

**ASSESSING THE CHALLENGES  
CONFRONTING DISTRIBUTIVE  
ELECTRICITY GENERATION**

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JANUARY 2003

## **Acknowledgement**

This paper is the final paper in a series of monographs on the impacts of electricity restructuring on the environment. Much of the background work for this manuscript was done by Gil Bindewald. Shashank Goel assisted with the calculations in the Appendices, and Karen Filipovich and Isabelle Morin were invaluable in tracking down data and editing drafts.

I am grateful to William Hogan and Vicki Norberg-Bohm at Harvard, Manoj Guha at American Electric Power, and Sam Napolitano and Skip Laitner at EPA for their advice and suggestions.

Funding for this project came from the U.S. Environmental Protection Agency and the Roy Family Fund. However, the conclusions in this paper remain those of the author, and do not necessarily reflect the views of those who advised or funded this work.

Finally, I would like to thank Kimberley Ednie and Susannah Marsh for their help in organizing and preparing the text, and for their patience and counsel.



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## **Executive Summary**

What role will distributive electricity technologies play in meeting future demand? Policy makers are divided on the answer. For some, these technologies represent the foundations from which a decentralized electricity system could be established—one in which small, clean generating systems gradually replace the existing system of large centralized power stations. To others, they represent an alternative to the siting and permitting problems that have plagued the construction of new transmission systems, while simultaneously realizing the high reliability standards required in an era of growing reliance on computing and communication technologies. To others still, distributive generation is seen as simply an economic alternative to meeting power needs. Finally there are skeptics who believe that smaller generators will never be as efficient or cost effective as larger centralized technologies.

To determine which of these scenarios is more likely to emerge, the paper poses two questions. What are the factors that will determine the competitiveness of distributive generation technologies, as opposed to electricity purchased from the existing centralized system? What do these factors tell us about the role of distributive generation technologies in the electricity commodity market over the near and mid-term?

The paper concludes that distributive generation technologies will have to dramatically improve their efficiency and reduce their costs if they are to become competitive with power purchased from the grid. Furthermore, even if over the next decade these technologies can be dramatically improved, centralized power technologies will also improve. In other words, distributive generation technologies are competing against a moving target.

But is the electricity commodity market the competitive battleground for distributive generation? The probable answer is no. There are several niche markets that are evolving quite rapidly and these could provide significant opportunities. Combined heat and power systems are already being installed by commercial and industrial users in many parts of the country. However, their competitive advantage is that they produce both heat and power simultaneously, not that they produce either one more economically. Another possible niche is ancillary electricity services such as increased reliability, emergency back-up power, and voltage support. The demand for these services is growing, and distributive generation could play a significant role in each. However, this marketplace is characterized by fierce competition from other emerging technologies, including demand-side management tools and new types of power storage equipment.

Finally, in some localities the proposed changes in the design of electricity markets could have far-reaching effects on the seasonal and hourly price of power. These prices will be volatile and will fluctuate in both the long and short term as demand patterns change and new investments are made. These new market rules could provide interesting opportunities for distributive technologies, but investors will have to examine power markets in a much more sophisticated fashion in order to evaluate the potential benefits.

### **Why Are Distributive Generation Technologies Unlikely To Be Competitive In The Electricity Commodity Market?**

First, distributive generation technologies have capital costs that are approximately double those of the newest central generation stations.

Second, today's gas-fired distributive generators, such as microturbines, have an efficiency rate that is about half that of a new gas-fired central plant. For microturbines to be competitive with grid based retail power priced at 12 cents, they would have to improve their efficiency level by approximately 50%. Some emerging technologies, such as fuel cell technologies, are likely to reach—if not exceed—those efficiency levels. But these technologies are not presently available.

Third, distributive technologies are small and thus operators must purchase their natural gas as commercial or small industrial customers. Central stations can buy their gas in bulk at much cheaper rates and often can bypass the distribution system and obtain their gas directly from the main transmission line. Anecdotal evidence suggests that this price differential may actually increase as gas companies upgrade their distribution networks to meet both growing demands and the requirements of new gas-fueled equipment.

Fourth, while newer fuel-based distributive generation options emit conventional pollution at levels that are comparable to those reached by new central stations, their low efficiency levels result in much higher carbon emissions per unit of electricity generated.

Finally, regulators and public officials are likely to resist any effort by customers to bypass the social costs of providing electricity to the broad population. These costs are embodied in electricity rates as a surplus charge on the wires. Thus efforts to leave the system and self-generate will require some type of payment to cover these “social costs.” This additional cost must be factored into any comparative economic analysis.

### **Additional Research**

- Fuel cell technologies may change this competitive balance, but their potential must be assessed not in comparison with today's central generating stations, but in comparison with generating options that will become available in the next decade. What will be the likely capital costs, efficiency levels, and emissions levels of central

electric generation alternatives for facilities built in 2010 and what improvements would be needed if distributive technologies were to be competitive with these facilities?

- While there have been many studies of future gas supplies and needed improvements in the interstate gas transmission systems, there has been very little analysis of the capability of the gas distribution system to meet the needs created by the emergence of new technologies, such as fuel cells.
- Finally, assuming the Federal Energy Regulatory Commission is successful in persuading the states and the electricity industry to adopt its recommendations for new transmission pricing rules and a standard market design, how will these changes affect future markets for distributive technologies? Under these new rules both suppliers and consumers will face new incentives. The character of these incentives and how the parties will respond to them will have a significant impact on the future market for distributive generation.





## Assessing the Challenges Confronting Distributive Electric Generation

The American public has grown accustomed to an electricity system characterized by large, central generating stations. The power from these facilities is transported to a widely dispersed customer base through a complex transmission and distribution network. Over the past seven decades the system has worked well, taking advantage of both economies of scale and technological advances to provide low-cost reliable electricity to millions of homes and businesses.

In recent years, some experts have predicted that this centralized model might be supplemented or even replaced by distributive power sources<sup>1</sup>. Decentralized options, such as modular electric generators (or storage) sited close to the point of use, could reduce or eliminate reliance on the central transmission system. Some of these sources, for example diesel-fired generators, have been around for decades. Others, such as wind turbines and photovoltaics, have emerged in the commercial marketplace over the last twenty years. Recently, there has been a growing interest in more sophisticated gas-fired distributive technologies, particularly microturbines. Even more efficient technologies, such as fuel cell generators, are likely to emerge in the future.

This paper identifies the factors that drive the economics of distributive generation by asking the following three questions. Is the present generation of distributive technologies likely to make a significant difference in baseload electricity marketplace? If not, what would have to change for this to occur? And how will the greater use of gas-fired distributive generators affect the level of air emissions? The paper concludes that the economics and the technology will have to evolve significantly beyond where they are today for distributive options to make a significant difference in baseload electricity markets. In the next decade, their impact on air emissions will therefore be negligible. This situation could change. New technologies, such as those utilizing fuel cells, may emerge and their efficiency will be greater and their emissions lower. But even these technologies may find it difficult to compete with new large centralized generating facilities, which will continue to benefit from cheaper natural gas and greater economies of scale.

