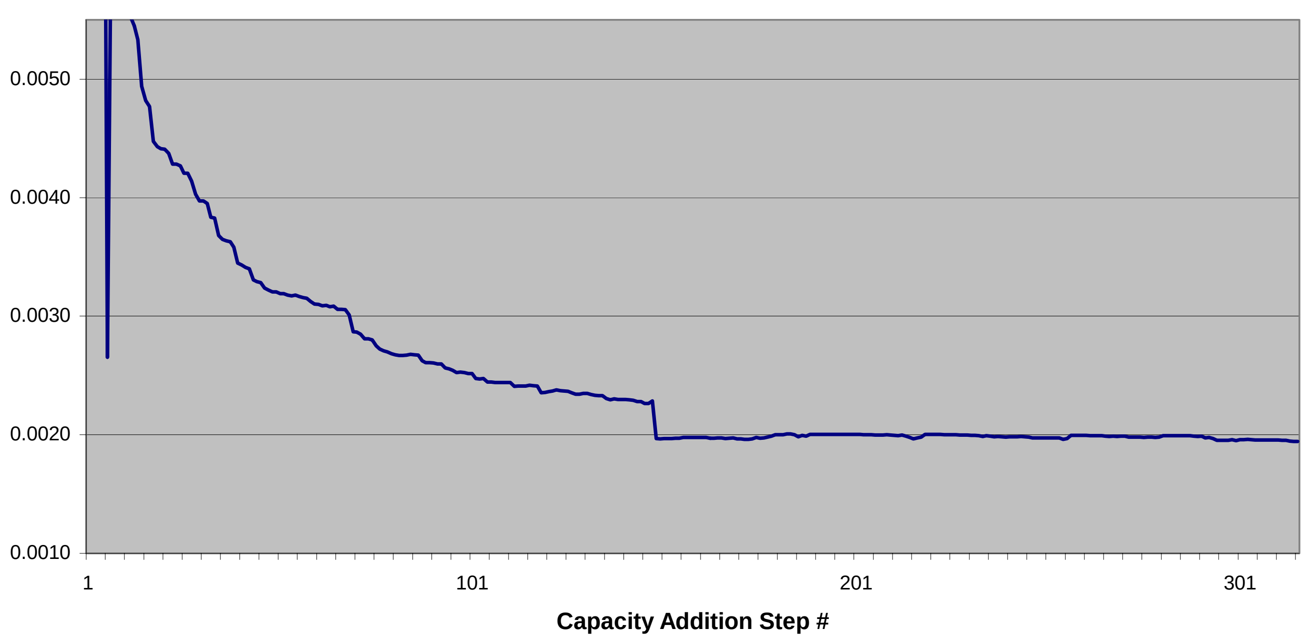
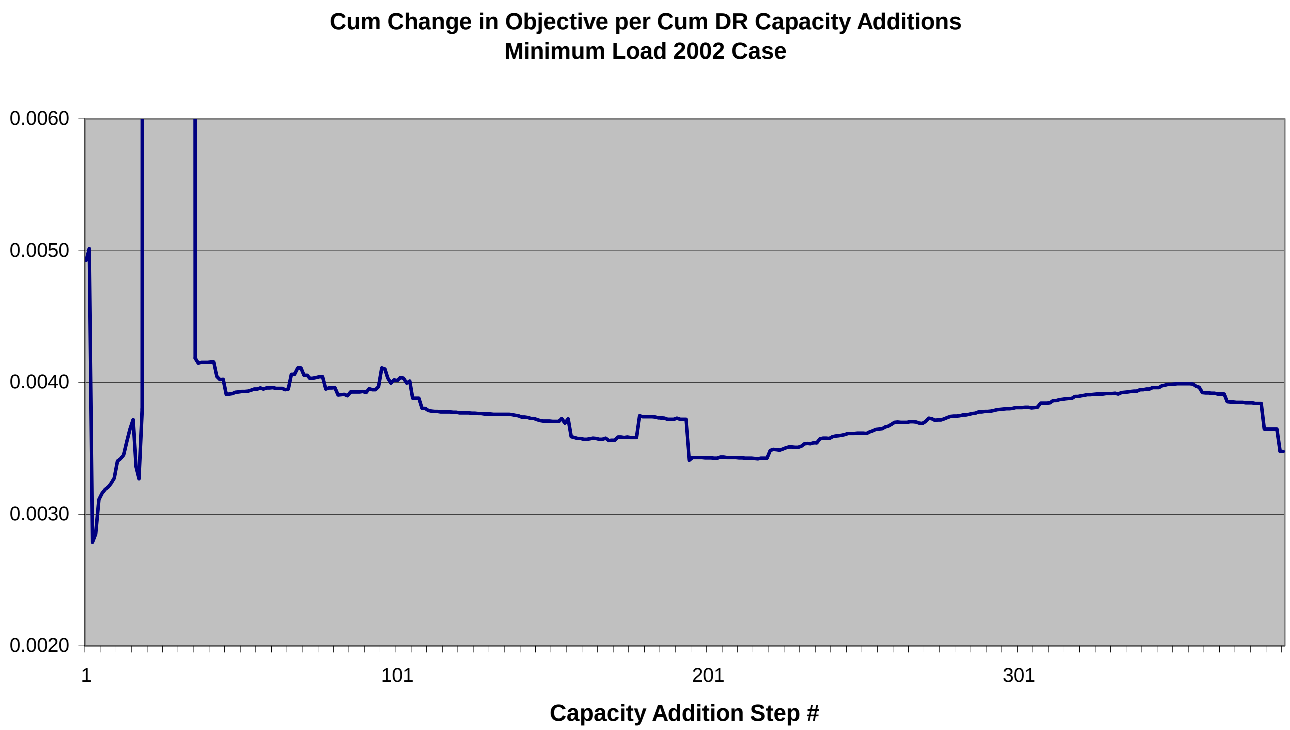
Winter Peak 2002 Case



