REPORT OF THE DISTRIBUTED ENERGY SUBGROUP OF THE NATURAL GAS DEMAND-SIDE MANAGEMENT ADVISORY GROUP

Presented to the Public Service Commission of Utah
Pursuant to the December 30, 2002
Order in Docket No. 02-057-02

June 1, 2004

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EXECUTIVE SUMMARY

Commission Order

This report is a presentation of the distributed energy and combined heat and power (CHP) component of the Natural Gas Demand-Side Management (DSM) Study commissioned under Section 6 of the DSM Stipulation and Settlement (Stipulation No. 3) approved by the Public Service Commission of Utah's (PSCU) December 30, 2002, order in Questar Gas Company's (QGC) rate case in Docket No. 02-057-02. Section 6 of Stipulation No. 3 states:

> "6. QGC and UEO will jointly fund a study of achievable, cost-effective gas DSM measures in Utah. Costs of this study will not exceed $50,000. The study will include information QGC will need to adequately evaluate DSM in its Sendout model for future IRP proceedings. The study will also specifically evaluate opportunities for gas-fired generation and combined heat and power; and will estimate the potential revenue impacts to QGC of implementing cost-effective DSM measures identified. The Study will be commenced after May 15, 2003, and be completed and presented to the Advisory Group and the Utah Public Service Commission no later than August 31, 2003."[1]

State Policy

Utah's energy policy calls for the development of new energy supplies sufficient to meet Utah's growing demand. Electricity generation from distributed generation technologies such as cogeneration and other distributed generation technologies are important potential sources of electricity supplies for Utah's ratepayers and economy. The Utah Legislature has declared that "[i]t is the policy of this state to encourage the development of small power production and cogeneration facilities,"

In Docket No. 02-057-02, the Utah Energy Office (UEO) testified that it considered gas-fueled on-site CHP systems to be a potential DSM technology. The UEO recommended that QGC actively promote and market CHP through a DSM initiative.

DSM Advisory Group Scope of Work

This report is the product of a CHP subgroup of the Natural Gas DSM Advisory Group (Advisory Group) formed to undertake the CHP aspects of Stipulation No. 3. The principal participants in the CHP subgroup were initially: QGC, UEO, Utah Association of Industrial Customers, Utah Division of Public Utilities, Intermountain Regional Application Center and Utah Committee of Consumer Services. As a result of CHP interest expressed in connection with PacifiCorp's January 24, 2003, Integrated Resource Plan and comments filed in Docket No. 03-2035-01, PacifiCorp joined the CHP subgroup. The addition of PacifiCorp provided for

[1] By order issued February 9, 2004, The Public Service Commission of Utah extended the deadline for completing and presenting the study until June 1, 2004.

synergies and cost effectiveness in the CHP aspects of the studies commissioned by Stipulation No. 3 and the significance of the cooperative effort between the electric and natural gas utilities cannot be overemphasized. It represents the first time QGC and PacifiCorp have shared data. Without this cooperation the Primen study would not have been possible. It has formed a strong foundation for the further pursuit of CHP in Utah.

PacifiCorp contributed $21,000 which along with the $16,000 funded by QGC and the $5,000 funded by UEO for CHP increased the total spent under Stipulation No. 3 from the stipulated $50,000 to $100,800 ($42,000 for CHP/Distributed Energy Generation and $58,800 for natural gas DSM evaluation).

Results and Recommendations

The principal element of this report is the attached Primen study: "Converting Distributed Energy Prospects into Customers, Comparing Salt Lake City Regional Users to North American/National Results, January 7, 2004." Additionally, this report provides a summary overview of current CHP technology and a discussion of the benefits and barriers to increased CHP use in Utah.

The Primen CHP Study builds on the more general nature of an April 12, 2003, NoviEnergy LLC CHP market study by identifying specific CHP prospects in the Salt Lake City area and by validating the Utah CHP market characteristics with national CHP market data. Consistent with Primen's National findings there is currently little CHP developed in the Salt Lake City area and the primary factors influencing CHP development are CHP economics, energy price predictability, and improved power reliability.

The Primen CHP Study drew information from 40 top prospects based on combined data about high load factor electricity customers from PacifiCorp and large natural gas heat customers from QGC. Ten of these customers indicated that they were interested in further pursuing CHP and therefore are now the primary targets for potential CHP pilot projects.

Based on the results of this study, the Advisory Group recommends that:

1. **QGC should target the ten customers who indicated they were interested in pursuing CHP to develop several pilot projects and work with the recently established Intermountain Regional Application Center (RAC) on the screening and evaluation of these ten customers.**

2. Since "[i]t is the policy of this state to encourage the development of small power production and cogeneration facilities," and the results of this and other studies indicate that there is additional CHP market potential in Utah, **the effort to understand and capture the potential benefits of CHP should continue.**

3. There are specific barriers that can be addressed that will improve the market efficiency. Many of these are being addressed in other jurisdictions and there is a great deal of resource information available. **The development of CHP in Utah will be enhanced**

through future PSCU actions that eliminate or mitigate the barriers addressed in this report.

OVERVIEW OF CHP / DISTRIBUTED GENERATION TECHNOLOGIES

Equipment and Technology

Distributed Energy (DE) technologies consist primarily of energy generation and storage systems placed at or near the point of use. DE provides the consumer with greater reliability, adequate power quality, and the possibility to participate in competitive electric power markets. DE also has the potential to mitigate congestion in transmission lines, control price fluctuations, strengthen energy security, and provide greater stability to the electric grid.

The use of DE technologies can lead to lower emissions and, particularly in CHP applications, to improved efficiency. It can satisfy at least a portion of the facility's electrical demand. The heat generated by the electric power generation equipment is used to provide heating, cooling, and/or dehumidification to buildings or industrial processes.

The key factors for CHP's financial attractiveness are coincidence of need for electric power and thermal energy, spark spread differential (the difference between generating electricity with natural gas and the electricity rate) and installed cost differential (installed cost per MW).

DE encompasses a range of technologies including fuel cells, microturbines, reciprocating engines, other power generation technologies. DE involves power interfaces, as well as communications and control devices for efficient dispatch and operation of single generating units, multiple system packages, and aggregated blocks of power.

Natural gas is the primary fuel for many DE systems. However, hydrogen may well play an important role in the future. Renewable energy technologies, such as solar electricity, solar buildings, biomass power, and wind turbines are also growing in popularity.

Reciprocating engines are the most common and most technically mature of all DE technologies. These engines are the fastest growing segment of the CHP market for CHP systems under 5 MW. Reciprocating engines use commonly available fuels such as gasoline, natural gas and diesel. Because the use of diesel and petro-fueled engines create a significant amount of pollution (both in terms of emissions and noise) relative to natural gas and renewable-fueled technologies, their use is actively discouraged by many municipal governments. Reciprocating engines have the highest maintenance costs among DE technologies due the large number of moving parts.

Turbines are the second most common technology used for power generation. A combustion turbine is an internal combustion engine that operates with a rotary rather than reciprocating motion. They are generally used for larger systems, greater than 4 MW or where high-pressure steam is needed. They are best suited for base-load applications but can also handle peaking and load following applications as well.

Microturbines are a newer generation of smaller combustion turbines. They are small in size and can be brought on-line quickly, and require less maintenance because they have a smaller number of moving parts. They usually generate in the range of 25 kW to 400 kW.

Promising CHP Market Sectors

Industrial

The industrial sector represents the largest share of the currently installed CHP capacity in the U.S., with the greatest potential for near-term growth. To date, CHP has been most successful in large process industries such as petroleum refining, pulp and paper, and chemicals that require large amounts of steam. Various markets, including petrochemicals, food products, bio-products, and biotech, rank as the highest priority for future growth.

District Energy

District energy systems may be installed at large, multi-building sites such as universities, hospitals, and government complexes. District energy systems also can be effective as merchant thermal systems providing heating (and often cooling) to multiple buildings in urban areas. Colleges and universities are the most promising applications, due to expected campus load growth and replacement of aging boiler capacity.

Government

As the largest energy consumer in the United States, the Federal government is an excellent candidate for DE and CHP because of new mandates to meet increased demand, reduce peak operating costs, enhance energy security and improve the reliability of electric power in federal facilities.

Commercial

Several reports indicate CHP potential and interest in large commercial office buildings, hospital/healthcare facilities, supermarkets, hotels/motels, and large retail markets.

CHP Benefits

Reduced Energy Costs

Energy costs can be reduced through the following CHP advantages:

- Increased energy efficiency - typical overall efficiencies of CHP systems are 60-75% vs. 25-30% for central generation.
- Customers with CHP systems will see reduced demand charges and electric energy costs. Any increase in fuel consumption is more than offset by the electrical savings.

Reduced Life-Cycle Costs

Even though the initial cost of CHP systems is higher than purchasing all electric power needs and using conventional equipment for cooling, humidity control and heating needs; the life-cycle cost of the CHP systems is generally lower because of the energy cost savings over its useful life of more than 20 years.

Lower Total Resource Cost

As demonstrated in the Tellus Study and other reports, CHP systems can have a significantly lower total resource cost (TRC) than conventional electric and gas resources.

Attractive Return on Investment

The return can be attractive if the incremental installed cost of CHP systems over conventional systems is treated as an investment, and the annual savings in its energy costs are treated as the return on that investment,.

Improved Power Reliability

Economic losses due to power outages have cost American businesses billions of dollars. Increased use of CHP in buildings will decrease the demand on the electric grid. In areas where the grid is at near capacity, the reduced demand provided by CHP may result in increased grid reliability.

Improved Environmental Quality

The use of DE technologies can lead to lower emissions (“green house gases” and NO_x) and, particularly in CHP applications to improve efficiency.

Barriers to Entry

Although technological advancements have made DE a credible option for on-site generation, there are currently many barriers impeding widespread adoption of these technologies. Some of these barriers include:

1) Lack of familiarity with CHP technologies, concepts and benefits
2) Natural gas and electric price volatility
3) Insufficient ‘spark spread’ – the relative difference in fuel costs verses electric costs
4) Institutional barriers
    a. Government regulations
    b. Grid interconnection issues
    c. Utility tariffs
    d. Coordination of DE policies between independent natural gas and electric utilities

Unresolved, these obstacles could hamper future market growth. Fortunately, there is a great deal being done across the country to address many of these barriers. While not directly applicable to Utah, these efforts can help in addressing Utah specific barriers.

