OAK RIDGE
NATIONAL LABORATORY

MANAGED BY UT-BATTELLE
FOR THE DEPARTMENT OF ENERGY

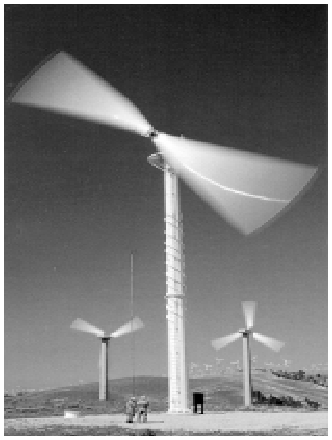
ORNL/TM-2001/290

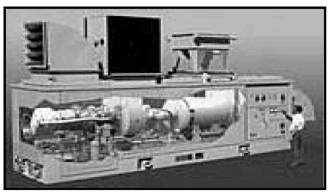
# Connecting Distributed Energy Resources to the Grid: Their Benefits to the DER Owner/Customer, Other Customers, the Utility, and Society

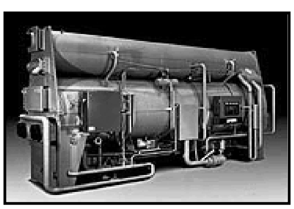
W. P. Poore
T. K. Stovall
B. J. Kirby
D. T. Rizy
J. D. Kueck
J. P. Stovall

UT-BATTELLE

ORNL-27 (4-00)







ORNL/TM-2001/290

Engineering Science and Technology Division
Nuclear Science and Technology Division

# CONNECTING DISTRIBUTED ENERGY RESOURCES TO THE GRID: THEIR BENEFITS TO THE DER OWNER/CUSTOMER, THE UTILITY, AND SOCIETY

W. P. Poore
T. K. Stovall
B. J. Kirby
D. T. Rizy
J. D. Kueck
J. P. Stovall

Februaryr 2002

Prepared by
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37831-6285
managed by
UT-BATTELLE, LLC
for the
U.S. DEPARTMENT OF ENERGY
under contract DE-AC05-00OR22725

**CONTENTS**

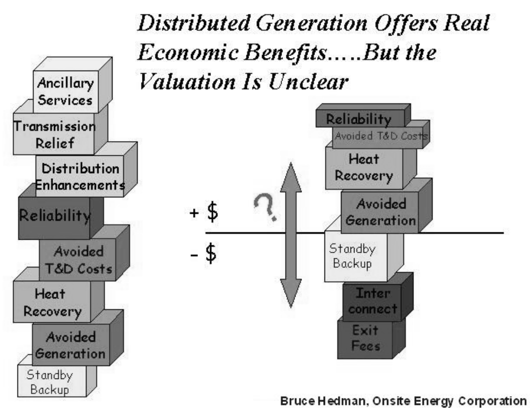
**Page**

## LIST OF FIGURES

## EXECUTIVE SUMMARY

The Distributed Energy Resource program (DER) of the U.S. Department of Energy (DOE) envisions DER as being a vital component to the future of electric power generation and delivery. Their vision for the United States is that it will have the cleanest and most efficient and reliable energy system in the world. DER will help make this happen by maximizing the use of affordable distributed energy resources.[1] Their long-term goal is that DER will achieve a 20% share of new electric capacity additions by 2010. They have established numerous strategies for implementing these goals that will support research, development, and demonstration (RD&D) for advancing generation and delivery systems architecture, including modeling and simulation tools.

The focus of site-specific DER assessments is typically limited to two parties, the owner/user and the local utility. Rarely are the impacts on other stakeholders, including interconnected distribution utilities, transmission system operators, generating system operators, other local utility customers, local and regional industry and business, various levels of government, and the environment considered. The goal of this assessment is to quantify benefits that accrue broadly across a region, recognizing that DER installations may have local, regional, or national benefits.




These costs and benefits will almost certainly not be evenly distributed, that is, one sector will have relatively higher costs and lower benefits than another. This introduces important issues of cross subsidy, which need to be fully understood when developing market rules. The markets, if properly designed to reflect these externalities, can be powerful tools for prompting desirable investment and operating responses. Ultimately, therefore, a more complete picture of the benefits associated with distributed resources will provide invaluable guidance for future policy decisions that impact a host of market rules.

Previous studies have identified many benefits associated with DER, such as improved power quality and reliability to the owner, energy efficiency improvements, deferral of distribution and transmission facilities, system voltage support, and peak load reductions, among others. Benefits related to improvements in grid reliability and security associated with increased DER penetration and reduced reliance on central station generation and transmission facilities also merit more attention since the events of September 11, 2001. An increasing number of industrial and commercial customers are finding that traditional levels of power quality and reliability are insufficient for the needs of their digital loads and are driving the installation of power conditioners, uninterruptible power supplies, and emergency generation. DER is a logical progression in a cycle to improve power quality and reliability, improve overall energy efficiency through the use of DER waste energy, and reap ancillary services savings from the utility. The previous work also identified technical, economic, and regulatory issues or barriers that impact DER projects.[2]

The objective of the current study is to develop a methodology capable of systematically assessing the combined effects of these numerous factors. This report, the first of the study, documents initial project efforts to develop the assessment methodology for quantifying these benefits, and includes a survey of nationwide DER projects, case studies of several installations, and identification of methodology objectives, requirements, variables, and data needs.

Approximately 160 DER sites nationwide were characterized in a preliminary assessment. Factors collected included:

- facility ownership;
- DER location;
- DER type or equipment class;
- usage as a combined heat and power application;
- application specifics and purpose;
- usage in grid parallel operation, equipment vendor; and
- DER owner.

The characterization confirmed benefits associated with diverse installations located in almost every state. Mature technologies such as reciprocating engines and combustion turbines (including combined cycle gas turbines) make up about 33% and 18% of the DER sites surveyed, respectively. Relatively new microturbine and fuel cell technologies comprised about 16% and 13%, respectively. Environmentally friendly wind and solar technologies account for 4% and 2%, respectively. The DER specific technology was not identified for about 14% of the sites surveyed.

Case studies of several installations that typify the diverse types, usage, and benefits of DER were prepared. They included (1) distributed generation employed to help a utility with an aging infrastructure and constrained distribution capacity meet a high, infrequently occurring summer peak load; (2) a Public Utility Regulatory Policy Act (PURPA) qualifying gas-turbine power plant that provides steam to a local food processing facility and power to a local power company; (3) a reciprocating engine cogeneration power plant operated by the Brookfield Zoo in Chicago that is run during business hours to supply electrical and thermal load; and (4) a power system that supplies electrical and thermal loads for Vanderbilt University's campus and hospital that also benefited the local distribution company during summer peak load capacity constraints. The case studies illustrate the value of DER to several beneficiaries; including owners, utilities, and society as it is used to cost-effectively meet a variety of needs.

The results of the DER characterizations and case studies were used to help identify the requirements, issues, and data needs for the DER benefits assessment methodology. Benefits and barriers observed in the characterization and case studies, in combination with those noted during a review of pertinent industry literature, were compiled. Economic factors affecting DER installations include utility rate structures; capital, operational, and maintenance costs; value of ancillary services; transmission and distribution expansion costs and deferral options; fuel costs; design, siting, installation, permitting, and regulatory costs; direct and indirect costs of outages to customers, utilities, and society; and other societal costs associated with environmental quality and land use, etc. As penetrations of DER interconnected to the utility network or grid increase, design, operations, and planning of present and future generation, transmission, and distribution facilities are affected. Additionally, DER may also reduce the vulnerability of regional electrical supplies due to decreased reliance on large central generating stations and transmission systems and increased fuel source diversity. DER will meet the high power quality and reliability requirements demanded by digitally dependent customers. For Internet servers, brokerage services providers and others, the cost impact of inadequate power quality has reached truly unaffordable levels. Many of these industries are installing DER purely for power quality correction.

At the same time, however, the control complexity of the electrical system will increase with greater numbers of smaller generation systems interconnected to the grid. Also, the generations flow will no longer be primarily restricted to a unidirectional flow from central generation along transmission paths to distributed loads. The generation paths will become increasingly bidirectional, especially if the cost incentives of ancillary services from the DER owners are included. The conventional design of electric power networks has DER penetration level limitations that will require additional changes (i.e., protection) in order to accommodate higher DER levels.  Work is underway to identify these DER trigger levels, which have been estimated to be above 5–10%.[3]

# 1. INTRODUCTION

The vision of the Distributed Energy Research Program (DER) program of the U.S. Department of Energy (DOE) is that the United States will have the cleanest and most efficient and reliable energy system in the world by maximizing the use of affordable distributed energy resources.[1] Electricity consumers will be able to choose from a diverse number of efficient, cost-effective, and environmentally friendly distributed energy options and easily connect them into the nation's energy infrastructure while providing benefits to their owners and other stakeholders.

The long-term goal of this vision is that DER will achieve a 20% share of new electric capacity additions in the United States by 2010, thereby helping to make the nation's electric power generation and delivery system more efficient, reliable, secure and less vulnerable, cleaner, economical, and diverse in terms of fuel use (oil, natural gas, solar, hydroelectric, etc.) and prime mover resource (solar, wind, gas turbines, etc.). Near- and mid-term goals are to develop new technologies for implementing and operating DER and address barriers associated with DER usage and then to reduce costs and emissions and improve the efficiency and reliability of DER. Numerous strategies for meeting these goals have been developed into a research, development, and demonstration (RD&D) program that supports generation and delivery systems architecture, including modeling and simulation tools.

The benefits associated with DER installations are often significant and numerous. They almost always provide tangible economic benefits, such as energy savings or transmission and distribution upgrade deferrals, as well as intangible benefits, such as power quality improvements that lengthen maintenance or repair intervals for power equipment. Also, the benefits routinely are dispersed among end users, utilities, and the public. For instance, an end user may use the DER to reduce their peak demand and save money due to lower demand charges. Reduced end user peak demand, in turn, may lower a distribution system peak load such that upgrades are deferred or avoided. This could benefit other consumers by providing them with higher reliability and power quality as well as avoiding their cost share of a distribution system upgrade. In this example, the costs of the DER may be born by the end user, but that user reaps only a share of the benefits.

This report, the first product of a study to quantify value of DER, documents initial project efforts to develop an assessment methodology. The focus of currently available site-specific DER assessment techniques are typically limited to two parties, the owner/user and the local utility. Rarely are the impacts on other stakeholders, including interconnected distribution utilities, transmission system operators, generating system operators, other local utility customers, local and regional industry and business, various levels of government, and the environment considered. The goal of this assessment is to quantify benefits and cost savings that accrue broadly across a region, recognizing that DER installations may have local, regional, or national benefits

An initial effort to characterize approximately 160 DER sites nationwide was completed and is described in Sect. 2 of this report. Case studies of several DER installations that typify its diverse types, usage, and benefits were then prepared and are presented in Sect. 3. Both the characterization and the case studies were used to help identify the requirements, issues, and data needs for the DER benefit assessment methodology as summarized in Sect. 4.

The DER model factors and requirements are discussed in Sect. 5. The methodology will address the factors identified in Sects. 1–4. It is proposed that the methodology use modified versions of several existing macro-economic modeling tools. Other efforts sponsored by the DER Office provide an important foundation for this model [e.g., the detailed evaluation of ancillary benefits in industrial applications, DER systems for industrial applications, Consortium for Electric Reliability Technical

Solutions (CERTS) Assessment of DER and Design of Microgrids, the cooling, heating, and electric power (CHP) regional databases, an assessment of the interactions between DER control strategies and existing distribution system controls, and the in-depth barrier analysis[2,4,5]].

## 2. SITE CHARACTERIZATION

A 1999 survey found over 2000 DER sites that use combined heat and power [Onsite Sycom Energy Corp]. These are only a fraction of the total DER population, because that number doesn't include the large number of power-only sites. Indeed, a partial survey of universities currently in progress has already found almost 100 power generating units, some of which are used to cogenerate steam or hot water [IDEA progress report to ORNL]. This survey and other previous DER surveys have concentrated on the technical description of each installation. As a part of this current study, however, information describing the perceived benefits of DER was sought. Toward this end, a limited survey was conducted providing basic information for approximately 160 DER sites.[6] The DER installations that were characterized in the survey were gathered from industry trade publications, Internet newsletters and forums, vendor websites, and other contacts. The survey was not intended to be an exhaustive list or to be statistically representative of the DER installations nationwide, but rather is a sampling of DER sites for which some information was readily available. The intent of the survey was to address the different applications and sites for DER and to identify the DER types and characteristics and benefit factors that need to be addressed. For each installation, an attempt was made to identify the following information.

- *DER owner and/or user of DER where it is installed*—the business or organization owning the property or facility where the DER is installed.
- *Location*—the city, state, or region (i.e., southeast) where the DER installation is located.
- *Equipment type or class*—the electric generating technology utilized, where the following terms represent:

  CCGT—combined-cycle gas turbine
  CT—combustion turbine
  DE—diesel engine
  GE—gas spark engine
  FC—fuel cell
  MT—microturbine
  PV—photovoltaic
  WT—wind turbine.

- *CHP*—a Yes/No field indicating whether or not the DER is implemented as part of a combined CHP application. Note that a value of Yes or No is used for all applications for which this information was available; a blank field indicates that the information was not available, but the application may still be CHP although it could not be readily determined.
- *Application Size*—the total electric power output (in kW) of the DER application if there are multiple DER units included.
- *Unit(s) Size*—the electric power output (in kW) of the individual units used for the DER application. Note that a few of the installations included in the survey consisted of units of multiple size, some of which were not specifically identified. For these cases, if the units were similar in size, an average value is used. Otherwise, a general range is included.
- *Application*—general description of the application for the DER, including any additional information provided related to the perceived benefits achieved or expected
- *Reason for Application*—the driver or motivation for implementing the DER at this site. The information in this field also indicates the perceived benefits of the DER installation.

