ORNL/TM-2005/257

ENGINEERING SCIENCE AND TECHNOLOGY DIVISION

Customer-Owned Utilities and Distributed Energy: Potentials and Benefits

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February 2006

Sponsored by
U.S. Department of Energy
Office of Electricity Delivery & Energy Reliability
Distributed Energy Program

OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37831
managed by
UT-BATTELLE, LLC
for the
U.S. DEPARTMENT OF ENERGY
under contract No. DE-AC05-00OR22725

CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACRONYMS

APPA	American Public Power Association
CHP	Combined Heat and Power
COU	Customer-Owned Utility
DE	Distributed Energy
DSM	Demand Side Management
EIA	Energy Information Administration
EOYB	End of Year Balance
EPA	Environmental Protection Agency
G&T	Generating and Transmission cooperatives
HL&P	Heber City Light and Power
IC	Internal Combustion
MW	Mega Watt
NEMEPA	North East Mississippi Electric Power Association
NERC	North American Electric Reliability Council
NRECA	National Rural Electric Cooperative Association
SPSA	Southeastern Public Service Authority
TVA	Tennessee Valley Authority

EXECUTIVE SUMMARY

The purpose of this study is to examine the customer-owned utility (COU) market, especially the municipal utility market, from the perspective of its Distributed Energy (DE) application potential. This report examines the overall municipal utility industry as compared to the electric industry as a whole and describes the possible ways that DE may be used in a customer-owned utility setting.

Few, if any, analyses of the benefits of DE have focused on the benefits specific to the size, structure, and responsibilities of customer-owned utilities. The benefits for a DE that is owned or operated by the customer-owned utility are shown in Table ES-1.

Table ES-1. Matrix Of Benefits From DE For The Customer-Owned Utility And The Local Site Of The DE

Benefit	*COU-Wide Benefit*	*Local Site Benefit*
Cost saving (electricity, CHP)	Savings based on cost of DE capital and operations versus purchased power from external entities (with possible net savings from steam use)	Savings based on shared savings with COU versus separate purchase of electricity and/or steam
Self-sufficiency	Community is less reliant on outside providers	Local site has redundant power supply from DE and grid
Improved reliability, quality	Local sources provide added reliability and power quality versus reliance on lines from external entities	Increased reliability through added electricity source, with backup from grid
Emergency response support	Local power to support critical infrastructure during emergency	Key infrastructure continued operation
Customer support	COU customers want options for power supply	Site will have more control over power and thermal supply
Flexibility	DE can be shifted to where most needed	Temporary or permanent improvements can be added quickly
Economic development	Community economic boost through added development	Site will have higher economic value
T&D savings	Savings based on marginal cost of expansion versus embedded cost	DE may be superior to added distribution infrastructure

A COU-owned DE system may be located at a substation to provide peaking support, at a city-owned facility to provide both thermal energy and emergency back-up to a critical load, or at a customer site to meet thermal and reliability needs. A substation installation will typically have the lowest combined heat and power (CHP) potential, but its interface with the grid is typically simple. Such systems are sometimes temporary in nature, with the DE resource relocated to a new substation when the load on the original location has grown to the point where it makes more sense to increase the capacity of the substation itself. Customer and city-owned facility DE locations are more traditional, and hark back to the days of wide-spread district heating. These systems have the potential for much greater energy efficiency, but their operation is complicated by the need to serve both electrical and thermal demands. The integration of these systems into the grid may also be more complicated. Examples of all these application types at customer-owned utilities were found and are described fully within the report.

Some of the customer-owned utility characteristics that may indicate the more promising DE targets include:

- Peak demand greater than 5 MW
- Waste fuel supply availability
- Customer-owned utilities with other municipal functions
- Customer-owned utilities with higher marginal distribution system costs.

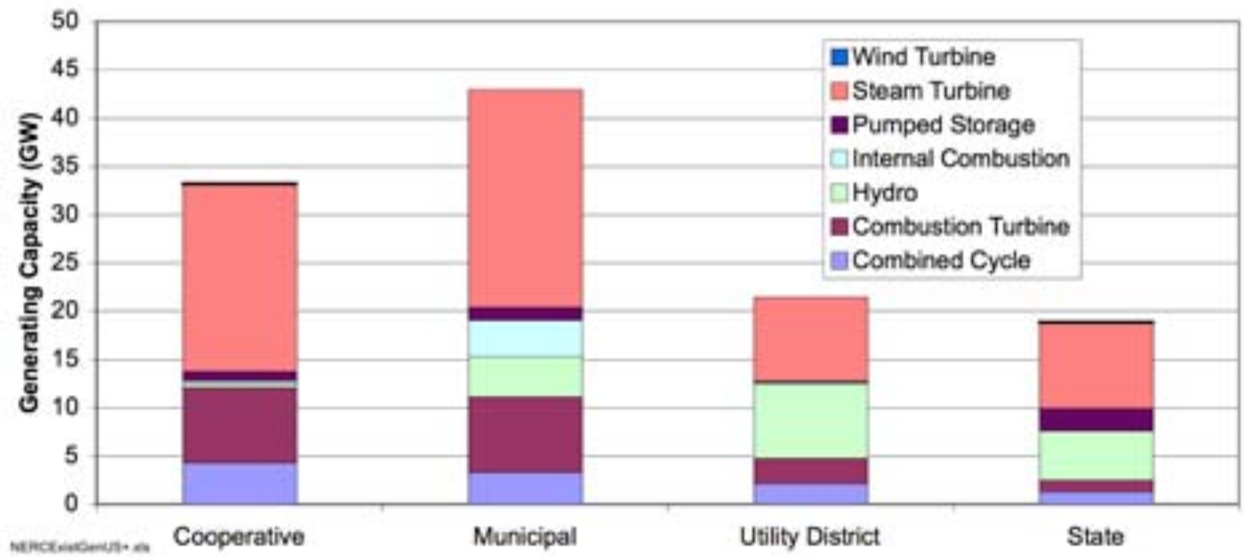
With these factors and the possible benefits in mind, a broad review of utility data was made to characterize the customer-owned utility community and to determine whether these factors are common amongst this population or are limited to only a few locations. The customer-owned utility market was found to be a broad array of entities, from tiny townships to large cities, from distribution-only grids to large, integrated power, gas and water utilities. As shown in Fig. ES-1, there are over 1,800 municipal utilities and almost 900 cooperative utilities, along with a smaller number of utility districts and state power agencies. As discussed above, DE offers benefits to some of these customer-owned utilities, while others may find that DE is not a good match for their system.

Figure ES-1. Customer-Owned Utilities In Contiguous US

Utility size can be classed according to retail power sales or generating capacity. Over one-fourth of the customer-owned utilities have less than $1 million in retail revenues and over one-half have less than $5 million. Less than 30% of these smaller utilities own generating capacity. However, there are some large utilities in this mix: 88 customer-owned utilities have retail revenues over $100 million, and about 80% of these own generating units. Even for those customer-owned utilities that do generate, the amount is generally just a fraction of their overall needs, with the rest coming from purchases. Over half the municipal utilities with generating assets have capacity factors less than 2%, which indicates that these utilities are using their generation for peaking or back-up purposes. Larger utilities, such as utility districts and state agencies, are more likely to use their generation assets to provide base-load power, with about two thirds showing capacity factors between 50 and 100%.

The types of generating equipment used by customer-owned utilities is summarized in Figure ES-2. Among all electricity producers, including utilities and non-utilities, 92% of capacity is central generation for electricity only and 7.5% is for cogeneration or distributed generation. However, for customer-owned utilities, less than 2% is classed as cogeneration or DE. Proportionately then, there appears to have been less DE development in the customer-owned utilities than in the rest of the utility industry, perhaps indicating an untapped market for DE in this sector.

Figure ES-2. Total Capacity of Generation by Prime Mover and Customer-Owned Utility Category



There are very few customer-owned utilities currently using waste fuels. Only two cooperatives and twelve government customer-owned utilities are included in the list of generators. The low number of customer-owned utilities using waste fuel may mean there is an untapped source of waste fuel for DE that could be exploited. There were only 313 municipal utilities identified that sell both natural gas and electricity. These customer-owned utilities may be more likely candidates for DE because they have access to the lower cost gas that a distributor receives.

Based on this assessment, there are many customer-owned utilities with the resources and experience base necessary to add economically-beneficial DE to their generation portfolio. The data also show that this market may not have been explored to the same extent as the private utility market. Considering the many beneficial factors that may uniquely apply for municipal utilities, this sector would seem to be an appropriate target for a more detailed market analysis and for DE educational efforts.

1. Introduction

Several benefits of Distributed Energy (DE) for utilities are: additional source of electricity, improved reliability and power quality, voltage support, increased opportunity for end-use response (load as a resource), transmission and distribution (T&D) displacement or deferral, emissions trading, an expanded district heating and cooling market, as well as others. These can be largely quantified and such quantification may help to encourage utilities to pursue this market. A number of studies have listed these benefits and previous work at ORNL has quantified some of them. (Poore et al. 2002, Hadley et al 2003, 2004)

Some utilities may be more likely candidates than others for entering this market and there are some characteristics that may distinguish these candidates from other utilities. For example, utilities that already are in the district heating market could more easily integrate DE into their system. Other characteristics could be utilities that sell both gas and electricity, utilities facing T&D expansion or replacement needs, or those needing locational ancillary services support.

There are several different categories of utilities: some private, some public. Municipal utilities and other customer-owned utilities may be good early adoption targets. This analysis is therefore focused on those utilities that are customer-owned, either directly or through government institutions. These customer-owned utilities are made up of the cooperatives, municipals, other political subdivisions (such as utility districts), and state-owned facilities. Federal agencies, while technically customer-owned, were not considered here because they have very different characteristics from the others, owning generation facilities that are either large central station plants or hydro plants and having little direct interaction with end-users

Many municipal utilities were built on the idea of distributed generation originally and only switched to purchasing power from others as large central stations became the most cost-effective solution. Municipal utilities may be especially good targets because they are more likely to have other characteristics that lend to exploitation of the benefits of DE. Some key factors may be:

- Is there a reliability or power quality problem on one or more of their feeders?
- Are key customers or their community progressive in exploring energy alternatives?
- Are they faced with the need for distribution and/or transmission upgrades?
- Do they serve a concentrated load center that has both electric and thermal loads?
- Do they have experience generating electricity?
- Do they belong to a municipal group that jointly owns electricity generation capacity?
- Do they sell both electricity and gas?
- Does their city also manage wastewater treatment or water treatment plants that can be sources of fuel or significant users of power?

How large of a market is this potentially? What municipal utilities may fit these criteria? The purpose of this report is to examine the municipal utility market from the perspective of its DE application potential. It examines the overall municipal utility industry as compared to the electric industry as a whole and describes the possible ways that DE may be used in a customer-owned utility (COU) setting.

2. DE Benefits from the Customer-Owned Utility Perspective

There have been a number of analyses of the benefits of DE. However, few, if any, have focused on the benefits specific to the size, structure, and responsibilities of customer-owned utilities. One European study has looked at the potential benefits for partnerships that include private industry and public municipal utilities. (Sundberg and Sjödin, 2003) A U.S. report (Hadley et al 2003) included a table outlining the various benefits that were quantified, as seen by customers, the local utility, and society as a whole. This table can be modified to explore the benefits for customer-owned utilities. The most likely scenario posed for this analysis is a DE that is owned or operated by the customer-owned utility; ownership and operation by a COU customer gives benefits and costs similar to that of any other type of utility.