Institutional Barriers

Government Regulations - Potential development of DE markets depends in large part on the policies and market rules developed by the Federal Energy Regulatory Commission (FERC) and state regulatory agencies. Some major issues pertain to:

- Utility stranded investment
- Impact of lost revenues on regulated utilities
- Siting and permitting
- Interconnection to the grid
- Environmental impacts
- Transmission-system scheduling and balancing
- Uncertain pricing and processes for negotiating buy-back electric rates

Grid Interconnection Issues - Interconnection is the linking of on-site generation to the electric utility's distribution grid. It requires the customer and the utility to install a variety of relays and monitoring devices on the customer's premises and at the connecting distribution lines, to ensure stability and protection of the grid and protection of the customer's site and generation facility. The complexity and cost of the interconnection tend to increase with the scale of the on-site generation project. The cost of interconnection at the DE customer's site and required upgrades to the distribution system are paid for by the customer.

There are numerous problems related to interconnection that need to be addressed by regulators and utilities before DE markets can thrive. They include:

- Technical issues at the point of interconnection
- Safety issues posed by the grid connection
- Distribution system reliability impacts
- Lack of uniform interconnection standards

Utility Tariffs - Tariff provisions and charges may alter the economics of DE for those interested in generating electrical power while remaining connected to the grid. Two principal types of tariffs impact DE decisions:

- Back-up tariffs, consisting of supplemental and standby charges, can significantly alter the economics between grid and distributed power. Back-up charges that are too high can make it uneconomical for the customer to bypass the system. Charges that are not well defined or standardized lead to financial uncertainty.
- Competitive transition charges are charges placed on distribution services to recover utility costs incurred as a result of the customer leaving the system

(i.e. Stranded costs are usually associated with generation facilities and services which are not recoverable in other ways).

- Long-term CHP contracts with electrical utilities contain provisions for liquidated damages in case of default.
- Purchased power pricing for those projects that may sell excess capacity and energy to the grid. Currently, pricing is based on avoided cost principles. These charges are subject to individual project pricing by the electric utility. There are ongoing disputes about how to calculate avoided cost rates. This also leads to financial uncertainty.

Coordination of DE Policies between Independent Natural Gas and Electric Utilities

Regulation of two of the major stakeholders – QGC and PacifiCorp – is approached independently, even though there are areas of overlap especially with respect to energy efficiency (DSM) and CHP. This separation makes it difficult to fully value and capture all of the customer and public benefits of CHP. For example, there is no consensus in Utah as to whether or not CHP qualifies as a DSM program on the natural gas or electric side or both although it is clear that both utilities have a vested financial stake in the matter.

<u>CHP /DE IN UTAH</u>

<u>Utah's Energy Policy and CHP/DE</u>

Utah's energy policy calls for the development of new energy supplies sufficient to meet Utah's growing demand. Electricity generation from DE technologies such as cogeneration and other DE technologies are important potential sources of electricity supplies for Utah's ratepayers and economy. The Utah Legislature has declared that "[i]t is the policy of this state to encourage the development of small power production and cogeneration facilities, and

"[t]To promote the more rapid development of new sources of electrical energy, to maintain the economic vitality of the state through the continuing production of goods and the employment of its people, and to promote the efficient utilization and distribution of energy, it is desirable and necessary to encourage independent energy producers to competitively develop sources of electric energy not otherwise available to Utah businesses, residences, and industries served by electrical corporations, and to remove unnecessary barriers to energy transactions involving independent energy producers..." Utah Code Ann. 54-12(1) – Small Power Production and Cogeneration

In Docket No. 02-057-02, the UEO testified that it considered gas-fueled on-site CHP systems to be a potential DSM technology that were found to be cost-effective in a study conducted by the Tellus Institute. CHP systems produce electricity and thermal energy for heating or process needs (they "co-generate"). In so doing, they make use of heat that would be wasted by conventional electric generating plants.[2] The UEO recommended that QGC actively promote and market CHP through a DSM initiative to increase QGC's net gas sales and improve the

[2] See *An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah*, Tellus Institute, May 2001.

efficiency of gas utilization for electricity generation while at the same time reducing the total resource costs of meeting Utah's electricity and natural gas needs.

Inventory of Existing and CHP and DE Projects

While three recent studies have shown a significant market potential for on-site CHP in Utah, currently there is relatively little CHP in either the commercial or industrial sectors. However, over the next 12 months a significant increase in CHP capacity in Utah is expected with at least two new projects scheduled to come on-line. The following are projects currently operating in Utah:

- Hill AFB: 1 MW
  Electric generation from methane generated by Wasatch Environmental waste disposal
- Maca Supply: 4 MW - electric generation
- Primary Children's Hospital: 2 MW - CHP
- Snowbird Ski Resort: 2 MW - CHP
- Tesoro Refinery: 22 MW - CHP
- Utah State University: 5 MW - CHP
- US Magnesium: 36 MW - CHP
- Davis County:1.6 MW
  Municipal solid waste steam boiler – steam to HAFB for heat and process
- PacifiCorp Little Mountain: 16 MW - CHP
  CT steam to GSL Mineral for process
- Questar Corp. facilities: 5.3 MW - CHP

Total: 94.9 MW

Summary of Previous Utah CHP/DE Assessments

Tellus Institute Study: Assessment of Combined Heat and Power and Distributed Energy Generation Opportunities in Utah

In the May 24, 2000 Report and Order in Docket 99-035-10, the Utah Public Service Commission directed PacifiCorp to:

> "…convene and manage a stakeholder advisory group [to] systematically review and evaluate PacifiCorp's current energy efficiency and renewable programs….Issues the [group] should address include, but [are] not limited to: program design, appropriate cost-effectiveness tests, funding levels, alternative funding mechanisms, evaluating cost-shifting, market transformation issues and equity issues."[3]

The advisory group concluded that an assessment of the achievable, cost-effective energy efficiency potential within PacifiCorp's Utah service territory was necessary in order to make

[3] Report and Order, Docket 99-035-10, page 83.

recommendations on the issues the Commission charged the group to address. Consequently, the Tellus Institute was selected to develop an assessment of the achievable cost-effective energy efficiency potential in Utah.

The Tellus Institute was asked to evaluate DSM potential, DSM program alternatives, and the benefit/cost ratios for DSM projects in Utah that appeared to be cost-effective. The study conducted by the Tellus Institute aimed to identify electricity savings that were potentially cost-effective and achievable through the application of new DSM program funding to actively promote those demand-side measures that could produce significant amounts of savings. The study modeled implementing new DSM through a multi-year initiative, with a year 2001 phase-in and full-scale operation during 2002 through 2006. After 2006, the continuing lifetime savings from measures assumed installed during this period, were estimated up through 2025.

Commercial and industrial use of CHP and distributed generation were DSM technologies evaluated by the Tellus study.

The study found that there is relatively little CHP in any sector in Utah as of 2000 – estimates ranged between 21 and 45 MW in total, mostly fueled by natural gas. The CHP potential for the commercial sector in Utah was estimated in *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, prepared for the US DOE's Energy Information Administration (EIA) in January, 2000. The industrial sector's potential for CHP was estimated based on the distribution of energy use by type of industry in Utah, and on *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector*, prepared for the EIA in January, 2000. Costs for CHP elements (boilers, turbines, generators, maintenance, etc.) were obtained from EIA reports and from individual vendors.

For the commercial sector the Tellus study assumed that CHP systems would be sized to meet electricity requirements at their host facilities. Because it is a major system reconfiguration, institutional or owner-occupied facilities that expect long tenancy were deemed potential hosts for CHP. Several different CHP technologies were screened—micro-turbines, fuel cell systems, combustion turbine (CT) systems, and internal combustion engines (ICE) at a variety of size configurations. Screening led to including 100 kW and 800 kW ICE systems in the portfolio, primarily in schools (including colleges and universities) and hotels, along with a limited number of 30 kW "microturbines" in the later years of the program.

For the commercial sector, the study estimated that with an energetically marketed CHP program including an incentive equivalent to 30 percent of the installed cost of a CHP system, which was envisioned being used to create below-market loan financing, nine percent of the market potential identified in the EIA report, or an estimated 48 MW, could be realized by the end of 2006.

For the manufacturing/industrial sector, several CHP technologies were screened — CT systems and ICEs at different size configurations, all fueled by natural gas. The study estimated that with actively marketed programs, delivering an incentive equivalent to 30 percent of the installed cost of a CHP system in the form of below-market loan financing, nine percent of the CHP potential in the EIA report, or 54 MW, could be realized by 2006.

Tellus CHP Options by TRC Benefit: Cost Ratio

Dollars in $1000, Present Value 2000

Sectors	Program Costs "Utility"	Customer	Resource Savings Electricity	Other	Total Benefits	Total Costs	Net Benefits	B/C Ratio
Commercial CHP	$13,804	$ 87,505	$437,553	$(144,579)	$235,921	$44,256	$191,665	5.3
Industrial C.H.P.	$13,973	$ 68,257	$233,221	$ (87,231)	$107,162	$43,402	$ 63,760	2.5
All CHP	$27,777	$155,762	$670,774	$(231,810)	$343,083	$87,658	$255,425	

Costs and benefits of the DSM-CHP portfolio were evaluated by Tellus for the period from 2001 through 2025. The combined, cumulative present value of energy resource savings from the CHP options in the commercial and industrial portfolio were over $343 million (2000 dollars). With total resource costs of $88 million, the net benefit was estimated at $255 million with the average benefit to cost (B/C) ratio of the combined programs being 3.9:1. The benefit cost ratios for the commercial and industrial sectors were estimated at 5.3 and 2.5, respectively.