This finding does not mean that there cannot not be a vibrant market for distributive technologies, including microturbines. While these technologies are unlikely to be competitive in the commodity market for electricity, there are specific expanding markets

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<sup>1</sup> "There is a technology revolution occurring right now. Some (power generators) may come in small packages and have the efficiencies of central power stations in the long run. When that happens, we will have a very dramatic shift to a more decentralized power system." Quoted from Senate Hearing "An oversight hearing to consider the outlook for America's natural gas demand", Thursday, May 25, 2000, by Laurence M. Downes, Chairman and CEO, New Jersey Resources, Wall, NJ on behalf of Distributed Power Coalition of America, Washington, DC ([http://energy.senate.gov/hearings/full\\_committee/naturalgas\\_demand/downes.htm](http://energy.senate.gov/hearings/full_committee/naturalgas_demand/downes.htm))

that may offer interesting opportunities. These include combined heat and power, reliability, voltage support, and other option values. These opportunities are discussed briefly in the final sections of the paper.

The paper begins by summarizing the recent debate and providing an overview of the economic determinants that shape the marketplace, such as capital, fuel, network dynamics, efficiency levels and environmental impacts. I then analyze the specific option of buying power from the grid against generating electricity using a gas-fired microturbine. I discuss how public policy might affect this market and whether there are supplemental opportunities for microturbines, beyond their use as an alternative to buying power from the grid. These include niche markets and opportunities that may occur because of peculiarities in a region's load profile. The paper concludes by posing several research questions that should be addressed in future studies.

### **WHY THE RECENT INTEREST?**

Interest in distributive technology has emerged for several reasons. First, the existing centralized system has encountered constraints. Siting new transmission lines and large generating stations can be difficult. Decentralized generation can avoid these constraints. Instead of slogging through an endless morass to permit new transmission and distribution lines, smaller generating facilities could be sited and operated within or near a customer's facility.<sup>2</sup>

Second, the difficulties in permitting and siting new transmission lines have created short-term reliability problems in some areas of the country. Most often these show up as price spikes, but in some instances they take the form of brownouts or blackouts. As parts of the country move to a more competitive power system, electricity prices become more volatile, and short-term reliability concerns are heightened. Decentralized power systems are seen by some as a means to reduce those price swings and to provide reliable power. Self-generation or community scale generation provides the owners with more control of both price and availability. Whether this scenario actually results in lower prices or greater availability remains to be seen.

Third, there is a perception that small power is friendlier to the environment than large power stations. As will be shown later, the reality depends heavily on the technologies used and the type of pollution. For example, it is hard to argue that a small diesel generator is cleaner than a new, large gas-fired facility. Greater reliance on renewable technologies and the potential for new technological breakthroughs in fuel cells, however, will reduce emissions and provide further environmental (cleaner air) and economic (lower compliance costs) benefits.

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<sup>2</sup> Zoning restrictions and local ordinances could present obstacles depending on the locality and the type of technology.

Finally, some states have added surcharges and distributive tariffs to recover uneconomic costs stranded by the transition to a more competitive market and to finance the costs of social programs, such as subsidies for renewables or aid to low-income customers. Consumers may see distributive technologies as a way of bypassing those charges.<sup>3</sup>

Are we approaching a new era marked by a greater reliance on smaller distributive electric generating technologies? Or is this scenario driven more by ideology than by economic reality?

## **THE DETERMINANTS**

The future penetration level of distributive technologies will be determined by thousands of consumers, who will compare costs and benefits of investing in distributive technologies with those of purchasing power directly from the centralized grid. These costs will depend on several key factors –capital, fuel, network services, efficiency levels, and environmental externalities. To make the decision more difficult, these five factors are dynamic. That is, they are continually changing as technologies, markets, and government policies evolve.

### **Capital Costs**

Capital costs refer to the costs of purchasing the generating system itself. They are usually measured by dividing the theoretical capacity of the equipment by its price tag. A 100-megawatt generator with a price tag of \$100 million will have a cost of \$1000 per kilowatt. Manufacturers are constantly seeking technological advances that will enable them to reduce these costs. As producers advance up the proverbial learning curve and as the demand for their product increases, the costs will drop. For example, wind generators in 1980 cost \$4,000 per kilowatt installed, while today this price has dropped more than three-fold to \$1,250 per kilowatt<sup>4</sup>. The cost per kilowatt of new distributive technologies is approximately double that of large central station generators, but their advocates argue that as sales increase, these capital costs will decline rapidly. Certainly for some of the newer distributive technologies, this may be true, but each technology is at a different point on the learning curve. Microturbine technology has been around for several decades, and thus it may be on the flatter part of the curve than advanced fuel cell technologies.<sup>5</sup> One has to look at each individual technology to judge how far and how rapidly capital costs are likely to decline. Further, even if the capital costs of distributive technologies decline rapidly, central station technologies will also be improving, and their costs may decline as well. Thus, distributive technologies will be competing against a moving, not a static, target.

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<sup>3</sup> This “benefit” is likely to be short-lived as policymakers will likely respond to the loss of revenues by enacting new regulations or statutes to recapture some or all of the lost revenues.

<sup>4</sup> Gipe, Paul, “Overview of Worldwide Wind Generation”, 1999 (<http://rotor.fb12.tu-berlin.de/overview.html>)

<sup>5</sup> For a discussion on technological learning in energy, see Norberg-Bohm, Vicki, “Pushing and Pulling Technology Into the Marketplace: The Role of Government in Technology and Innovation in the Power Sector,” February 11, 2002. Washington, D.C. (Carnegie Endowment).

## **Efficiency**

The comparative efficiency of the technology, or how much fuel is needed to generate a kilowatt-hour of electricity, is probably the most important factor determining the relative economics of generating equipment. As fuel prices increase, this factor becomes more important. In the last two decades, the efficiencies of gas-fired central generating facilities have improved significantly and today are in the range of 48-52 percent.<sup>6</sup> This figure is close to double that of gas-fired microturbines. This means that it will take twice the fuel to produce a kilowatt-hour of electricity in a microturbine than in a large combined-cycle gas-fired station.

Admittedly, this is not true of every distributive technology. Combined-heat and power (CHP) technologies can have much higher efficiency levels than microturbines used exclusively for power generation because they not only produce electricity, but also hot water for processes or space heating applications. However, to realize the efficiency potential of CHP technologies, designers must balance the electricity and hot water needs of the user. Given differences in seasonal loads, this can be a challenge. CHP is discussed in a later section of this paper.

It is also true that manufacturers of fuel cell technologies are striving for efficiency levels in the mid to high 40s before the end of this decade. If these levels are realized, the comparative economics of distributive technologies will improve. However, over the same period, manufacturers of central station gas-fired facilities will also be trying to improve the efficiency of their equipment. Thus an efficiency level of 40-50 % may not be sufficient to penetrate the electricity commodity market.

## **Fuel Prices**

If fuel prices – specifically natural gas prices – decreased, or if small-scale distributive technologies could gain access to cheaper gas supplies than central station generators, then the importance of the efficiency differential between the two technologies would diminish. But as I will show later, the opposite is more likely to be true. As demand for gas increases, prices will rise. How fast or how far prices will increase is an open question, but few experts believe that gas prices will be lower over the next two decades than during the past two.

Further, more central stations purchase gas in large volumes and thus can negotiate special arrangements with both producers and transporters – opportunities that are not available to smaller generators, who are treated in the market as any other small industrial commercial customer. The cost of distributing large volumes of gas to a single user is significantly less than distributing gas to hundreds of small or mid-sized users. As a result, most owners of distributive generators are paying fuel prices that are 50-70% higher than those paid by central generators.