Table 1. Matrix Of Benefits From DE For The Customer-Owned Utility And The Local Site Of The DE

Benefit	*COU-Wide Benefit*	*Local Site Benefit*
Cost saving (electricity, CHP)	Savings based on cost of DE capital and operations versus purchased power from external entities (with possible net savings from thermal energy use)	Savings based on shared savings with COU versus separate purchase of electricity and/or thermal energy
Self-sufficiency	Community is less reliant on outside providers	Local site has redundant power supply from DE and grid
Improved reliability, quality	Local sources provide added reliability and power quality versus reliance on lines from external entities	Increased reliability through added electricity source, with backup from grid
Emergency response support	Local power to support critical infrastructure during emergency	Key infrastructure continued operation
Customer support	COU customers want options for power supply	Site will have more control over power and thermal supply
Flexibility	DE can be shifted to where most needed	Temporary or permanent improvements can be added quickly
Economic development	Community economic boost through added development	Site will have higher economic value
T&D savings	Savings based on marginal cost of expansion and expansion incremental size	DE may be superior to added distribution infrastructure

2.1 Cost saving

Customer-owned utilities typically purchase power rather than generate it so their price of power is the wholesale price or contract price rather than the cost of generation. Contract terms are likely to include both energy and demand charges, so DE used to reduce peak demands can save on both energy and demand payments. Alternatively, if the utility purchases power from the wholesale market, then DE used during the peak periods when prices are highest will be most cost-effective. However, cost savings must be high enough to offset the cost of investment in the DE asset.

One way to improve the economics and efficiency of DE is to use the thermal exhaust for some productive end-use. This is called Combined Heat and Power (CHP). By using CHP, overall energy use can increase from around 30% of input energy to over 70% or higher. Use of CHP optimizes fuel use by maximizing thermal energy recovery and integrating end-use equipment such as boilers, water heaters, steam systems, and chillers.

A key factor for the success of a CHP project is to have a steady, nearby end-use for the heat. A customer-owned utility may consider city-owned facilities such as schools, community centers, office buildings, jails, hospitals, or water treatment plants. However, an added complication of CHP is sizing and operating the equipment for two separate purposes: electricity and thermal energy. Trade-offs must be made in that electricity may be needed when heat is not, or vice versa. If the DE is to be used mainly for peak-shaving or as back-up capacity, it is unlikely to be suitable as a CHP candidate.

2.2 Self-sufficiency

A community may desire to be more self-sufficient in their resources. For homeland security reasons, the community may want generation of their own, especially key facilities for disaster response or simply as a backstop to supplies from outside organizations. A customer-owned utility may consider adding DE to city-owned facilities such as schools, office buildings, jails, hospital, or water treatment plants. In this way it can both provide needed emergency generation as well as providing day-to-day supplies of electricity and/or heat.

2.2.1 Example: The University of Mississippi

The University of Mississippi installed a DE system consisting of 10 diesel generators with a maximum generation capacity of 20 MW. This system allows the university to participate in the Tennessee Valley Administration (TVA) load curtailment plan, saving about $1,000,000 per year in power costs. Prior to the construction of the generation facilities, the university did not have full campus backup protection. Now full power can be restored in less than a minute.

The university is a customer of the North East Mississippi Electric Power Association (NEMEPA), a distributor of TVA electricity. NEMEPA is a not-for-profit cooperative concerned only with keeping its revenue neutral. Under this curtailment program, the university purchases its utility power at a reduced rate which causes a reduction in the revenue margin that NEMEPA previously collected from the university. However, NEMEPA has been contracted by the University to manage the generation facility and NEMEPA also added a small facilities charge to the university's utility bill for equipment needed for the generation project. This arrangement essentially kept their revenue neutral, even though the university's overall energy bill was greatly reduced. TVA receives less revenue from the university, but the load curtailment plan allows TVA to curtail customer demand rather than invest in more generation facilities or pay higher market prices for excess power during peak demand period. Overall this DE system was beneficial to the university and the TVA and was neutral in its effect on the local power cooperative. (Stieva, 2004)

2.3 Improved reliability and power quality

Since distribution customer-owned utilities are separate from the territory covered by private utilities, the electrical connections between the two may be weak and there may be little incentive for the private firms to improve the connection. Low voltage, harmonics, lack of reactive power, or frequent outages may reflect the lack of a robust connection to the larger grid. Customers at the end of a line, such as cooperatives or small municipal utilities, frequently face greater problems with connection quality. DE can provide a local source for ancillary services that boost the power quality and reliability. DE can even improve the power quality back on the neighboring utility's grid, and thus may be able to sell ancillary services back to the neighboring utility. Negotiations on prices and connections should reflect this added value, rather than penalize the DE.

2.4 Emergency response support

One responsibility of cities is to provide for emergency response in the case of fire, storms, or other disasters (natural or man-made). Local generation through DE is more likely to keep the lights on when storms knock out transmission or distribution lines. The DE can be located in the critical infrastructure for the ongoing operation of the city such as emergency shelters, hospitals, police and fire stations, and municipal water and sewage facilities, as well as in key private sector facilities such as grocery stores or gas stations. Radio broadcast systems may be powered by DE. Traffic control systems are an important component for public safety; self-powering these can greatly lower the level of disruption from storms.

2.4.1 Examples: Weather-related outages

Examples of critical loads that could be served by DE include weather events in Memphis and Boston. During a freak storm in Memphis TN in July 2003, power was out for much of the city for several days, and in parts of the city for several weeks. About 75% of the traffic lights were without power, creating congestion and safety concerns at intersections. The airport was closed down, causing both traveler and freight disruptions. In October 2005, a weather-related power outage that left 20,000 customers in the Northeast without electricity also shut down two sewage treatment plants, spilling raw sewage into Boston Harbor and a nearby river.

2.5 Customer support

By offering another method for customers to receive electricity, DE can increase customer satisfaction. For various reasons, some customers may prefer to have onsite generation, such as grocery stores, hotels, industries, or rural users. Some customers are required to have back-up generation, such as hospitals.[1] Furthermore, DE may use alternate generation technologies such as renewable energy (e.g., wind, biomass, solar). Local customers who want their energy from such technologies could have the choice offered them.

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[1] Even hospitals that are required to maintain emergency power generators may be surprised to learn that these code-required generators are sized to support life-critical services only. Many convenient and revenue-producing services, such as MRI and CAT scans, are not powered in the event of a grid outage.

2.5.1 Example: Waverly, Iowa

The city Waverly IA, long a leader in energy efficiency and renewable energy, has installed two 0.7 MW wind turbines. These represent 4% of their capacity of 33.8 MW or 5% of their peak demand of 29 MW.

2.6 Flexibility (portability, lease/buy)

One advantage of DE is that the equipment can be put in place relatively quickly and moved if requirements change. If a given distribution circuit is being stressed, then a DE project can be added to relieve some of the demand. If the demand later declines, or grows such that an expansion of the circuit is justified, then the DE can be moved to another spot on the system. Many DE manufacturers make their equipment portable, including using skids or tractor-trailer beds as their platforms.

Financially, the DE projects are small enough and standard enough that financing through leasing may be an option. Even if purchased, since the equipment is readily transportable, there is a ready after-market, lowering the investment risk. A DE project that can be packed up and sold if no longer needed is less risky than an upgrade in distribution lines and substations.

2.6.1 Example: Tallahassee FL Municipal Power

The city of Tallahassee, Florida was faced with an extended outage on one of their generating units that would have left them with insufficient contingency reserves for the summer peak load. They elected to lease and install temporary DE, bringing in 50 MW of backup power for a four month period. The DE, consisting of 12 transportable gas-turbine generating sets, was installed at an existing substation. Although the units were never run after their initial operating tests, they provided the needed reserves (Rafter, Dan, 2004).

2.7 Economic development

Because DE projects are small and as CHP require end-uses for their exhaust, they can fit readily into a redevelopment project to provide electric and thermal energy. They are not necessarily separate, stand-alone facilities but can be part of a broader economic development park. Power and heat from the DE can be sold to individual tenants within the redevelopment. Customer-owned utilities will have an easier route to this type of development than developers in private utility territories will because the customer-owned utility has the franchise to deliver these services.

2.7.1 Example: Dell Children's Medical Center of Central Texas

A DE system is an integral part of a new children's hospital in a brownfield development at the site of Austin's former Robert Mueller Municipal Airport site, as shown in Figure 1. The DE system has been designed to provide electricity, hot water, chilled water, and black-start capabilities to the hospital and to future tenants in the development. The DE system includes thermal storage and turbine inlet cooling to improve the electricity production during hot weather. The high efficiency, low-emissions system is also being used to provide energy efficiency credits toward a LEED designation.(Mardiat, 2005)

Figure 1 Part of the DE System at Dell Children's Medical Center of Central Texas and an Overview of the Brownfield Site Development Plan. (Mardiat, 2005)

2.8 T&D savings

Utilities typically assess the T&D potential of DE by focusing on opportunities where planned expansions or upgrades of the distribution system can be avoided or deferred. Marginal costs for new distribution system equipment vary widely, as discussed further in Sect. 4.5. Because of this cost variability, the avoided T&D cost of DE is typically evaluated case-by-case, based on the specific conditions, and considering plans for upgrading an existing distribution system. The required investment in distribution equipment over some future period without DE is compared to the required investment with DE (Hoff 1996, Price et al, 2005). Then the value of DE is determined based on its ability to defer the cost of expanding or upgrading the distribution system. From this perspective, DE may have a net value because investments in traditional distribution and/or transmission equipment often include large increments resulting in a period of excess capacity until demand increases to utilize that capacity. In essence, smaller increments of DE can reduce traditional distribution capacity costs by more precisely matching capacity expansion to growth in demand.

Avoided T&D costs for DE do not necessarily occur at the same time that DE capacity is added because often the T&D resources are already in place. However, in the long run, T&D resources must be maintained, replaced, and usually augmented to meet system growth. Therefore, in the long-term view, DE should contribute to a reduction in T&D expenses.

Most customer-owned utilities do not maintain a transmission system but rather purchase power from either their generation and transmission (G&T) cooperative, municipal power agency, nearby private utility, or the wholesale market. Deferral of transmission upgrades would be of indirect interest to these customer-owned utilities but would be value to the upstream generator. The customer-owned utilities that do own transmission assets, either directly or through their ownership of the upstream generating entity, would directly see a value from the deferral.

3. Potential Applications for COU-Owned DE

3.1 Substation

The least complicated location for installation of DE is within one of the utility's substations. The infrastructure needed for connecting and monitoring the DE are largely in place (except perhaps fuel supply), and the location is already controlled by the utility. Injection of power at the substation does not alter the topology of the local grid, avoiding any possibility of power flowing back from customer sites into the lines. This improves the control and safety of the distribution system.

On the other hand, it is less likely that the waste heat from the DE can be used when the DE is in a substation. Unless the utility has a potential need nearby, or can sell the waste heat to a customer nearby, the exhaust will not be used and the overall efficiency will be less.

3.1.1 Example: McMinnville Electric System

The McMinnville Electric System in McMinnville, Tennessee, operates a block of 11 diesel generators to provide peaking power to the TVA system and back-up power for the city of McMinnville. When operating, the 20 MW capacity of the installation provides approximately 40% of the city's total demand and is tied into a critical care feeder circuit that services the local hospital and jail. The system is permitted to run a maximum of 350 h/year due to emissions limitations and typically runs four to six hours at a time when dispatched by TVA, meeting both winter and summer system peak loads. Generation credits for this system paid by TVA have helped McMinnville Electric System control their costs to the point that they are currently charging their retail customers the fourth lowest rates in the TVA system. As a part of their long-term contract with TVA, TVA provides low-sulfur diesel oil to the installation at a cost that is below the current market price. The system was constructed within an existing substation, which reduced the installation cost.