Benefit/Cost Results for CHP Options and Measures

Commercial/Institutional Options

Option	Major Measure	TRC B/C Ratio	RIM B/C Ratio
Combined heat & power		2.5	3.1
(All industry CHP systems are gas-fired and assumed to replace natural gas boilers	800 kW Engine	2.1	3.2
	3 MW Engine	2.4	3.5
	10 MW combustion turbine (CT)	2.8	2.9

Industrial Options

Option	Major Measures	TRC B/C Ratio	RIM B/C Ratio
(All CHP Systems are natural gas-fired)	30kW micro-turbine	4.4	-11.0
	100 kW Engine	6.1	-12.0
	800 kW Engine replacing electric boiler	6.1	-11.9
	800 kW Engine replacing gas boiler	2.1	- 5.7

NOVI Energy CHP Market Potential Report, April, 2003

PacifiCorp initiated a study to estimate the market potential for CHP applications within its Utah service territory. This study used the following data sources: "The Market and Technical Potential for Combined Heat and Power in the Industrial Sector," ONSITE SYCOM Energy, January, 2000; "An Economic Analysis of Achievable New Demand-Side Management Opportunities In Utah," Tellus, May, 2001; and PacifiCorp (Utah Power) Utah customer demographic data. Combining these data sources with NOVI's experience in actual CHP project development, they developed an approximation of the CHP market specific to Utah Power customers.

The study concludes that there is a 100 MW-150 MW potential for CHP over a five-year period. Project development would need to coincide with customers' plans for facility retrofits (major remodels and/or boiler replacement), facility expansion or new developments. These opportunities are highly dependent upon the general market and economic conditions, the customers' industry health and each customer's specific financial situation.

The study identified a number of barriers to CHP project development. As a next step the study recommended that specific customer project opportunities would need to be identified for detailed analysis and evaluation.

Primen Study

Converting Distributed Energy Prospects into Customers
Comparing Salt Lake City Region Energy Users to North American/ National Results

Top-line Findings

DE markets have started to rebound, following a ~2 year decline in the market

Economics remain the underlying key to DE decisions, but economics alone won't sell distributed energy

Compared to their peers in other parts of North America, Salt Lake City region energy users are

- Slightly more knowledgeable about DE
- More concerned about natural gas price volatility
- Less concerned about warranties/service for DE, or about environmental permitting
- Express more confidence in electric utilities as being a credible DE partner

Contents

- Executive summary from North American study
- Research approach
- Key findings, including a comparison of energy users from the Salt Lake City region with a sample of businesses from the U.S. and Canada

1. Executive summary -- national study

In 2003, the market for distributed energy (DE) bottomed out and began to rebound
About 13% of customers in 100 kW to 10 MW size range are prospects for DE.
▸12,000 North American energy users are **strong prospects** for DE
The top three drivers for DE are

- ▸Energy cost savings
- ▸Improved power reliability
- ▸Predictable energy prices

Energy users have a number of concerns about DE
▸Users want service warranties and service agreements even though they want to retain control
▸User concerns about environmental permitting are greater now than in previous years
▸Users are concerned about rising and volatile natural gas prices even though natural gas remains their preferred fuel
Blackouts and other electric service failures create short-lived "moments of opportunity" for closing DE deals
Best candidates for DE

- ▸Companies that are expanding or relocating facilities
- ▸Companies that are replacing aging central plant, including boilers, chillers, heating systems and/or generators

Companies typically make decisions to acquire DE using a team approach, which results in a lengthy and labor-intensive sales process

When it comes to providing DE equipment, electric utilities are deemed less credible than manufacturers or third-party developers by energy users

2. Research approach

The main *Distributed Energy Market Study 2003* findings are based on Primen proprietary quantitative and qualitative surveys of U.S. and Canadian energy users:

- ▸806-respondent quantitative survey (10 kW – 10 MW)

–Pre-August 2003 blackout

- ▸100 qualitative interviews

The comparisons we present in this report are based on qualitative interviews with 40 energy users from the Salt Lake City region (referred to as "SLC users" below):

- ▸Recruits for interviews were nominated by Questar Gas and PacifiCorp, but interviewed by Primen staff

Findings are also based on Primen's on-going research on DE markets, technologies, and regulatory issues

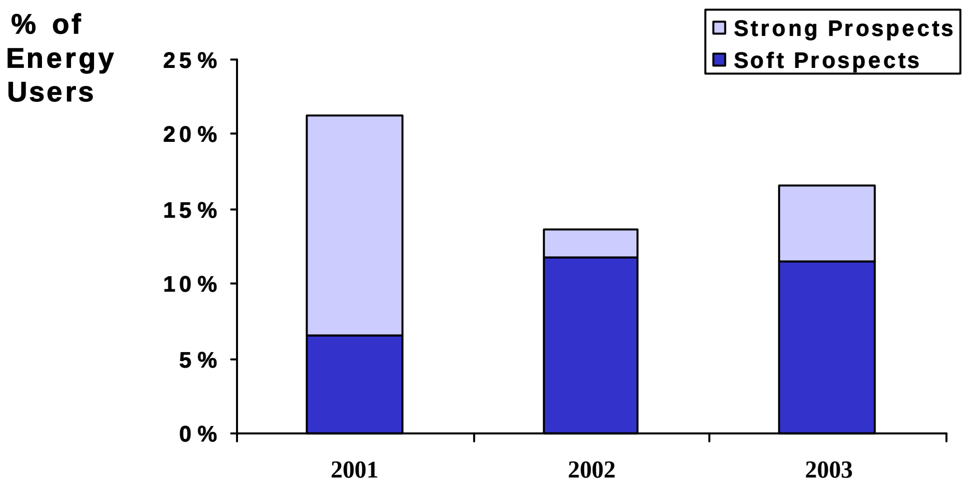
3. Key findings from North American and SLC samples

Interest in baseload DE starting to rebound

Converting prospects into customers

- Main drivers for DE
- Understanding of DE technologies and applications
- Issues and concerns about DE
- Moments of opportunity
- Who's behind the decision to acquire DE?
- The role of the utility

Nationwide, interest in baseload DE is growing again (300 kW-to-5 MW demand)



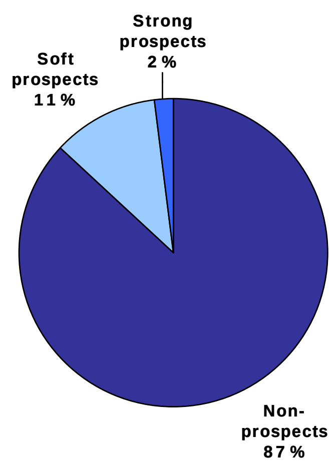
Source: Primen Quantitative Survey Results

* * Not enough quantitative responses in SLC region to statistically portray local trend

13% of national businesses surveyed are DE prospects; 2% are strong prospects

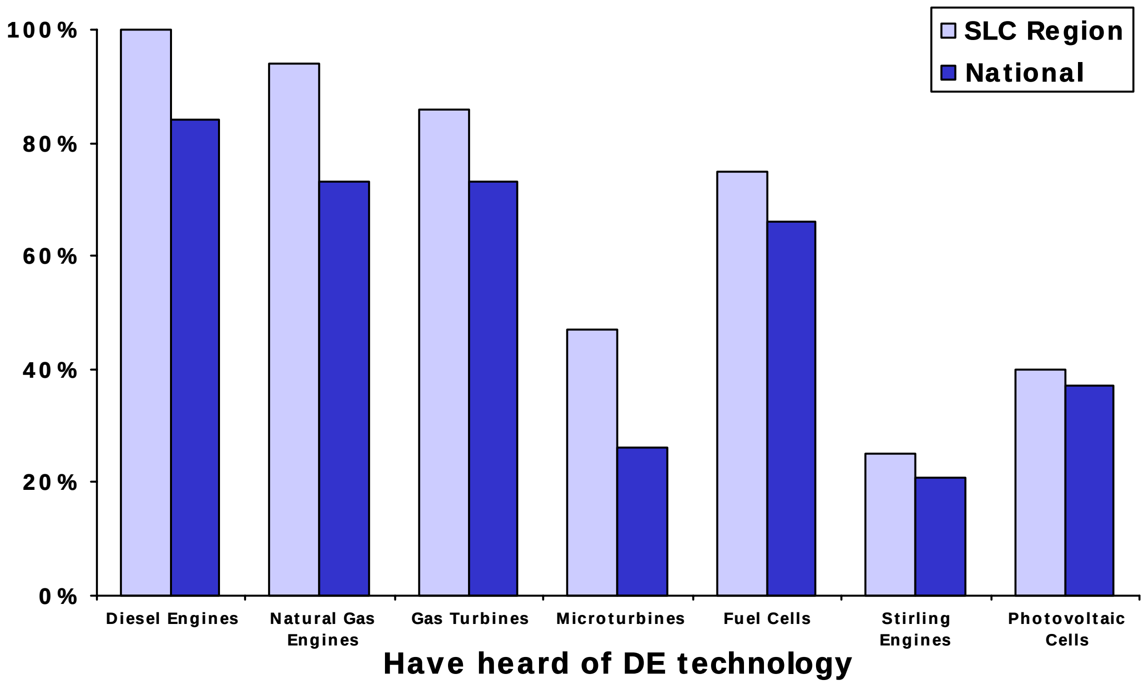
The market for baseload distributed energy (DE) is far below where it was three years ago, but **significant opportunities remain**