Cum Change in Objective per Cum DG Capacity Additions
Winter Peak 2002 Case (Light Load Limited)

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Minimum Load 2002 Case
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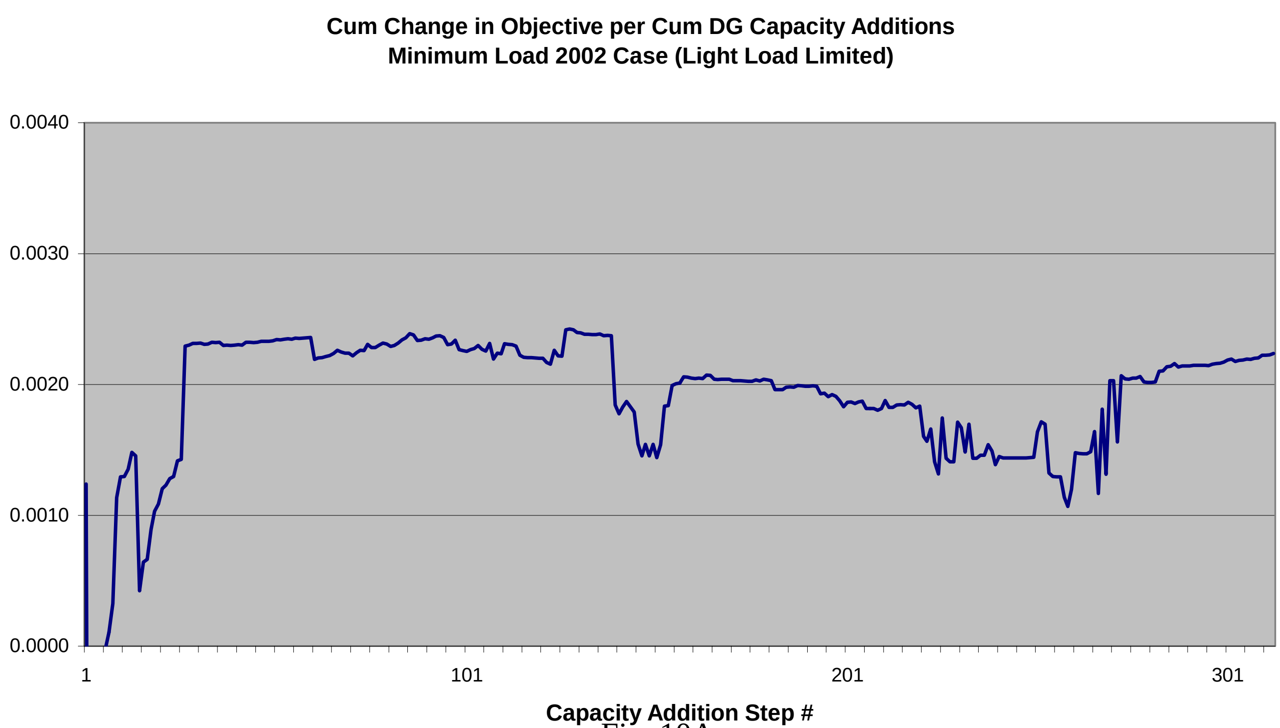
0.0020
1
101
201
301
Capacity Addition Step #