- *Grid-Parallel Operation*—a Yes/No field indicating whether or not the DER application is configured for grid parallel operation. Note that a value of Yes or No is used for all applications for which this information was available; a blank field indicates that the information was not available, but the application may still be configured for parallel operation although it could not be readily determined.
- *Vendor/Installer*—any available information related to the companies facilitating the application including the manufacturer of the DER hardware, suppliers of the control equipment, the system integrators, etc.
- *Ownership*—the company that owns the DER equipment.  This field also indicates whether the utility, customer, etc., financed the application.
- *Contact*—the person to contact regarding the DER application information

Figure 1 shows the location of the DER installations included in this survey across the United States. Note that numerous San Francisco, Los Angeles, Chicago, New York, Boston, and Washington, DC, installations share "dots" on the map.  Although this survey is not a statistically representative sample, the concentrations of DER installations in California, the northeast near New York, and the Chicago area are logical given the generation capacity deficits in these areas over the last 3–4 years.  In addition to the concentrations in these "hot spot" areas, Fig. 1 also indicates that DER installations exist all across the country, including Alaska and Hawaii.  Table 1 shows the actual number of DER installations included in the survey that are located in each state.

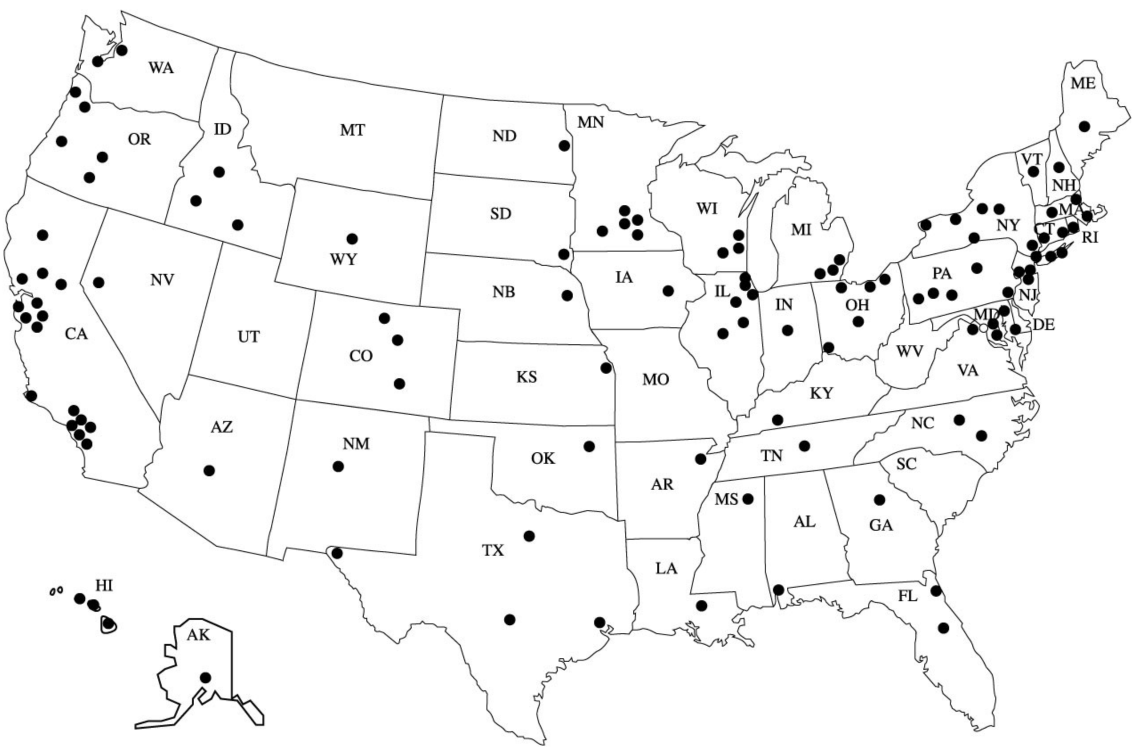



**Fig. 1.  Geographic dispersion of DER installations identified in survey.**

**Table 1. Number of DER survey installations by state.***

| State | DER sites | State | DER sites |
|---|---|---|---|
| CA | 25 | LA | 1 |
| NY | 18 | AZ | 1 |
| IL | 17 | AR | 1 |
| MA | 7 | IA | 1 |
| NJ | 7 | AL | 1 |
| PA | 7 | GA | 1 |
| MN | 5 | IN | 1 |
| MI | 5 | MS | 1 |
| OR | 5 | KY | 1 |
| FL | 4 | RI | 1 |
| OH | 4 | VA | 1 |
| HI | 4 | WY | 1 |
| MD | 4 | ND | 1 |
| CO | 4 | NE | 1 |
| TX | 4 | TN | 1 |
| WI | 3 | NM | 1 |
| AK | 3 | NV | 1 |
| ID | 2 | SD | 1 |
| WA | 2 | OK | 1 |
| NC | 2 | KA | 1 |
| CT | 2 | | |

*The survey data is not statistically representative of nationwide sites. It simply represents readily available data.

Figures 2 and 3 show the DER technology breakdown for the installations included in the survey. Again, although not statistically representative of DER installations in general, the survey shows that reciprocating engine generators, either diesel or gas-fired, are the most common DER technology with a third of those included in the survey classified in this way. Microturbine, fuel cell, and combustion turbine installations each comprise approximately 15% of the DER installations. Combined-cycle gas turbines, wind turbines, and photovoltaic panels each account for less than 5% of the installations. The specific generating technology could not be identified from the available information for approximately 15% of the installations in the survey. Approximately 60% of the installations are CHP applications, although there are unknowns regarding CHP application.

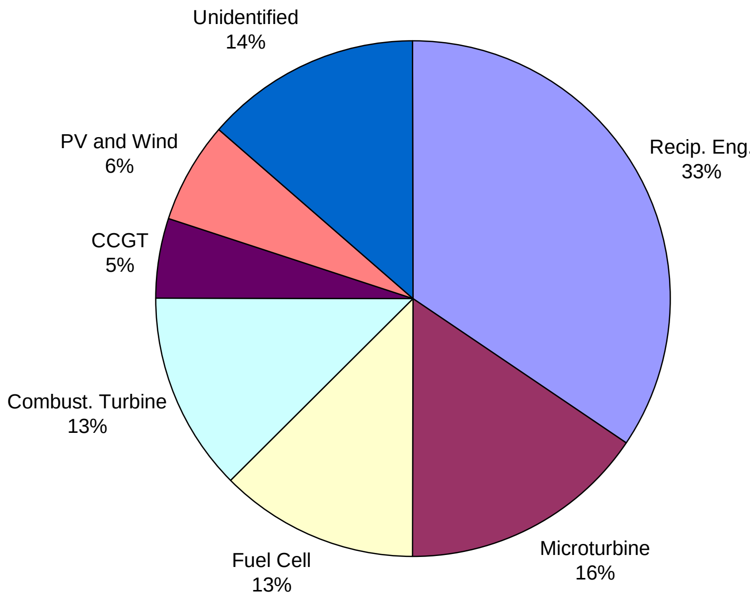



**Fig. 2. DER technology breakdown by the number of installations included in the survey.**

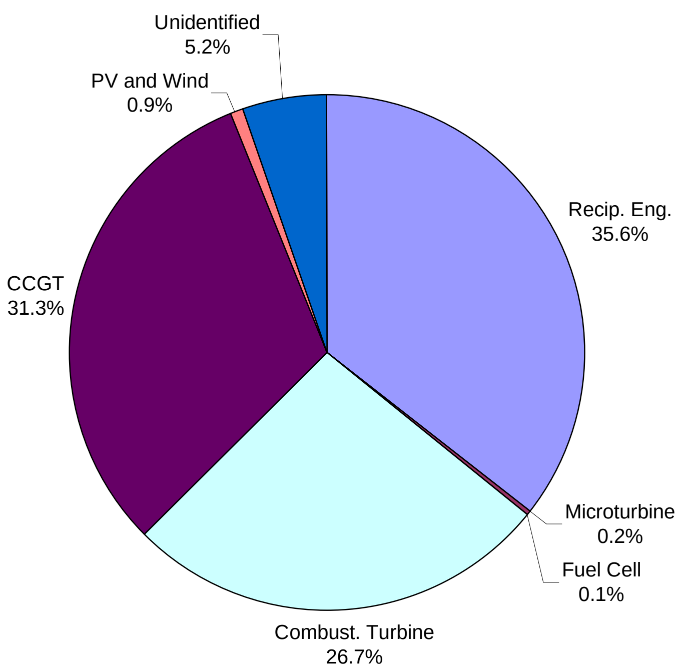



**Fig. 3. Distribution of technologies by installed capacity.**

The 162 installations included in this limited survey vary considerably in total application size, where application size is the aggregate of the electrical output of all of the generating units in the installation. Figure 4 shows the number of installations included in the survey per electrical output ranges.

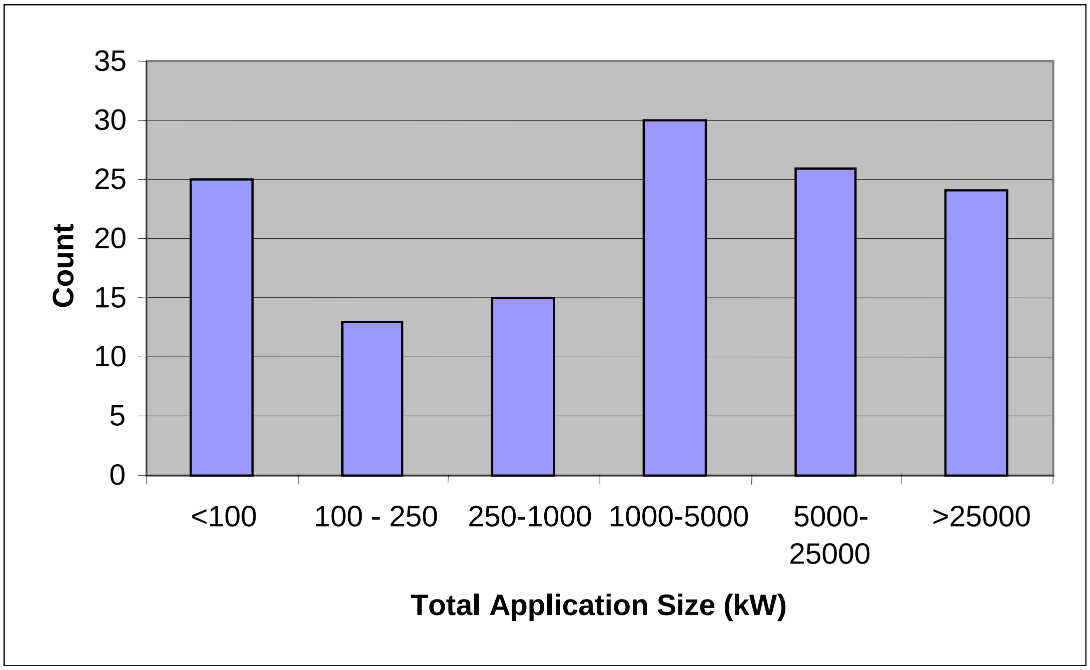



**Fig. 4. Number of installations per total DER installation electrical output.**

Figure 5 shows the distribution of individual units, as opposed to the total installation size. A high percentage of the individual units fall in the ranges characterized by the microturbine and fuel cell size units, less than 100 kW, and the ranges characterizing the larger reciprocating engine and gas turbine units, greater than 1000 kW.

It is also interesting to examine the ownership of the DER units included in this survey. Figures 6 and 7 show the ownership according to number of installations and installation capacity, respectively. Approximately 21% of the installations are demonstrations, with installation costs subsidized by the government, the utility, and or the manufacturer. Many of these demonstrations are fuel cells or microturbines, and they account for only 2% of the installed capacity for this survey. Three of the installations are labeled merchant/PURPA. These are large units, accounting for 20 % of the installed capacity, and they sell their electrical generation to a utility and their thermal generation to another customer. Utilities own one-fifth of the installations, but they account for almost one-half of the installed capacity.