- More than 12,000 business establishments, in the 100 kW to 10 MW demand

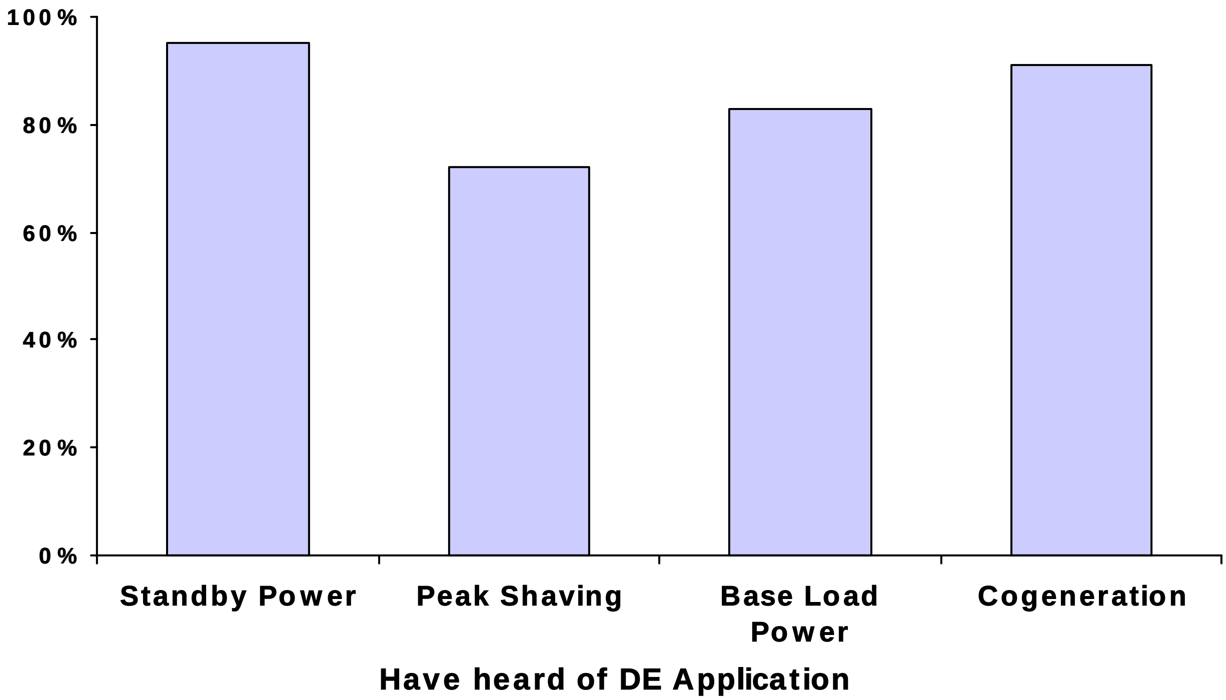


Source: Primen 2003 Quantitative Survey Results

SLC users are more familiar with DE technology options than N. Am users



SLC users are fairly familiar with DE application options



Core appeal of DE remains the bottom line

Nationwide, prospects identify their three top drivers for DE:

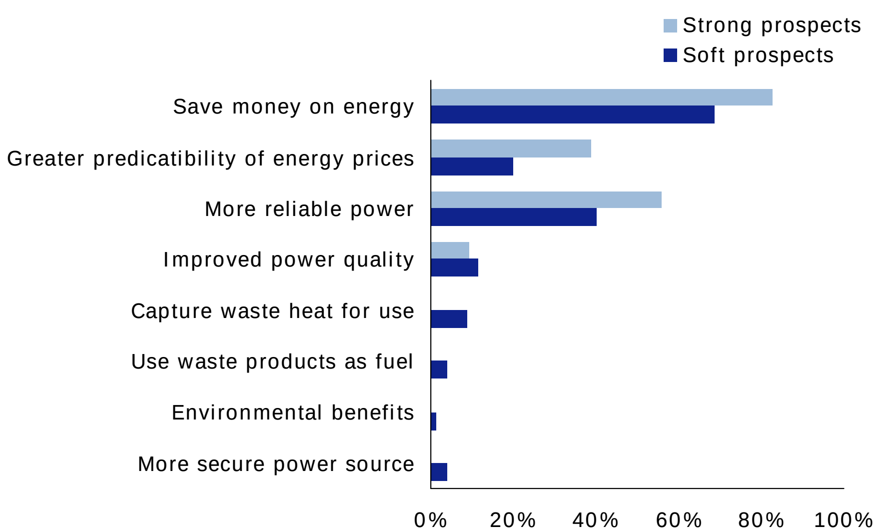
- Energy cost savings
- Improved power reliability
- Predictable energy prices

For the SLC users, the top three drivers are the same as the nationwide results:

- Cost savings was the number one reason customers mentioned for considering DE.
- However, predictable energy prices were cited more often than improved power reliability.

Drivers for DE (from national quantitative survey)

The 2003 quantitative survey results support the thoughts expressed in the qualitative interviews



Source: Primen 2003 Quantitative Survey Results

Driver #1: Energy cost savings

Prospective DE customers in the U.S. and in the SLC region want to know that their new installations will save them money in either the short-term or long-term.

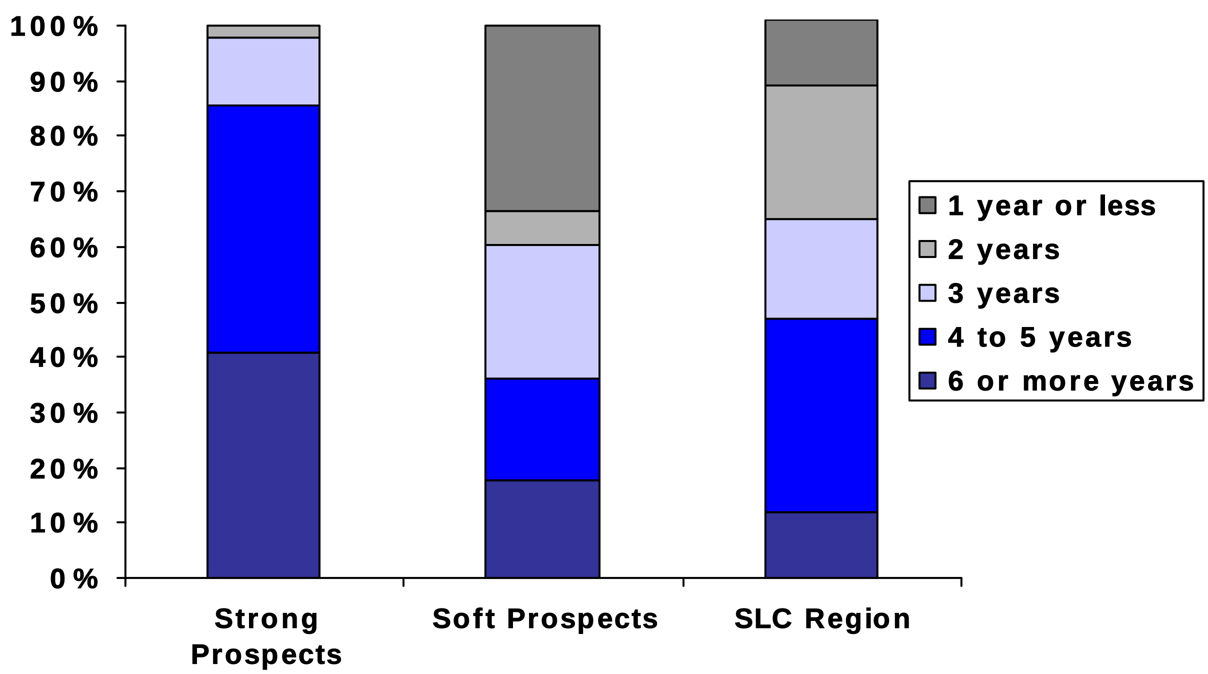
Savings can come in a variety of forms

- Directly reducing payments to the electric service providers
  - "The cost of energy accounts for 58% of our operating budget, so we absolutely need to look for ways to reduce our energy costs." Church, Utah
- Reducing costs from unreliable power
  - "We just cannot afford to be knocked off--even for a moment. Doing so results in thousands of dollars lost in product and damage to equipment." Fiber Manufacturing Facility, Utah
- Reducing price fluctuation risks in volatile markets
  - "Prices lately have been awry. I need a crystal ball to see where prices are going. It makes it extremely difficult to make plans budget-wise." Refinery, Utah.

SLC user's payback expectations in-line with national sample

DE prospects from the national quantitative study indicated reasonable requirements for payback on DE capital expenditure

- 86% of strong prospects and 37% of soft prospects find a 4-year or more payback period acceptable.
- Only 47% of SLC users find a 4-year or more payback period acceptable, which is in-line with the combined prospects for national survey.



Driver #2: Predictable energy prices

Energy users want greater predictability of energy prices and are willing to consider price hedging mechanisms that use futures contracts to lock in a more predictable fuel price.

- For budgeting purposes
  - "Price volatility of natural gas is definitely a concern. Price hedging mechanisms would definitely be of interest to us. With the way prices have been fluctuating all over the place, obviously if we could lock in long term we would be in a much better place for planning." Refinery, Utah
- For price certainty
  - "Locking in rate [using futures contracts] would help me out immensely. The rates would be settled and I wouldn't have to worry about them for a specified period of time. I'd definitely be interested if the initial price was right." Industrial Facility, Utah

Driver #3: Improved power reliability

Energy users with the most interest in DE systems are often motivated by the high costs associated with unreliable electric service or power quality problems
Outages, or even sags or surges, can have severe consequences for users, resulting in economic losses from