Cum Change in Objective per Cum DG Capacity Additions
Minimum Load 2002 Case (Light Load Limited)
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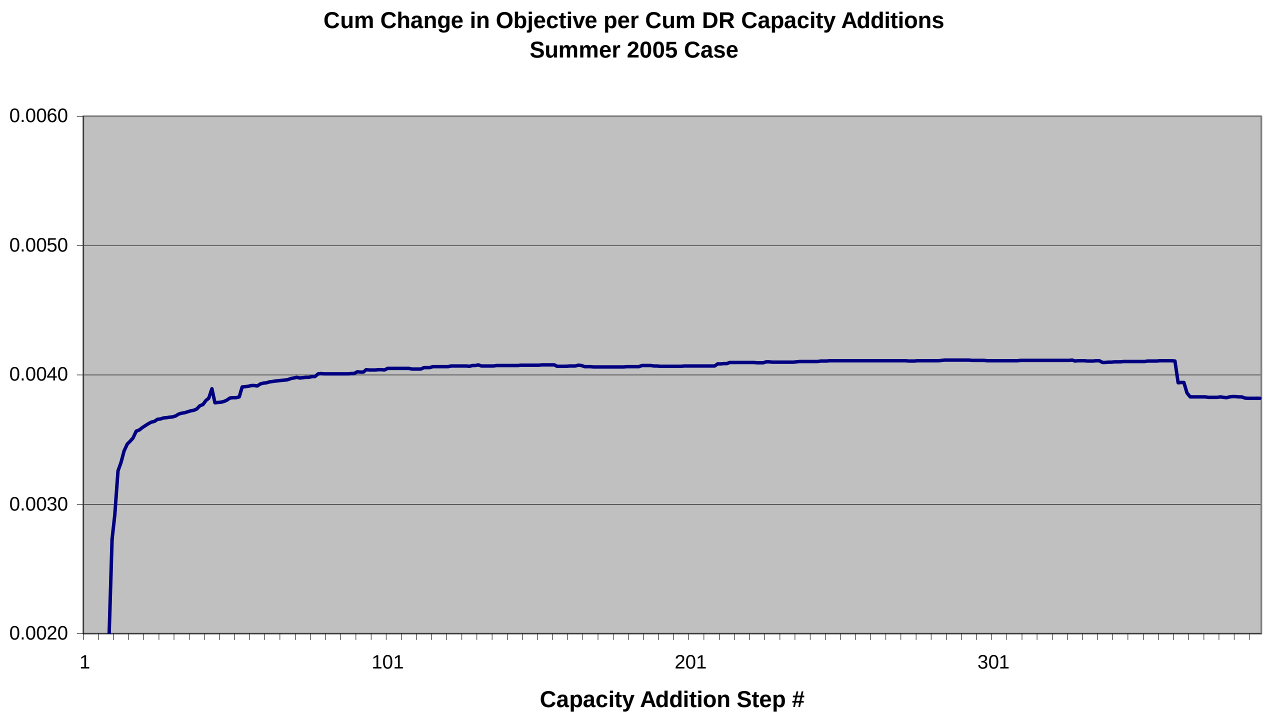
101
201
301
Capacity Addition Step #

Fig. 10A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Summer 2005 Case
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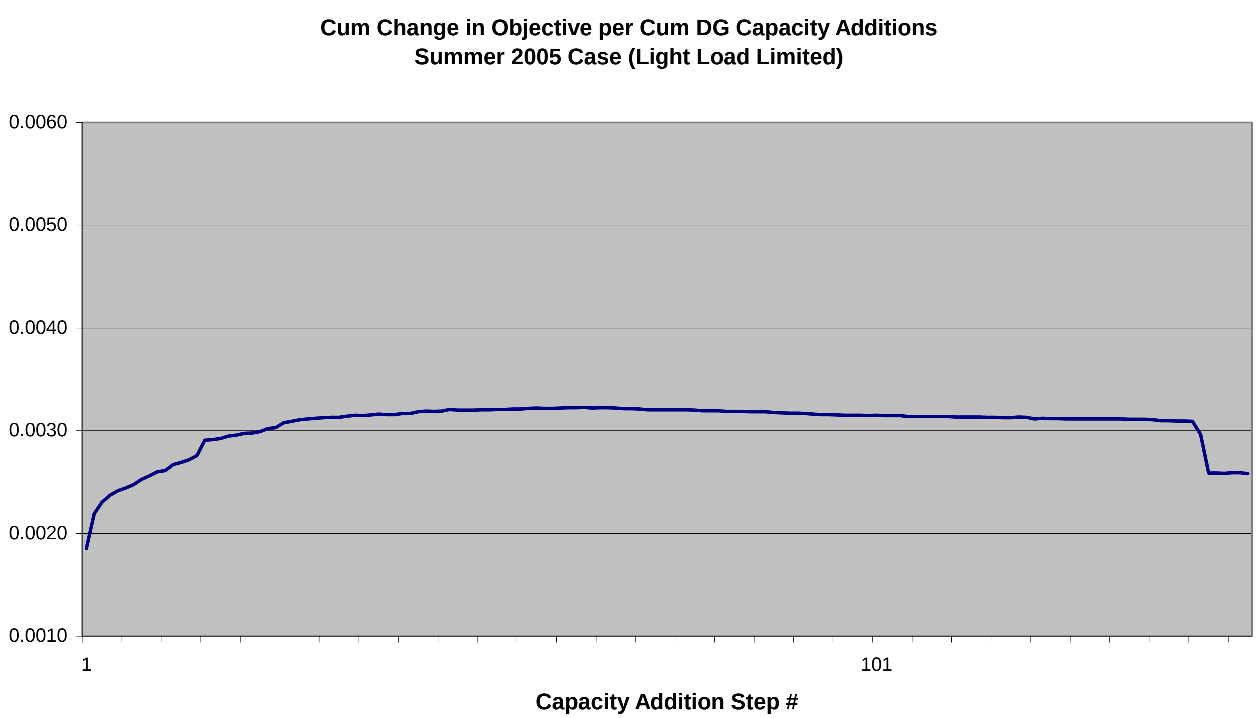
1
101
201
301
Capacity Addition Step #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0.0020
0.0010
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101
Capacity Addition Step #