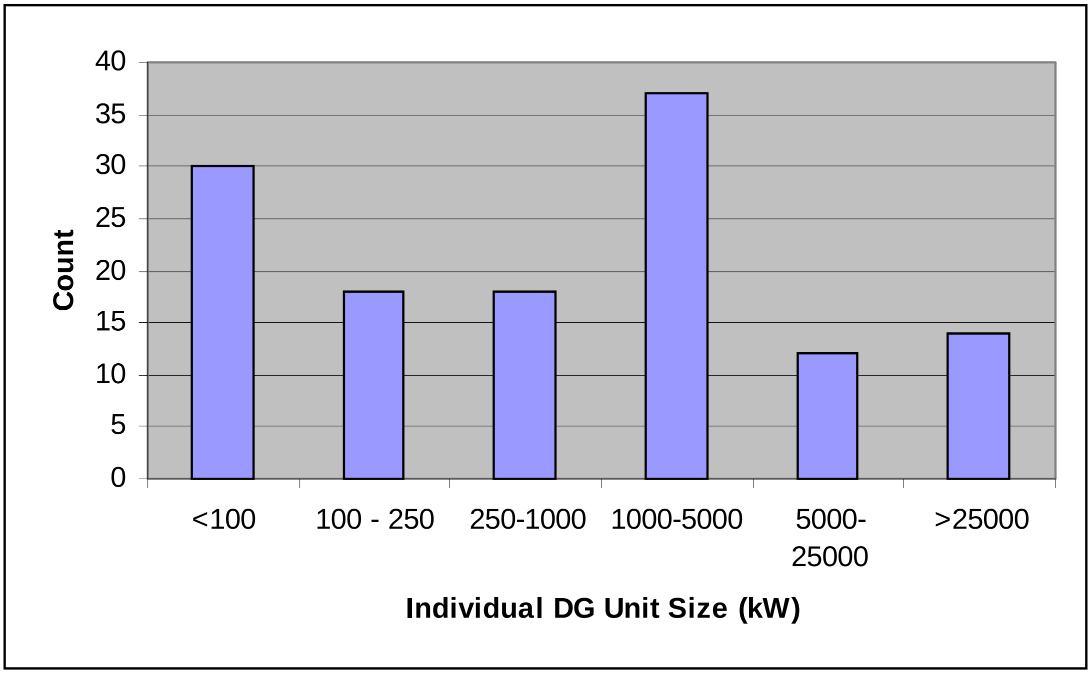



**Fig. 5. Number of installations utilizing individual DER units per electrical output range.**

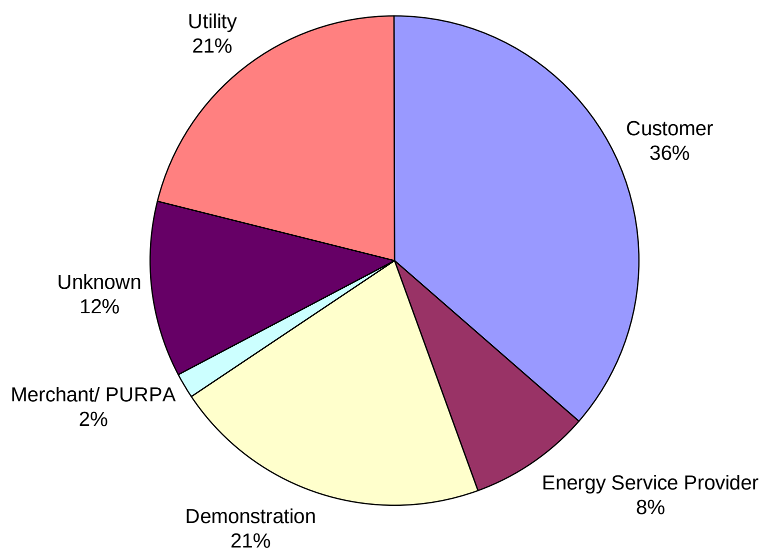



**Fig. 6. Type of ownership by number of installations.**

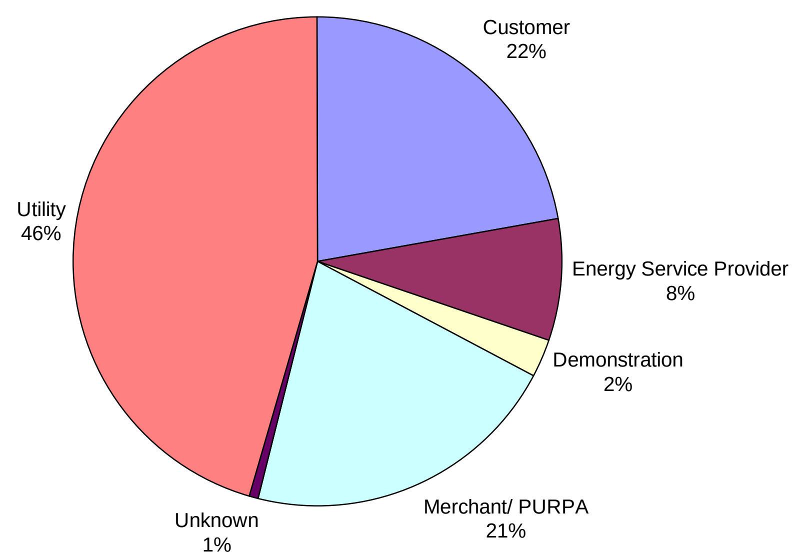



**Fig. 7. Type of ownership by installed capacity.**

# 3. CASE STUDIES

The site survey noted that there are DER installations in almost every state in the United States and that there are numerous reasons for their installation, including power system reliability, reducing energy costs, improving efficiency through CHP, meeting peak power demands, emergency power, and other reasons. In order to gain additional insight, several DER sites were studied in more detail in order to quantify the benefits, economics, and other factors associated with the installations to their owners and to other affected parties, such as interconnected utilities and society.

Four case studies were performed.[6,7] The first study describes a narrow coastal island with occasional high summer peak loads that challenge an aging distribution system. The second case study examines a cogeneration plant that was built primarily in response to PURPA and provides steam to a potato processing facility in Idaho. The third case study examines a CHP application at the Brookfield Zoo in Chicago. The fourth case study describes the Vanderbilt University's power plant that produces the steam requirements and a portion of the electric power needs of the medical center and campus in Nashville, TN. Each case study described below provides a description of the facility, its operation, its economic picture at a high level, and the issues and risks that were faced by the operators and stakeholders.

## 3.1 CASE STUDY 1—NARROW COASTAL ISLAND DER INSTALLATION

### 3.1.1 Description

This case study describes an actual DER installation that is being used by an electric utility in the northeastern United States. The utility serves a narrow coastal island off the northern Atlantic coast with permanent and summer populations of 15,000 and 100,000 residents, respectively. Approximately one summer out of three, the island receives no ocean breeze and conditions are unusually hot and humid. These conditions result in an island peak load that exceeds 70 MW but for only a few days. Summer peaks for the other 2 years only reach approximately 67% of this peak summer load (or ~47 MW), and the normal (average) daily peak demand is between 30-40% of the annual peak (or ~14–19 MW). Because of this low load factor, the revenue return on the utility investment required to meet the peak demand is quite low. Consequently, as the area load grows to the point that it exceeds the maximum capacity of the existing power supply, distributed generation is a viable alternative to the normal "wires" solution. The area is fed by an aging 23 kV subtransmission system, which is, in turn, supplied by a 69 kV transmission system. There are three distribution substations on the island supplying a 12.47 kV distribution system. Figure 8 shows a simplified one-line diagram for the planning area including the distribution system on the island. The 23 kV system is near maximum capacity when the summer peak occurs. There are five 23 kV submarine cables feeding the island from the mainland. For at least two possible contingencies associated with these cables, the peak load at the south end of the island out of the Island Sub #3 substation cannot be served. For the summer of 2001, these contingencies were covered with 5 MW of leased diesel generators (DG) installed in the Island Sub #3 substation. The DG units are also supporting the area preceding the construction of new transmission capacity.

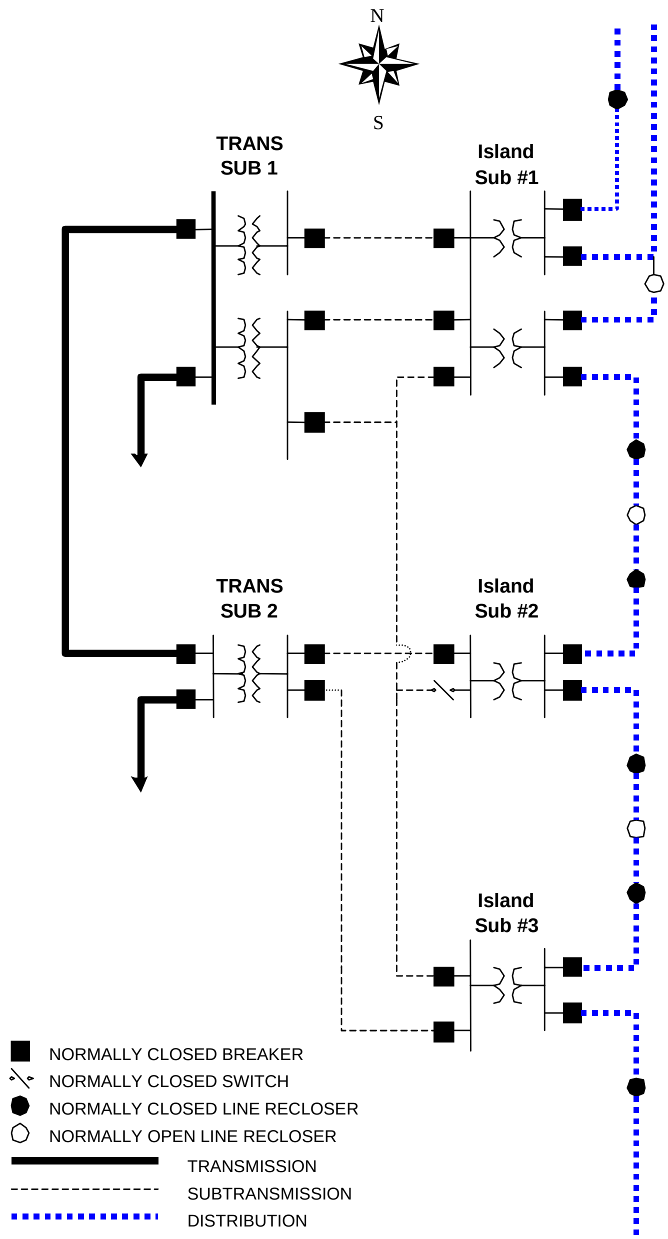



**Fig. 8. Narrow Coastal Island one-line diagram.**

In addition to the decision to cover the 2001 summer peak with the leased DG units, the utility is considering the use of DG to maintain margins for the next several years. They estimate that there are between 5–7 years of capacity remaining in the normal configuration of the 23 kV system provided DG is available to meet the peak conditions. The 69 kV system will be reinforced by 2004 with an extension of the 230 kV transmission system. In the meantime, however, an outage on the 69 kV to 23 kV substation feeding the island can make it difficult to serve the load in the northern part of the island. Transmission system studies suggest that an additional 5 MW of generation on the island would help cover this contingency. Following the installation of DER in the critical southern location, the next optimal location was found to be a few miles north of the Island Sub #1 substation. This would cover the single contingency loss of a 69 kV line feeding the 23 kV to the island and would free up capacity on the two feeders out of Island Sub #1 that serve the northern half of the island.

### 3.1.2 Benefits

This case considers two DER solutions. The first is the use of DER to cover possible contingencies and to support area transmission voltages. This solution includes the 5 MW of diesel generators that were installed at the Island Sub #3 substation during the 2001 summer months and an additional 2 MW of DER that would be needed for the same purposes by about 2003. The second DER solution described in this case study is the use of smaller, customer-owned DER to provide additional capacity as the demand on the island grows over the next several years. This solution has been studied and is being considered for implementation.

The chief competing alternative to using DER to maintain the power delivery reliability on this island is a "wires" solution (or distribution system upgrade). A primary consideration of the wires alternative is retiring the old subtransmission system. Advancements in line and cable technology and increases in load have rendered this system obsolete, and maintenance is becoming more costly. To retire the existing 23 kV subtransmission system, the transmission system (two lines for redundancy) would be extended to the Island Sub #1 substation. The Island Sub #1 substation would be rebuilt with two new 70 MVA transformers stepping down directly from 69 kV to the 12.47 kV distribution voltage. Two 12.47 kV express feeders would be run from Island Sub #1 to the southern part of the island to pick up the distribution load now served from the Island Sub #2 and Island Sub #3 substations. The total cost of the "wires" solution, which includes both the wires upgrade and the substation upgrade, is approximately $10M. Just on gross rating alone, this results in a marginal cost of approximately $90/kVA, which is on the high side for typical wires investment of $20–100/kVA. This high-side value results from the need to upgrade the substation in addition to new lines. If the load continues to grow as expected, the wires solution would have to be implemented in about six years to serve the peak load in the normal configuration, even if the DER units were available to handle the contingency loads.

DER is attractive to the utility in this case because the additional capacity is needed only in the summer months to serve the seasonal load. Therefore, leasing diesel generators is a very cost-effective option to cover these contingencies and to allow deferral of the wires solution until it is absolutely necessary. In addition to the lower cost of leased units, a major benefit is the ready availability of self-contained DG on trailers. These can be brought to the site and connected through a step-up transformer in a very short period of time, especially if compared to the time required to install the wires solutions. The cost to purchase such a unit outright is currently about $200/kW. However, several vendors offer leasing arrangements where the units are leased only for the summer months for applications like the one described here. The lease cost is approximately $40/kW-year plus approximately $50K initial installation cost incurred in the first year for each pair of trailers.

A comparison of the cash flows associated with the DG leasing option and the wires alternative indicates that applying DG units as needed over the next six years can defer the T&D investment, saving approximately $1M (2001 dollars). These savings can be larger if revenues associated with selling energy into the power markets are considered.

In summary, the benefits achieved for the summer 2001 DG installation and the benefits expected from the on-going DG solution being considered are:

1. Deferral of transmission and distribution (T&D) investments by the utility. Because of the annual load profile of the island, the return on permanent investments in T&D infrastructure are such that leasing DG units to cover possible contingencies during the summer peak load periods is an attractive alternative. Technical and economic analyses show that DG can defer these T&D investments for as much as 6–7 years, saving approximately $1M.

2. Increased reliability for energy consumers on the island. The application of the DG at Island Sub #3 for the 2001 summer provided the island with an added measure of protection against sustained interruption of electrical service. Even if the utility elects to pursue the "wires" solution, DG will have provided a useful bridge between the finalization of the wires plan and the actual wires implementation.
3. The short time frame required for the DG installation provides both economic and reliability benefits when the uncertainty of the load growth is considered. For example, additional units can be quickly installed to meet unexpected growth. Alternatively, if the growth is less than expected, the low cost leased units can extend the deferral time before the wires are replaced.

The second DER plan would involve the implementation of smaller, high-efficiency generation technologies over several years to offset growth in electrical load. These would be customer-owned and much of the potential benefit will be to customers in the form of lower total energy costs. However, if sufficient generation can be installed in appropriate areas on the island, deferral benefit to the utility is possible by delaying distribution line upgrades.

### 3.1.3 Costs

The costs associated with the installation of DG at Island Sub #3 for the 2001 summer included the explicit costs of leasing the units and site work at the substation to allow for their installation. All maintenance for the units is included in the leasing costs. There are fuel costs that must be considered, and, given that the units will likely be utilized most on summer weekends when the market cost of power is relatively low, the fuel costs may be more than the cost of purchased power. However, these costs have all been considered in an economic comparison of the DER solution with the wire solutions and this analysis indicated that the DER solution was the most economical choice.

### 3.1.4 Risks

The risks associated with adopting the DG solution are related to uncertainties in the projected load growth and uncertainties in the ability of the existing wires to provide service for another six years. I.E., if either the base load grows more quickly, or if the wires fail prematurely, it may be necessary to upgrade the wires before the planned six-year period. This would then negate the financial benefits of deferring the wires upgrade expenses. However, this risk is offset by the very qualities that led to the selection of DG in the first place – its short installation time and lower capital costs. Selecting the wires solution at the current time would result in much higher sunk costs and less flexibility to meet the uncertain load growth.

The second phase of DG may not provide significant deferral value to the utility if the DG is either not sited in the proper location or there is an insufficient amount of DG installed by customers. It may not be possible to find enough customers with sufficient thermal load to install energy-efficient DG economically. And of course, once the wires are installed, this additional capacity would have no remaining deferral value of the DG to the utility, although they would continue to provide value to their owners.