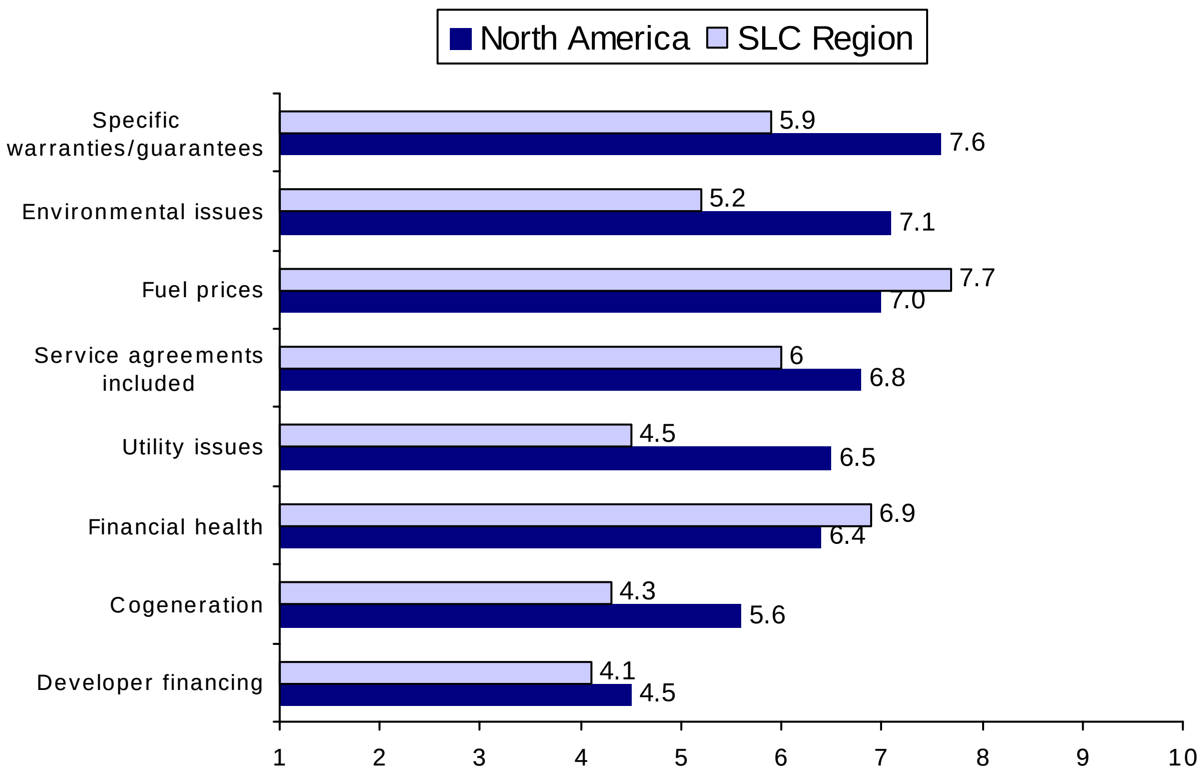
- Loss of production time
  - "When we had an outage that lasted 6+ hours, all we could do was send people home. We have continuous processes so the facility wasn't back up and running for another 24 hours. The loss of production time really hurt us." Paper Products Manufacturing Facility, Utah
- Actual loss of product
  - "Our processes are continuous so major outages shuts the process off mid-steam and we lose all of our product. If the outage is too long our completed products could freeze." Manufacturing Facility, Utah
- Damage to equipment
  - "An outage can cause severe damage to our sophisticated medical equipment. One of those pieces of equipment could cost in the $100,000 range. It forces us into using UPS systems where we normally wouldn't need to simply to protect our equipment. So that increases cost for us." Hospital, Utah

It takes more than savings to close DE deals

Cost savings and enhanced reliability are the fundamental needs driving energy users to DE, but to really sell DE to a user, other criteria need to be addressed, including

- The company's financial position and/or the state of the economy
- Availability of financing from the vendor/project developer
- Specific warranties or guarantees provided
- Service agreement included/offered
- Support for addressing environmental or permitting issues
- Electric service provider's flexibility, or lack thereof, in resolving tariff and interconnection issues
- Fuel prices, particularly for natural gas
- Ability to cogenerate heat, steam, or chilled water along with power

Key issues influencing DE sales:
North America and SLC region



Key issues influencing DE sales:
North America and SLC region (cont.)

For North America, the top concerns are:

1. Service agreements
2. Warranties
3. Environmental permitting issues
4. Fuel prices

For SLC users, the top concerns are:

1. Fuel prices
2. Company financial position and/or the state of the economy
3. Service agreements
4. Warranties

SLC users' concern over fuel prices

Fuel prices, specifically natural gas, were the most important concern to SLC energy users

- Concern is valid since natural gas prices have spiked twice in recent years, reaching double the levels of the prior decade.
- As a result, onsite generation projects are more difficult to justify from an economic standpoint.
  - "Fuel prices have a major impact on this project. But even with the fuel prices going up as they have the effect that it ultimately has is that it pushes the payback of the equipment down the road farther. So if it were originally a 7 year payback it might be pushed to 8 or 9 years." Hospital, Utah
  - "If natural gas prices continue increasing like they have, I don't think we can make onsite generation. We'll need a longer payback period and the executives won't be too happy with that." Manufacturing Facility, Utah.

Nevertheless, SLC users still see natural gas as the principal fuel option available to them

SLC users' concern about service agreements and warranties

Nationally, warranties and service agreements have the highest overall impact:

- This is most likely because they are closely linked to the customers' most important goal: financial benefits.
- Energy users are aware that they need warranties to keep systems running smoothly
- Energy users understand that their service technicians lack the required skills to keep the equipment operating at peak efficiency, especially in the beginning.

For SLC users, concerns about warranties and service agreements are not as strong, but still an area that ranks high

SLC users' less concerned about environmental regulations

Nationally, we observe increased concern regarding environmental issues

- Several respondents that already installed DE mentioned that their onsite generators are under close environmental scrutiny
    - "Environmental issues are becoming more and more important recently. We are asked to document more and the comply with the State Clean Air Act." Wastewater Treatment Facility, Utah

- Several also reported that they were not allowed to peak shave with existing equipment because of environmental restrictions
- DE prospect concerns over increasing environmental regulation is legitimate. In the past three years, California and Texas enacted new air emission control regimes.
    - Other states could follow their lead and issue new standards that are tighter than existing regulations

However, only 10% of SLC users said that they were fairly familiar with regulatory issues

- "I rely on the environmental engineer to take care of those issues." Refinery, Utah
- "I have no idea of regulatory issues. It would be nice if someone could outline those issues for me before I investigate the project, so I am not wasting my time on something that can't be done." Resin Manufacturer, Utah
- Emissions and permitting issues seem to pose the most challenges

SLC users have concerns over their company's financial position & economy

SLC users also frequently cited concerns in two other areas

- Their company's financial position
    - For North America as a whole, this ranked far lower
- The general state of the economy and capital availability
    - Several of the SLC users mentioned how any DE project must compete with non-energy projects for a limited supply of capital investment dollars
    - "The overall economy had a major impact on us! It delayed our project by over a year." Hospital, Utah

Opportunity for DE sales

DE installations require significant capital expenditures, happen infrequently, and are highly dependent on market conditions at the moment of the sale

As a result, correctly timing the sales effort can mean the difference between a successful deal and a fruitless string of contacts

An opportunity for DE sales efforts occurs when:

- Obsolete or failing equipment needs replacement
- Crises in infrastructure or market conditions occur
- Electric service failures damage sensitive equipment or cause downtime

Opportunity for DE:
Obsolete or failing equipment

An astute facilities manager plans ahead for replacing older, worn out equipment, such as boilers, chillers, and heating systems.

- If energy managers perceive a need for near-term capital expenditure in these areas, they are more receptive to the extra step of modifying the system design to incorporate the additional DE benefits.
- In addition, getting one capital expenditure approved is much easier than battling over two different projects
  - "Our standby generators are old and need to be replaced. As I began looking into replacing them for standby, I also added in a scenario where we also added in cogen since we were doing the research already. Now it looks like we'll be adding cogen." Refinery, Utah
  - "The last generators we installed are from 1988, but three of them failed air quality regulations, so we are looking to replace those." Wastewater Treatment Facility, Utah

Opportunity for DE: Electric service failures

Energy users who are particularly sensitive to electric service failures and how those failures affect business operations are prime candidates for DE following power failures

- Frustration and exasperation can be just as compelling than a simple cost-benefit analysis
  - "Even just a blip could be devastating for us. I mean, we're talking $100,000 of dollars each day we are down. It is extremely frustrating to not be able to keep our operations going." Refinery, Utah.

However, companies that think their local electric service companies provide reliable power, or think they can easily suspend and restart operations are less favorable prospects for DE

Hospitals are an exception, partly because of their unique need for uninterrupted power, and also because their facility managers already have experience with onsite generation systems

- Hospitals universally have standby DE systems
- Hospitals are also great candidates to upgrade from standby only to more complex baseload or peak-shaving systems
- The one drawback is that, either through regulation or tradition, hospitals keep their backup systems on entirely separate from their primary electric feed, requiring the installation of two complete DE systems for separate functions.
  - This can be overcome through engineering approaches or educating hospital decision-makers and helping them overcome regulatory hurdles.

Moment of opportunity for DE: Infrastructure or market crises

Energy users' perceptions of market conditions and trends largely determine whether they are truly viable DE prospects.

- Our North American research indicates that users who believe their electric service can be relied upon for stable, reasonably priced power are poor candidates for a DE sale.
- On the other hand, if local or regional events raise doubts about the predictability of their provider, onsite generation becomes more attractive. Moments of large-scale electric system or market failure create considerable uneasiness among customers, creating increased interest in DE.
  - Witness California during the past few years and, more recently, northeastern U.S., where high interest in DE has existed

These are only considered 'moments' of sales conversion opportunity because their affect fades with time. When a crisis situation occurs, users may shift their plans, but once the crisis passed, they revert to "business as usual."

Who's behind the DE decision?

The process of deciding whether to invest in DE systems is not standardized among energy users.

That's because DE acquisition represents an infrequent, capital-intensive purchase that requires input and signoff from multiple centers within the purchasing organization.

Despite the lack of a common protocol, many companies use a team approach

- An internal, primary "champion" usually shepherds the project along
  - For SLC users, the internal "champion" was typically the facility or plant manager, but it could also include executives from the strategic division or financial department.
- The project is then presented to other important stakeholders in the company, where each department provides its "two cents" in the decision-making process

Both private businesses and public institutions appear to have seemingly ad hoc decision making processes when it comes to DE.

▸Both types of organizations are accustomed to making capital expenditures and typically have processes in place for approving such purchases.
▸Since DE impacts a wide range of stakeholders within an organization, the usual process may be expanded to include others- thereby extending the approval process time even longer.

In addition, many publicly owned institutions have additional hurdles to cross.
▸Government organizations usually require a sign-off at least from the administrative head of the organization.
▸A public vote from an elected government body, such as a city of county council, may also be required.