2.5-1 BARRIERS APPENDIX

Appendix 2.5-1

Bus	Substation	Feeder	Customer Class	Peak Load (kW)	SP DG Rank	DG Unit (kW)	SP Output (kW)	KP Output (kW)	WP Output (kW)	ML Output (kW)
8854	Center2	Feeder 104	200-1,000 kVA	508	14	305	305	305	305	305
538	Center3	Feeder 203	Over 1,000 kVA	2,210	111	850	850	850	850	850
541	Center3	Feeder 303	Over 1,000 kVA	436	26	262	262	262	262	262
5169	Center3	Feeder 303	Over 1,000 kVA	164	33	98	98	98	98	98
5256	Center3	Feeder 303	200-1,000 kVA	55	38	33	33	33	33	33
5255	Center3	Feeder 303	200-1,000 kVA	109	39	65	65	65	65	65
9130	Center3	Feeder 303	200-1,000 kVA	109	46	65	65	65	65	65
5250	Center3	Feeder 303	200-1,000 kVA	55	52	33	33	33	33	33
540	Center3	Feeder 303	Over 1,000 kVA	436	86	262	262	262	262	262
8365	Center3	Feeder 303	200-1,000 kVA	109	96	65	65	65	65	65
7671	Center3	Feeder 303	200-1,000 kVA	55	104	33	33	33	33	33
5302	Center3	Feeder 303	Over 1,000 kVA	164	105	98	98	98	98	98
524	Core1	Feeder 305	Over 1,000 kVA	192	1	115	115	115	115	0
5163	Core1	Feeder 305	200-1,000 kVA	14	2	8	8	8	8	0
8205	Core1	Feeder 305	200-1,000 kVA	24	3	14	14	14	14	0
9129	Core1	Feeder 305	200-1,000 kVA	48	4	29	29	29	29	0
8701	Core1	Feeder 305	Over 1,000 kVA	72	5	43	43	43	43	0
8923	Core1	Feeder 305	200-1,000 kVA	24	6	14	14	14	14	14
8404	Core1	Feeder 305	200-1,000 kVA	24	7	14	14	14	14	14
7285	Core1	Feeder 305	200-1,000 kVA	11	8	7	7	7	7	7
5191	Core1	Feeder 305	Over 1,000 kVA	72	100	43	43	43	43	43
500	North2	Feeder 102	Over 1,000 kVA	1,158	121	695	695	695	523	695
8661	North2	Feeder 202	Over 1,000 kVA	372	9	223	223	103	0	0
8313	North2	Feeder 202	200-1,000 kVA	124	10	74	74	74	0	0
5185	North2	Feeder 202	200-1,000 kVA	248	11	149	149	0	0	0
503	North2	Feeder 202	Over 1,000 kVA	991	12	595	595	595	549	549
8890	North2	Feeder 202	Over 1,000 kVA	496	13	298	29	298	298	298
504	North2	Feeder 203	Over 1,000 kVA	776	18	466	466	466	466	466
5113	North2	Feeder 203	Over 1,000 kVA	388	31	233	233	233	233	233
5248	North2	Feeder 203	200-1,000 kVA	97	44	58	58	58	58	58
5144	North2	Feeder 203	Over 1,000 kVA	388	49	233	233	233	233	225
9011	North2	Feeder 203	200-1,000 kVA	97	58	58	58	58	58	58
5240	North2	Feeder 203	Under 200 kVA	22	63	13	13	13	0	13
5205	North2	Feeder 203	200-1,000 kVA	146	64	88	88	88	0	88
8126	North2	Feeder 203	200-1,000 kVA	97	67	58	58	58	58	58
5168	North2	Feeder 203	Over 1,000 kVA	291	72	175	175	175	175	175
8595	North2	Feeder 203	Over 1,000 kVA	291	81	175	175	175	175	175
8038	North2	Feeder 203	Over 1,000 kVA	291	89	175	175	167	175	175
8594	North2	Feeder 203	Over 1,000 kVA	291	99	175	175	175	175	175
8973	North2	Feeder 203	Over 1,000 kVA	388	110	233	225	233	233	233
505	North2	Feeder 204	Over 1,000 kVA	2,235	53	1341	1341	1341	1341	1341