Although TVA doesn't pay for reactive power, the diesel generators provide voltage support that is felt in Decatur, TN, about 50 miles away. The McMinnville Electric System personnel noted that the TVA power feed to their system fell below the contractual level of voltage support about 30 times during the previous year.

At the same substation, the McMinnville Electric System is hosting a collaborative effort to develop and demonstrate a reciprocating engine-generator fueled by a soybean-based bio-diesel product.[2] With an innovative after-treatment emissions system now being tested, they hope to reduce the emissions by 80% to 90% compared to an oil-fired diesel engine. They are hoping that this system will qualify as a supplier for TVA's Green Power program, which would substantially increase the value of the bio-diesel generated power.

[2] Other participants include the U.S. Department of Energy, The TVA, Stowers Caterpillar, EmeraChem, the American Public Power Association, The Tennessee Soybean Growers Association, Phillips Sales and Service, Gant Oil Company, BioDiesel of Mississippi, the National BioDiesel Board, the University of Minnesota and the University of Tennessee.

Figure 2 McMinnville Electric System Peaking Power Diesel Generator Sets with General Manager Rodney Boyd

3.1.2 Example: Powell Valley Electric Cooperative

The Powell Valley Electric Cooperative serves eight rural counties in an area about 120 miles wide along the border of Tennessee and Virginia. In this sparsely populated region, the co-op has less than nine customers per mile of distribution line and a winter peak load of about 170 MW. Maintaining low power costs for their co-op members in this challenging environment is important to the staff and led them to install 22 MW of distributed generation in 2000. The DE is available to provide contracted peaking power for TVA on a 5-minute dispatch notice, to serve a critical needs circuit in Powell Valley in case of a grid power failure outside their system, and to provide black-start power to a 700 MW fossil-fueled TVA power plant located about 20 miles away. This 700 MW power plant is also the main source of power to Powell Valley, and running the DE reduces the load on the connecting transmission line by 20 MW. The eleven diesel-fired engines can be dispatched remotely and are permitted to run up to 1,400 hours per year, but are typically used to meet TVA's peak demand 500 to 600 hours per year. (When purchased, these engines met the California emissions limits, although those limits have become stricter since that time.) The contract with TVA has a 10-year term and Powell Valley expects a six-year simple payback on their investment. To reduce the economic risk to the co-op, Powell Valley (1) negotiated a buy-back arrangement with the engine manufacturer at the end of the ten-year contract, and (2) negotiated a provision so that TVA is the installation fuel manager. TVA keeps a 30-hour supply of diesel fuel on site which has been adequate, even considering the winter conditions on the winding mountain roads.

Figure 3 Powell Valley Distributed Generation with General Manager Randall Myers and Ronny Williams

3.2 City-owned facility

One advantage that a municipally-owned utility has over other types of utilities with regard to DE is that the city has other facilities that require thermal energy, either for heating, water-heating, or chiller operation. Their facilities may include schools, jails, hospitals, community centers, municipal offices, and water or wastewater treatment plants. The equipment can include CHP so that heating or cooling is provided for the facility as well.

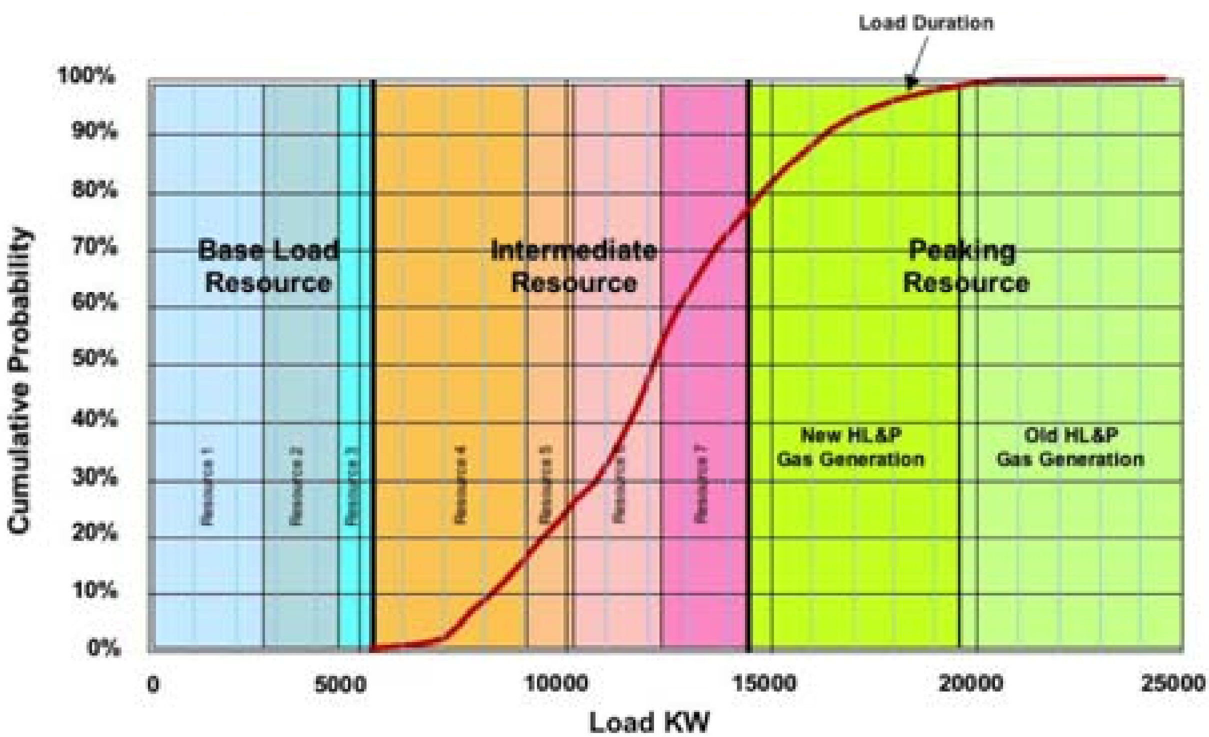
Historically, municipal utilities have also provided district heating and cooling services. This third-party owner-operator status can be extended to CHP systems. Municipal utilities are also in a good position to 'wheel' electricity from the DER to the greater power grid.

3.2.1 Example: Heber Light and Power

Heber Light & Power (HL&P), the municipal utility in Heber City, UT, operates a set of distributed generation facilities to supply a large fraction of their overall demand locally. (Devine 2003) A combination of advanced gas-fired generators, diesel generators, and hydro can provide up to 12.5 MW, as compared to their peak summer demand of ~ 20 MW and winter demand of ~25 MW. In the early 2000's they realized that purchasing power with long-duration 24-hour block contracts meant that though they paid less during peak times, they were paying above the market price during much of the time. They changed their operating strategy to use their equipment to interact with the market, dispatching power from their plants when hourly market prices rise above the operating cost.

A load duration curve traditionally plots the load, or demand, against the percent of the season that load is *met or exceeded*. However, in Figure 4 the load duration data is overlaid upon the stack of power resources available to HL&P. In this form, the load duration curve shows instead the fraction of time that customer demand is *at or below* the given demand level. (For example, in this curve, the load is below 5000 kW 0% of the time, because that is the base load.) Because the peaking resources are the most expensive, they are called upon last, but were still used some 20% of the time that year. As demand has grown the curve has moved to the right and the HL&P gas generation has been called on more frequently.

Figure 4. Heber Light and Power 2002 Load Duration vs. Resource Stack (Adams and Broussard 2004)



Furthermore, the equipment provides them a reliability hedge. Financially, this allows them to contract for lower prices from plants on a unit-contingent basis. Physically, it gives capacity in case of outages from the transmission grid. They are located on the end of a 138 kV radial line and having local capacity for over half of their demand means that they can still provide power in the event of a major outage. Locating the power generation close to the load also improves the power quality.

The utility provides power to Heber City, other small cities nearby such as Midway and Charleston, and parts of Wasatch County. They are expanding their coverage as other municipal utilities ask to join in and have HL&P dispatch their equipment for them. HL&P is considering whether to install remote dispatch capability that will allow them to bring on plants in cities as far as 40 miles away based on the hourly price of power.

3.3 Customer site

The traditional use of DE is on end-user sites, such as hospitals and on college campuses. The owner/operator then uses the electricity and thermal energy for internal purposes. The owner may also sell excess electricity to the utility. Third parties may actually operate the equipment for the owner. Another arrangement that may prove more attractive to utilities would be for the customer-owned utility to sign an agreement to own and operate the equipment on the customer's site. The customer may only need the thermal energy, or they may have a reason for having on-site generation but not want to get into that business themselves. In this arrangement, the customer would receive the benefits of the electricity or thermal energy while the utility has more control of the operation of the DE for its own support. As the University of Mississippi example showed, in Sect. 2.2.1, it is also possible for a customer-owned facility to be operated by the local utility.

3.3.1 Example: Dairyland Power Cooperative

Dairyland Power Cooperative is a generation and transmission cooperative, providing power to 20 municipal utilities and 24 distribution cooperatives using a generation mix that includes 985 MW of coal-fired central-station power, 93 MW of combustion turbines, and 24 MW of hydroelectric power. Its peak demand for 2004 was 831 MW. The cooperative is also using distributed generation, with 17 MW of wind energy, 3 MW of landfill gas energy, and 0.75 MW of methane produced from cow manure (with three more dairy projects under construction). In the landfill gas and bio-gas projects, DPC has contracted with other companies to transform the renewable waste products into combustible gas. In both locations, DPC owns and operates the generator and feeds the power into its wholesale grid. In the dairy projects, the waste heat from the reciprocating engines is used locally at the farms, further improving the system efficiency (Dairyland Power, 2005 and Environmental Power, 2005).