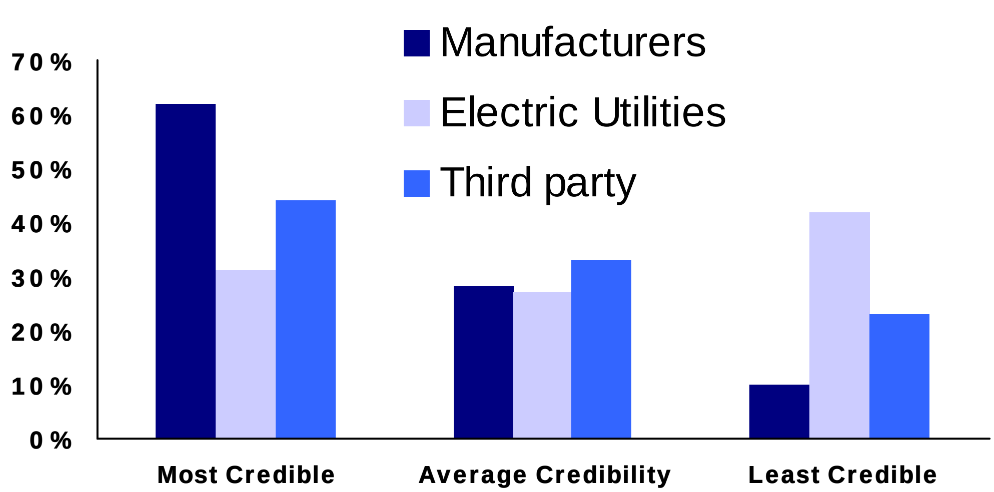
DE providers and role of the electric utility

North American energy users believe that manufacturers and third-party developers are more credible equipment suppliers and DE service providers than electric utilities.

SLC users, though have more faith in electric utilities than manufacturers
▸"Equipment manufacturers are obviously credible. That's their business. That's how they make their bread and butter. They'll try to outdo their competition." Refinery, Utah
▸"Utilities are definitely the least innovative of the three- they are just comfortable with the status quo so they won't make an effort to be innovative." Fiber Manufacturing Facility, Utah
▸"Third-party developers are not biased toward any particular equipment. They make their money by providing the best possible solution for us. We'd look for a company that has proven itself in the past." Industrial Facility, Utah
▸"Since their business is customer focused, I'd rather go with a third-party project developer. I don't have to worry that they are pushing some worthless equipment on me, just to get the equipment sale." Sporting Goods Manufacturer, Utah

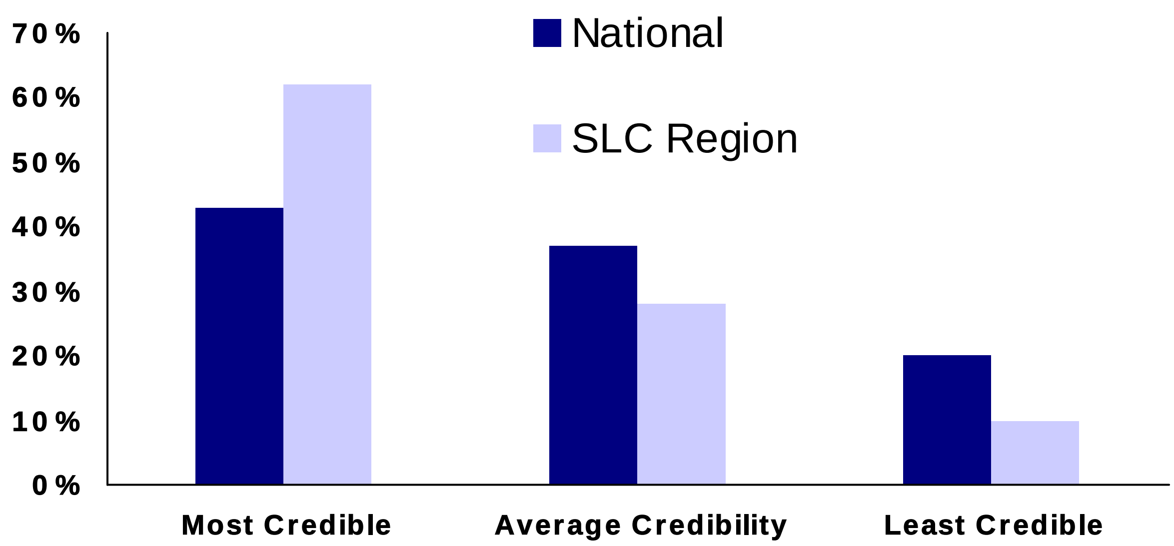
Credibility of DE equipment providers

When SLC users were asked to rate the credibility of DE equipment providers, manufacturers were rated the most credible, and utilities as the least credible.



SLC users trust manufacturers far more than North American respondents
SLC users are more likely than the national average to consider manufacturers as the most credible source for DE equipment.

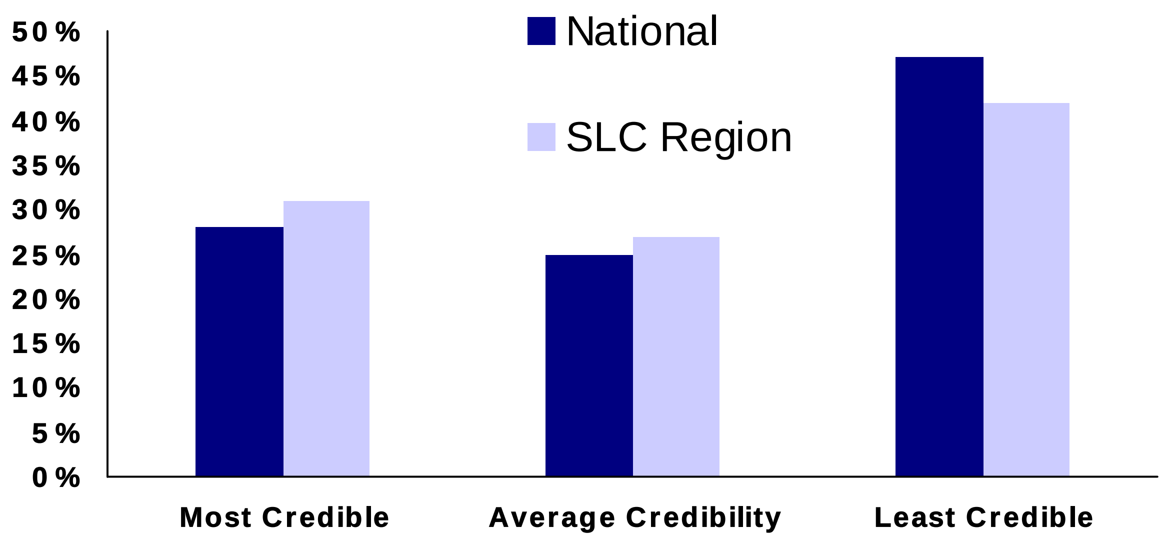
Credibility of Equipment Manufacturers as Providers of DE Equipment



SLC region users also rank electric utilities more favorably

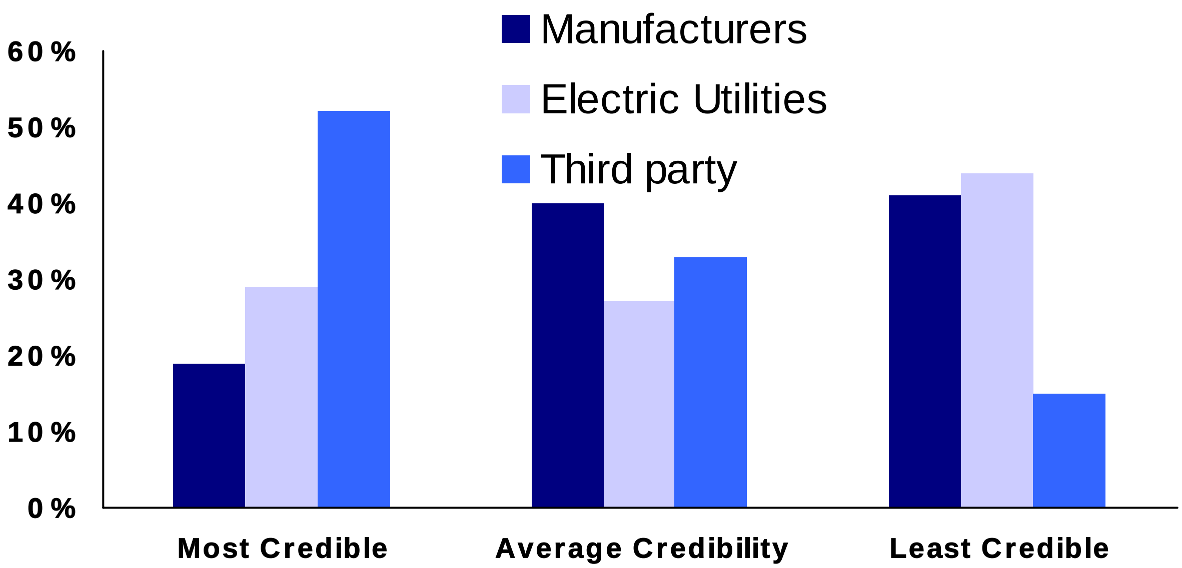
SLC and North American users consider electric utilities the least credible as providers of DE equipment, although less so in the SLC region.

Credibility of Electric Utilities as Providers of DE Equipment



SLC Users see third party companies as most credible DE service providers

SLC users rank third-party companies as the most credible DE service provider, while most energy users see utilities as the least credible.