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<sup>6</sup> European Union Research and Technology Development Information Clearinghouse: “ Combined Cycle Power Generation.” [http://europa.eu.int/comm/energy\\_transport/atlas/htmlu/ccpg.html](http://europa.eu.int/comm/energy_transport/atlas/htmlu/ccpg.html)

## **Public Policy**

While capital costs, efficiency rates and fuel prices may all work against distributive generators, network costs would seem to work to their advantage. If one is self-generating, by definition one is not relying on the central transmission and distributive systems to access the power, and does not have to pay for them. Thus, the price of using those networks can be subtracted from the cost of generating power from the distributive technology. However, these “savings” are contingent on several factors.

First, most firms or commercial customers will want to retain a connection to the main grid in order to access power in the event of an emergency. Distribution utilities usually demand a high price for this connection, since they must retain the infrastructure to respond, if and when the customer asks for power. The price of retaining back-up access to the grid must be netted from the “savings.”

Second, many jurisdictions are using the distribution system (the wires) to “tax” the customers for social costs, such as subsidies for the poor, or to cover costs stranded when the system moved to a more competitive regime. The incumbent electric utilities will fight hard to prevent customers from bypassing these costs by leaving the system. Often this results in the parties reaching a settlement in which the customer wishing to leave the system agrees to pay, either gradually or in a lump sum, their “fair share” of these social and stranded costs. Again, these costs must be factored into any calculation of the “savings” from bypassing the wires.

Finally, government regulators see bypass as a regressive outcome. The customer leaving the system may benefit by not having to pay for the wires, but those costs will now be borne by the users remaining on the system, many of whom will be homeowners. Such a scenario is unlikely to be politically sustainable.

## **Externalities**

The final determining factor is the relative level of government externalities, or more specifically, the cost of complying with mandated emission reductions. This cost is a direct function of both existing regulations and expected requirements. Before making an investment that would be amortized in ten years, one would want to be sure that the value of the investment will not be erased by a new set of requirements prior to the tenth year. Future regulatory mandates are an important consideration in any decision to invest in gas-fired distributive technologies. Both large central generating technologies and distributive generating equipment emit relatively low amounts of conventional pollutants. Where they differ is in carbon dioxide emissions. The lower efficiency levels of distributive technology results in much higher carbon emissions than those from more efficient gas combined cycle facilities.

The impact of government policies is partially subjective. Obviously, if the distributive generator is a wind or solar unit, the owner will reap the benefit of avoiding air pollution compliance costs. The relative value of these avoided costs depends on one's

expectations of the stringency of government emission restrictions. If one thinks the government will require substantial restrictions on carbon emission then one would attribute a higher value to the compliance costs avoided, and one's estimate of the benefits of investing in distributive renewable generation compared with buying power from the grid will improve. In the past, regulators allowed a generator's incremental compliance costs to be passed along to the customer as opposed to being absorbed by the producer. As states move to a more competitive wholesale market, such costs will be treated as any other input cost. Further, there is a move to a greater reliance on market mechanisms to achieve compliance. Market mechanisms will lower the overall cost of compliance, but competitive market forces will require electricity companies to absorb a greater percentage of these costs and will make any calculation of their impact on electricity prices uncertain.

### **MICROTURBINES VS. GRID-BASED POWER: A COMPARISON**

How these factors affect the commodity market for electricity generation can be illustrated by comparing the actual cost of a specific distributive technology to the cost of buying power from the grid. The choice of what technologies, what regions and what time period to consider can make a huge difference, but the purpose of this exercise is not to make a definitive determination of the costs and benefits, since they are constantly changing. Rather, it is to provide the reader with a better understanding of how to approach such a comparison.

I consider one distributive generating unit – the Capstone 330 microturbine, a 28 kW unit that in the summer of 2001 cost \$40,000 to buy and install. The manufacturer asserts that it has a useful life of 40,000 hours and operates at an efficiency of 26%.<sup>7</sup> The unit runs on natural gas.

Investment and use of this unit is compared with purchasing power from the grid. The grid price is comprised of a number of factors, including generation, transmission and distribution costs. Further, the generation costs reflect a mix of generators – not exclusively the cost of new advanced technologies. The analysis focuses on two regions – Ohio and the sections of California served by Pacific Gas and Electric Company – and grid prices as they were reported in 2001. During this period, prices were unusually high in California, but by providing a high-price scenario, the analysis gives the reader a better sense of the relative economics of the two choices. For example, it allows us to contemplate how high grid prices have to be before the present generation of distributive technologies becomes competitive in the electricity commodity market. Ohio prices, while slightly lower than the national average, more accurately reflect the economic conditions faced by users in most states.

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<sup>7</sup> The efficiency of microturbines ranges from 23% - 29%. The Capstone 330 is in the middle of this range. Energy Nexus Group, "Gas Fired Distributed Generation Technology Characteristics," March 2002, p. 25.

To compare the costs of purchasing power from the network and the costs of using an onsite microturbine, let us assume that a small industrial or commercial enterprise is deciding between buying power from its local distribution company or purchasing and operating several new microturbines.

Unlike the large gas-fired central generating station, which has access to fuel at a lower rate because it buys in bulk, I assume the small industrial or commercial customer buys gas at the higher commercial tariff. For example, the cost of gas to an average commercial or small industrial customer in Ohio in the summer of 2001 was \$8.40 per mcf,<sup>8</sup> while a centralized power facility could buy it at prices that ranged from \$4.00 to \$7.00 per mcf<sup>9</sup>. The characteristics of the two options are summarized in Table 1.

**Table 1: Characteristics of the Distributed Generation and Centralized Generation Options**

	Capstone model 330	Gas-combined cycle facility <sup>9</sup>
Efficiency	26%	48 - 52%
Fuel Costs	\$6.50 - \$8.40 per mcf	\$4.00 - \$7.00 per mcf
Capital Costs	\$1400 per KW	\$650 per KW

While rates might be slightly higher or lower in specific areas, a small to moderately-sized commercial or industrial customer in Ohio was able to buy power off the grid for an average of 8.87 cents per kilowatt-hour<sup>10</sup>. Using a conservative cost of capital rate of 8%, the cost of power generated by the microturbine would be 16.65 cents per kilowatt-hour or almost double the cost of buying grid-based power. (See Appendix A for calculations).

In the Californian case, we used the electricity price in the areas served by the Pacific Gas and Electric Company (PG&E). Both gas and electricity tariffs change between the summer and winter seasons. In the winter, electricity tariffs decrease and gas tariffs increase. In the summer the reverse occurs—gas prices are lower and electricity prices are higher

The cost to a commercial customer buying electricity from the PG&E system in the summer was 17.2 cents per kilowatt-hour and in the winter it fell to 11.7 cents per kilowatt-hour<sup>11</sup>. The assumptions for purchasing and operating the microturbine are the same as used in the Ohio case, except that natural gas prices are slightly lower in

<sup>8</sup> Public Utilities Commission of Ohio, Ohio Utility Rate Summary, August 6, 2001

<sup>9</sup> Derived from Data from Federal Energy Regulatory Commission, "Form 423, The Price and Quality of Fuels for Electric Plants," August 2001. <<http://www.ferc.fed.us/documents/forms/forms.htm#ele>>

<sup>10</sup> Public Utilities Commission of Ohio, Ohio Utility Rate survey dated Aug 6, 2001. <[www.puc.state.oh.us/ohioutil/](http://www.puc.state.oh.us/ohioutil/)>

<sup>11</sup> These figures are derived from the schedules A-10 and E-EPS of PG&E for Medium General Demand, Metered service as of August 2001.