Appendix 2.5-1 (cont.)

Bus	Substation	Feeder	Customer Class	Peak Load (kW)	SP DG Rank	DG Unit (kW)	SP Output (kW)	KP Output (kW)	WP Output (kW)	ML Output (kW)
5226	North4	Feeder 101	Over 1,000 kVA	312	30	187	187	187	187	187
9091	North4	Feeder 101	Over 1,000 kVA	187	48	112	112	112	112	112
9093	North4	Feeder 101	Over 1,000 kVA	187	57	112	112	112	112	112
9090	North4	Feeder 101	Over 1,000 kVA	187	66	112	112	0	112	0
9088	North4	Feeder 101	Over 1,000 kVA	187	78	112	112	0	112	0
526	North4	Feeder 101	Over 1,000 kVA	499	92	299	234	299	234	299
527	North4	Feeder 103	Over 1,000 kVA	1,448	120	530	530	530	530	530
8527	North4	Feeder 104	200-1,000 kVA	35	17	21	21	21	21	21
7687	North4	Feeder 104	Under 200 kVA	13	19	8	8	0	8	8
9048	North4	Feeder 104	200-1,000 kVA	115	21	69	69	69	69	69
5176	North4	Feeder 104	200-1,000 kVA	26	22	16	16	0	16	16
8283	North4	Feeder 104	200-1,000 kVA	58	25	35	35	0	35	35
5148	North4	Feeder 104	Over 1,000 kVA	231	27	139	139	139	139	139
7668	North4	Feeder 104	200-1,000 kVA	35	32	21	21	0	21	0
8411	North4	Feeder 104	200-1,000 kVA	115	36	69	69	69	69	69
8341	North4	Feeder 104	200-1,000 kVA	58	40	35	35	0	35	35
8633	North4	Feeder 104	200-1,000 kVA	115	43	69	69	69	69	69
8497	North4	Feeder 104	200-1,000 kVA	87	50	52	52	52	52	52
8698	North4	Feeder 104	Over 1,000 kVA	173	54	104	104	104	104	104
9087	North4	Feeder 104	Over 1,000 kVA	173	60	104	104	0	104	104
5118	North4	Feeder 104	200-1,000 kVA	58	68	35	35	35	0	0
8156	North4	Feeder 104	Under 200 kVA	12	71	7	7	0	7	0
8131	North4	Feeder 104	200-1,000 kVA	115	74	69	69	69	69	0
8905	North4	Feeder 104	Over 1,000 kVA	231	80	139	139	139	139	139
8417	North4	Feeder 104	200-1,000 kVA	58	88	35	35	35	35	0
8658	North4	Feeder 104	200-1,000 kVA	115	91	69	69	69	48	0
8501	North4	Feeder 104	200-1,000 kVA	58	95	35	35	35	35	0
8227	North4	Feeder 104	200-1,000 kVA	87	101	52	31	52	52	52
7606	North4	Feeder 105	Under 200 kVA	34	15	20	20	0	20	0
8228	North4	Feeder 105	200-1,000 kVA	231	16	139	139	139	139	139
8161	North4	Feeder 105	Over 1,000 kVA	461	23	277	277	277	277	277
5034	North4	Feeder 105	Over 1,000 kVA	615	42	369	369	369	369	369
7736	North4	Feeder 105	200-1,000 kVA	92	75	55	55	0	55	0
7495	North4	Feeder 105	200-1,000 kVA	154	84	0	0	0	0	0
8894	North4	Feeder 201	Over 1,000 kVA	55	107	33	33	33	23	33
9092	North4	Feeder 202	Over 1,000 kVA	209	132	125	125	125	0	125
531	North4	Feeder 203	Over 1,000 kVA	604	34	362	362	362	335	362
8893	North4	Feeder 203	Over 1,000 kVA	302	61	181	181	181	181	181
8904	North4	Feeder 203	Over 1,000 kVA	302	82	181	181	154	181	154
530	North4	Feeder 203	Over 1,000 kVA	604	98	362	335	362	362	362
532	North4	Feeder 204	Over 1,000 kVA	1,608	59	690	690	690	617	690
533	North4	Feeder 205	Over 1,000 kVA	908	69	545	545	545	498	545
7690	North4	Feeder 301	Over 1,000 kVA	171	97	103	103	103	103	0
8187	North4	Feeder 301	200-1,000 kVA	114	108	68	68	68	68	59
7702	North4	Feeder 301	200-1,000 kVA	114	122	68	68	68	68	68
8190	North4	Feeder 301	200-1,000 kVA	114	123	68	68	68	68	68
5054	North4	Feeder 301	200-1,000 kVA	57	124	34	34	34	34	34
8281	North4	Feeder 301	Over 1,000 kVA	171	125	103	103	103	103	103
7689	North4	Feeder 301	Over 1,000 kVA	171	126	103	103	103	103	103
5094	North4	Feeder 301	200-1,000 kVA	86	127	52	52	52	52	52
7612	North4	Feeder 301	200-1,000 kVA	114	128	68	68	68	68	68
8541	North4	Feeder 301	Over 1,000 kVA	171	129	103	103	103	103	103
5098	North4	Feeder 301	Over 1,000 kVA	228	130	137	110	59	59	137
7986	North4	Feeder 303	200-1,000 kVA	226	102	136	136	136	136	136
534	North4	Feeder 304	Over 1,000 kVA	2,033	56	130	130	130	130	130
535	North4	Feeder 305	Over 1,000 kVA	1,893	87	520	520	520	520	520