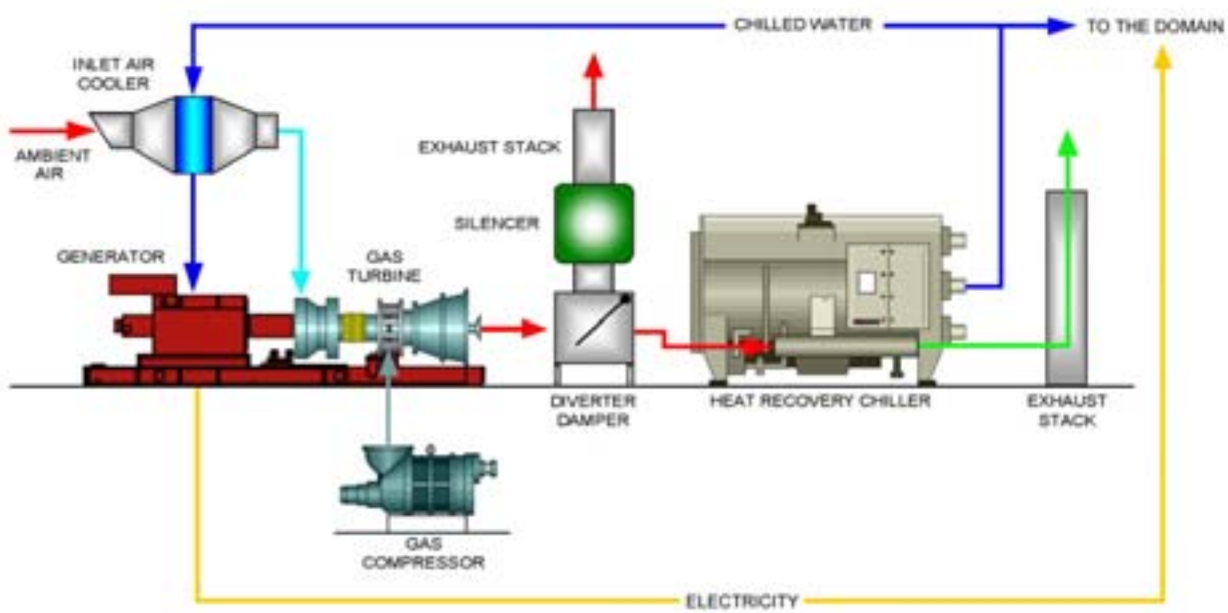
3.3.2 Example: Austin Energy

Austin Energy, the municipal utility in Austin Texas, was included in the study of successful publicly-owned utilities for demand-side management (DSM) described in Section 4.1. They have continued their pioneering ways, and recently added a DE project to a major development within the city. This project was jointly sponsored by the city and the Department of Energy's Office of Distributed Energy. The city and Oak Ridge National Laboratory engaged Burns &

McDonnell to develop, install, and test a modular distributed energy system at the Domain in Austin, a multi-use complex that includes retail, residential, and industrial space. The project has received several awards, including an Engineering Excellence Award from the Texas Council of Engineering Companies. (Berry 2005)

The system has been shown to be highly efficient, with up to 80% of the energy input being used to make electricity or chilled water for the complex. It includes a 4.5 MW turbine-generator and 2500-ton absorption chiller, with an inlet air cooler, gas compressor, and controls to optimize efficiency (Figure 5). Another key aspect of the project is that it incorporates a modular design. Each major component was shipped from the manufacturer already assembled, which eased construction and lowered cost. The project has been so successful that Austin Energy is installing a second CHP system to provide electricity and chilled water, as described previously, to the Dell Children's Hospital, also located in Austin, TX.

Figure 5. Integrated Energy System Includes Natural Gas Turbine And Heat Recovery Chiller.



Because of the utility ownership, many logistical and permitting issues were eased. The power from the generator feeds a micro-grid for the entire complex, as does the chilled water. Typically, DE owners have great difficulty selling the power to other entities except the local utility because of the franchise agreement that only lets the utility sell power. Secondly, in Texas utilities can get emissions credit for the savings in thermal energy that a CHP provides. If the project only generated electricity, then the facility's NO_X emissions would be above the limits set in regulations, but by including the energy savings from CHP, the overall emissions rate is within the regulations. Municipal ownership of DE becomes a win-win as the utility can generate more power within its borders while energy is saved and emissions reduced.

4. Possible Target Markets

The customer-owned utility market is a broad array of entities, from tiny townships to large cities, from distribution-only grids to large, integrated power, gas and water utilities. As discussed above, some of DE's advantages may only apply to some customer-owned utilities, while others may find that DE is not a good match for their system. Below are some possible ways to evaluate the customer-owned utility market to determine those customer-owned utilities that may be more likely to be interested in deploying DE.

4.1 Attributes of success from DSM Study

DE requires a utility to look at ideas beyond the traditional generation and distribution methodology, similar to evaluations of DSM. The 1994 DSM study at customer-owned utilities (Flanigan and Hadley 1994) has relevant insights into what factors are most likely to lead to successful implementation. The study included case studies of five government-run customer-owned utilities: the City of Austin (TX), Burlington Electric Department (VT), Sacramento Municipal Utility District (CA), Seattle City Light (WA), and Waverly Light and Power (IA).

Seven characteristics were identified as contributing to the success of the utilities. These are (in no particular order): 1) high power rates, 2) other economic factors, 3) heightened environmental awareness, 4) state emphasis on IRP/DSM, 5) local political support, 6) large-sized utilities, and 7) presence of a champion (Table 2). (The characteristic labeled other economic factors includes supply-side crisis, high avoided costs, or expected capacity shortfall.)

Table 2. Attributes of DSM Success.

	Austin	*Burlington*	*Sacramento*	*Seattle*	*Waverly*
High Rates	○	●	◒	○	◒
Other Economic Factors	●	●	●	○	●
Environmental Awareness	●	●	○	●	○
State Emphasis on IRP/DSM	○	◒	●	●	◒
Local Political Support	●	●	●	●	●
Large-sized Utilities	●	◒	●	●	○
Presence of a Champion	●	◒	●	●	●

True = ● Partly True = ◒ Not True = ○

Only one of the seven factors, local political support, applied to every utility, but each of the utilities met at least four of the conditions identified. Some of the factors, such as a supply-side crisis or champion, were important in the initiation of the programs, but once the programs were institutionalized other factors became more important. Of the utilities studied, three are among the twenty largest customer-owned utilities in the country, while Burlington is at the 90th percentile and Waverly at the 70th. Smaller utilities generally do not have sufficient staff to devote at least one full-time person to DSM unless some of the other factors influence their staffing.

4.2 Customer-owned utilities with peak demand between 5 MW and 125 MW

Instead of segmenting the customer-owned utility market by retail revenue (as above), it is also possible to segment the market by peak demand. Robert Webster, a DE developer, identifies the utilities with demands between 5 MW and 125 MW as an untapped market (Webster 2005). Customer-owned utilities smaller than 5 MW are likely to be too small to have the infrastructure needed for operation of DE. Utilities above 125 MW may think individual DE projects are too small to have much impact on their overall operations or else have their own staffs for examining and exploiting DE possibilities. Utilities between these two amounts are small enough that a DE project could have a significant influence on their overall peak yet large enough that they could incorporate DE into their operations. At the same time, their personnel resources are such that they may not have considered going beyond the traditional distribution mode of operation.

For customer-owned utilities of this size, government-run customer-owned utilities are more likely to have some of their own generation already. Only 9% of cooperatives of all sizes operated any generation in 2003 (Figure 6), while the government-run utilities all had higher percentages. Fully 96% of cooperatives in this size category had no generation, while only 71% of government-run utilities had none (Table 3).

Figure 6. Percentage of Customer-Owned Utilities that Generate, by Retail Revenue and Type (%)

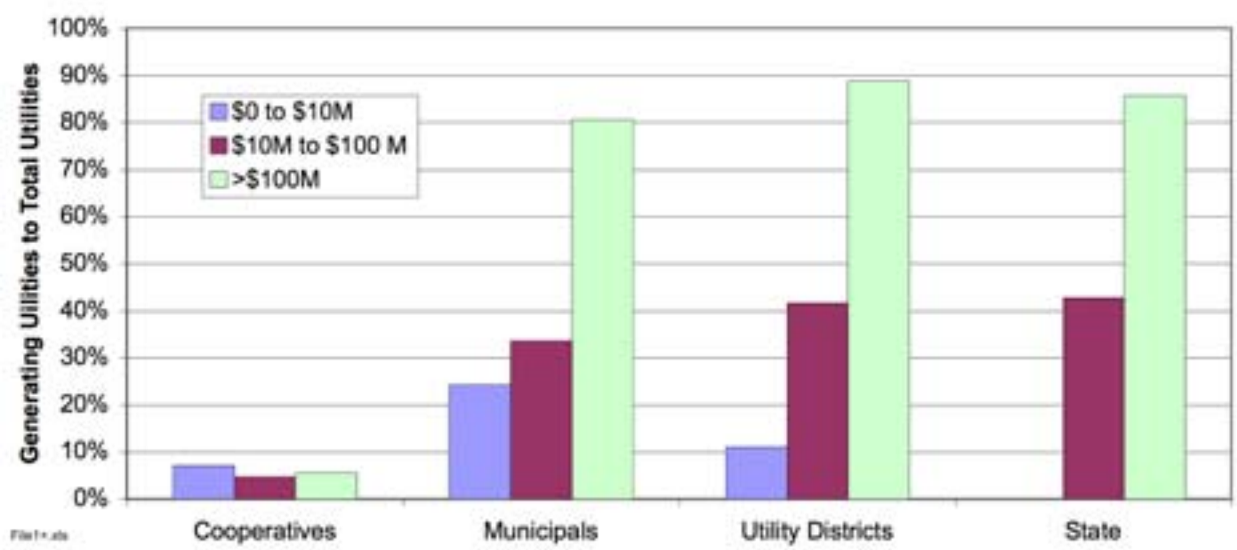


Table 3. Number and Percentage of Customer-Owned Utilities (between 5 MW and 125 MW) Aggregated by the Ratio of Self-Generation to Total Supply

	Cooperatives (number)	*Cooperatives (percent)*	*Govt-Run (number)*	*Govt-Run (percent)*
0%	581	96%	819	71%
0% - 10%	15	2%	247	21%
10% - 20%	2	0%	21	2%
20% - 50%	1	0%	29	3%
50% - 80%	0	0%	17	1%
80% – 90%	0	0%	7	1%
90% - 100%	5	1%	16	1%

4.3 Customer-owned utilities with waste fuel supplies

Very few customer-owned utilities generate electricity using waste fuels (municipal solid waste, landfill gas, other biomass gas, waste wood). However, all communities face issues of solid waste disposal and wastewater treatment. By using modern technologies for recovering landfill gases, collecting methane from wastewater digesters, or cleanly burning municipal solid waste, customer-owned utilities can both remove a waste stream from the environment and have a fuel for producing electricity. The amount of fuel may be small in the smaller communities, but the amounts are in line with some of the smaller DE technologies such as internal combustion (IC) engines or microturbines. Alternatively, multiple customer-owned utilities can band together to create a larger waste treatment/generator site, such as the Southeastern Public Service Authority (SPSA) of Virginia. It is a consortium of eight municipalities in the state that was organized in 1976, initially for water supply and regional solid waste disposal was added (SPSA 2005).

Despite the current lack of facilities using waste fuels, the future potential may be significant. The Environmental Protection Agency (EPA) has evaluated the potential landfill methane generation sites across the U.S. They found that, "As of December 2004, approximately 380 landfill gas energy projects were operational in the United States. These 380 projects generate approximately 9 billion kilowatt-hours of electricity per year and deliver 200 million cubic feet per day of landfill gas to direct-use applications. EPA estimates that more than 600 other landfills present attractive opportunities for project development." Table 4 provides a summary of the potential methane projects derived from the EPA database.(U.S. EPA, 2005)

Table 4. Summary EPA Landfill Methane Database

Status	*U.S. Capacity (MW)*
Operational	1428
Shutdown	234
Construction	124
Candidate*	742
Potential*	364
Sum: Candidate and Potential	1106

*Note: Candidate sites meet criteria including landfills with a minimum amount of waste in place (1 million tons) and within 5 years of closure. Potential sites do not meet these criteria but have the potential to over time.

4.4 Customer-owned utilities with other municipal functions

Although customer-owned utilities are owned by their customers, not all of them are associated with other government functions. The utility district may be a stand-alone entity rather than part of the municipal government. However, those customer-owned utilities that are a part of a larger organization may have a greater need for generation and also an opportunity to use the waste heat. A focus should be placed on those utilities that are connected to a local government that also maintains the other public facilities in the area, such as schools, hospitals, and emergency services. These provide ready locations for DE and have a higher need for locally generated power.

4.5 Customer-owned utilities with high marginal distribution system capital costs; statistical trends

Other factors being equal, a DE project that defers necessary expansions and upgrades to the distribution system in locations where these avoided costs are relatively high will be more attractive to a municipal utility. Although each investment must be individually evaluated, utility characteristics of past distribution expenditures help provide a basis for focus.