California, reflecting lower distribution costs. The microturbine costs would be 14.60 cents per kilowatt-hour in the summer months and 15.65 cents in the winter. The relative costs of electric generation in the two states are presented in Table 2.

**Table 2: Relative Costs of Electric Generation in 2001**

State	Period	Cost of buying from grid	Cost of Microturbine *
Ohio		8.87 ¢/kWh	16.65 ¢/kWh
California	Summer	17.20 ¢/kWh	14.60 ¢/kWh
	Winter	11.70 ¢/kWh	15.65 ¢/kWh
	Annual weighted average	14.45 ¢/kWh	15.13 ¢/kWh)

\* includes both capital and operating costs

At first, purchasing microturbines in California seems competitive with buying power from the grid. In reality the comparison is more complicated, since most manufacturing companies would want to retain the ability to draw emergency power from the grid, if or when their microturbines failed. Utilities usually demand that customers pay a stiff monthly charge for this service, since the utilities have to maintain the infrastructure to deliver the back-up power, if and when it is demanded.<sup>12</sup> This back-up charge may tip the costs in favor of buying power from the grid even in a state with high electricity price. On the other hand, Californian utilities found that it was in their short-term interest to stimulate greater use of microturbines and other distributive generation options to avoid having to purchase power from the skyrocketing wholesale power market. I will delve into the cost and benefits of these subsidies in greater detail later.

If the Capstone 330 is not presently competitive with purchasing power for the grid, are the factors that shape the competitive market likely to change? To answer this question, I will look at five specific factors: (1) Natural Gas prices (2) Efficiency levels (3) Market Restructuring (4) Public policy and (5) Grid reliability.

### **Natural Gas Prices**

If natural gas prices are a major contributor to the cost of operating a microturbine – either with the present array of technologies or with future technologies – will they increase or decrease in the future? One can divide the natural gas system into three components: production prices at the wellhead, transmission of the gas from the wellhead to the city gate, and distribution from the city gate to the customer. If a customer is large

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<sup>12</sup> Actual rates depend on the size of the customers' load, whether the emerging power demanded is during peak demand period, the cost of reactive power, and transmission tariffs. In the PG&E territory, an average firm would pay a monthly reservation charge of \$2.55 per kilowatt plus 39 cents for every on-peak KWH actually purchased. California Public Utility Commission – CAL P.U.C. advice letter No. 220ZE and No. 1692E-D.

enough, it may be able to bypass the last component, but gas customers who purchase microturbines do not usually fit this description.

DOE's Annual Outlook projects the demand for natural gas to increase dramatically over the next twenty years.<sup>13</sup> As discussed earlier, lower gas prices combined with high electricity tariffs will benefit microturbines, while high gas prices and low electricity tariffs will work the other way. Thus the DOE wellhead price projections do not bode well for the current generation of microturbines.

One could make the same argument for long distance gas transmission. Larger facilities, however, will have the option of negotiating directly with the pipeline and thus often have the opportunity to obtain discounts from the published transmission tariffs. Furthermore, many of those users are connected directly to interstate pipelines and thus can bypass the local gas distribution company and its rates. Smaller users do not have the same opportunities. In most cases, they will be unable to avoid the published transmission rates or the distribution tariffs. In older systems, the distribution tariff can be as much as 40% of the total retail cost of the fuel.

Are these distribution costs likely to change? While there has not been much in the way of serious research in this area, anecdotal evidence suggests that they are more likely to increase than decrease. This will be especially true in older cities with antiquated gas infrastructures. Furthermore as demand increases, some parts of the country will have to invest in additional gas storage facilities to meet the larger loads, which will continue to vary seasonally – high in the summer and winter, and low in the spring and fall.

The problem is compounded if microturbine technology advances to greater use of fuel cells. Most fuel cell technologies will use natural gas. Further, most fuel cell technologies need gas at higher pressures than conventional gas-fired equipment, thus distribution companies will have to invest in new equipment in order to increase the pressure in the local system and prevent disruptions<sup>14</sup>. Since fuel cell microturbines are still five to ten years away from rapid commercialization, this problem is not perceived as an immediate concern, but the situation could change if and when new technology emerges.

Finally, at the distribution level, it is more costly to install new or upgraded pipelines than new electric wires<sup>15</sup>. This simple fact will continue to favor a buying power from the grid.

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<sup>13</sup> U.S. Department of Energy. *Annual Energy Outlook 2002*, Appendix, Table 13A.

<sup>14</sup> Alternatively, the consumer could add a small compressor, but this will increase the price of the fuel cell equipment.

<sup>15</sup> Discussion with officials at Keystone Energy, July 2002. The one caveat is that many gas distribution companies might choose to offer subsidies that may hide this difference.

### **Efficiency**

Small microturbines (28 kW) have efficiency levels between 26-28% while new gas-fired combined cycle units have efficiency levels around 50%. This differential will make it difficult for the present generation of microturbine technology to be competitive. But what if new technologies became significantly more efficient?

Table 3 presents the efficiency levels that microturbines would have to reach to be competitive with power from the existing grid. The calculations were based on the gas and electricity grid prices that existed in the summer of 2001. In the case of Ohio, efficiency levels would have to reach 95.12%—levels that are improbable.

**Table 3: Engineering Efficiency Required to Compete with Central Station Power**

	Efficiency for Distributed Generation
Ohio	95.12%
California (Summer season)	19.89%
California (Winter season)	43.70%

See Appendix B for calculations

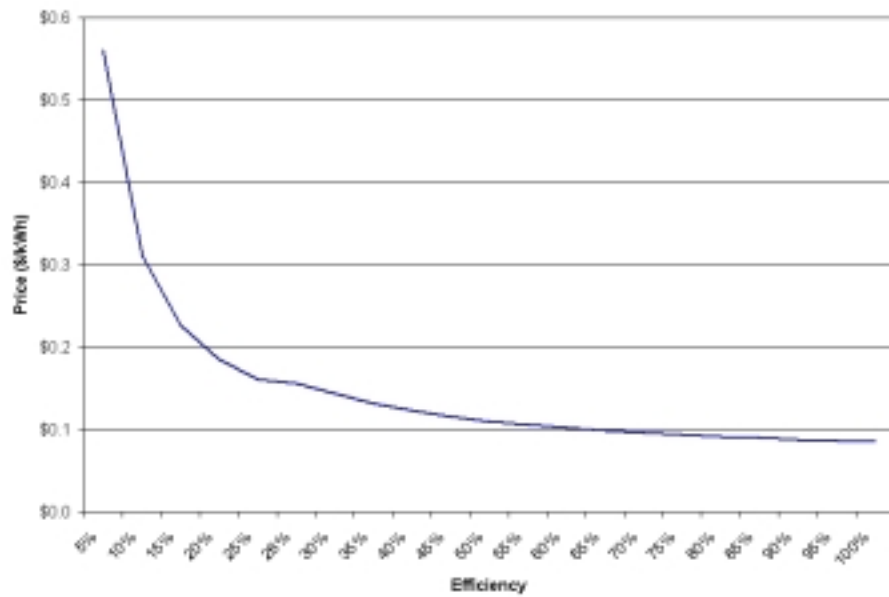
The situation in California in 2001 was different because of unusually higher grid prices. In the summer months, when grid prices were above the cost of power generated by a conventional microturbine, efficiency levels could have dropped to 20% and still be competitive. In the winter, when grid tariffs dropped significantly, distributive generation technologies would have had to achieve a 43.7% efficiency level to break even. While the existing array of microturbines cannot achieve these levels, most of the fuel cell and CHP technologies under development should be able to do so. Each state will have a different break-even efficiency threshold. If most new distributive generation will run on gas and central stations have a continuing purchasing advantage, then improving efficiency factors becomes the critical determinant of how these new technologies will fare in the marketplace.