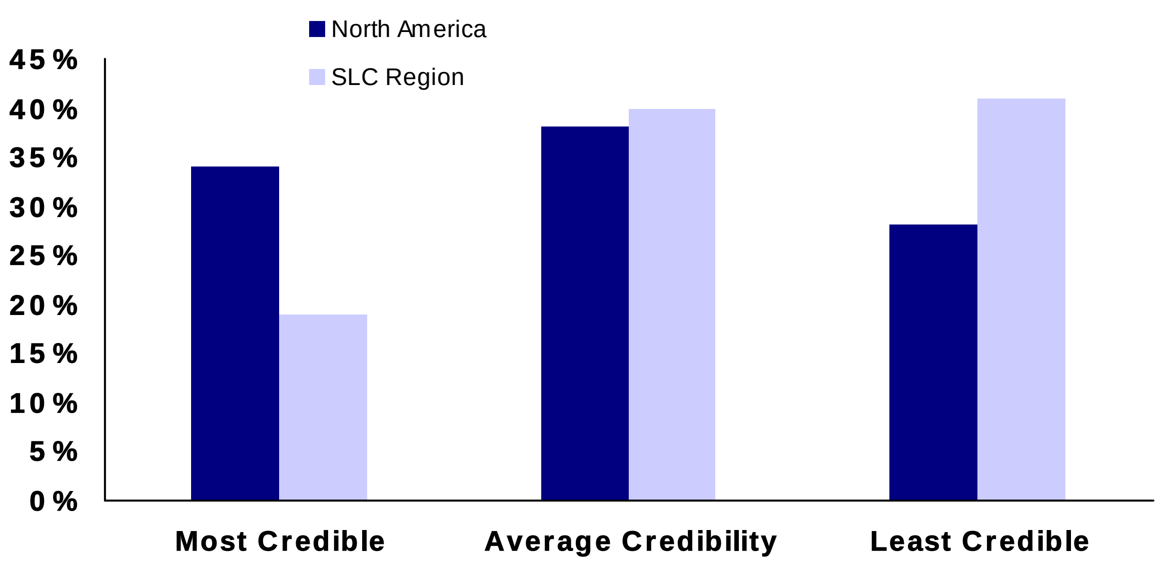
SLC users don't think manufacturers are credible DE service providers

SLC Users are less likely than the national average to consider manufacturers as the most credible source as DE service providers.

- Several SLC users mentioned the lack of local resources as a reason for not considering equipment manufacturers as a credible source for service.

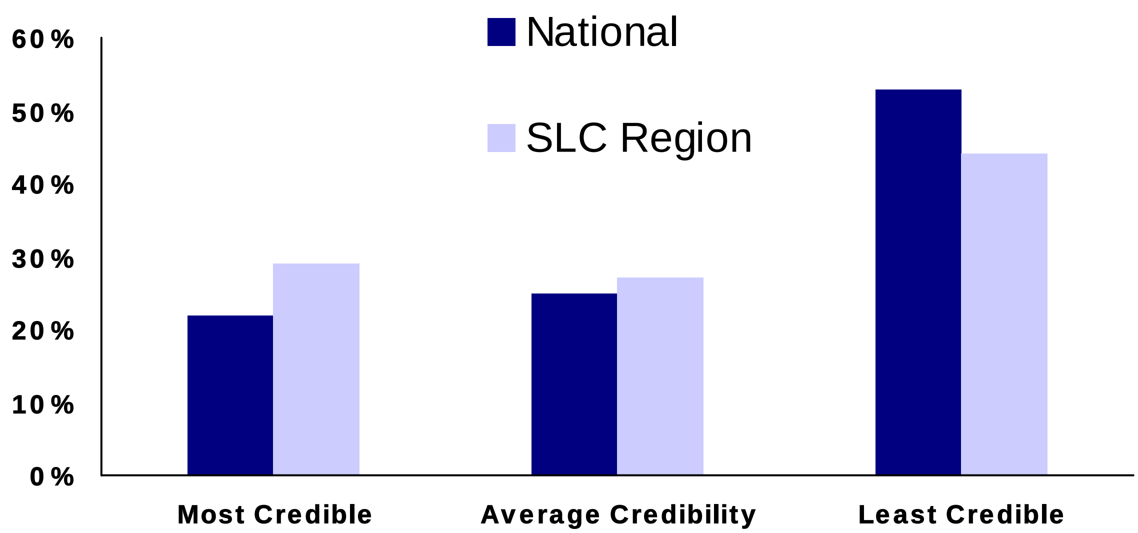
Credibility of Equipment Manufacturers as DE Service Providers

Percent of Respondents



Electric utilities seen as least credible DE service provider

Electric Utilities are considered the least credible as DE service providers both in North America and in the SLC region. However, SLC users are more likely to consider them as credible sources.



Utility credibility questioned

Some energy users believe that by offering both electric service and onsite generation, utilities are competing against themselves. This creates divided loyalties.

- "I don't expect them [utilities] to be involved unless there was something in it for them." Hospital, Utah.
- "It seems kind of like the utility would be biting off their own toe… if it [the DE system] runs off fuel oil, or diesel, or gas, they're not getting the income off of it." Grocery Store, South Dakota.

Utilities are considered the least credible with more than 50% of energy users. Some energy users even expressed outright disbelief that utilities can provide these services at all.

- "A utility providing service?! I didn't think they were in that kind of business. I'd have to take their proposal with a grain of salt." Fiber Manufacturing Facility, Utah.

What SLC users are looking for before buying DE

Over half of the SLC users emphasized that they would need to see references or testimonials from other customers.

- "Well, before I'd go with any of these types of companies, I would ask for a list of references. And I'd make sure that I checked those references thoroughly. I don't want my facility to be a test-case." Technology Manufacturer, Utah.
- "It would be great if I could go in and see a similar system that has already been put in place. That would make me sleep easier if I choose to go with them." Refinery, Utah.

SLC users require their service provider to have local service technicians.

- "I don't think equipment manufacturers are a credible source for service since I highly doubt that they have the local resources available to come out and take care of my problems." Refinery, Utah.
- "In a service provider, I look for somebody that can provide the specifications in service training and have service technicians locally so that response time is faster." Hospital, Utah

WHAT INCENTIVES ARE IN PLACE ELSEWHERE[4]

California

California tops the list of best states for DE. Even with its budget struggles, the Golden State still has established a volume and momentum that offers a wide diversity of DE opportunities. From 1997 to 2003, the state collected $756 million from its utilities for the Renewable Resource Trust Fund. So far, the California Energy Commission has doled out $344.2 million for renewable projects that include 5,300 photovoltaic- and wind-energy systems for homes and businesses.

The state's policy-makers have made some smart moves to encourage DE. There are no exit fees for DE generators producing less than 10 MW and no standards for CHP projects that use output-based permitting, a method that avoids air-quality penalties for businesses that upgrade with CHP technologies.

The Interstate Renewable Energy Council (IREC) ranks California second in financial incentives for residential-customer-sited photovolatic programs. Additionally the state has 43 DE-based projects managed by the United States Department of Energy (DOE).

New York

New York started early in the DE field. In the late 1990s, the state's Public Service Commission (PSC) established a system-benefits charge that currently commits about $150 million/yr. toward programs to promote energy efficiency, renewable-resource development, and low-income energy-efficiency services. The state has committed about $614 million to programs that include

[4] DISTRIBUTED ENERGY, The Journal for Online Power Solutions – March/April 2004 by Ed Ritchie

the installation of renewable-generation systems capable of producing enough electricity for more than 166,000 homes and nearly 100 MW of onsite CHP systems.

The state also established a $3 million distributed-generation pilot program for one of its gas utilities. The Partnership for Distributed Generation pilot program provides funding to customers to defray the cost of installing equipment. This program already supports about 6 MW of systems with nearly 20 additional customers expressing interest. The New York PSC is encouraging the state's remaining gas utilities to consider similar pilot programs.

The New York State Energy Research and Development Authority (NYSERDA) has released a new program "Program Opportunity Notice," PON 800, to support DG and CHP demonstration projects, feasibility studies, and product development. NYSERDA plans to spend $12 million for the new effort, with about two-thirds of the investment in demonstration projects. They will cover 15% to 60% of a demonstration project's cost, with a cap of $1 million. Feasibility studies are eligible to be funded at 50% cost-share, up to $500,000, while product development will be funded at 50% cost-share up to $500,000.
The state has 18 DE-based projects managed by DOE.

Massachusetts

The Massachusetts Renewable Energy Trust (MRET) oversees a $150 million state fund for renewable development. The trust recently took a $17 million cut when the state withdrew money to help defray its 2003 budget shortfall, but, in a move that defines the state's energy philosophy, the legislature promised to buy $17 million of green electricity for government buildings.

The state also has a strong DE advocate in the Massachusetts Technology Collaborative (MTC). MTC recently announced $2 million in grant funding from MRET to four emerging-technology demonstration projects:

- $500,000 to construct a hydroelectric plant with a 20-kW capacity utilizing six Gorlov helical turbines in the Merrimack River
- $496,976 to construct and demonstrate a CHP biomass gasification system at Heyes Forest Products, a sawmill and dry-kiln facility
- $500,000 to install a 500-kW ocean-wave demonstration facility as part of a multistate effort with Connecticut, Massachusetts, and Rhode Island
- $499,886 to scale up, construct, and demonstrate a 10-dry-tpd biomass technology at the Hubbard Forest Industries sawmill.

Additionally MTC introduced a $3.5 million grant program from MRET. The funds are designated for 100 new solar-electric installations and 21 recipients to develop new and renovated energy-efficient buildings.

In the fuel-cell arena, Massachusetts has a $5 million Premium Power Installation Grant program that provides up to 25% of the total capital costs, with a maximum of $2 million per project for fuel cells. The state committed an additional $6 million to fuel-cell technology and has eight fuel-cell projects to show for its investment. The latest is a FuelCell Energy 250-kW molten-carbonate installation at a US Coast Guard facility.

The state has 18 DE-based projects managed by DOE. IREC ranks Massachusetts 16th in financial incentives for residential-customer-sited photovoltaic programs.

Ohio

Ohio is focusing most of its efforts on the fuel-cell industry. The Ohio Fuel Cell Initiative, announced in May 2002, is a $103 million program designed to position Ohio as a national leader in the growing fuel-cell industry and to spur economic growth and jobs. The initiative and the Wright Capital Project Fund are key components of Governor Bob Taft's Third Frontier Project, a $1.6 billion plan to create high-paying jobs.