Data for 177 municipal utilities were examined to determine the likely impact of DE on avoided distribution system costs.[3] The End of Year Balance (EOYB) for the distribution system accounts and total retail power sales for each municipal utility were used to characterize the utility investments in their distribution systems. Figure 7 shows that these utilities sold about 100 to 450 GWh/year during 1995 and 2003. Most of the utilities increased their power sales over this eight-year time period, but 11 utilities showed a decrease in sales. Figure 7 also provides a comparison of average embedded distribution system investments, taken from the EOYB and normalized by the retail power sales, in 1995 and 2003. Only three of the utilities showed a decrease in their EOYB over this eight year time period. The minimum distribution system costs in 1995 and 2003 were less than $5/MWh.

Figure 7 and the underlying data suggest two interesting points. First, the average incremental cost for the distribution assets purchased over that eight-year period to serve the increased load was about twice the average embedded cost in 2003. This reflects the increase from embedded costs (total distribution assets) to average marginal costs for distribution assets for the period 1995 to 2003. Second, these municipal utilities have a wide spread of incremental net distribution expenditures. The range is from less than $20 per MWh to over $500. The municipal utilities with higher incremental distribution costs may be good targets for DE because of higher deferred capital costs.

In order to explore this issue, a regression analysis was performed. The details of the analysis are shown in Appendix A.

[3] PowerDat and/or Energy Velocity databases, which have been derived from publicly available Electric Information Administration (EIA) and Federal Energy Regulatory Commission electric utility data bases

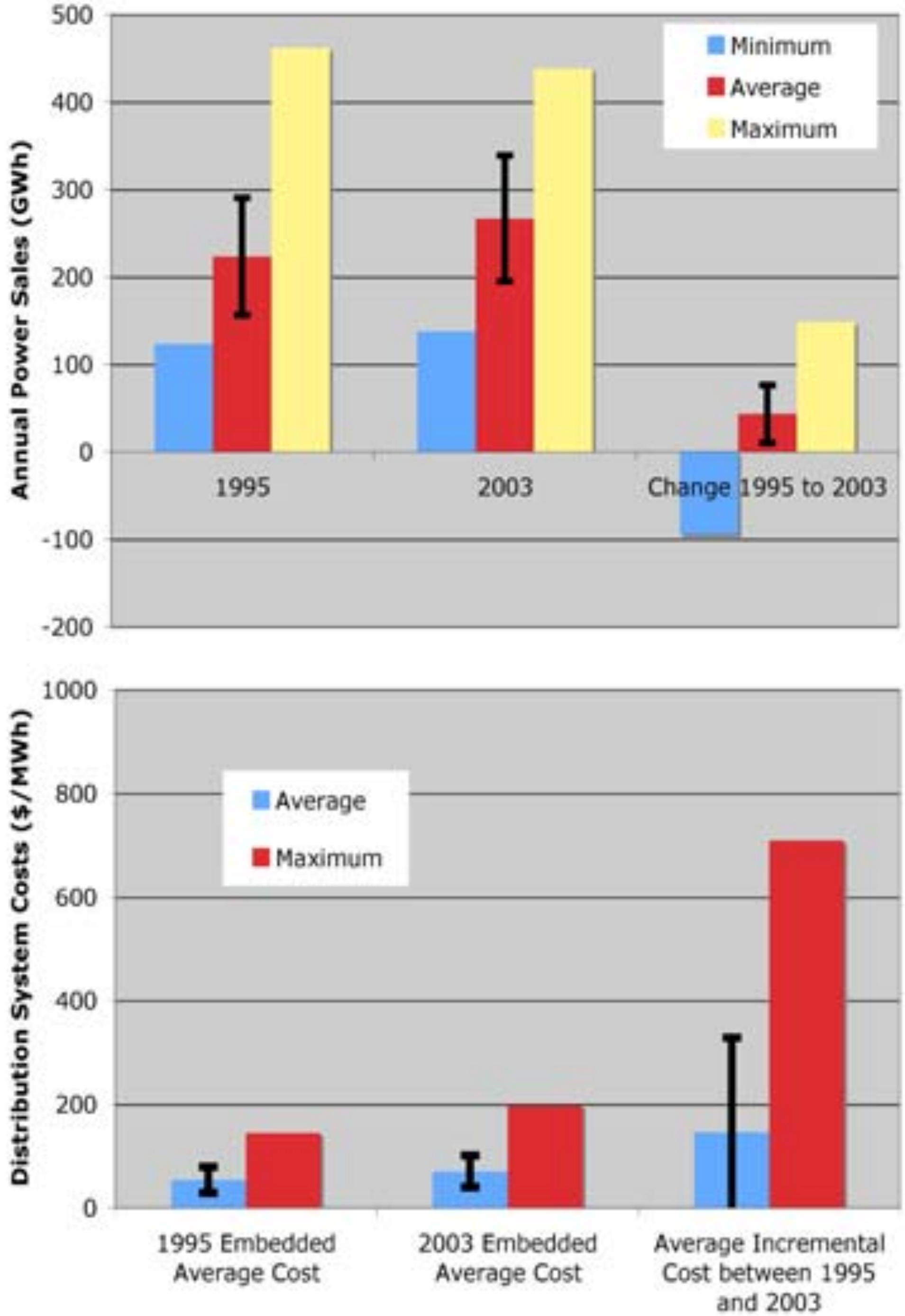
Several conclusions can be drawn from the analysis:

- Slower growth in demand leads to greater deferred investments and consequently higher benefits for DE projects. Supporting this result, it is recognized that the lumpy nature of distribution system investments tends to produce low utilization factors for capacity increases in regions with slow demand growth.

- The more costly the existing system, as indicated by the embedded costs, the more costly the incremental costs.

- The faster the growth in distribution system investment, the greater the cost of those investments.

Figure 7. A Comparison Of Embedded And Incremental Distribution Costs For 177 Municipal Utilities.



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5. Customer-Owned Utility Characteristics

5.1 All types of utilities

The Energy Information Administration (EIA) collects annual information on utilities using the EIA-861 form (EIA 2005). In this, they separate utilities into eight different categories. Table 5 shows some of the key data about each type:

Table 5. Types Of Utilities In The U.S. And 2003 Revenue (EIA 2005)

	Number of Utilities	*Total Revenue G$*	*Retail Revenue G$*	*Percent of Retail Revenue*	*Median size, Total Revenue M$*	*Median size, Retail Revenue M$*
Cooperative	885	38	24	9%	19.1	15.6
Municipal	1846	30	27	10%	2.7	2.6
Political Subdivision	124	10	6	2%	11.5	5.4
Muni Market Authority	19	4	0	0%	117.0	0.0
State	26	14	11	4%	71.0	13.5
Private	223	207	168	64%	335.8	197.6
Power Marketer	150	184	24	9%	97.6	11.3
Federal	9	12	1	0%	91.6	16.3
Total	3,282	499	260	100%		

Total revenue includes electricity sales to consumers, charges for distribution of electricity that is purchased from others, electricity sold to other utilities for resale, adjustments from previous years, and other revenue such as wheeling charges and connection fees. Summing total revenues to find the total size of the market would double-count those electric sales to other utilities that are in turn sold to consumer. What we call "retail revenue" includes the retail sale of electricity plus the revenue from delivery of electricity sold by third parties. In many parts of the country, consumers can purchase electricity from a company other than their local utility and only pay the utility for using its distribution system. Combining these two categories gives a good representation of the utility's interaction with retail consumers, those most likely to use distributed energy resources.

Privately-owned utilities are by far the largest provider of electricity to retail customers, both in terms of percentage of total amounts and in the typical size of the utility. In terms of retail revenue, municipal utilities have the second largest percentage of the market. However, since there are so many more municipal utilities, their typical size is very small. The median utility (half are larger, half are smaller) has annual revenue of only \$2.6 million. Considering total revenue, the difference between utility types is even more pronounced. The median private utility has \$336 million in total revenues, while municipal utilities' revenues only increase to \$2.7 million.

The American Public Power Association (APPA), the service organization for publicly-owned utilities, describes the governance of public power as "governed by their consumer-owners through locally elected or appointed officials. In a few states, public power systems are regulated by state utility commissions. Some public power communities vest authority in their local city governing body – such as a city council – to guide the utility. Others have independent elected or appointed utility boards." (APPA 2005) These officials are those that would need to approve any major investment such as DE.

Some of the other types of utilities are similar to municipals. Political subdivisions other than municipalities may have different boundaries from the local municipality and are likely to be organized solely to provide electricity. Examples include public power districts or irrigation districts. These are typically larger and are mainly in the far western states and Nebraska. Municipal market authorities are generally consortiums of municipal utilities that have banded together to develop larger central power stations. They then sell their power to the municipals (hence the lack of retail revenues). State authorities both generate and sell power to other utilities and directly to retail customers. Some of the largest are in New York, California, and Texas. State authorities also include the territorial utilities for Puerto Rico, Guam, and Virgin Islands.

According to the National Rural Electric Cooperative Association (NRECA), electric cooperatives are:

- Private independent electric utility businesses;
- Owned by the consumers they serve; incorporated under the laws of the states in which they operate;
- Established to provide at-cost electric service; and
- Governed by a board of directors elected from the membership, which sets policies and procedures that are implemented by the cooperatives' professional staff.

There are two types of cooperatives: distribution cooperatives that deliver electricity to the consumer and generation and transmission cooperatives that generate and transmit electricity to distribution co-ops. (NRECA 2005a) Cooperatives were formed in the 1930's in rural regions through the Rural Electrification Act of 1936 because of the lack of private investment in their territories (Basin Electric 2005).

Federal utilities include the Tennessee Valley Authority and Bonneville Power Authority, among others. These mainly provide power through resale to municipals and other publicly-owned utilities with their retail sales to large industrials in their territories.

5.2 Size distribution of customer-owned utilities

While most municipals are small, their size distribution is quite scattered. Of the 2015 utilities (including municipals and other political subdivisions) over one-fourth have less than $1 million in retail revenues and over one-half have less than $5 million (Table 6). Combining the last four categories, there are 60 of these utilities that sell only on the wholesale market to other utilities so have no retail revenues. However, because the wholesale utilities are owned by a consortium of small utilities, they may yet be interested in distributed energy despite their lack of retail sales.

For example, the North Carolina Eastern Municipal Power Agency sells all power to municipals in the state but also funds significant amounts of demand-side management.

Cooperatives are somewhat larger on average than other customer-owned utilities, with a median retail revenue of $15.6 million (Table 5). However, there are no very large cooperatives. The largest, Jackson Electric Member Corp. of Georgia, has $287 million of revenue, but is smaller than 20 other customer-owned utilities.

Table 6: Number Of Customer-Owned Utilities Grouped By 2003 Retail Revenue.

Retail Revenue M$	***Cooperative***	***Municipal***	***Political Subdivision***	***Municipal Market Authority***	***State***	***Total COU***
0	57	5	25	19	11	117
0–1	14	514	13	0	0	541
1–2	20	282	9	0	1	312
2–5	72	378	14	0	0	464
5–7	60	126	12	0	0	198
7–10	85	107	6	0	0	198
10–20	209	185	14	0	3	411
20–50	248	160	18	0	2	428
50–70	51	28	2	0	1	82
70–100	33	25	2	0	1	61
100–200	25	20	3	0	2	50
200–500	11	9	4	0	1	25
500–700	0	2	0	0	0	2
700–1,000	0	3	1	0	1	5
1,000–2,000	0	1	1	0	0	2
2,000–5,000	0	1	0	0	3	4
All Utilities	885	1846	124	19	26	2900

There are some large utilities in this mix: 88 customer-owned utilities have retail revenues over $100 million. The six largest, with annual retail revenue over $1 billion each, represent almost one third of all retail revenues. The top twenty customer-owned utilities have over half of all revenues. However, with cumulative revenues over $40 billion, that still leaves over $20 billion in revenues from all of the smaller entities.