Microturbines will not take significant baseload market shares from the central grid until the efficiency level of the technology improves. Figure 1 shows the PG&E system in the winter of 2001, illustrating how increases in microturbine efficiency levels lower the cost of using this technology. At efficiency levels of 25%, microturbine costs are in the vicinity of 16.0 cents – a level that was approximately four cents higher than grid based power. However, at 50% efficiency level the break-even price drops to approximately 11.0 cents per kilowatt-hour, which would be almost 1.0 cents per kilowatt-hour lower than grid-based power in this region and competitive with existing power price in regions such as the Northeast. At 70% efficiency the threshold prices drops still further to 9.6 cents per kilowatt-hour. The corresponding numbers for Ohio (see Figure 2) are 17.1 cents per kilowatt-hour (25% efficiency), 11.5 cents (50% efficiency) and 9.9 cents (70% efficiency). Retail prices of electricity in many regions in the United States remain below 10 cents per kilowatt-hour, so in those regions, substantial efficiency gains will be necessary for microturbines to become competitive<sup>16</sup>.

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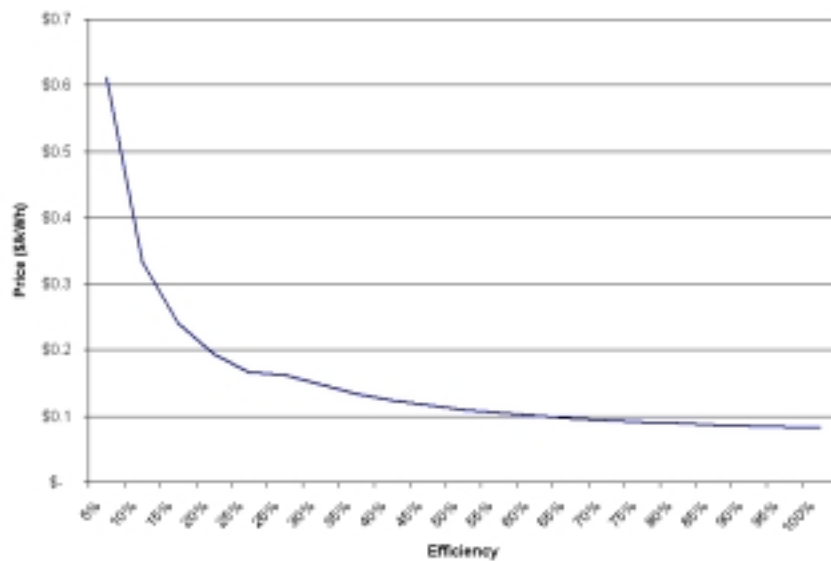
<sup>16</sup> U.S. Department of Energy, Energy Information Administration.  
[http://www.eia.doe.gov/cneaf/electricity/page/fact\\_sheets/retailprice.html](http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/retailprice.html)

**Figure 1: Cost of producing electricity with microturbine in California (per kWh) in the Winter 2001.**



Source: See Appendix B

**Figure 2: Cost of producing electricity with microturbine in Ohio (per kWh)**



Source: See Appendix B

## **Market Restructuring**

If the price of grid-based power increases, the comparative price of microturbine and fuel cell generated power will improve. But are grid prices likely to increase? Many states have restructured their electricity sector and established a competitive market for wholesale power<sup>17</sup>. Theoretically, increased wholesale competition should reduce the price of power generation. However, recent events in California and elsewhere have indicated that this is not always the case. Yet it would probably be a mistake to use the California electricity markets in 2000 and 2001 as a barometer for future price movements.

First, there is good reason to believe that over time the market design mistakes made in the initial stages of wholesale competition will be corrected. Improvements in transmission pricing and the use of futures and other energy derivatives should reduce the magnitude of price volatility and the price of grid-based power. The Federal Energy Regulatory Commission and many of the state regulatory commissions are working to correct the existing flaws in the competitive system. Thus there is a strong possibility that the marketplace of 2005 will be less volatile than the marketplace of 2001.

Second, one of the major factors contributing to the recent swings in generation costs has been natural gas prices. As we have seen earlier, increases in the price of gas will disproportionately impact generation options with lower efficiencies as compared with those with higher efficiencies. Therefore until distributive gas-fired generation options can achieve efficiency levels in the mid-forties or higher, increases in gas prices will hurt, not help, their competitive position.

If central power generation costs are as likely to decrease relative to those for distributive technologies as they are to increase, then transmission and distribution costs must increase, if the competitive position of microturbines is to improve. These costs comprise fifty percent or more of the cost of grid-based power and usually include social costs. However, in most states, one would have to witness a doubling of transmission and distribution costs for today's gas-fired distributive technologies to become competitive. While there is considerable uncertainty surrounding future transmission tariffs, the important point is that higher tariffs for use of the "wires" will, all else held constant, benefit distributive technologies. But these benefits are unlikely to be sufficient to offset other cost disadvantages.

Finally, changes in the market design will improve the efficiency of the electricity system. While these changes are not apt to change the comparative economics of distributive technologies in the baseload commodity market, they are likely to create interesting niche markets, which I discuss later.

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<sup>17</sup> As of December 2002, the Energy Information Agency reported 24 states with active (18), delayed (5), or suspended (1) restructuring of their electricity industry (monthly reports are available on [http://www.eia.doe.gov/cneaf/electricity/chg\\_str/regmap.htm](http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.htm).)

## **Public Policy**

Proponents of distributive technologies argue that if government intervened to reduce regulatory red tape, streamline administrative processes and eliminate market barriers, the comparative economics would dramatically improve. These barriers include lengthy approval processes, rigid connection and safety requirements, regulatory hurdles in the form of prohibitively high back up or standby charges, insurance requirements, and the absence of standard business practices for crafting interconnection agreements. Previous studies have identified and characterized many of these obstacles and suggested ways they can be reduced<sup>18</sup>. However, none of the studies has tried to estimate the cost of the barriers, and thus it is unclear how much reducing existing barriers will change the fundamental economics of distributive power.