Ohio is home to quite a bit of the nation's coal supply, and FuelCell Energy began running the world's first fuel-cell power plant on coalmine methane gas at the Rose Valley site in Hopedale, OH. The project is cofunded by DOE's National Energy Technology Laboratory and will demonstrate the feasibility and advantages of methane from coalmines to generate electricity cleanly and efficiently. The state has 18 DE-based projects managed by DOE.
As for solar energy, IREC ranks Ohio 31st in financial incentives for residential-customer-sited photovoltaic projects.

Connecticut

Home to both FuelCell Energy and UTC Fuel Cells, Connecticut is strongly vested in the fuel-cell industry. The Connecticut Clean Energy Fund (CCEF) has announced a request for proposals to install and demonstrate fuel cells (greater than 1 kW) under the CCEF Fuel Cell Initiative, now in its third year. CCEF, the state's public benefits fund, is financed by a surcharge levied against the state's electrical ratepayers.

The funding level is set at up to $4 million. Proposals are requested from fuel-cell manufacturers or integrators, and teaming of parties is encouraged and can include a wide variety of organizations. FuelCell Energy recently benefited from this program with the sale of a 250-kW unit to Yale University.

The state has 23 DE-based projects managed by DOE. IREC ranks Connecticut 17th in financial incentives for residential-customer-sited photovoltaic projects.

Illinois

Illinois restructured its utility laws in 1997 and created the Illinois Public Benefit Program to fund the Renewable Energy Resources Trust Fund and the Energy Efficiency Program. Revenue from this fund is expected to amount to approximately $100 million/yr. over 10 years. Of this money, 50% goes toward the Renewable Energy Resources Trust Fund, and the remaining 50% goes to the Coal Technology Development Assistance Fund. Money for the Coal Fund is distributed according to the Illinois Coal Technology Development Assistance Act. Money from this program is distributed to residential electricity customers for creating energy-efficiency improvements.

An additional $250 million comes from the Clean Energy Community Trust Fund, established through a settlement with Commonwealth Edison Company. The fund is used in programs for efficiency and renewables and includes grants, loans, venture-capital support, and other financial incentives. Funding is limited to in-state projects that benefit Illinois's environment or economy.

Illinois is also home to the Midwest Regional Application Center for CHP. The MAC is a partnership between the University of Illinois at Chicago- Energy Resources Center (UIC/ERC) and the Gas Technology Institute (GTI). It is sponsored by the U.S. Department of Energy and Oak Ridge National Laboratory. The focus of the MAC is to provide unbiased information, education, and technical assistance in the promotion of CHP where it "makes sense" in the eight state Midwest Region (Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio and Wisconsin).

The state has 23 DE-based projects managed by DOE. IREC ranks Connecticut 10th in financial incentives for residential-customer-sited photovoltaic projects.

New Jersey

The state is investing heavily in transmission infrastructure and spending more than $125 million/yr. on renewable energy and energy efficiency. The New Jersey Clean Energy Program promotes energy efficiency through grants and rebates for renewable-energy generation. The result is approximately 50 MW of clean, renewable power generation. The state's Board of Public Utilities and its Economic Development Authority recently announced a program to make $60 million in low-interest financing available for investment in renewable-energy generation and for efficiency and renewable-energy upgrades for small and medium-sized businesses.
The state has two DE-based projects managed by DOE. IREC ranks New Jersey seventh in financial incentives for residential-customer-sited photovoltaic projects.

Minnesota

Minnesota has a long history of DE activities. Its DE-friendly net-metering law was enacted in January 1983, and the state is one of the earliest to mandate net metering by legislative statute. It covers all renewable-energy resources and cogeneration up to 40 kW and is available to all customer classes and types of utilities throughout the state. Minnesota utilities must purchase net-excess generation at the average retail rate.

In 2001, the legislature required the state's Public Utilities Commission to develop standards for interconnection and operation of distributed-generation facilities.

IREC ranks Minnesota 14th in financial incentives for residential-customer-sited photovoltaic projects.

Minnesota is among the top five wind-energy-producing states in the nation, generating more than 320 MW of electricity, enough to power 320,000 homes.

The state has four DE-based projects managed by DOE.

Michigan

Michigan is basing most of its DE strategy on supporting fuel cells through its education system. The Michigan Energy Efficiency Grant, provided by the Michigan PSC, offers assistance to organizations to develop and improve the quality and application of energy-efficient technologies and to create or expand the market for such technologies.

FuelCell Energy has partnered with Grand Valley State University to install and service a fuel-cell power plant for its Energy Institute's 26,000 ft research center in Muskegon, MI. Funding for the entire project, including the building and the fuel cells, is being provided for by a $3 million alternative-energy grant from the Michigan PSC and bonding from the City of Muskegon.

The state has five DE-based projects managed by DOE.

Pennsylvania

The Pennsylvania Sustainable Energy Board currently oversees four sustainable-energy development funds designed to build on Pennsylvania's success with funding renewable-energy projects, such as wind farms and solar projects. To date, the funds have provided approximately $22.3 million in loans and $1.8 million in grants for more than 100 projects.

Pennsylvania is home to one of the biggest guns in the power-generation and fuel-cell industry: Siemens Westinghouse. The company has been performing basic research and product development of solid-oxide fuel cells for more than 40 years. Fuel cell manufacturers Power+Energy Inc. and Franklin Fuel Cells Inc. also are headquartered in the state.

The state has five DE-based projects managed by DOE. Solar energy is a high priority, and IREC ranks Pennsylvania fifth in financial incentives for residential-customer-sited photovoltaic projects.

Oregon

The Oregon Energy Loan Program made its first loan in 1981 and supports the production of DE from renewable resources, such as water, wind, geothermal, solar, biomass, waste materials, and waste heat. The program is available to individuals, businesses, schools, cities, counties, special districts, state and federal agencies, public corporations, cooperatives, tribes, and nonprofits. Projects must be in Oregon, however.

Oregon expects wind generation and fuel cells to be strong performers in the DE residential market and offers a tax credit of $0.60/kWh estimated to be saved during the first year, up to $1,500. Fuel-cell systems must have a minimum rated stack capacity of 0.5 kW and a maximum rated system capacity of 10 kW.

IREC ranks Oregon 12th in financial incentives for residential-customer-sited photovoltaic projects. The state has three DE-based projects managed DOE.

INTERMOUNTAIN REGIONAL APPLICATION CENTER AND IT'S ROLE IN FACILITATING CHP

The Intermountain Regional Combined Cooling, Heating and Power Application Center (RAC) is a new regional initiative aimed at increasing the installed base of CHP within the five-state region of Wyoming, Utah, New Mexico, Colorado and Arizona. It is patterned after the Midwest Regional Application Center for Combined Heat and Power in Illinois. The Center is funded by the U.S. DOE, the State Energy offices of the five states, natural gas and electric utilities including QGC and Utah Power and several private for- and non- profit companies. etc Group, Inc. in Salt Lake City is the lead organization and is currently acting as the Center's director. Other partners include Energy Strategies, Inc. (ESI) in Salt Lake City and the Southwest Energy Efficiency Project (SWEEP) in Boulder, Colorado.

The RAC could become a valuable asset within Utah for identifying and coordinating the numerous interests represented by the stakeholders in the CHP arena. In particular, the RAC could help bridge some of the institutional barriers that exist between electric and natural gas utility regulation.

To promote the installation of CHP, the RAC will conduct education and outreach activities throughout the region, emphasizing applications of CHP technologies across the commercial, institutional and industrial sectors. One goal is to transfer to the commercial and institutional sectors the valuable lessons learned in the more experienced industrial sector.

The center will develop and host workshops in the region and will work with local and regional champions to educate regulators, end users, state and local governments, utilities, and others on the economic and environmental advantages of CHP.

The RAC will identify and facilitate high impact projects in the region with an emphasis on integrated systems, applications in the recreation, hospitality and hospital sectors, and on the small system (<15 MW) sector. The RAC will also promote more traditional CHP projects in the industrial sector. Projects that are repeatable regionally and or nationally, and with significant financial and environmental benefits will be targeted.

Education and outreach activities will include developing a regional CHP coalition, identifying and recruiting local CHP project champions, assessing the baseline of each state, designing and maintaining a website, and developing written and oral presentation materials.

The RAC will perform project screening and documentation and will, within the resources available, provide technical assistance in project development and implementation. For a limited number of specific potential sites the RAC will provide technical assistance to architects, engineers, manufacturers, and/or owners as required. The type of technical assistance provided may include, but is not limited to:

1. CHP screening tools and feasibility assessments
2. Equipment recommendations
3. Support on the installation of thermal recovery equipment or new generation technology

4. Project presentation to financial and technical decision makers
5. Technical assistance will not include providing funds for equipment costs

The screening and facilitation activities have already begun in Utah, working with PacifiCorp and QGC on their CHP opportunity assessments requested by the PSCU. The RAC has been an active participant in the activities leading to this report and will continue to be involved in policy discussions related to CHP within Utah.

RECOMMENDATIONS

Questar and the RAC Should Coordinate Efforts to Develop CHP

Forty Utah companies were identified by QGC and PacifiCorp as prospects for DE based on their natural gas and electric load profiles. These forty customers were asked as part of the interview process if they would like to talk further with a representative from QGC or PacifiCorp about on-site generation. Ten customers responded to this question in the affirmative. These customers are the primary target for DE pilot projects. **QGC should target the ten customers who indicated they were interested in pursuing CHP to develop several pilot projects and work with the RAC on the screening and evaluation of these ten customers.**

CHP Development Efforts Should Continue

Since "[i]t is the policy of this state to encourage the development of small power production and cogeneration facilities," and the results of this and other studies indicate that there is additional CHP market potential in Utah, **the effort to understand and capture the potential benefits of CHP should continue.**

PSCU Actions will Enhance CHP Development Efforts

There are specific barriers that can be addressed that will improve the market efficiency. Many of these are being addressed in other jurisdictions and there is a great deal of resource information available. **The development of CHP in Utah will be enhanced through future PSCU actions that eliminate or mitigate the barriers addressed in this report.**

APPENDIX

Appendix A: Converting Distributed Energy Prospects Into Customers
Appendix B: Main Quantitative Findings