5.3 Location of customer-owned utilities

The customer-owned utilities are scattered across the country, with a large proportion in the Midwest and South (Figure 8). However, when considering the relative size of the utilities, we find large retail sales volumes in California, New York, Texas, Tennessee, Washington, Arizona, and Florida (Figure 9).

Figure 8. Customer-Owned Utilities In Contiguous US

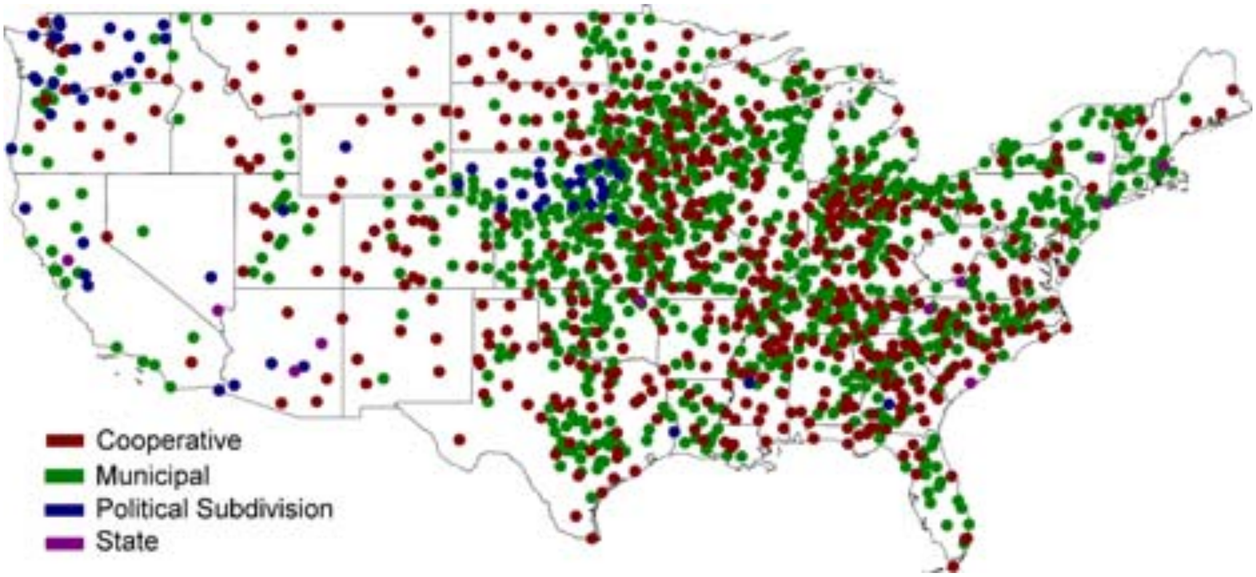
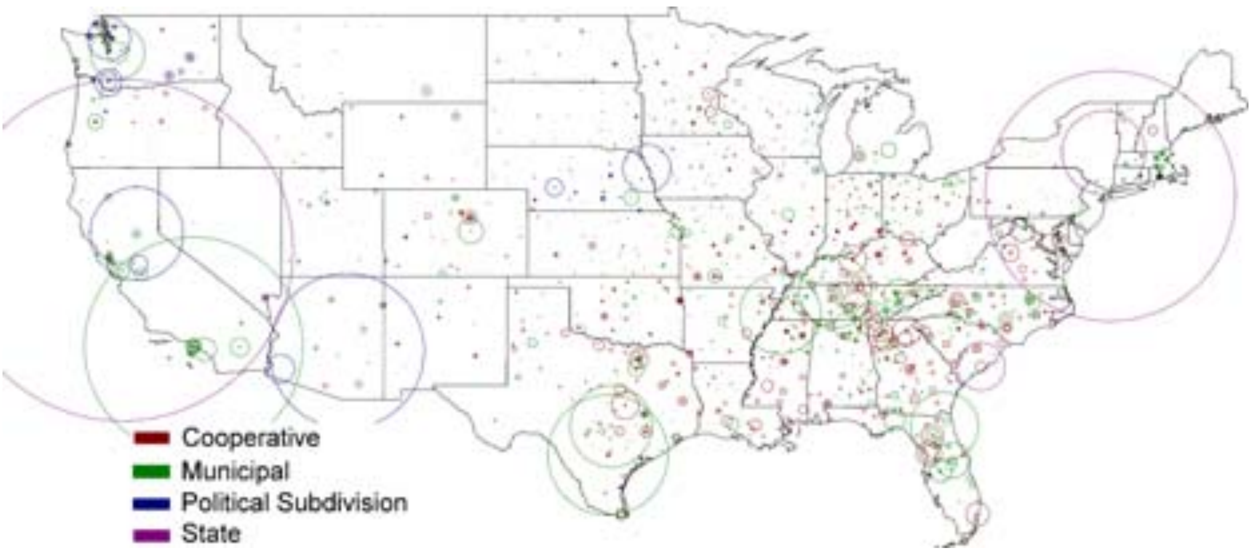


Figure 9. Customer-Owned Utilities In Contiguous US With Markers Showing Relative Size Of Retail Revenue.

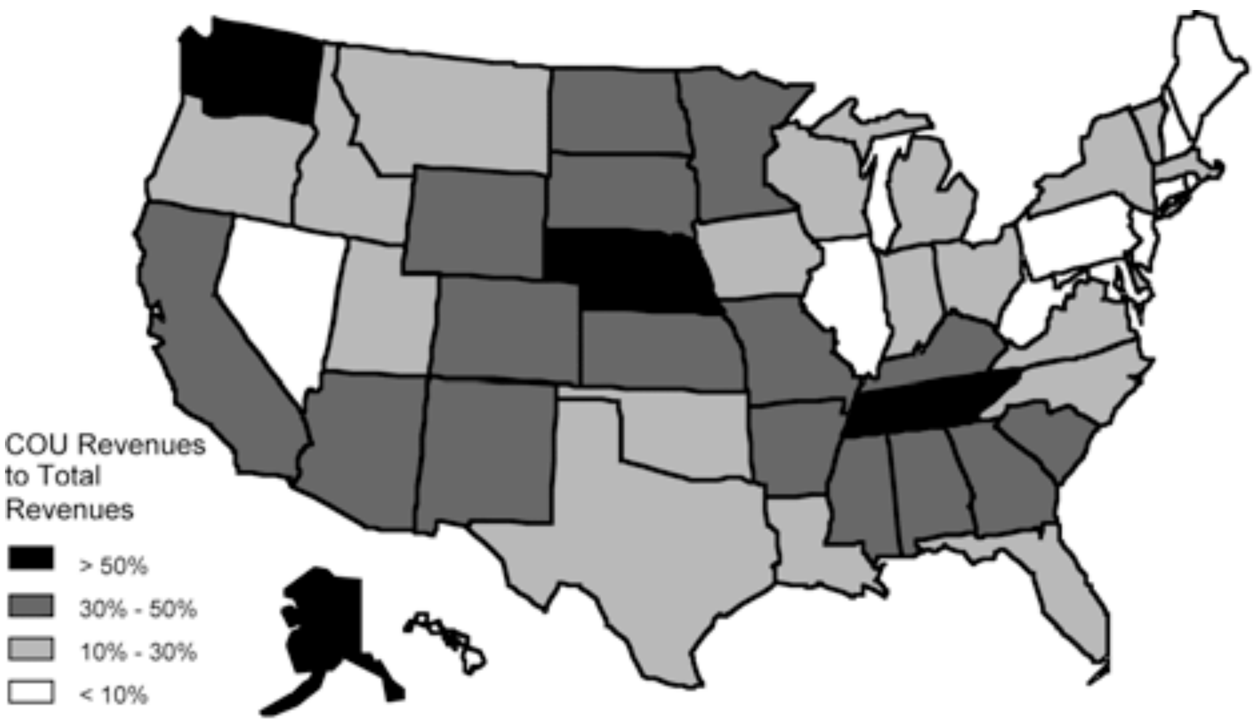


The largest, called the Electric Power Fund of the California Department of Water Resources, is actually a state-run department that is large because of the California restructuring fiasco. The department normally buys power mainly for water pumping but was recently tasked with buying much of the power in the state because of the bankruptcies and contract problems that the private firms had in 2000-2002. This new power is bought on contracts signed by the state and sold to customers of private utilities. Because of the difference between its normal power purchase and the specific purchases on behalf of investor-owned utilities, the latter is identified as a separate entity in the database. The other two large municipals in California are the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District.

New York's largest publicly-owned utility is the Long Island Power Authority. This entity was formed to take over the Long Island Lighting Company that was faced with large costs for the abandoned Shoreham nuclear plant. The other large utility there is the New York Power Authority, which provides power to other customer-owned utilities as well as private companies. Texas has two cities with large municipal utilities: San Antonio and Austin. Tennessee has a number of relatively large municipals, purchasing their power from TVA.

When compared to total retail revenue, customer-owned utilities make up a fairly high percentage of sales. In many states, they provide between 30% and 50% of the power sold (Figure 10). Nebraska has the highest percentage from customer-owned utilities at 100% (no private or federal utilities) while Tennessee is 94%. Ninety percent of Alaska's power comes from customer-owned utilities and 57% of Washington's.

Figure 10. Ratio of Retail Revenues from Customer-Owned Utilities to Total Retail Revenues by State