Environmental externalities can also play a significant role in shifting the relative competitiveness of power options. Tougher emission reduction requirements will increase the costs of producing power from dirtier facilities far more than cleaner facilities and provide an advantage to the firms who either emit less or can reduce their emissions more cheaply. For example, emission requirements for sulfur dioxide (SO<sub>2</sub>), nitrogen dioxide (NO<sub>x</sub>), particles, and mercury will increase the cost of generating power from older coal-burning facilities in the Midwest by 6.8 to 13.6 mills/kWh<sup>19</sup>. While older coal facilities will still retain an economic advantage over new gas-fired generators, this advantage will shrink. If CO<sub>2</sub> reductions are mandated, the competitive positions of the two options will shift ever farther, and depending on the extent of the mandates, could begin to favor new gas facilities over existing coal plants<sup>20</sup>.

Some older forms of distributive generation have emission levels that are substantially higher than those from new baseload gas combined cycle plants. Table 4 shows that NO<sub>x</sub> levels from diesel generators are almost 100 times greater and particle emissions are almost 20 times greater.

While diesel generators are large enough to attract the attention of regulators at both the federal and state levels, microturbines and other small types of distributive power options have not yet received much attention. Because of their size and their relatively low emission levels, they will likely remain below the proverbial regulatory radar screen until their market penetration levels are higher.

Microturbines are comparatively much cleaner than diesel generators. While their NO<sub>x</sub> emissions are slightly higher than a new-state-of-the-art gas combined-cycle unit, they are lower than those from gas turbine peaking units. Microturbines are cleaner than the existing array of generating units in most regions. The one exception is carbon dioxide

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<sup>18</sup> National Renewable Energy Laboratory, Making Connections, (SR\_200-28053, July 2000), US Department of Energy, Strategic Plan for Distributed Energy Resources, (Washington DC Sept 2000 and Arthur D. Little, "Distributed Generation: Policy Framework for Regulators, Cambridge 1999.

<sup>19</sup> Lee, Henry and Shashi Kant Verma, "Coal or Gas: The Cost of Cleaner Power in the Midwest," ENRP Discussion Paper E-2000-08, August 2000. p. 39.

<sup>20</sup> Ibid. p. 44.

emissions. Lower efficiency levels result in CO<sub>2</sub> emissions approximately twice that of a new combined cycle plant. However, these levels will come down dramatically if phosphoric acid fuel cells can be commercialized.

**Table 4: Emissions levels of different generation options.**

	New large gas combined cycle	Microturbine	Phosphoric acid fuel cell	Large gas turbine	Controlled diesel
NO <sub>x</sub> lb/MWH	0.06-0.12	0.41	0.03	0.55	5.91
SO <sub>2</sub> lb/MWH	0.0004	0.008	0.005	0.006	0.49
PM 10lb/MWH	0.04	0.08	---	0.07	0.74
CO <sub>2</sub> lb/MWH	776	1,477	973	1,188	1,537

Source: Regulatory Assistance Project and Bluestein, Joel, "Environmental Benefits of Distributed Generation" 12/18/2000 and Energy Nexus Group, "Gas-Fired Distributed Generation Technology Considerations," March 2001, p. 25.

### **Running the Meter Backward**

As technology improves, proponents argue that distributive generators might be able to sell all or a portion of the power they produce into the grid. Thus the distribution system would operate like a two-way street. Power could flow from the system to a commercial customer and could flow from a customer to the grid. Meters that measure the flow to and from the customer would be needed, and the grid operator would have to establish a sophisticated process allowing the system to anticipate power flows in either direction. For the purpose of discussion, I look at the following question: Assuming that the technologies and regulatory protocols emerge to allow these transactions, under what conditions would the transactions be economical?

As wholesale power prices fluctuate hourly and seasonally, there will be times when wholesale prices are quite high. In an efficient system, customers will have the ability to bid a price at which they will sell their power back into the grid. This power may take the form of contracted electricity that customers would have consumed but are now willing to "sell" back to the grid, or in a world of self-generation, it could take the form of selling, as opposed to using, the power they produce. As more parties have access to these markets, available supply will increase, and hourly grid prices should come down.

How competitive will microturbines or other distributive technologies be? Even at very high efficiency levels, today's microturbine technology will be producing power at approximately 10 cents per kilowatt-hour as compared to 3.5 cents for a new combined cycle gas-fired facility. If the power is used where it is produced, the customer may be able to avoid many of the system costs, such as the wires and social charges, thus



providing microturbines with a competitive benefit. However, if the power produced is sold into the grid, wire charges will come back into play and even super-efficient microturbines or fuel cell generators will have difficulty competing with large central facilities. Admittedly, there may be hours when wholesale prices will be high enough to provide an opportunity to economically sell power into the grid, but these will be few and become even fewer as a more competitive market for managing peaks emerges.

### **Subsidies**

But isn't it true that California utilities have been willing to offer significant subsidies to encourage commercial and industrial customers to purchase distributive technologies? In this instance, the utilities were looking not at the costs and benefits for their customer, but at the costs and the benefits to themselves.

If the utilities do not take ownership of the microturbine, what are they buying? First and foremost they are buying reliability. Utilities have an obligation to serve and meet reliability standards. Therefore, if they have a choice between foregoing 8.5 cents per kilowatt-hour in revenue by encouraging a customer to self-generate or purchasing wholesale power for 10 cents, they will choose the former and save 1.5 cents. In other words, subsidizing some of their commercial or industrial customers to purchase distributive technologies may be a cheaper option for some utilities than buying peak power on the wholesale market.

In most instances, utilities do not face as stark a choice. In many states, they have an ability to pass on to their customers fluctuations in wholesale prices. However, this was not the case in California where prices were frozen. Under these circumstances, it made economic sense for the utilities to search for ways to avoid paying exorbitant wholesale costs. To get a sense of the size of the needed incentive, let us assume PG&E had to buy wholesale power at prices higher than 20 cents per kilowatt-hour for 2,000 hours in the summer. Let us also assume that it could not charge more than the published retail tariff of 15 cents, of which no more than 6.5 cents per kilowatt-hour of the cost of purchasing wholesale power can be passed forward to the consumer. In this circumstance, they should be willing to pay as much as 5 cents per kilowatt-hour to avoid having to buy power at 20 cents.

The case for subsidizing the purchase and care of microturbines gets more complicated because wholesale prices might be much lower during some parts of the year, and by accelerating the use of microturbines the utility would be foregoing revenues in excess of the wholesale price during those periods. To do this calculation correctly, the analyst must look at the whole year. In the thirteen months between June of 2000 and June of 2001, the monthly average of California wholesale prices in the PX day-ahead market was consistently over 10 cents per kilowatt-hour, or 3.5 cents higher than the wholesale cap<sup>21</sup>. Therefore, there was a strong case for subsidizing microturbines in California

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<sup>21</sup> Joskow, Paul L., "California Electricity Crisis", September 2001 (Updated). p.60.

during the summer of 2001. But the California scenario is an anomaly, both in terms of wholesale price levels and the government imposed restrictions on passing wholesale prices onward to the customer. Generally wholesale markets look more like those in Ohio, with much lower wholesale power prices, and no regulatory restrictions on their pass through. Thus the incentive for the utilities to provide discounts and encourage their consumers to invest in distributive generation is much lower in these other states.