A final risk concerns power quality. Both DG and wires solutions pose their own power quality concerns. Long transmission and distribution lines are inherently vulnerable to weather as well as equipment induced disturbances. Being closer to the load DG can increase power quality and provide voltage support but potential power quality issues can arise if the units were to trip offline.

## 3.2 CASE STUDY 2—MAGIC VALLEY FOODS COGENERATION PLANT

### 3.2.1 Description

This case study describes a 10 MW PURPA qualifying facility (QF) in Rupert, ID. This plant was built primarily in response to the PURPA law to provide steam and electricity to Magic Valley Foods' potato processing facility in a more energy efficient and environmentally friendly way.

The cogeneration plant is operated by a third party who sells steam to Magic Valley Foods and electrical energy to Idaho Power. The plant is situated near a natural gas pipeline that runs through the area and is ~0.5 mile from an electrical power system substation. It burns natural gas in a combustion turbine manufactured by Solar Turbines (Caterpillar Corp) and uses the high-temperature waste heat to produce steam needed in the processing of potatoes. Formerly, Magic Valley Foods used coal-fired boilers to generate steam. The present operator of the plant is Black Hills Power.

This plant is somewhat unique in that it is physically located in the service territory of a rural electric cooperative that buys power from the Bonneville Power Administration. The power is wheeled through Idaho Power lines. The plant is interconnected to the utility system at the transmission level rather than the distribution system and sells power to Idaho Power. Being a PURPA QF, Idaho Power is required to buy the power. The Idaho Public Service Commission initially set the price for electric power at approximately $80/MWh but has dropped the price that Idaho Power is required to pay to approximately $50/MWh in recent years. This is typical for PURPA QF generation throughout the nation.

Magic Valley Foods also converted their coal boiler to natural gas. This is currently used for standby steam generation in case of an outage of the cogeneration plant.

### 3.2.2 Benefits

As with many PURPA QF plants, the primary benefits are to the DER plant operator and the recipient of the plant's thermal energy. In this specific case, the plant operator has benefited by being able to sell electricity at a relatively high price compared to the local market and, also, to sell the steam to Magic Valley Foods. It was not determined if Magic Valley Foods is able to benefit financially from the sale of the DER plant's electric power.

Although contractual arrangements are not known, the steam supplied from the cogeneration plant is assumed to be have been provided at a more favorable cost than operating the coal boiler. Besides the air quality issues, the conversion to natural gas likely reduces maintenance costs for the steam boiler.

The societal benefits are largely related to the emissions from the plant. By converting from coal to natural gas, the air quality would be expected to improve significantly.

According to Idaho Power, the utility did not notice any benefits from this plant until the winter of 2000–2001 when the California energy crisis resulted in skyrocketing electricity prices. The region served by Idaho Power is not deregulated and is likely to be one of the last areas in the nation to deregulate. The area currently enjoys some of the lowest energy prices in the nation, so there is little incentive to deregulate.

Idaho Power is required to buy the power from this cogeneration facility. Most of the time, this cost is substantially higher than the cost from Idaho Power's own generation facilities and the regional prices for purchased power. The utility's regulating agency apparently permits the utility to pass through the cost of this power so that there is no net cost to the utility. During the period when power prices in the western

United States were $250/MWh and higher, the power from PURPA QFs was a bargain. All QFs selling power to Idaho Power were dispatched on as much as possible.

The utility has identified few benefits to the transmission and distribution system that result from the DER. The utility did not need any additional capacity in the area when the cogeneration plant was built and still has sufficient system capacity to serve its service territory. Since the plant is interconnected at the transmission level there is no impact on the local distribution systems. Therefore, there is no investment deferral that can be claimed as a benefit to the utility. The dynamic voltage support offered by the DER has not been valued by the utility. The facility is too small to likely defer transmission expansion in the future. Thus, the main benefit of the DER to the utility is to serve as a hedge against power market price spikes. It is not known if the benefit has been quantified but should have been substantial during the high-price period.

#### 3.2.3 Costs

If the utility is able to pass through the cost of the purchased power to its other customers, then one might argue that other utility ratepayers are subsidizing the costs of operating this facility. There is some validity to this, although the net impact to the ratepayer is likely minor since the capacity of QFs on the system is small. Of course, this was some of the motivation of the PURPA law: to develop financial support for more efficient and less polluting electricity supplies.

The recent volatility of the natural gas market can put a squeeze on the economics of operating the plant at times. Assuming that the cogeneration facility has long-term contracts for purchased power and steam, rising gas prices can negate the economics of operating the plant. These same long term power contracts (or regulated PURPA prices) prevent the DER from profiting from high regional power prices.

While society benefits from improved air quality, it is also paying a cost for this benefit. The higher natural gas prices of recent times have been partly attributed to an increase in the number of gas-fired generating plants being connected to pipelines throughout the nation. PURPA QF generation is just one example of using natural gas to generate electricity. Merchant power plants also account for a substantial portion of this consumption. While the price increases can be partly attributed to the lack of gas delivery and storage capacity to support these plants, utility engineers frequently voice their concern about the wisdom in the long term of switching substantial electricity generating resources to a single fuel.

#### 3.2.4 Risks

A risk is the long-term supply of natural gas. While the outlook is good for the next decade, it is uncertain how long this will continue. Of course, this cogeneration plant represents one of the more efficient uses of the gas resource, in contrast to simple-cycle merchant plants designed strictly for generating electricity at peak price periods.

### 3.3 CASE STUDY 3—BROOKFIELD ZOO COGENERATION AND STANDBY POWER PLANT

#### 3.3.1 Description

The basic information on this case comes from published information from the supplier of the cogeneration system, Nicor Solutions of Naperville, IL.

The DER system is installed at the Brookfield Zoo in Chicago, one of the nation's preeminent zoos. The motivation for installing the system initially came from a 24-h power outage in 1996 that nearly necessitated the moving of the zoo's dolphin population to Florida. In addition to acquiring backup generation capacity, 2200 kW of generation was installed as cogeneration, supplying thermal load as well as electrical load.

The DER technology consists of two 1100 kW natural gas engines and one 1600 kW diesel generator. The gas engines operate from 9:00 a.m. to 6:00 p.m. daily while the diesel operates only during an emergency. At other times, the zoo purchases all its power from Commonwealth Edison (Com Ed). When outages occur, the entire zoo load can be served by running the diesel generator in addition to the gas engines.

### 3.3.2 Benefits

According to the marketing literature from Nicor Solutions, the zoo expects a positive cash flow of more than $700,000 over 10 years. There is no detail given on how this benefit is computed. However, from the basic information supplied, some details can be deduced.

The engine-generator system is to run 9 h per day. Assuming daily operation, the generators will produce approximately 7300 MWh per year. Over 10 years, this will be roughly 73000 MWh less downtime for rebuilds. In round numbers, the positive cash flow averages out to $10/MWh, or $0.01/kWh. This is assumed to include the benefits from both offsetting the thermal load from other sources of energy and the purchase of electrical power.

The generators are operated only during daylight hours, and there are several possible reasons for this mode of operation. This time may coincide with a higher-priced electricity rate, or it may be the time of the zoo's peak load (which would likely be associated with the time when they are open to the public), which could allow them to reduce their demand charge. This could also be the only period when there is sufficient thermal load to economically justify running the gas engines.

Official comment from Com Ed has not been received with respect to this case. However, some information has been gathered from industry sources with some knowledge of the general situation for DER in the Chicago area. Com Ed is one of the leading utilities in applying mobile generators to help meet capacity during summer peaks. This gave them the ability to provide support for transmission system contingencies and to operate as a hedge against high-power market practices. With the past two summer temperatures being cooler, Com Ed has reduced its leasing of mobile generators.

It is unknown if there are any distribution deferral benefits to the utility in this cogeneration application. It is believed that Com Ed has sufficient power delivery capacity in the distribution network to supply the entire load in case of a failure of the Brookfield Zoo cogeneration. However, there may be several distribution areas in the Com Ed service area that have constraints.[8] Constraints such as overloaded substation transformers would benefit from having load offset by DER. If these constraints exist, DER would certainly have value to the utility.

If this is a simple behind-the-meter interconnection, generation means a reduction in electricity revenue from serving this load. Like most utilities in this situation, Com Ed has been known to resist the implementation of interconnected customer-owned generation. In recent years, the company has been more receptive given the notable problems with supply constraints of some recent hot summers. While the value of this kind of cogeneration may not be easily quantified, there is an implicit benefit to the utility in offsetting high electricity prices. This may be reflected in high-demand penalties imposed on the zoo if the generation fails to operate, although specific tariffs for this case study were not confirmed.

Therefore, the quantified benefits in this case are predominantly on the user side. By being able to supply the thermal load during the day, the application is able to generate a net positive savings.

#### 3.3.3 Costs

One cost incurred in the DER operation will be refurbishing the reciprocating engines periodically. Typically, this is done about every 16,000 hours of operation, or about every five years in this case. It is not known if that cost has been factored into the projected positive cash flow.

The utility would not be expected to incur many incremental costs for serving this site. In all likelihood, sufficient capacity was in place prior to the 1996 outage that initiated the installation of this generation. Depending on the rate tariff, the zoo may incur demand penalties or backup power charges if the cogeneration were to be out of service.

#### 3.3.4 Risks

With $0.01/kWh net savings (or about 10 to 20% savings on electricity costs), the savings at this site would be sensitive to any volatility in natural gas prices and electricity rates. However, the availability of multiple energy sources can also provide a buffer from such volatility. Engine failures over the 10-year period could significantly erode the projected savings. A larger margin in the net savings would offer more of a cushion.

### 3.4 CASE STUDY 4—VANDERBILT UNIVERSITY POWER SYSTEM

#### 3.4.1 Description

The Vanderbilt University central energy plant provides thermal and electrical loads for the Vanderbilt University and the University Medical Center. Vanderbilt's thermal loads (including five absorption chillers) are met using three 70,000 lb/h coal-fired boilers and, beginning early in 2002, with two heat recovery steam generators attached to two gas turbine generators. Vanderbilt's electrical loads are met by a combination of power purchased from the Nashville Electric Service (NES) and its own generation facilities, including a 7 MW backpressure turbine generator, a 4.5 MW fully condensing turbine generator, two 5 MW gas turbine generators (effective in early 2002), and two 2.75 MW emergency diesel generators. Additional 100,000 lb/h and 70,000 lb/h boilers are used as standby units. Figure 9 shows the boilers and generations that make up the Vanderbilt cogeneration facility.

Vanderbilt base-loads its steam load requirements with its coal-fired boilers and steam recovered from the exhaust of the gas turbines. Additional steam needs are met with supplemental, high-efficiency natural gas firing to the turbine exhaust.

#### 3.4.2 Benefits

There are several key benefits for Vanderbilt owning and operating a distributed power generating source onsite. The primary benefit is the utility cost savings that can be realized with the use of limited interruptible power (LIP) and economy surplus power (ESP) contracts. Vanderbilt presently has a LIP contract with the Tennessee Valley Authority (TVA). This contract allows Vanderbilt to buy power at cheaper rates when its demand exceeds the contract's firm demand, providing that Vanderbilt is capable of reducing its demand below the firm demand within 24 hours. The LIP rates are significantly lower than other rate schedules.

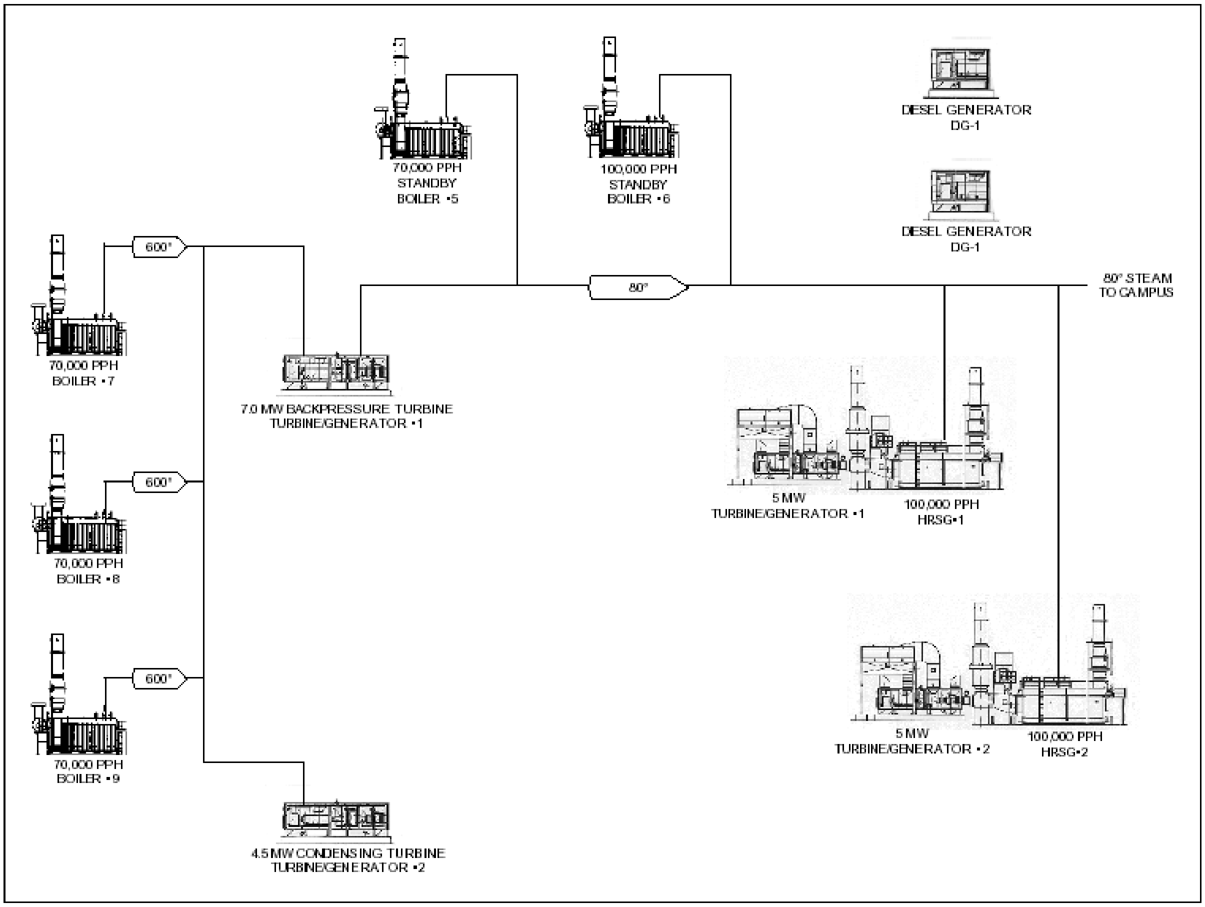



**Fig. 9. Vanderbilt cogeneration facility.**

A second benefit to the use of distributed power is that it provides a level of protection from catastrophic failures on the utility side. In the summer of 1998, NES experienced a short period where several distribution lines experienced low voltage due to being near capacity and were close to failure. In order to circumvent a power outage to the entire system, Vanderbilt and other DER customers were asked by NES to begin to generate power to reduce the load to the utility. With the ability to generate approximately 50% of its total load, the Vanderbilt system and the NES distribution network continued to operate without any interruptions.