Appendix 2.5-1 (cont.)

Bus	Substation	Feeder	Customer Class	Peak Load (kW)	SP DG Rank	DG Unit (kW)	SP Output (kW)	KP Output (kW)	WP Output (kW)	ML Output (kW)
6837	North6	Feeder 201	200-1,000 kVA	173	51	104	104	104	101	0
6879	North6	Feeder 201	200-1,000 kVA	69	62	41	41	41	41	0
5097	North6	Feeder 201	Over 1,000 kVA	460	65	276	276	276	276	0
5304	North6	Feeder 201	Over 1,000 kVA	460	93	276	276	276	0	276
9012	North6	Feeder 201	200-1,000 kVA	173	113	104	104	0	0	104
5123	North6	Feeder 201	200-1,000 kVA	173	133	104	104	104	104	104
8363	North6	Feeder 202	200-1,000 kVA	41	77	25	25	25	0	0
5172	North6	Feeder 202	200-1,000 kVA	41	83	25	25	25	0	0
8445	North6	Feeder 202	200-1,000 kVA	41	103	25	25	25	0	0
9086	North6	Feeder 202	Over 1,000 kVA	275	106	165	165	165	0	0
7645	North6	Feeder 203	200-1,000 kVA	80	20	48	48	48	0	0
7654	North6	Feeder 203	200-1,000 kVA	80	24	48	48	48	0	0
7662	North6	Feeder 203	200-1,000 kVA	80	28	48	48	48	0	0
8401	North6	Feeder 203	200-1,000 kVA	178	29	107	107	107	0	0
8233	North6	Feeder 203	Under 200 kVA	40	35	24	24	24	24	24
7557	North6	Feeder 203	200-1,000 kVA	178	41	107	107	107	107	107
8787	North6	Feeder 203	200-1,000 kVA	178	45	107	107	107	6	6
8517	North6	Feeder 203	Over 1,000 kVA	533	55	320	320	320	320	320
7449	North6	Feeder 203	200-1,000 kVA	107	79	64	64	0	64	64
515	North6	Feeder 203	Over 1,000 kVA	1,421	85	853	608	672	853	853
5052	North6	Feeder 205	Over 1,000 kVA	480	37	288	288	288	0	0
5273	North6	Feeder 205	200-1,000 kVA	54	70	32	32	32	32	0
8592	North6	Feeder 205	Over 1,000 kVA	360	73	216	216	216	0	0
5053	North6	Feeder 205	200-1,000 kVA	120	131	72	72	72	0	0
506	South3	Feeder 104	Over 1,000 kVA	859	47	515	515	515	515	515
5051	South3	Feeder 104	Over 1,000 kVA	429	76	257	257	257	257	257
9133	South3	Feeder 104	Under 200 kVA	24	90	14	14	14	14	14
5254	South3	Feeder 104	200-1,000 kVA	215	94	129	129	129	129	129
8730	South3	Feeder 104	200-1,000 kVA	161	109	97	97	97	97	97
8542	South3	Feeder 104	Over 1,000 kVA	322	112	193	193	193	193	193
5016	South3	Feeder 104	200-1,000 kVA	107	114	64	64	64	64	64
8827	South3	Feeder 104	200-1,000 kVA	64	115	38	38	38	38	38
5135	South3	Feeder 104	200-1,000 kVA	48	116	29	29	29	29	29
7412	South3	Feeder 104	Under 200 kVA	24	117	14	14	14	14	14
5222	South3	Feeder 104	200-1,000 kVA	64	118	38	38	38	38	38
8499	South3	Feeder 104	200-1,000 kVA	161	119	97	97	97	97	97