Do subsidies make a difference in the choice between investing in distributive technology and buying from the grid? It depends on how the subsidy is designed, but in most instances the answer is positive. For example, the Netherlands' government heavily subsidizes combined heat and power (CHP) – a form of distributive technology. As a result, over 38% of Dutch electricity is supplied by co-generation or distributive generation.<sup>22</sup> Whether this constitutes a cost-effective response to the country's energy needs is uncertain and a question for another study, but if the subsidy is set high enough, investors will respond.

This paper suggests that if microturbine generation is to become competitive in electricity commodity markets with purchasing grid-based power, some combinations of the following will have to be true.

- a) Efficiency levels must increase to at least 45%.
- b) Capital costs per kilowatt will have to decrease dramatically
- c) The cost of grid-based power will have to increase.

Do my findings suggest that the potential of smaller scale distributive technology to penetrate electricity commodity markets is exaggerated? Without significant improvements in the economics and the technology, this clearly is the case. Some might argue that this paper is making the wrong comparison; the market for today's distributive generation is not in meeting baseload or immediate power demands, but rather in filling particular niches. While the evidence is anecdotal, there seem to be several market trends that are promising.

### **OPPORTUNITIES AND NICHES**

There are four emerging market niches that may create measurable opportunities for distributive technologies: (1) Hot water; (2) Demand for surplus reliability; (3) Voltage or system support; and (4) Option value. It is important to point out that all of these are benefits that go beyond the simple production of electricity.

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<sup>22</sup> [http://tecs.energyprojects.net/links/final\\_publishable\\_reports.pdf](http://tecs.energyprojects.net/links/final_publishable_reports.pdf)

### **Hot Water**

Proponents of Combined Heat and Power (CHP) systems often claim that their technology clearly shows that distributive technologies are competitive with purchasing power from the central grid. CHP systems have found substantial market opportunities in Europe, and there are indications that even without subsidies, there are promising opportunities for these technologies in the commercial and industrial markets in the United States. It is true that if one subtracted the value of the hot water, this would not be the case<sup>23</sup>. Therefore a market comparison of CHP systems should look at the cost of providing both electricity and hot water from conventional sources. However, there are many potential customers who have a demand for both, and there are opportunities to cluster industrial and commercial users to balance the demand for heated water and power.

### **Reliability**

In recent years, a number of new industrial processes and technologies have emerged that require a much higher level of electricity reliability. This is often referred to as “nine to the ninth” power reliability. Instead of needing a power source that is available 99.9 percent of the time, processes now need power 99.9999999 percent of the time in order to function seamlessly. A spokesperson for Oracle Corporation was quoted as saying this level of reliability is worth “millions of dollars per hour.”<sup>24</sup> A semi-conductor plant can lose 8 hours of production from a one-minute loss of power, since they have to restart many of their processes from scratch.<sup>25</sup> The Department of Energy estimates that a one-hour blackout costs a brokerage operation \$8.48 million.<sup>26</sup> Telecommunications, software, medical, pharmaceutical, and Internet companies are all highly susceptible to power reliability and quality problems.

If a firm can buy 168 kilowatts of back-up generation capacity for \$240,000 and thus avoid potentially losing millions of dollars, it would be financially reasonable to install that capacity. Using DOE’s numbers for the brokerage firm, the investment would pay for itself in the first two-minutes of a blackout.

Anecdotal evidence indicates that reliability and power security (in quality) have been the major drivers in the recent sales of microturbines. As the communications and computing technologies require even greater reliability, distributive technologies will be one of the options for filling this niche. Other options will include superconductive equipment and flywheel technologies that capture, store, and release power for short periods of time.

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<sup>23</sup> The hot water can be used to heat a building or provide process steam for mechanical energy.

<sup>24</sup> Cited in Yeager, Kurt and Karl Stahlkopf. “Power for a Digital Society.” *E-Visions 2000 Conference*, RAND, Washington D.C. October 11, 2000. p. 155 (available electronically at <http://www.rand.org/scitech/stpi/Evision/Supplement/>)

<sup>25</sup> Bruner, Richard. “How High-Tech Copes with Rolling Power Blackouts” *Semiconductor Magazine*, Vol. 2, No. 4, April 2002

<sup>26</sup> US Department of Energy, Strategic Plan for Distributed Energy Resources, Sept 2000, p.7.

### **Voltage and System Support**

Earlier, we saw that an electric utility confronting high wholesale prices and an inability to pass these costs on to the final consumer might find it in its self-interest to subsidize some of its customers to install microturbines. There are some additional benefits that utility companies would be willing to buy.

For example, many of the regions of the country are now proposing new rules on how they will price electricity transmission. Many of them are moving to a system of congestion pricing which will allow the parties in the market to identify where the transmission system is congested and/or in need of voltage support. This support can take the form of new transmission, a new generating facility, the reduction or leveling of the electricity load or it could take the form of installing distributive technologies. In this instance the economic competition would be between the relative costs and benefits of purchasing distributive generation and investing in other options for providing this system support. In some cases the electric utility or the owner of the distribution and transmission system would invest in distributive technologies directly, in others they could subsidize the purchase. In many cases non-utility investors, including consumers, might be the primary source of the investment.

### **Option Value**

Option value basically quantifies purchasing the right—but not the obligation—to seize a market opportunity should that opportunity emerge. For example, the cost of generating power varies. When demand is low, the grid operator can dispatch large baseload plants that are relatively inexpensive to operate, but when demand ratchets upward, the operator must seek power from more costly sources. The cost of buying power during the 200-400 hours of greatest demand, usually on hot summer days, can be very expensive. While purchasers of power see the peak prices as an expense, generators see it as an opportunity to make money. It is not unusual for the marginal price of power during the 200-400 hours of peak demand to be 10-30 times the average price.<sup>27</sup>

Historically, these peak costs were buried in the tariffs. In other words the utilities hedged this price volatility. As the generation sector is unbundled from the retail end of the industry, this volatility must be paid by the purchaser of wholesale power and in some jurisdictions by large retail customers who are subject to tariffs that reflect real time power costs. This latter group is likely to grow in number as regions restructure their electricity sector to give more choice to their industrial customers.

Under a restructured electricity system, electricity price peaks provide a financial opportunity for anyone who has the ability to supply power at below marginal cost, or anyone who would otherwise have to buy power at marginal cost. For example, if a

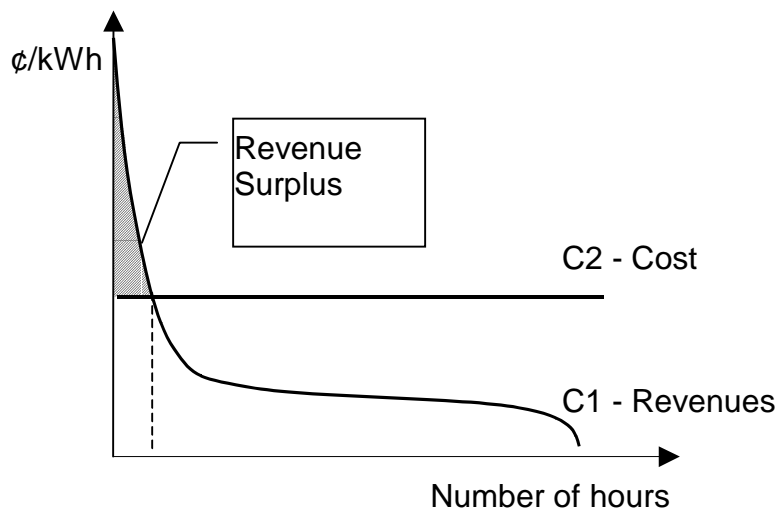
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<sup>27</sup> The price of power at any hour is assumed to be the marginal clearing price—the cost of generating the last kilowatt-hour demanded. Some regions of the country have not restructured their electricity market, thus the vertically integrated utility continues to absorb these high peak prices. For this exercise, however, we are assuming that the industry is unbundled).