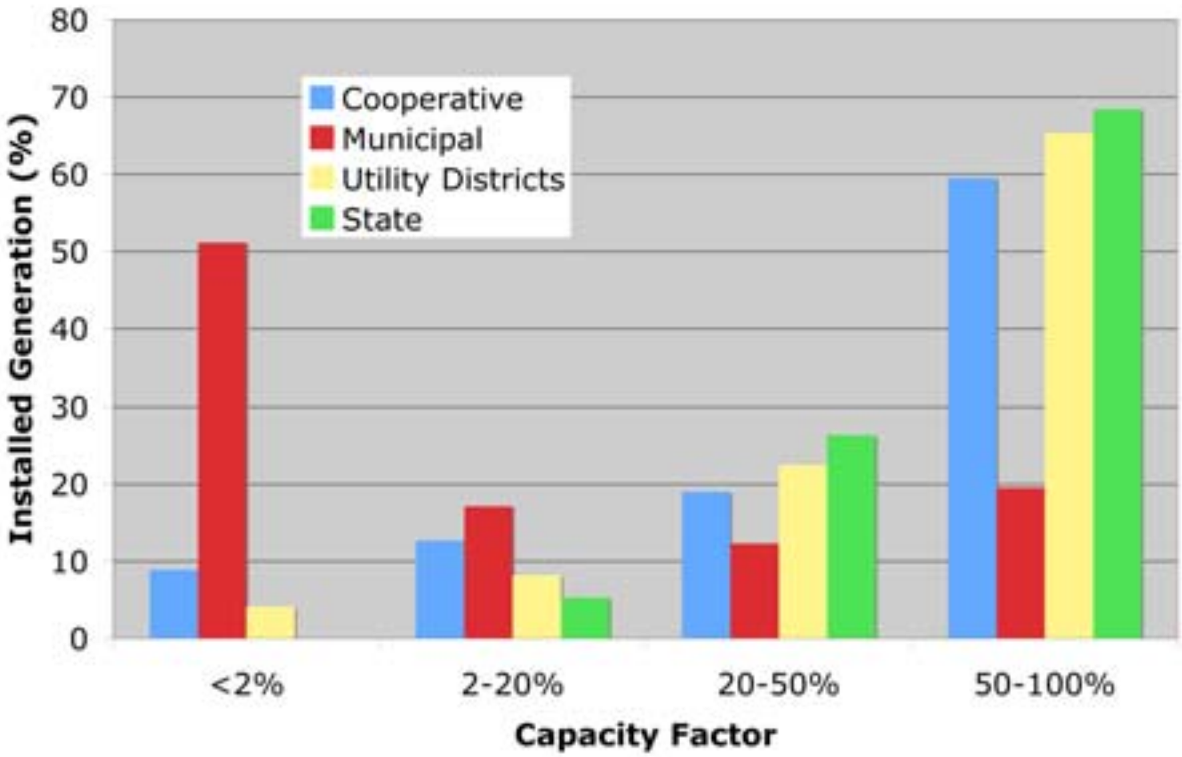


5.4 Generating customer-owned utilities

Most of the customer-owned utilities purchase their power from elsewhere, but some generate power as well. Overall, 28% of municipals, 40% of other political subdivisions, and 9% of cooperatives generate power. As shown in Figure 6, the smaller utilities are less likely to generate. Besides these utilities, a large number of the utilities band together to generate power from the municipal market authorities in their respective regions. These larger agencies, while only selling to utilities, may be involved in end-user energy efficiency projects such as demand side management. Even federal agencies that sell their power to customer-owned utilities, such as the Tennessee Valley Authority (TVA) or Bonneville Power Authority, may provide DSM programs as well. They may be interested in creating DE projects to strengthen their grid.

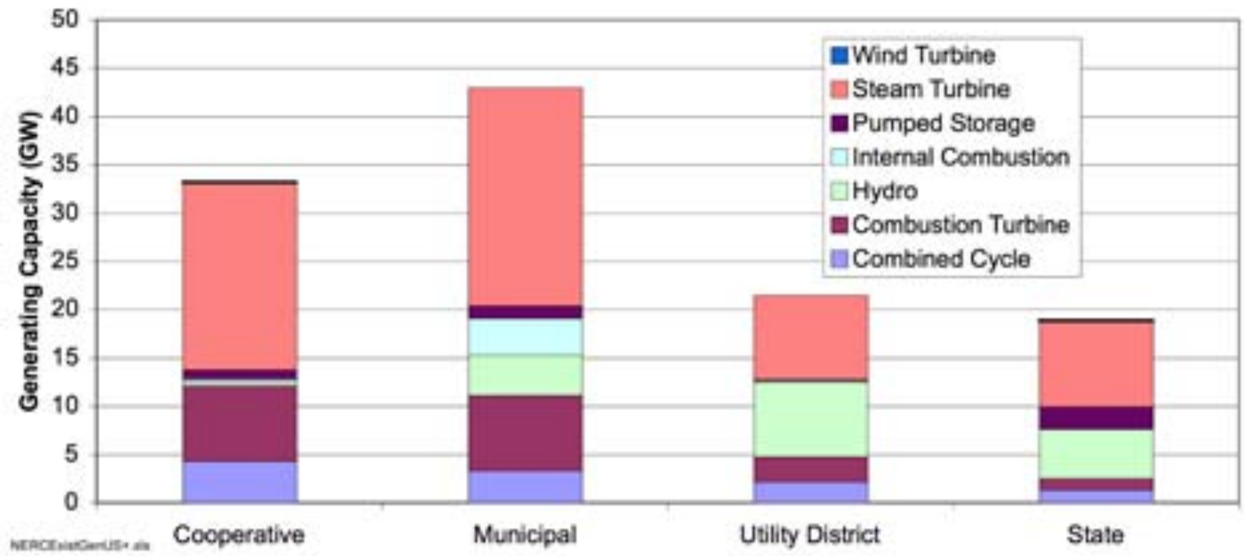
Even for those customer-owned utilities that do generate, the amount is generally just a fraction of their overall needs, with the rest coming from purchases. Figure 11 shows that over half the municipal utilities with generating assets have capacity factors less than 2%. (The capacity factor is the ratio of the power generated divided by the amount of electricity that could have been generated if the plant were run 365 days per year at full capacity.) These smaller utilities may be using self-generation as a peak-shaving option or for emergency back-up, a clear opportunity for distributed generation. Larger utilities, such as utility districts and state agencies, are more likely to use their generation assets to provide base-load power, with about two thirds of these categories showing capacity factors between 50 and 100%.

Figure 11 Capacity Factors by Customer-Owned Utility Category



The North American Electric Reliability Council (NERC) releases data on existing and planned generators in their Electricity Supply and Demand Database (NERC 2005). Combining that information with the EIA database, we can find the amount of installed capacity for each generation type owned by customer-owned utilities (Figure 12).

Figure 12. Total Capacity of Generation by Prime Mover and Customer-Owned Utility Category



Most of the generation capacity for cooperatives is from steam turbines, followed by combustion turbines and combined cycle plants. They have relatively little hydro and internal combustion capacity. Municipals also have a large amount of the fossil-fired turbine plants, but also a significant quantity of IC engines and hydroelectric capacity. Other political subdivisions and state-owned utilities also have high levels of hydro capacity. Many of these were initially created to manage hydro resources within a region or state.

The capacity that utilities own may be larger equipment dedicated to power generation, used as cogeneration at facilities that can use both electricity and steam, or smaller sites where it qualifies as distributed generation in the NERC database. Among all electricity producers, including utilities and non-utilities, 92% of capacity is central generation for electricity only and 7.5% is for cogeneration or distributed generation (Table 7). Among customer-owned utilities, the ratio is even more heavily weighted towards central generation. Proportionately, there appears to have been less DE development in the customer-owned utilities than in the rest of the utility industry, perhaps indicating an untapped market for DE in this sector.

Table 7. Capacity from Central vs. Distributed Generation (MW)

	Cooperative		*Municipal*		*Political Sub-division*		*State*		*All Generators*	
	MW	%	MW	%	MW	%	MW	%	MW	%
Central Generator	33,128	100%	42,027	98%	21,120	98%	18,889	100%	912,392	92%
Distributed or Cogenerator	77	0.2%	933	2.2%	385	1.8%	0	0%	73,583	7.5%

Waste products can be a significant source of primary fuel for generators. Waste materials can include landfill gas, municipal solid waste, other biomass gases (such as from wastewater treatment digesters), or wood wastes. While many of the waste sites are owned by public bodies, other sites (or the power facilities on them) are owned and/or operated by private entities (Table 8). Besides private firms, a large number of these waste-fired facilities are operated by cities or other public entities that do not sell power on a retail basis. Rather, they generate the power for sale to the local utility or for internal use only. Examples are the Little Rock Wastewater Utility with three 0.5 MW IC engines running off of biomass gas or the Southeastern Public Service Authority (of VA) that operates three 20 MW municipal solid waste-fired steam-turbine facilities.

Table 8. Waste-fuel Power Plant Capacities by Owner Type (MW)

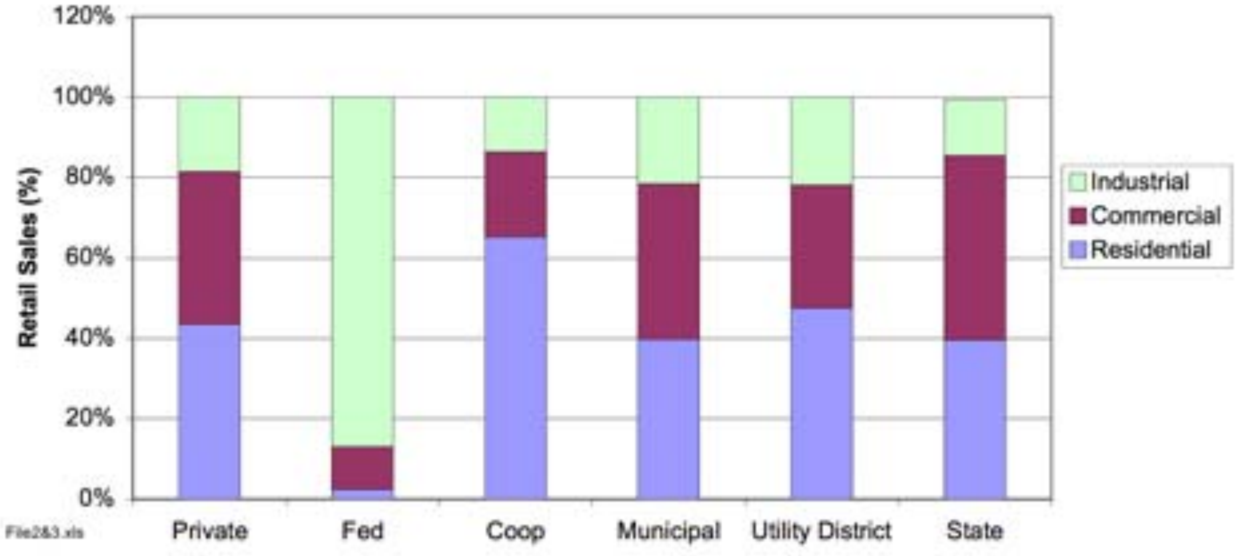
	Private	*Cooperative*	*Public COU*	*Public Non-Utility*
Municipal Solid Waste	2,083	39	102	547
Landfill Gas	762	4	27	129
Other Biomass Gases	36	0	16	82
Wood/Wood Waste	2,285	0	102	55

Overall, there are very few customer-owned utilities currently using waste fuels. Only two cooperatives and twelve government customer-owned utilities are included in the list of generators. The low number of customer-owned utilities using waste fuel may mean there is an untapped source of waste fuel for DE that could be exploited.

5.5 Proportions of customer types

Cooperatives serve proportionately more residential customers than private utilities, but the other customer-owned utilities have similar splits between residential, commercial, and industrial consumers (Figure 13). This reflects the rural nature of much of the cooperatives' customer base. Federal utilities' end-use sales are dominated by industrial sales because most of their sales are wholesale, to other utilities. A high proportion of residential customers may make DE less attractive to cooperatives since most individual residential customers have relatively small loads with a high ratio of peak to average demand. However, there may still be opportunities on their remaining loads or through aggregation of residential demands.

Figure 13. Proportion of Total Retail Sales by Customer Type for Each Utility Type



The NRECA organization points out an additional issue that cooperatives face regarding the density of their customer base (NRECA 2005). While private utilities have 35 customers per mile of distribution, and municipals have 47, cooperatives on average have only 7 customers per mile (Table 9). Small DE that provides power for single customers may be very applicable in cooperative districts, because the costs associated with distribution infrastructure are higher. DE may lessen the need for investment in distribution upgrades.

Table 9. Electric Utility Comparisons (Source: NRECA 2005)

	Investor-Owned	*Publicly Owned*	*Cooperatives*	
				Total
Miles of Distribution Line	50%	7%	43%	100%
Assets (billions)	$616	$154	$86	$856
Equity (billions)	$181	$50	$26	$257
				Average
Customers per mile of line (density)	35	47	7	33.9
Revenue per mile of line	$62,665	$86,302	$10,565	$60,827
Distribution plant per Customer	$2,229	$2,309	$2,845	$2,362

5.6 Combined electric and gas utilities

The customer-owned utilities that distribute both gas and electricity already are more likely candidates for DE because they have access to the lower cost gas that a distributor receives. This would reduce the resulting cost of distributed electricity and make it more likely to be economic. Conversely, those utilities that do not sell gas would see a net reduction in energy sales if customers purchase the gas for the DE from some other entity. This could be less of a problem if the utility owns the DE and purchases the gas. By aggregating the purchase for multiple DE projects in their territory, they may be able to get access to lower cost gas than individual customers.