A third benefit Vanderbilt experiences with the use of onsite generation is the multifuel capability of the systems. With the ability to utilize natural gas, coal, or fuel oil to produce steam and power, Vanderbilt has the ultimate flexibility to enter arbitrage with local vendors. These negotiations inherently lower the operating cost of the facility.

### 3.4.3 Costs

Vanderbilt University presently has a contract demand of 39 MW and a firm demand of 19.5 MW, or 50% of the contract demand. This means that Vanderbilt will buy power at the normal utility rates for energy and demand below 19.5 MW. However, when the demand exceeds 19.5 MW, they will pay reduced LIP rates. In addition, Vanderbilt is required to curtail its demand below 19.5 MW within 24 h notice by the utility. The LIP analysis assumes that a total of 17 MW of on-site generation can be generated during a curtailment period. This arrangement has provided Vanderbilt with significant cost savings, ~$1.2 million over the past 12-month period.

One additional cost of installing a DER will be meeting the local environmental regulations. Under New Source Review, the facility met the definition of a Major Modification and was subject to a Prevention of Significant Deterioration (PSD) review. The computer modeling of atmospheric pollutant concentrations conducted for the Vanderbilt facility demonstrated compliance with both the National Ambient Air Quality Standards and allowable ambient air increments. The gas turbines at Vanderbilt were also subject to the New Source Performance Standards, which included an emission standard for NOx emissions and required a performance test after the initial start-up to demonstrate compliance with the standard. The Vanderbilt facility is not located in a designated nonattainment area, and, therefore, lowest Achievable Emissions Rate and offsets were not applicable.

### 3.4.4 Risks

Vanderbilt runs its own utility system and assumes the costs and risks of running the system. They buy, operate, and maintain their generating and distribution equipment. They negotiate their own agreements with equipment suppliers, fuel suppliers of various types, electrical power with NES and TVA, and interact with capital markets. With increased energy efficiency gained through cogeneration, this well-managed system offers considerable savings.

NES is attentive to Vanderbilt's system, as well as other customers with on-site generation. The consensus at NES concerning the system challenge in 1998 is that distributed power generators like Vanderbilt provided some benefit at the time and could have provided more if their capacity were greater. Additionally, the Vanderbilt substation was only able to provide limited voltage support to NES' power lines experiencing the most operational problems because of their relative locations, see Fig. 10. (Vanderbilt has since added an additional 10 MW in electric generating capacity that is expected to become operational in early 2002.) Reflecting a common utility preference, NES stated that the benefits to their system would be maximized if they were more directly involved in the selection, location, and maintenance of DER resources. Clearly improved methods for customer/utility mutual support are required that do not involve one entity having to own the facilities of the other.

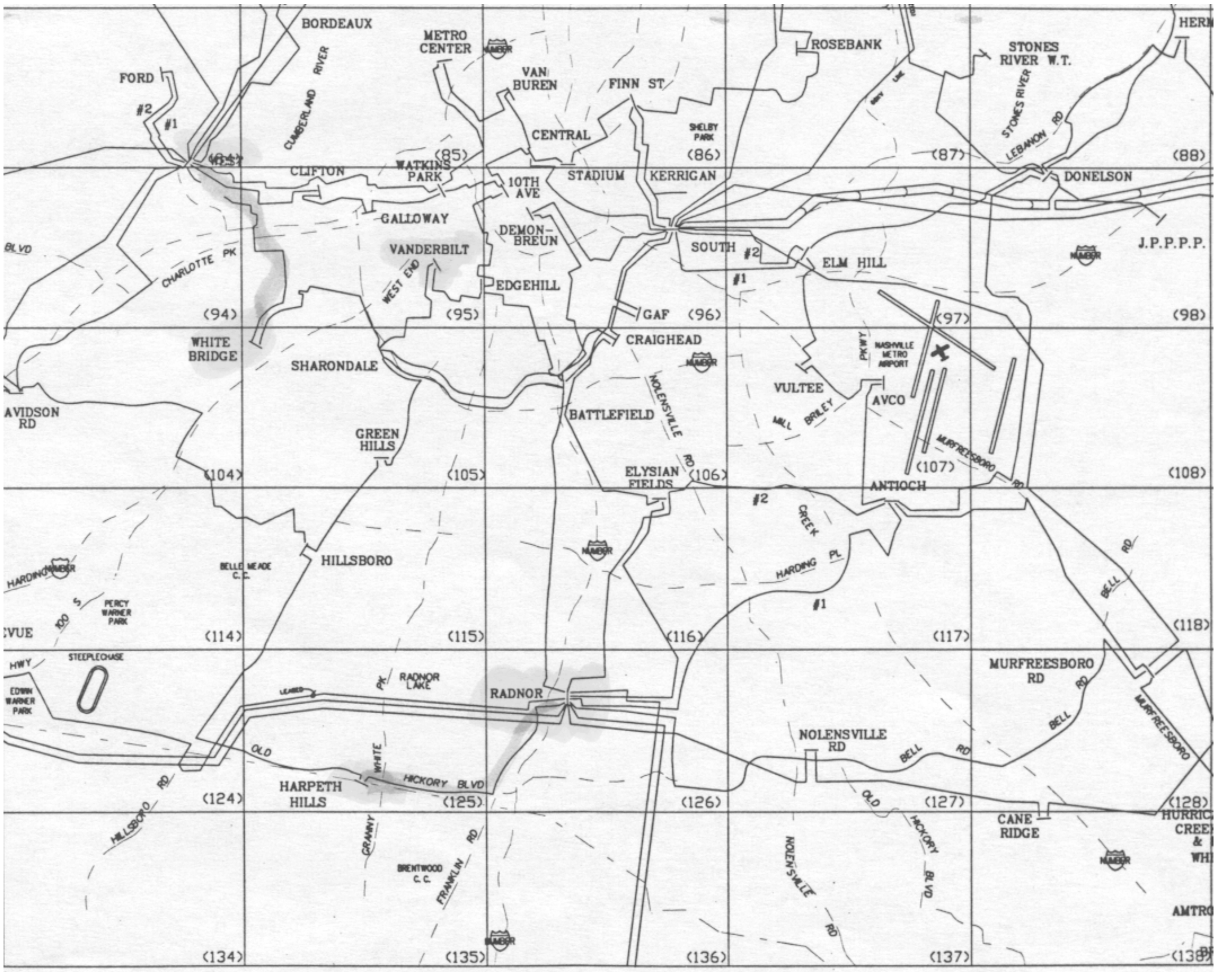



**Fig. 10.  NES electrical distribution map (Vanderbilt area).**

# 4. SUMMARY OF SURVEY AND CASE STUDY DER BENEFITS

A review of the surveyed DER installations and the more detailed case studies reveals the variety of benefits that accrue to the owners, energy users, and the utilities. Benefits to other parties are not typically revealed by such instruments.

The broad survey noted each installation owner's reasons for installing DER, and these reasons are a good summary of the owners' perceived benefits. Some owners responded with a single reason, others with four or five. Figure 11 summarizes these reasons. The most common response was to take advantage of cogeneration, which increases the overall energy-use efficiency. Cost reduction was often cited by these same customers. Reliability improvements were nearly as frequent; these included both outage avoidance and power quality considerations. Meeting peak demands was frequently cited as a reason by utility-owned DER installations and was sometimes directly identified as addressing a grid (transmission or distribution) constraint. A significant fraction of the DER were installed in response to regulatory signals; that is, they were designed to avoid peak demand charges or to enable the customer to participate in an interruptible rate structure. Both end-users and utilities cited the avoidance of price spikes as their reason for installing DER.

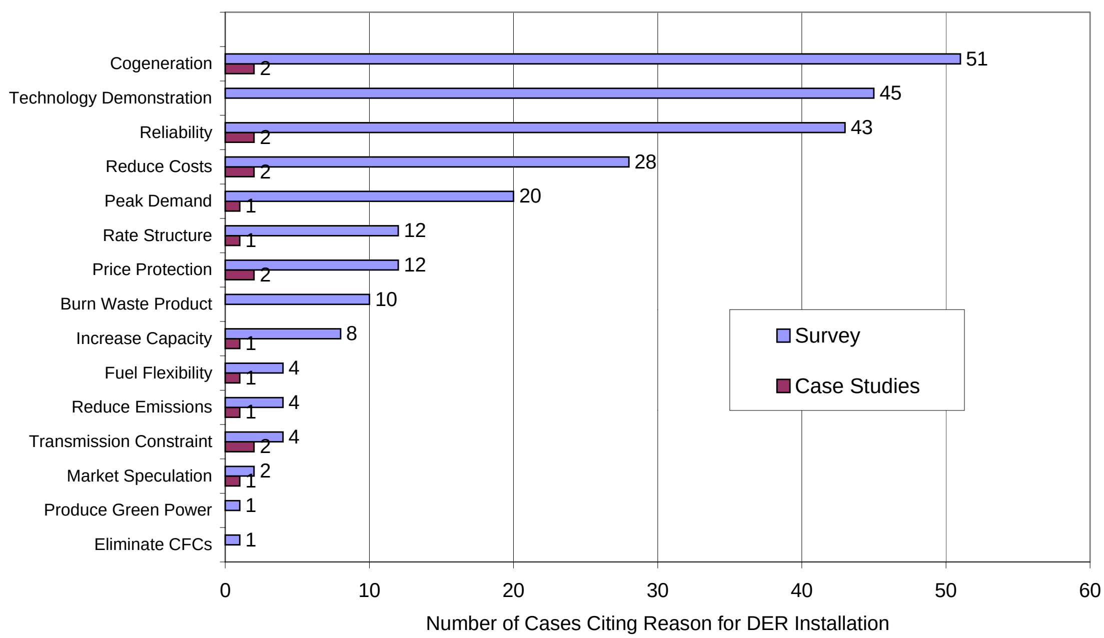



**Fig. 11. Reasons cited for installing DER.**

A review of the more detailed case studies reveals similar benefits; again cogeneration, reducing costs, increasing reliability, and price protection were leading incentives. One case study was also a clear example of a localized transmission constraint, while two other case studies mentioned such constraints as possible factors.

According to this limited review, a majority of the DER tended to fall into three major categories. Many were installed to meet base load growth or replacement; these typically employ cogeneration and were recognized as reducing overall energy costs. Others were installed to meet peak loads, sometimes by a customer avoiding peak demand charges and sometimes by a utility with a need to serve these less frequently encountered load levels. The selection of DER technology for such peaking applications tended toward those with a lower capital/operating cost ratio in recognition of their relatively low hours of use. The third major category of installations were associated with technology demonstrations. The large proportion of DER demonstrations is closely associated with the rapid pace of change and development in this field as well as with the recognition of DER benefits by both public and private funding organizations.

After the well-understood economic benefits comes the more complex issue of reliability benefits. Some of the cases discussed the ability of DER to serve as a back-up power source during an utility power outage. Several discussed the ability of DER to enhance the local power quality, providing a measure of insurance against not only outages but also against voltage sags. This broader area of power quality and ancillary benefits has been more fully explained in Ref. 4, but any broad exploration of DER benefits must address them as well. These ancillary benefits include voltage support or stability, VARs, contingency reserves, and black start capability.

Many customers need a higher level of power quality than is presently supplied by their local utility or distribution company. These customers include healthcare, communications, semiconductor manufacturing, some food processing, etc. Voltage sags and interruptions for these customers cause outages which result in a significant economic impact from spoiled products, lost raw materials, lost production time, etc. These customers are aware that they are suffering from a problem with power quality, but the cause of the problem, the extent of the problem, and the solution are not always well known. A few industries have explicitly defined their power quality requirements. Their work offers insight into the impacts of poor power quality on other customers as well and, therefore, may be useful in determining the value of DER power quality improvements.

Semiconductor manufacturers face an extreme cost penalty from voltage sags that interrupt their manufacturing process. The Semiconductors Manufacturer's Institute (SEMI) has developed a power quality requirements curve (see Fig. 12) that gives the minimum voltage vs time that their equipment is expected ride through. With this curve, they can specify tools such as adjustable speed drives or controllers that are designed to function during the anticipated power quality events. Voltage sag susceptibility information is now available on a range of equipment from computers and microprocessors to relays and solenoid valves. By defining their power quality susceptibility level, the customer could design their DER level to exactly match their power quality needs. Interestingly, in areas with the worst problems with voltage sags, such as at the ends of distribution feeders, ancillary services such as voltage regulation and supplementary reserve are most needed. Further, inverter-based DER (such as microturbines and storage devices) can be designed such that the full dynamic voltage support capability of their active power electronics system is available even when real power is not being produced, i.e., when the DER is turned off and no fuel is being consumed. Appropriately compensating the DER owner is critical for the utility to be able to exploit this capability.

The survey and case studies have identified benefits enjoyed by the customers, and sometimes by the utilities. However, other members of society also gain from the use of DER. When cogeneration increases the overall energy conversion from less than 40% to more than 80%, economic and environmental benefits almost always follow. The economic benefits can include an increase in price stability for other customers, a reduction in the demand for fuel supplies with a corresponding reduction in their cost, a delay in energy price increases associated with a delay in transmission/distribution system infrastructures. There can be other, more indirect, economic benefits to society as well. For example, if production waste and other costs decrease, product prices may fall as well.