2.5-2 DER BEST PRACTICES QUESTIONNAIRE

Appendix 2.5-2

DER Best Practices Questionnaire

This brief questionnaire is aimed at Distributed Generation project sponsors, host sites, private companies using DG systems, city planning and development agencies, and other public agencies actively involved in the promoting Smart Grid and permitting of DG projects.

<u>Best Practices in Smart Grid Development and Permitting of DG</u>

Silicon Valley Manufacturer's Group SVMG) is a sponsor of a study funded by the California Energy Commission concerning benefits from "Distributed Resources and Generation". Distributed Generation (DG) refers to on-site electrical generation, grid connected, powered by fossil fuels or renewables (i.e. PV), with back-up and/or supplementary power from the grid. California DG systems less than 1 MW are exempt from standby fees and charges because these are considered important customer-based supply side systems. **What permitting models facilitate DG, so that DG would cumulatively contribute to help meet future energy demand?**

This questionnaire/"interview" seeks to contact those, as applicants and as officials, knowledgeable of requirements and conditions when applicants file for plans, permits and approvals for DG from local authorities. To the extent that the information is not proprietary, please provide as much detail as possible in answering and follow-up with a phone interview.

1. Examples of a DG project as the basis of this "interview" --

(Type and size of system)____

Location____

Host site____

Name of jurisdiction or permitting agency, and contact names — (list more than one if applicable,)

____
____

2. Issues in obtaining or approving permits and/or interconnection approvals included
____
____
____

DER Best Practices Questionnaire
(cont.)

3. Discussion of conditions and requirement considered necessary before approval is granted.

____
____

4. Conditions in obtaining permits and/or interconnection approvals that resulted in, or could have resulted in, schedule delays or increased costs included

____
____.

5. Assistance received/provided and guidance procedures included

____
____
____

6. Policy statements and procedures adopted and/or implemented by agencies (including your agency) or other authorities helpful in the completion of siting of a DG project include (cite names of contacts and information).

____
____
____
____

7. Policy and process changes recommended to facilitate approval include

____
____
____

DER Best Practices Questionnaire
(cont.)

8. I am willing to be contacted to further discuss the DG permitting process?

Name________________Organization_____________ Tel Number___________

Date______________ e-mail ___________________________

Suggestions of Best Practices in Permitting DG_______________________________

Thank you and Return to:
rita@ritanortonconsulting.com

Rita Norton
Rita Norton & Associates, LLC
18700 Blythswood Dr
Los Gatos, CA 95030
(408) 354-5220 fax 408- 354-6148

APPENDIX 2.5-3 SUGGESTIONS OF BEST PRACTICES IN PERMITTING DG

R I T A   N O R T O N   &   A S S O C I A T E S ,   L L C
4 0 8 - 3 5 4 - 5 2 2 0   (F A X   4 0 8 - 3 5 4 - 6 1 4 8)

rita@ritanortonconsulting.com

Problem --- DER applicant faces the Building Counter at City Hall – each project is treated as an exotic application. Your staff dedicates themselves to explain technology, impacts and understand local procedures for review, and approval. Not infrequently, this process can take up to 8 or more months.

Solution --- Local governments update their regulatory framework to recognize DER as a benefit to the local power grid, the community and applicant, and provide approval as normal business. In regions, where grid congestion is projected to occur, offers incentives and expedited approval.

The project --- The CEC funds Peter Evans, New Power Technology to identify benefits of DER for the grid. SVMG and Rita Norton &Associates, as subcontractors, work to develop "best practices" for the local permitting DER and Smart Grid Development.