Many of the government-run customer-owned utilities do have a separate gas distribution function. The EIA has a listing from the respondents to the EIA Form-176 that includes 884 municipal gas utilities (EIA 2005b). However, of these 884 municipals, only 313 are municipals that also provide electric service; the rest are towns or cities that receive their electricity from other entities. Gas cooperatives are much rarer; the EIA-176 database only lists twelve gas cooperatives and of these, only four are also electric cooperatives. Those areas that are not provided natural gas service by their municipality or cooperative either may be served by private gas firms or not have gas service, only using propane instead.

Utilities that use diesel generators for their DE do not need to be concerned with access to natural gas. Diesel IC engines are in more widespread use as small generators because of their low initial cost, reliability, and availability of fuel. However, diesel IC engines typically have higher emissions than natural gas-fired engines or turbines. In many parts of the country, this limits the amount of time that they can operate to less than 200 hours per year due to permitting issues. This makes them less attractive as a peak-shaving option since they can only run a maximum of 2.2% of the time. In fact, some permits restrict the diesel engine use to short tests and back-up service, so that they are not available for peak-shaving in any case.

5.7 Demand-side management activities

Demand-side management programs are utility programs that provide information and incentives to customers to reduce or shift their demands. These lower the need for additional capacity and can be cost-effective when compared to alternative supplies. In the 1980's and 1990's many utilities instituted these plans, often as a requirement from their public utility commissions. Similarly, a number of publicly-owned utilities implemented such programs in order to help their customers (Flanigan and Hadley 1994). While a fair number of these programs lost steam in the late 1990's and more recently, many utilities continue to offer them. The utilities that do so may also be more receptive to DE projects because of their familiarity with working with customers on smaller-scaled projects.

According to EIA's data (EIA 2005), there are a fair number of smaller utilities that provide DSM (Table 10). For cooperatives, it is more concentrated in the larger utilities, with 20% of those with over $10M in retail revenues having DSM programs, versus 10% of those <$10M. One interesting fact is that twelve cooperatives that have no retail sales (G&T cooperatives) fund DSM programs. The most active of these, Great River Energy in Minnesota, spent almost $15M on DSM in 2003.

Table 10. Number of Utilities with DSM Programs, by Size of Revenues

Retail Revenue M$	*Coop-erative*	*Municipal*	*Political Sub-division*	*State*
0	12	5*	1	
0 - 1		35	1	
1 - 2	2	25		
2 - 5	6	31	1	
5 - 7	2	7	2	
7 - 10	14	16		
10 - 20	39	12	1	1
20 - 50	43	21	7	
50 - 70	11	6	1	
70 - 100	11	6	1	
>100	11	19	6	3

* Municipal Market Authorities that resell to municipal utilities

Municipal utilities are a little less likely to have DSM programs than cooperatives: 8% of those with <$10M and 15% of those with >$10M in retail revenues. However, over a third of the other political subdivisions over a $10M in revenues have programs. The largest of these, Sacramento Municipal Utility District, spent over $21M in 2003 on DSM. It has long been active in DSM and was profiled in the Flanigan and Hadley report.

6. Summary and Conclusions

Consumer-owned utilities are a largely untapped potential market for DE technologies. There are significant advantages for these utilities in the deployment of DE, and there are fewer institutional hurdles in the form of private company profit goals or private property siting restrictions.

A COU-owned DE system may be located at a substation to provide peaking support, at a city-owned facility to provide both thermal energy and emergency back-up to a critical load, or at a customer site to meet thermal and reliability needs. A substation installation will typically have the lowest CHP potential, but its interface with the grid is typically simple. Such systems are sometimes temporary in nature, with the DE resource relocated to a new substation when the load on the original location has grown to the point where it makes more sense to increase the capacity of the substation itself. Customer and city-owned facility DE locations are more traditional, and hark back to the days of wide-spread district heating. These systems have the potential for much greater energy efficiency, but their operation is complicated by the need to serve both electrical and thermal demands. The integration of these systems into the grid may also be more complicated.

Some of the customer-owned utility characteristics that may indicate the more promising DE targets include peak demand greater than 5 MW, waste fuel supply availability, customer-owned utilities with other municipal functions, and customer-owned utilities with higher marginal distribution system costs. Customer-owned utilities already own more than 115 GW of generating capacity, but less than 2% of that is distributed generation and much of it is only used for peak-shaving and back-up purposes.

Based on this assessment, there are many customer-owned utilities with the resources and experience base necessary to add economically-beneficial DE to their generation portfolio. The data also show that this market may not have been explored to the same extent as the private utility market. Considering the many beneficial factors that may uniquely apply for municipal utilities, this sector would seem to be an appropriate target for a more detailed market analysis and for DE educational efforts.

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Appendix A: A Statistical Analysis of Marginal Distribution System Costs

First, all 177 utilities and five variables were tested as explanatory variables for the normalized average incremental distribution system costs. These explanatory variables included total EOYB account balance in 2003, annual growth rate of this variable from 1995 to 2003, annual growth rate of retail sales over the same period, embedded average of EOYB per MWh, and incremental revenue per MWh increase in retail sales over this period. For the estimated regression equation, these variables explained only about 15% (the r-squared statistic) of the utility to utility variation in normalized average incremental distribution system costs. Most of this variation can be explained by a one-variable model using embedded average EOYB.

A subset of this data was then defined to include only municipal utilities with annual retail sales growth rates between 1% and 3%. The overall range was from -2.8% to 8.9%. The elimination of higher and lower growth rates was done in order to facilitate a simple linear regression. Also, it's reasonable to expect that growing municipal utilities would be more likely to embrace DER because they must find some means to serve their growing increasing load. The data set used included 101 municipal utilities out of the original 177, as shown in Figure 14. For this group of medium growth utilities, 87% (r-squared) of the variation in the incremental EOYB per MWh was explained by an equation estimated from 3 variables and shown in Eq. 1. All variable coefficients had a level of statistical significance greater than the 99%.

$$\text{Average incremental investment} = 55 + 22X_1 - 90X_2 + 2.5X_3 \quad \text{(Eq. 1)}$$

Where:

Average incremental investment is the Change in EOYB/Change in Power Sales ($/MWh),

X_1 = Each 1% Average Annual Change in EOYB Distribution Value,

X_2 = Each 1% Average Annual Change in Retail Sales, and

X_3 = Each $1.00/per MWh of Embedded Distribution Capital Costs.

As single variable regressions, average embedded cost explained about 43% (r-squared) of the variation in normalized incremental costs, the growth rate in EOYB explains about 33% (r-squared) and the growth rate of sales explains about 13% (r-squared) of the variation in normalized incremental costs.

Several conclusions can be drawn from this analysis, as listed here and shown in Figure 15:

- The negative coefficient for the retail sales growth (X_2) suggests that slower growth in demand for distribution services leads to greater deferred investments and consequently higher benefits for DE projects. Also, the lumpy nature of distribution system investments tends to produce low utilization factors for capacity increases in such regions of slow demand growth.

- The more costly the existing system, as indicated by the embedded costs (X_3), the more costly the incremental costs.

- The faster the growth in distribution system investment (X_1), the greater the cost of those investments.

Figure 14 Trends Shown By Data Used For Regression Analysis Shown In Eq. 1

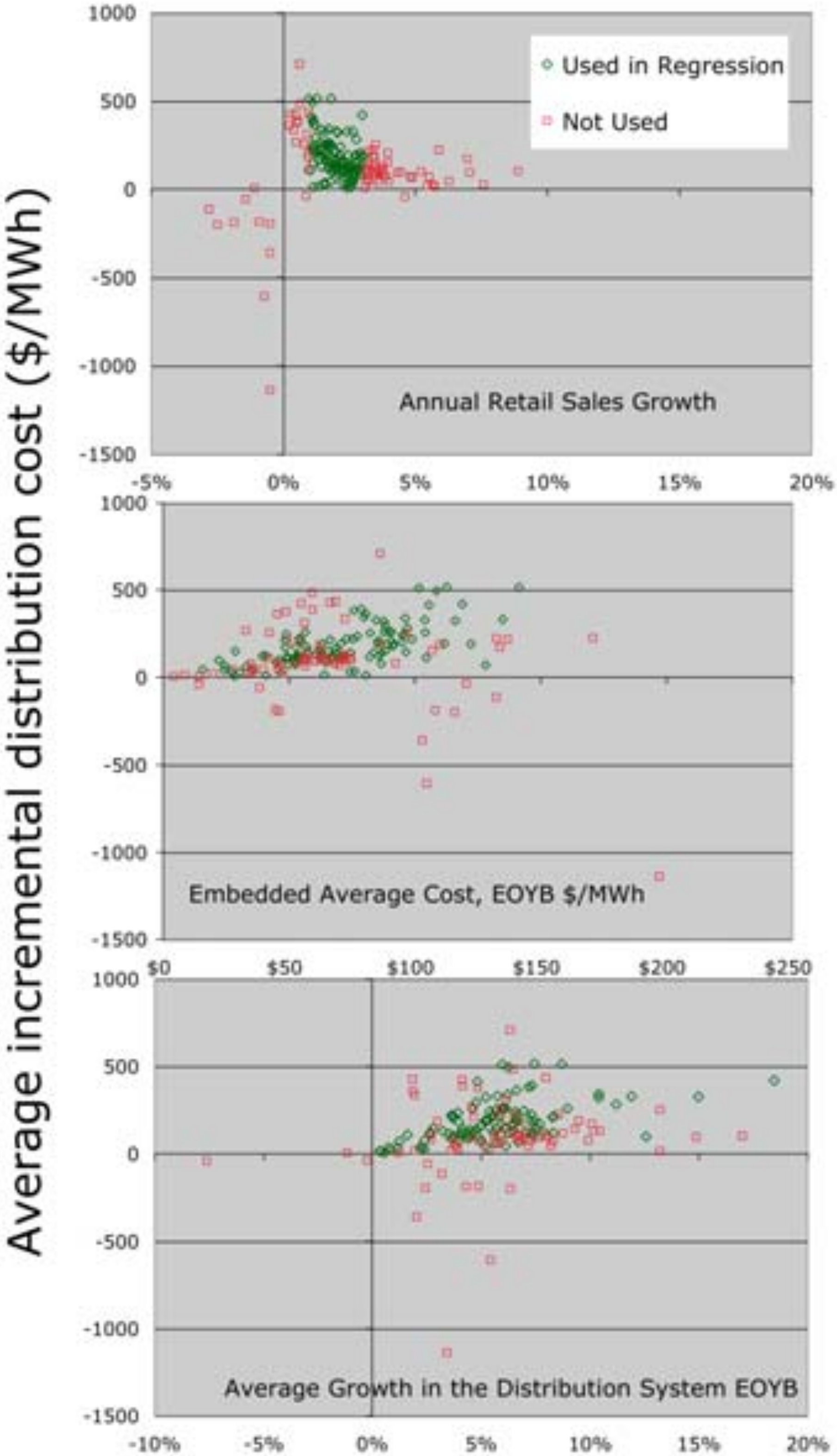

Figure 15 Predicted Incremental Distribution System Costs From Eq. 1