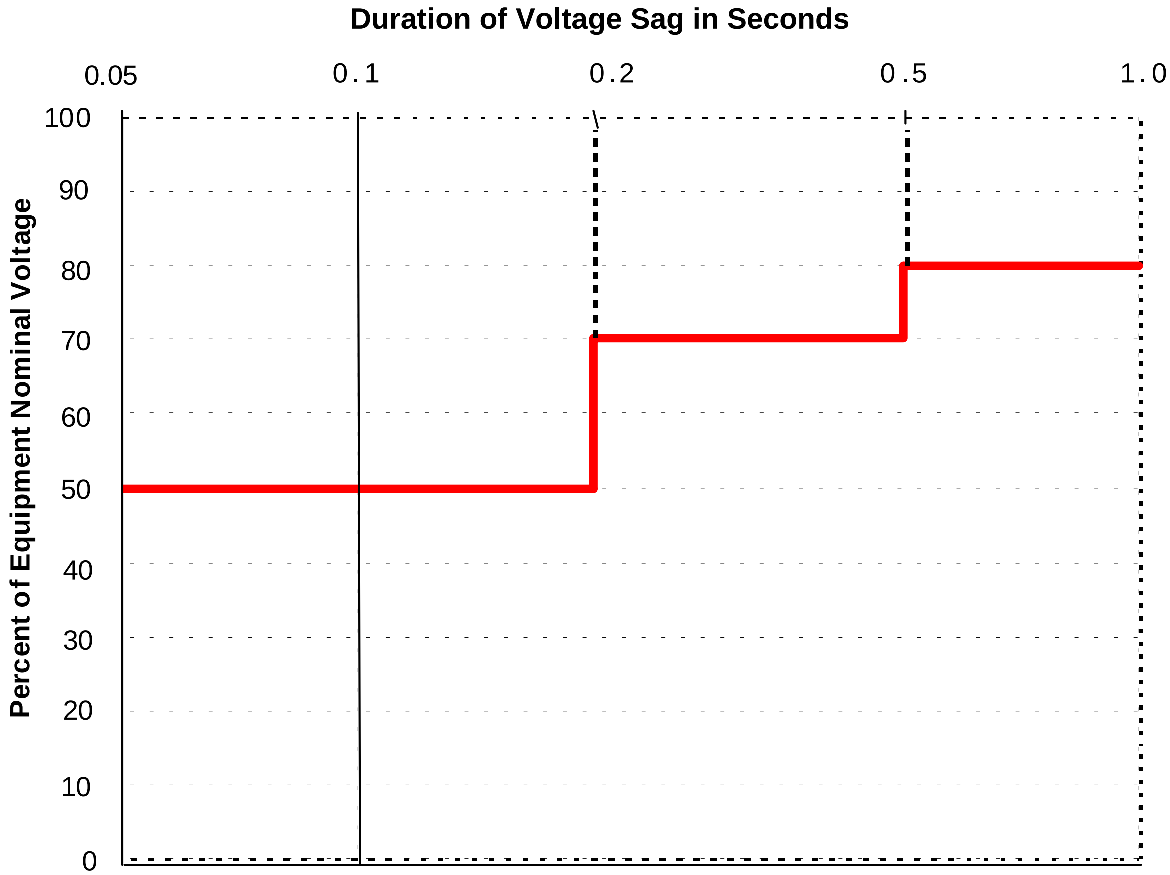



**Fig. 12. Semiconductors Manufacturer's Institute power quality requirments.**

The environmental benefits are more complex and may not occur in the same geographical location as the DER. For example, if the DER is placed in an urban area, combustion emissions may be reduced in some more remote, less densely populated region but may increase in that local urban environment. In addition to the geographic complexity, the net impact on emissions depends on the DER technologies and on the alternative central station technology. There is also an efficiency gain associated with the production of electricity close to the point of use because that reduces transmission line losses. Some DER technologies, such as cogeneration, are more efficient than central station power generation. The net impact of DER on emissions also depends on the fuel mix used to generate the region’s central station power. Figure 13 is a prototypical fuel supply curve. If the DER is gas-fueled and displaces gas, the emissions reduction will depend on the specific technologies and efficiencies involved. If gas-fueled DER displaces coal-fired combustion, there will almost always be a net improvement in the environment, although as described above, that improvement may not be enjoyed in the same location as the DER installation. However, if the DER displaces nuclear power, there could be a net increase in emissions, although the environmental impact of nuclear waste would be somewhat diminished.

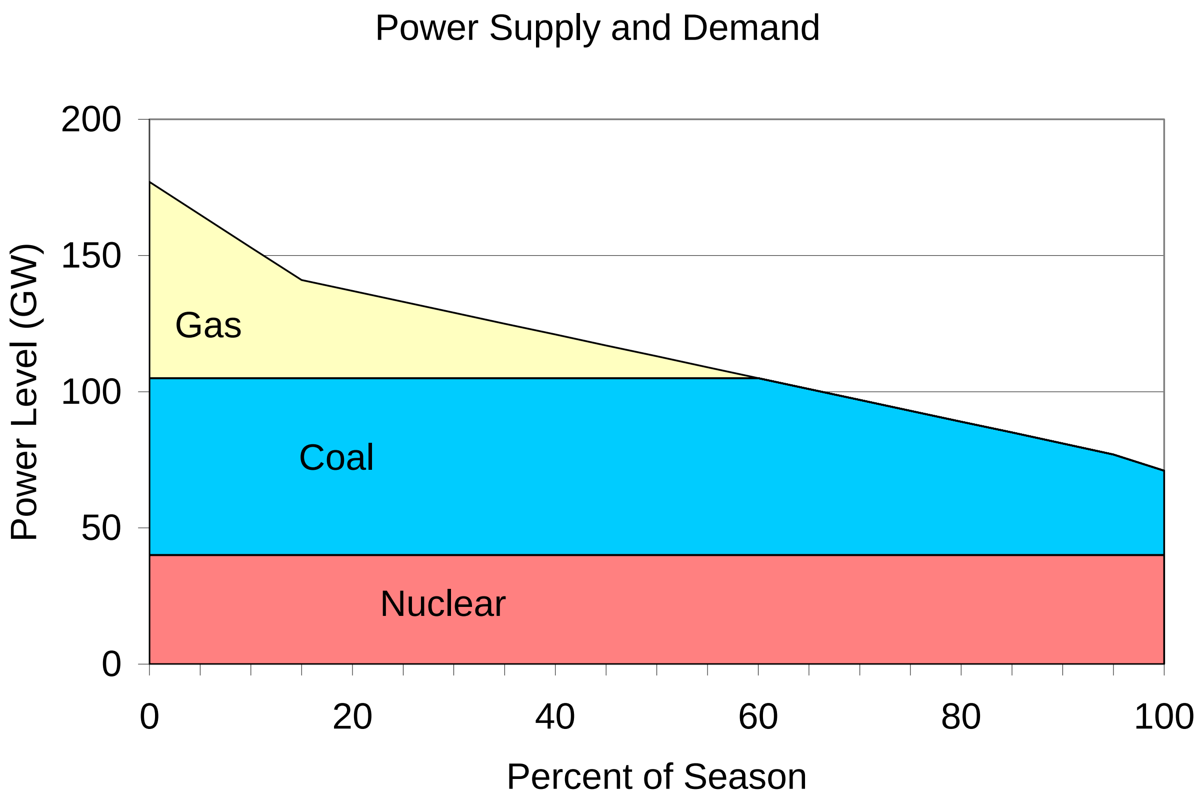



**Fig. 13. Prototypical regional electricity production fuel mix curve.**

# 5. ANALYSIS METHODOLOGY

The survey and case studies helped to identify benefits associated with installing and operating DER at various sites. In particular, benefits associated with electric system reliability, power quality, and reduced costs for providing electric power to the site were noted. However, expanding from these anecdotal examples to an overall understanding of the scope and magnitude of DER benefits is not straightforward. Indeed, the efforts described in this report are seen as but the first step in a more comprehensive study of DER benefits.

As in the preceding case studies, the focus of site-specific assessments is typically limited to two parties, the owner/user and the local utility. Rarely are the impacts on other stakeholders, including interconnected distribution utilities, transmission system operators, generating system operators, the local and regional population, local and regional industry and businesses, various levels of government, and the environment considered. The goal of this study is to quantify benefits that accrue broadly across a region, recognizing that DER installations may have local, regional, and national benefits. This complexity will require the development of an assessment methodology that builds upon existing technology and econometric assessment tools.

A literature review (Appendix A) of current, pertinent industry periodicals and articles was conducted to build upon the observations from the site survey and case studies to ensure that the benefits, issues, conditions, and data needs considered necessary for the assessment methodology were comprehensive. Additionally, the review helped identify data sources that may be especially helpful. Several issues were also identified that could potentially limit the benefits of DER under certain circumstances, such as technical and regulatory issues

Just as DER installations are as varied as the customer needs they were installed to meet, so are the problems or obstacles often encountered during their deployment. Such barriers have been previously documented and discussed.[2] Barriers may be technical, business practice, economic, regulatory, or environmental and may add considerable uncertainty to a DER project's viability. The most important barriers will be explicitly addressed by this benefits methodology, including:

- deregulation and restructuring rules (including the effects of uncertainty);
- utility cost recovery structures, including standby and backup power charges and stranded costs and transition charges;
- access to wholesale power markets and/or real-time energy pricing;
- environmental regulations and permitting procedures;
- current business models and practices;
- natural gas supply and pricing;
- tax and depreciation policies;
- communications and control requirements for varying levels of deployment;
- interconnection practices and approach;
- equipment reliability and safety certification;
- T&D reliability and safety concerns;
- consideration as alternatives to T&D upgrades; and
- lead time for technology development.

Many of these issues are in a state of flux and will, therefore, be examined by defining multiple scenarios. For example, considerable effort has been directed at the DER interconnection standard issue, notably the IEEE P1547 (Ref. 14), IEEE Std 929 (Ref. 15), UL 1741 (Ref. 16), the Public Utility Commission of Texas' Distributed Generation Interconnection Manual,[17] and several other interconnection guides and manuals. Because the outcome of these efforts is anything but certain, this benefits methodology will examine several possible interconnection arrangements.

Likewise, the Regulatory Assistance Project has closely examined regulatory issues associated with DER. Their work will serve as the foundation for multiple regulatory scenarios within this current study.

This project has the goal of integrating the issues affecting increasing DER penetration such that benefits of aggregate installations, including affects on power system quality and reliability as well as economics may be assessed. Longer term goals include (1) optimizing DER-type, penetration, and operation for specific system conditions, (2) quantifying the sensitivity of the various benefit factors for the optimized configuration, and (3) developing a rational transition plan for the distribution system design (from conventional to a new design) to better facilitate and take advantage of DER.

Just as this initial evaluation began with specific case studies, the aggregate study will also start with prototypical DER installations. These detailed time-series DER models will then be scaled to examine the aggregate benefits of all the DER installations in a region. The intent is not to develop a model that provides individual project results that are sufficiently robust for case specific investment decisions. Rather, the model will be designed to provide insight into the array of benefits that DER can provide to individuals as well as to the overall power system, other customers, and society as a whole. The modeling effort will also provide a structured analysis method that helps assure that all of the important factors are considered, all of the costs accounted for, and all of the benefits captured.

Expanding from this prototypical DER installation model to a more global assessment will be accomplished by taking advantage of a number of existing tools, including the Oak Ridge Financial Model (ORFIN), Oak Ridge Competitive Electricity Dispatch (ORCED), and the National Energy Modeling System (NEMS).[9-11] The first model, ORFIN, was developed to examine the impacts of restructuring on a single utility. It combines detailed pricing and financial analysis with an economic dispatch model over a multiyear period. Multiple plants, purchased power contracts, transmission, distribution, deferred tax credits, and demand-side management are all modeled for economic dispatch. The second model, ORCED, expanded the model from a single utility to integrate a region's supply and demand, including both the financial and emissions aspects of electricity generation. Specifically, the ORCED model was developed to analyze a variety of public-policy issues related to the many changes under way in the U.S. electricity industry. One such aspect built into the model is the ability to analyze the market penetration of new energy-production and energy-use technologies and the effects of their adoption on fuel use, electricity use and costs, and carbon emissions. These tools, plus extensive experience with nationally recognized energy models, such as NEMS (developed by the Energy Information Administration to forecast national and regional energy supply and demand), provide the ability to analyze the effects of various energy efficiency projects on emissions reductions and economic changes. They have been used in the past to analyze the impact of policies and technologies on air emissions, to study the impact of hydropower facility relicensing, to study the potential reductions from biomass cofiring on a local, regional, and national level, and to study the cost impact of multiemission regulations vs emission by emission regulation.[11-13]

Other tools are also available if necessary. For example, ORNL has collaborated with CERTS in an effort to model the expected behavior of multiple distributed generators connected to the power distribution system. These efforts were aimed at lowering the cost and maximizing the benefit of distributed generation resources as an integral part of the electric grid. A sampling of available analysis codes includes Power System Simulator (PSS/E), Production Costing (in-house models and DYNASTORE), Electromagnetic Transient Program (EMTP), Power System Harmonic Simulation and Analysis (V-Harm), System Reconfiguration Analysis Program (SYSRAP), and Powerdat Database System.

# 6. CONCLUSIONS

A brief survey of ~160 existing DER installations and four case studies of specific installations show that DER is now being used in every U.S. state and is providing increasing numbers of owners with high quality and reliable electric power and, with cogeneration, highly efficient energy utilization. Customers are reaping cost savings and gaining improved power quality and reliability. They are also increasing their energy security; a benefit gaining increased attention since the events of September 11.

Interconnected utilities are also benefiting as customer-owned DER helps to mitigate distribution system capacity constraints, provide voltage support, improve the stability of the system, reduce line losses and line congestion, and defer expansion of distribution and transmission facilities. Society benefits from a more secure and stable electric power system and reduced environmental releases.

Most DER assessments are limited to two parties—the owner/user and the local utility. Rarely are the collective benefits (or impacts) on other stakeholders, including interconnected distribution utilities, transmission system operators, generating system operators, other local utility customers, local and regional industry and businesses, various levels of government, and the environment considered, let alone quantified. The objective of the current study is to develop a methodology capable of systematically assessing the combined effects of numerous factors associated with increasing penetrations of DER.