Opportunities to support project –

- **Utilities – Join the effort to provide input from utility perspective in public affairs with coal governments.**
- **Local governments and municipal organizations show case provision in General Plan and adopted policies, which simplify the permitting of DER.**
- **DER project developer- Join the effort and describe problems encountered and solutions you suggest.**

To further discuss the DG permitting process and participate in this effort at whatever level of activity ---

Name________________Organization_____________ Tel Number___________

E-mail ___________________________

Suggestions of Best Practices in Permitting DG_______________________________

Thank You!

APPENDIX 2.6-1 MODEL RESOLUTION APPENDIX

Appendix 2.6-1
Model Resolution

Resolution for the Adoption of a Distributed Generation
Comprehensive Model Ordinance for Sustainable Development

Whereas the city of ________________ is committed to the conservation of resources for the protection of the environment, and utility cost savings for current and future generations;

Whereas a commitment to implement all cost-effective energy efficient measures is the highest priority for the community;

Whereas distributed generation, or the on-site generation of electricity (other than for standby purposes) using any one or a combination of a variety sources, including solar, clean-burning natural gas (especially when combined with heat recovery), fuel cells, and wind provide benefits to our community through cost-effective energy sources, enhanced performance of the electric power delivery network, energy reliability, savings to utility customer and deferring expensive grid infrastructure investment;

Whereas many new opportunities for sustainable economic development include Zero Energy Homes, Hydrogen Highway, each applications of distributed energy systems;

Whereas federal and state policy in recognition of these benefits concurrently encourage use of distributed generation, including its status as a priority resource in the state's Energy Action Plan, the availably of Public Benefit "buy-down funds", waiving of stand-by charges, opportunities for net-metering and protocols for utility cooperation and interconnection;

Whereas potential future benefit from distributed generation is significant and would only be realized by providing a fair and consistent response to applicants for City permits;

Whereas presently applicants submit separate forms and City staff, in many cases unfamiliar with these products and their impacts, are unable to expeditiously process them;

Whereas these delays and uncertainty in the application of these regulations cost money and reduce the market penetration of these highly beneficial energy supply options;

Therefore the City Council of ____________________ hereby directs the Administration to:

1) Codify the General Plan to cite the benefits of Distributed Generation as an beneficial practice;
2) Provide a point of contact at the Permit/ Planning Department for all Distributed Generation permits consisting of permits for electrical, plumbing and building into one easy-to-use packet and develop a timeline for review such that the process is consistent with other types of city review;
3) Develop a revised zoning ordinance with provisions for the standards and requirements for small Distributed Generation (under 1,000kW) as a permitted use in commercial, industrial, and agricultural districts, and, in residential, public, and open space districts and in cases as deemed necessary as a conditional use. The standards for noise and equipment should be no more restrictive than that for other similar equipment or appliances in those districts. Visual impacts should not be required to comply with conditions any more strict than those used for other accessory equipment in those districts. Where appropriate, standards should align with and utilize externally-derived standards such as the CARB distributed generation emission standards and the Clean Air Act's "Best Available Control Technology" standard.
4) Implement expedited approval procedures, for all Distributed Generation permits less than 1,000 kW.
5) Standardize approvals for all distributed generation less than 1,000 kW.
6) In concert with the planned unit development of new business office, commercial, institutional, and industrial developments, utilize non-propriety software to estimate the cost-effectiveness, feasibility, and sizing of distributed generation in the ranges of 100 kW to 10 MW.
7) Coordinate efforts with homes builders and developers for the construction of Zero Energy Homes
8) Establish coordination with the AQMD with respect to air emissions to develop a standard procedure for the all major manufactured Distributed Generation products currently listed on the US DOE website for Distributed Generation and notify manufacturers and DG businesses/contractors to provide product impact information, in particular air emissions, as verified by independent governmental agencies and sources.
9) Undertake a review with the electric utility serving our community to identify points in the electric power delivery system within our community where distributed generation would provide benefits to the performance of the power delivery system.
10) Undertake a review with the electric utility serving our community to identify points within our community where overload of the electric power delivery network or growth is forecast so as to reduce the need for new and expense transmission and distribution upgrades.
11) Undertake a CEQA review for the cumulative impacts of multiple distributed generation projects, particularly in locations identified where these projects would enhance performance of the power delivery network or defer network upgrades.

12) Work with other neighboring local governments in a regional cooperative effort in the enactment of a consistent set of Distributed Generation zoning and permitting requirements so that applications can take advantage of "smart application" standardization
13) For solar distributed generation (PV's), develop recommendation for special handling including expedited review, waiving of permit fees, reduction of business/sales tax on materials.
14) Provide an annual report on the activities underway under the Distributed Generation policy including amount of clean electric power provided locally, reduction in CO_2 emissions, and net economic impacts.