An analysis approach has been outlined in this report to achieve these goals. The analysis will begin with a time-series evaluation of a variety of DER technologies and utility grid situations to provide prototypical values for regional econometric models. Multiple scenarios will be evaluated to consider the wide range of possible regulatory and technical environments. Since costs and benefits are not always evenly distributed, one sector may have relatively higher costs and lower benefits than another. This introduces important issues of cross subsidy, which need to be fully understood when developing market rules. The markets, if properly designed to reflect these externalities, can be powerful tools for prompting desirable investment and operating responses. However, recent experience in California shows that an incomplete understanding of the distributed benefits and costs can lead to an inappropriate market design and disastrous economic consequences. Ultimately, therefore, a more complete picture of the benefits associated with distributed resources will provide invaluable guidance for future policy decisions that impact a host of market rules.

# 7. REFERENCES

1. U.S. Department of Energy, *Strategic Plan for Distributed Energy Resources*, prepared by the Office of Energy Efficiency and Renewable Energy and Office of Fissil Energy, September 2000.

2. B. Alderfer, M. Eldridge, and T. Starrs, *Making Connections: Case Studies of Interconnection Barriers and Their Impacts on Distributed Power Projects*, prepared for the National Renewable Energy Laboratory, Golden, CO, May, 2000.

3. Roger C. Dugan, Thomas E. McDermott, D. T. Rizy, and Stephen J. Steffel, *Interconnecting Single-Phase Backup Generation to the Utility Distribution System*, report prepared by Electrotek, Oak Ridge National Laboratory, and Conectiv.

4. C. R. Hudson, B. J. Kirby, J. D. Kueck, and R. H. Staunton, *Industrial Use of Distributed Generation in Real-Time Energy and Ancillary Service Markets*, ORNL/TM-2001/136, Oak Ridge National Laboratory, Oak Ridge, TN, September 2001.

5. T. Bryson, W. Major, and K. Darrow, *Assessment of On-Site Power Opportunities in the Industrial Sector*, ORNL/TM-2001/169, prepared by Onsite Energy Corporation for Oak Ridge National Laboratory, Oak Ridge, TN, September, 2001.

6. *The Use of DG to Reinforce System Reliability on the Delmarva Peinsula*, Study Prepared in Support of Office of Power Technologies, U.S. Department of Energy, prepared by Electrotek, September 27, 2001.

7. *Distributed Energy Resources*, A Case Study of Vanderbilt University, presented by I. C. Thomasson Associates, Inc., November 2, 2001.

8. *Meeting Electric Infrastructure Constraints with Distributed Generation, Case Study—Commonwealth Edison Service Territory*, American Gas Association, August 2001.

9. S. W. Hadley, *Orfin: An Electric Utility Financial and Production Simulator*, ORNL/CON-430, Oak Ridge National Laboratory, Oak Ridge, TN, March 1996.

10. S. W. Hadley and E. Hirst, *Orced: A Model to Simulate the Operations and Costs of Bulk-Power Markets*, ORNL/CON-464, Oak Ridge National Laboratory, Oak Ridge, TN, June 1998.

11. Energy Information Administration, Office of Integrated Analysis and Forecasting, *National Energy Modeling System: An Overview 2000*, Dept. of Energy, Energy Information Administration, March 2000.

12. S. W. Hadley, *The Impact of Carbon Taxes or Allowances on the Electric Generation Market in the Ohio and Ecar Region*, ORNL/CON-463, Oak Ridge National Laboratory, Oak Ridge, TN, July 1998.

13. M. J. Sale and S. W. Hadley, *Estimating Hydropower's Contribution to the Control of Greenhouse Gas Emissions*, Waterpower XII Conference, Salt Lake City, UT, July 9-11, 2001

14. *Draft Standards for Interconnecting Distributed Resources with Electric Power Systems*, IEEE P1547/D08, sponsored by the IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage of the IEEE Standards Association, 2001.

15. John Stevens, *IEEE Std 929-2000—Background, Implications and Requirements*, 2000.

16. *Inverters, Converters, and Controllers for Use in Independent Power Systems*, http://ulstandardsinfonet.ul.com/scopes/1741.html.

17. *Distributed Generation Interconnection Manual*, Public Utility Commission of Texas, prepared by Distributed Utility Associates, and Endecon Engineering, March 15, 2001.

## APPENDIX A—BIBLIOGRAPHY

### General

1. DOE Strategic Plan for Distributed Energy Resources, September 2000

2. *Distributed Resources Web (www.disgen.com)*, in EPRI Solutions Web site.

3. *Distributed Generation—Securing America's Future with Reliable, Flexible Power*, prepared for the U.S. Department of Energy, Office of Fossil Energy, Federal Energy Technology Center.

4. *National CHP Roadmap—Doubling Combined Heat and Power Capacity in the United States by 2010*, prepared by the United States combined Heat & Power Association in cooperation with U.S. Department of Energy, U.S. Environmental Protection Agency, March 2001.

5. *Strategic Plan for Distributed Energy Resources*, prepared by Office of Energy Efficiency and Renewable Energy, Office of Fossil Energy, U.S. Department of Energy, September 2000.

6. Thomas E. Hoff and Christy Herig, *The Benefits of Distributed Resources to Local Governments: An Introduction*, a presentation in Chicago, IL, September 21, 2000.

7. Thomas E. Hoff, *The Benefits of Distributed Resources to Local Governments: An Introduction*, prepared for Christy Herig, National Renewable Energy Laboratory, September 12, 2000 (Draft).

8. Marc W. Goldsmith, *Distributed Generation—The Next Wave of the Technology-Enabled Revolution*, presentation to the Edison Electric Institute, June 2001.

9. "Energy Infrastructure: Electricity Transmission Lines," from *Energy Facts—An Educational Series Designed for Policymakers*, Alliance for Energy and Economic Growth.

10. "Bibliography List from "Bibliography List from E3 Publications," from http://www.ethree.com/Consulting/e3pubs.htm .

11. "Utility Case Study: T*D Siting in Nashville," in *Electrotek Concepts*.

12. "Web-Based Operational Solutions for Energy and Utility Companies," from website http://www.livedata.com/default.htm.

13. "Distributed Power Program" website, http://www.eren.doe.gov/distributedpower/.

14. Karl Stahlkopf and Wade Malcolm, "Distribution System Technology for the 21st Century," in *The Electricity Journal*, pp. 49–57 (May 1998).

15. Thomas Ackermann, Göran Andersson, and Lennart Söder, "Distributed Generation: A Definition," in *Electric Power Systems Research*, **57**, pp. 195–204 (2001).

16. Douglas J. Smith, "Distributed Generation: The Power to Choose," in *Power Engineering*, **105(3)**, pp. 32–36 (March 2001).

17. *Distributed Energy: Towards a 21st Century Infrastructure*, A Report of The Consumer Energy Council of America Distributed Energy Domestic Policy Forum, July 2001.

18. Brendan Kirby and Eric Hirst "Maintaining Transmission Adequacy in the Future," in *The Electricity Journal*, pp. 62–72 (November 1999).

19. Rod Taylor, "Let's Not Come Down Too Hard on Grids," in "Letters to the Editor" in *The Electricity Journal*, pp. 2–3 (October 2000).

20. "Distributed Generation: An Action Plan for Co-ops," in *Management Quarterly*, **40(2)**, pp. 20*ff* (Summer 1999).

21. "The Distributed Future—Technological Advances and Deregulation Offer More and More Opportunities to Put Generation Closer to the Load," in *Electric Perspectives*, **23(3)**, pp. 20*ff* (May/June 1998).

22. R. Brent Alderfer, M. Monika Eldridge, and Thomas J. Starrs, *Making Connections—Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects*, NREL/SR-200-28053, National Renewable Energy Laboratory, May 2000.

23. Jay Morrison, *White Paper on Distributed Generation*, prepared for the National Rural Electric Cooperative Association.

24. *Distributed Utility Planning: An Introduction to Concepts and Issues*, from Web site http://www.state.vt.us/psd/ee/ee-DUP.htm .

25. *The Role of Distributed Generation in Competitive Energy Markets*, from the "Distributed Generation Forum," March 1999.

26. Eric Hirst, *The California Electricity Crisis—Lessons for Other States*, prepared for Edison Electric Institute, July 2001.

27. "Distributed Generation Report 07/16/01–07/29/01," in *Energy Info Source: Your World of Energy* (2001).

28. "MMW1.0: Not Only for Substations," in *Power Delivery News*, June 1999.

29. "Advice to Utilities: Embrace DG," from *Distributed Power News*, June 2001.

30. Steven P. Lindenberg, *Distributed Generation: An Action Plan for Co-ops*.

31. Thomas Ackermann, Göran Andersoon, and Lennart Söder, "Distributed Generation: A Definition," in *Electric Power Systems Research*, **57**, pp. 195–204 (2001).

**Reliability and Technical**

32. Brendan Kirby and Eric Hirst, *Bulk-Power Reliability and Commercial Implications of Distributed Resources*, February 5, 2000.

33. *Least-Cost Paths to Reliability: Ten Questions for Policy Makers*, from "Issuesletters" web site.

34. *Reliability Assessment 1997–2006: The Reliability of Bulk Electric Systems in North America*, prepared for the North American Electric Reliability Council, October 1997.

35. *Findings and Recommendations to Enhance Reliability from the Summer of 1999* (Final Report), a Report of the U.S. Department of Energy's Power Outage Study Team, March 2000.

36. Benjamin F. Hobbs, "Optimization Methods for Electric Utility Resource Planning," in *European Journal of Operational Research*, **83**, pp. 1–20 (1995).

37. Ching-Tzong Su and Guor-Rurng Lii, "Reliability Planning for Composite Electric Power Systems," in *Electric Power Systems Research*, **51,** pp. 23–31 (1999).

38. Graham W. Ault and James R. McDonald, "Planning for Distributed Generation Within Distribution Networks in Restructured Electricity Markets," in *IEEE Power Engineering Review*, pp. 52–54 (February 2000).

39. A. Sundaram, *Power Quality Impacts of Distributed Generation. Guidelines—Final Report*, EPRI, December 2000.

40. B. Banerjee, *Capacity Planning, Power Quality, Reliability, and Availability for Internet Facilities. Volume 1: Digital Society Evolution, Issues Facing Stakeholders, and E-Commerce Market Segments—Final Report*, EPRI, December 2000.

41. B. Banerjee, *Capacity Planning, Power Quality, Reliability, and Availability for Internet Facilities. Volume 2: Technical Considerations—Final Report*, EPRI, December 2000.

42. L. Goel, "Power System Reliability Cost/Benefit Assessment and Application in Perspective," in *Computers & Electrical Engineering*, **24**, pp. 315–324 (1998).

43. J. O. Kim, S. W. Nam, S. K. Park, and C. Singh, "Dispersed Generation Planning Using Improved Hereford Ranch Algorithm," in *Electric Power Systems Research*, **47**, pp. 47–55 (1998).

44. Marija D. Ilić, José R. Arce, Yong T. Yoon, and Elena M. Fumagalli, "Assessing Reliability as the Electric Power Industry Restructures," in *The Electricity Journal*, pp. 55–67 (March 2001).

45. *Distributed Generation: System Interfaces,* An Arthur D. Little White Paper, 1999.

46. Brendan Kirby and John Kueck, *Review of the Structure of Bulk Power Markets Grid of the Future White Paper*, ORNL/TM-2000/41, January 2000.

47. Rich Cowart and Cheryl Harrington, *Distributed Resources and Electric System Reliability* (Review Draft), February 2001.

48. Richard H. Cowart et al., *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets*, prepared for The National Association of Regulatory Utility Commissioners, June 2001.

49. L. Goel, "Power System Reliability Cost/Benefit Assessment and Application in Perspective," in *Computers & Electrical Engineering*, **24**, pp. 315–324 (1998).

50. "Distributed Generation Reliability Metrics," web site http://www.gri.org/pub/solutions/dg/rel_metrics.html .

51. Will McNamara, "Nstar Takes Steps to Increase Reliability," in *Energy Info Source: Industry Commentary: Issue Alerts*.

52. *Power Delivery News*, EPRI Newsletter, October 2000.

53. "Consortium for Electric Infrastructure to Support a Digital Society," in *Power Delivery News*, March 2001.

54. *Power Delivery News*, EPRI Newsletter, July 1998.

**Economics and Regulatory**

55. "EPRI Planning Tools Help PSEG Tackle Growth: Distribution Expansion Strategies, Hudson River Waterfront," from EPRI Area Investment Strategy Model.

56. Thomas E. Hoff (Stanford University and Pacific Energy Group) and Christy Herig (National Renewable Energy Laboratory), "Managing Risk Using Renewable Energy Technologies," to be published in *The Virtual Utlity: Accounting, Technology & Competitive Aspects of the Emerging Industry*, Shimon Awerbuch and Alistair Preston (eds.), Kluwer Academic Publishers, Norwell, MA.

57. Fred Gordon (Pacific Energy Associates, Inc.), Joe Chaisson (Joe Chaisson and Associates), and Dave Andrus (Economic and Engineering Associates), Helping Distributed Resources Happen: A Blueprint for Regulators, Advocates, and Distribution Companies, Final Report, published for Eric Heitz of The Energy Foundation.

58. B. Kirby and N. Lenssen 1999, Shifting the Balance of Power: Grid Interconnection of Distributed Generation, E Source, The Distributed Energy Series, Boulder, Colorado, October

59. R. Staunton, J Kueck, B. Kirby, J. Eto 2001, Demand response: An Overview of Enabling Technologies, Public Utilities Fortnightly, November

60. J. D. Kueck, B. J. Kirby, J. Eto, R. H. Staunton, C. Marnay, C. A. Martinez, C. Goldman 2001, Load as a Reliability Resource in Restructured Electricity Markets, ORNL/TM-2001/97, Oak Ridge National Laboratory, Oak Ridge TN, June

61. E. Hirst and B. Kirby 2001, Metering, Communications and Computing for Price-Responsive Demand Programs, April

62. B. Kirby and E. Hirst 2001, Using Five-Minute Data to Allocate Load-Following and Regulation Requirements Among Individual Customers, ORNL/TM-2001-13, Oak Ridge National Laboratory, Oak Ridge TN, January

63. E. Hirst and B. Kirby 2000, Retail-Load Participation in Competitive Wholesale Electricity Markets, Edison Electric Institute, Washington, DC, and Project for Sustainable FERC Energy Policy, Alexandria, VA, Dec

64. B. Kirby and J. Kueck 2000, How Buildings Can Prosper by Interacting With Restructured Electricity Markets, ACEEE, August

65. B. Kirby and E. Hirst 1999, Load as a resource in Providing Ancillary Services, American Power Conference, Chicago, Illinois, April

66. B. Kirby 2001, Restructured Electricity Markets Offer Increased Complexities and Opportunities for Cogeneration, Cogeneration and Competitive Power Journal, fall

67. B. Kirby 2000, Restructured Electricity Markets Offer Increased Complexity and Increased Opportunities, Association of Energy Engineers, Globalcon 2000, April

68. E. Hirst and B. Kirby 2000, Bulk-Power Basics: Reliability and Commerce, The Regulatory Assistance Project, Gerdiner, ME, March

69. E. Hirst, B. Kirby and S. Hadley 1999, Generation and Transmission adequacy in a Restructuring U.S. Electricity Industry, Edison Electric Institute, Washington, DC, June

70. E. Hirst and B. Kirby 1998, Unbundling Generation and Transmission Services for Competitive Electricity Markets, ORNL/CON-454, Oak Ridge National Laboratory, Oak Ridge TN, January.

71. E. Hirst and B. Kirby 1998, Simulating the Operation of Markets for Bulk-Power Ancillary Services, The Energy Journal, Vol. 19, No. 3

72. E. Hirst and B. Kirby 2001, Key Transmission Planning Issues, the Electricity Journal, October

73. E. Hirst and B. Kirby 2001, Transmission Planning: Weighing Effects on Congestion Costs, Public Utility Fortnightly, July

74. E. Hirst and B. Kirby 2001, Transmission Planning for a Restructuring U.S. Electricity Industry, Edison Electric Institute, Washington, DC, June

75. B. Kirby and E. Hirst 2001, Real-Time Performance Metrics for Generators Providing the Regulation Ancillary Service, The Electricity Journal, April

76. B. Hirst and B. Kirby 2001, Measuring Generator Performance in Providing Regulation and Load-Following Ancillary Services, ORNL/TM-2000-383, Oak Ridge National Laboratory, Oak Ridge TN, January

77. B. Kirby and E. Hirst, 1998, Generator Response to Intrahour Load Fluctuations, IEEE Transactions on Power Systems, Vol 13 #4, PE-627-PWRS-0-12-1997, November

78. E. Hirst and B. Kirby 1996, Ancillary-Service Details: Regulation, Load Following, and Generator Response, ORNL/CON-433, Oak Ridge National Laboratory, Oak Ridge, TN, September.

79. J. Cadogan, M. Milligan, Y. Wan, and B. Kirby 2000, Short Term Output Variations in Wind Farms - Implications for Ancillary Services in the United States, October

80. B. Ernst, Y. Wan and B. Kirby 1999, Short-term Power Fluctuation of Wind Turbines: Looking at Data from the German 250 Mw Measurement Program from the Ancillary Services Viewpoint, American Wind Energy Association Windpower ‘99 Conference, Washington, DC, June

81. B. Kirby, E. Hirst, B. Parsons, K. Porter, and J. Codagan, 1997, Electric Industry Restructuring, Ancillary Services, and the Potential Impact on Wind, American Wind Energy Association, June

82. B. Kirby and E. Hirst 2000, Pricing Ancillary Services so Customers Pay for What They Use, EPRI, July

83. E. Hirst and B. Kirby 2000, Time-Averaging Period For the Regulation Ancillary Service, IEEE Power Engineering Review, July

84. B. Kirby and E. Hirst 2000, Customer-Specific Metrics for The Regulation and Load-Following Ancillary Services, ORNL/CON-474, Oak Ridge National Laboratory, Oak Ridge TN, January.

85. E. Hirst and B. Kirby 2000, Ancillary Services: A Call for Fair Prices, Public Utilities Fortnightly, January

86. B. Kirby and E. Hirst 1999, New Blackstart Standards Needed for Competitive Markets, IEEE Power Engineering Review, Vol. 19, No. 2, pp9, February

87. E. Hirst and B. Kirby 1998, Creating Markets for Ancillary Services, Pricing Energy in a Competitive Market, EPRI, June

88. B. Kirby and E. Hirst 1998, Characteristics of Concern in Supplying, Consuming, and Measuring Ancillary Services, The Future of Power Delivery in the 21st Century, The Electric Power Research Institute, Palo Alto, California, May

89. B. Hirst and B. Kirby 1998, Ancillary Services: The Neglected Feature of Bulk-Power Markets, The Electricity Journal, April.

90. B. Kirby and E. Hirst 1997, Ancillary-Service Details: Voltage Control, ORNL/CON-453, Oak Ridge National Laboratory, Oak Ridge TN, December.

91. E. Hirst and B. Kirby 1997, Ancillary-Service Details: Operating Reserves, ORNL/CON-452, Oak Ridge National Laboratory, Oak Ridge TN, November.

92. E. Hirst and B. Kirby 1997, Creating Competitive Markets for Ancillary Services, ORNL/CON-448, Oak Ridge National Laboratory, Oak Ridge TN, October.

93. E. Hirst and B. Kirby, 1997, Ancillary-Service Details: Dynamic Scheduling, ORNL/CON-438, Oak Ridge National Laboratory, Oak Ridge TN, January

94. B. Kirby and E. Hirst 1996, Ancillary-Services Costs for Twelve U.S. Electric Utilities, ORNL/CON-427, Oak Ridge National Laboratory, Oak Ridge, TN, March.

95. E. Hirst and B. Kirby 1996, Electric-Power Ancillary Services, ORNL/CON-426, Oak Ridge National Laboratory, Oak Ridge, TN, February

96. “Executive Summary,” from Conference Proceedings of the Distributed Generation Roundtable, April 25–26, 1996.

97. Thomas E. Hoff, Howard J. Wenger, and Brian K. Farmer, Distributed Generation: An Alternative to Electric Utility Investments in System Capacity.

98. Small is Profitable: Why Our Bigger-is-Better Electricity System's Days are Numbered, from Web site Act Now.

99. Thomas J. Starrs and Howard J. Wenger, Policies to Support A Distributed Energy System, REPP Special Report.

100. Nick Lenssen, "How Will Distributed Generation be Deployed?" from Web site http://www.localpower.org/article.html .

101. Working with Regulators to Reveal the Value of Distributed Resources, prepared for The Regulatory Assistance Project.

102. Robert J. Camfield and Anthony G. Schuster, "Pricing Transmission Services Efficiently," in The Electricity Journal, pp. 13–32 (November 2000).

103. Douglas J. Smith, "Cogeneration, Distributed Generation and Peak Shaving Drive the Market for Small Gas Turbines," in Power Engineering, 104(10), pp. 70–74 (October 2000).

104. "Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation[A]," in Energy Journal, 16(2), pp. 111ff (1995).

105. "Changing the Rules for Independent Power Producers," in International Power Generation, 21(5), pp. 53ff (July 1998).

106. Michael Hsu, "An Introduction to the Pricing of Electric Power Transmission," in Utilities Policy, 6(3), pp. 257–270 (1997).

107. B. W. Ang, J. P. Huang, and K. L. Poh, "Break-Even Price of Distributed Generation Under Uncertainty," in Energy, 24, pp. 579–589 (1999).

108. David E. Dismukes and Andrew N. Kleit, "Cogeneration and Electric Power Industry Restructuring," in Resource and Energy Economics, 21, pp. 153–166 (1999).

109. Nainish K. Gupta and Herbert G. Thompson, Jr., "Buying Wires: The Market Value of Transmission Assets," in The Electricity Journal, pp. 50–54 (April 2000).

110. Robert A. Laurie, "Distributed Generation: Reaching the Market Just in Time," Guest Editorial in The Electricity Journal, pp. 87–94 (March 2001).

111. Distributed Generation: Policy Framework for Regulators, An Arthur D. Little White Paper, 1999.

112. Distributed Generation: Understanding the Economics, An Arthur D. Little White Paper, 1999.

113. David Moskovitz, "Profits and Progress Through Distributed Resources," in The Regulatory Assistance Project, February 2000.

114. "Distributed Resources and Distribution Company Profitability (Draft), in The Regulatory Assistance Project, April 28, 1999.

115. Wayne Shirley, Richard Cowart, Rich Sedano, Frederick W. Weston, Cheryl Harrington, and David Moskovitz, Distribution System Cost Methodologies for Distributed Generation, prepared for The National Renewable Energy Laboratory, The Regulatory Assistance Project, July 31, 2001.

116. Thomas E. Hoff, Using Distributed Resources to Manage Risks Caused by Demand Uncertainty.

117. Thomas E. Hoff, Identifying Distributed Generation and Demand Side Management Investment Opportunities.

118. "Performance Based Regulation—A Policy Option for A Changing World," in Issuesletters.

119. Resource Dynamics Corporation, Economics of Distributed Generation: T&D Applications, presented at the AEIC–COEPA 1999 Meeting, Santa Fe, NM, September 28, 1999.

Standards

120. Working Safely with Photovoltaic Systems, prepared by Daystar, Inc., Energy Engineering.

121. Chris Larsen, Bill Brooks, Tom Starrs, Connecting to the Grid. A Guide to PV Interconnection Issues, Third Edition, prepared for the Interstate Renewable Energy Council's PV4You Interconnection Project, 2000.

122. Inverters, Converters, and Controllers for Use in Independent Power Systems, UL-1741, Underwriters Laboratories, Inc., January 17, 2001.

123. IEEE P1547/D07—Draft Standard for Interconnecting Distributed Resources with Electric Power Systems, IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage of the IEEE Standards Association, 2001.

124. Distributed Utility Associates and Endecon Engineering, Distributed Generation Interconnection Manual, prepared for the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, March 15, 2001.

125. IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems, Institute of Electrical and Electronics Engineers, Inc., 2000.

126. John Stevens, The Interconnection Issues of Utility-Intertied Photovoltaic Systems, SAND 87-3146, Sandia National Laboratories, June 1997.

Environmental

127. Peter S. Glaser, "Green Power Marketing Claims: A Free Ride on Conventional Power?" in The Electricity Journal, pp. 32–40 (July 1999).

128. Edward M. Meyer and Mannshya Grace Hu, "Clean Distributed Generation: Policy Options to Promote Clean Air and Reliability," in The Electricity Journal, pp. 89–98 (January/February 2001).

129. Nathanael Greene and Roel Hammerschlag, "Small and Clean is Beautiful: Exploring the Emissions of Distributed Generation and Pollution Prevention Policies," in The Electricity Journal, pp. 50–60 (June 2000).

130. Sheryl Carter, Emissions from Distributed Generation, presented to the California Energy Commission Siting Committee Workshop, Evaluating Distributed Generation CEQA and Permit Streamlining, April 20, 2000.

Miscellaneous Reports

131. Distributed Generation Monitor, Volume 1, Issue 4, June/July 2001.

132. Distributed Generation Monitor, Volume 1, Issue 3, April/May 2001.

133. Distributed Generation Monitor, Volume 1, Issue 2, February/March 2001.

134. "Reliability of Natural Gas Power Generation Systems," in Natural Gas Power Generation Solutions.

135. Electricity Generation: A Key Element of Reliability, from the Edison Electric Institute.

136. A. B. Poole, Distribution Efficiency of Electrical Power, presentation, March 11, 1998.

137. Steven Nadel, Fred Gordon, and Chris Neme, Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems, an ACEEE publication, November 2000.

138. Chi-Keung Woo, "What Went Wrong in California's Electricity Market?" in Energy, 26, pp. 747–758 (2001).

139. Syska & Hennessy, Task C2 Report for Evaluate Building Heating and Cooling Systems, DG System Integration and Reliability Impacts on Telecommunication Facilities Project, submitted to Oak Ridge National Laboratory, reference Subcontract 4000006128, ZGP-01-000.

140. Syska & Hennessy, Task C5 Report for Schematic Design, DG System Integration and Reliability Impacts on Telecommunication Facilities Project, submitted to Oak Ridge National Laboratory, reference Subcontract 4000006128, ZGP-01-000.

141. Syska & Hennessy, Task C3 Report to Evaluate Heat Recovery Options, DG System Integration and Reliability Impacts on Telecommunication Facilities Project, submitted to Oak Ridge National Laboratory, reference Subcontract 4000006128, ZGP-01-000.

142. Syska & Hennessy, Task C1 Report for Analysis of Existing Electrical System, DG System Integration and Reliability Impacts on Telecommunication Facilities Project, submitted to Oak Ridge National Laboratory, reference Subcontract 4000006128, ZGP-01-000.

143. Distributed Energy Resources Annual Operating Plan Fiscal Year 2001 (Draft), U.S. Department of Energy, Office of Power Technologies, Office of Energy Efficiency and Renewable Energy, October 24, 2000.

144. "Crisis in California: Part 1 What Really Happened, and Why," in Management Quarterly, 42(2), pp. 44ff (Summer 2001).

145. G. A. Kern, R. H. Bonn, J. Ginn, and S. Gonzalez, “Results of Sandia National Laboratories Grid-Tied Inverter Testing,” presented at the 2nd World Conference and Exhibition on Photovoltaic Solar Energy Conversion, Vienna, Austria, July 6–10, 1998.

146. Steve Hester, IEEE 929-2000 Recommended Practice for Utility Interface of Photovoltaic (PV) Systems, a presentation.

147. Chi-Keung Woo, Ira Horowitz, and Khoa Hoang, “Cross Hedging and Forward-Contract Pricing of Electricity,” in Energy Economics, 23, pp. 1–15 (2001).

148. “Waste Heat Absorption Chillers,” in Absorption Cooling Web site http://www.mechanicalsystems.com/absorpti.htm .

149. “The Alliance and Its Objectives,” in the Alliance for Energy & Economic Growth, http://www.yourenergyfuture.org/aboutus.cfm.