utility company faced very high prices for peak electricity and had limited ability to buy cheaper power from outside its region, it could purchase a bank of microturbines. The utility would be able to avoid paying the exorbitant wholesale prices for power during peak hours by producing power using its microturbines. If the cost of generating electricity from the microturbine was 70 cents per KWh, and prices stayed above 70 cents per kWh for more than 400 hours per year, investment in microturbine would pay for itself.<sup>28</sup>

The marginal cost of supplying power during the days of highest demand will vary. Figure 3 depicts a hypothetical cost curve for power (C1). For a very limited number of hours it might be as high as \$1000 per megawatt hour, at another time it might be \$500 per megawatt, and for others \$200. Power generated by the microturbine is represented by the level cost curve (C2). The triangle above C2 and below C1 is the revenue surplus that the microturbine generator would enjoy.

**Figure 3: Hypothetical revenues from distributed generation during hours of high price peaks.**



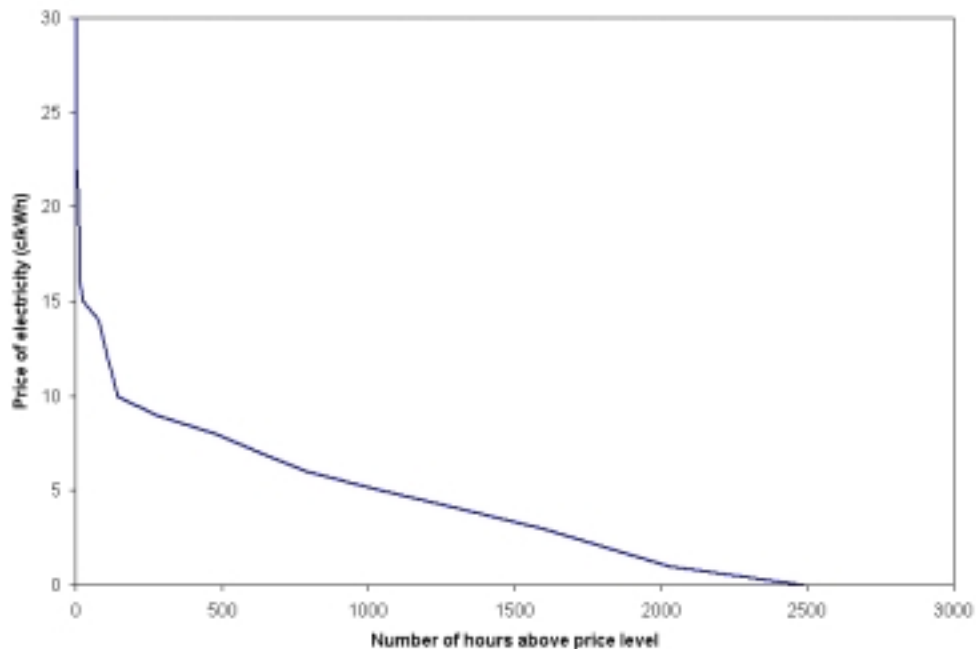
A microturbine owner would benefit from the high marginal costs during periods of peak demand. There are two important caveats. First, the demand for power is sensitive to both weather and economic activity and these can change from year to year. As one can see by the slope of the cost curve C1 in Figure 3, high prices are observed for only a few hours per year. If the circumstances that triggered the high price peaks in one year do not occur in the next, the cost curve in the second year may not have the same needle peaks, and the microturbine owner may not enjoy the same level of profit.

<sup>28</sup> This figure is much higher than when the microturbine is used to supply baseload power as in the earlier examples, because the microturbine is now only being used for a few hundred hours per year. Thus the capital costs must now be allocated to a much smaller number of KWhs. See Appendix C for more details.

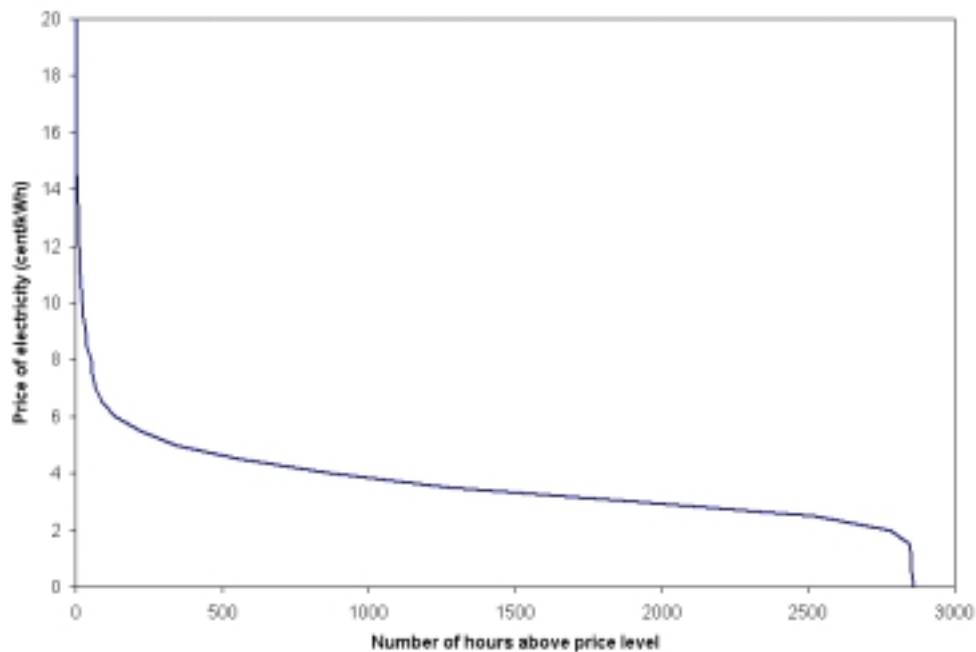
Second, there are other competitive options available to meet the peak demand. The options include building large-scale peak generating equipment (30-50 megawatt combined cycle facilities), upgrading the transmission interconnections with other regions, or implementing demand-side options, whereby large consumers reduce or forgo using electricity and are paid the marginal costs.

Looking at the utility load curves over the recent summers, one finds that the hours in which the wholesale price of electricity exceeded 10 cents per kilowatt-hour were surprisingly few. Figures 4 and 5 show electricity clearing prices for San Francisco and New England in the summer of 2001. Even in San Francisco there were less than 250 hours when the price was over 10 cents per kilowatt-hour. Thus at first glance, the option value for a relatively high cost microturbine does not look promising.

**Figure 4: California Power Exchange Ex-Post Energy Prices in San Francisco Zone During June-September 2001.**



**Figure 5: Electricity Clearing Prices in ISO-New England Power Exchange During June-September 2001**



However, those numbers may hide the true cost of generating and transmitting power during these peak hours. For example, there is no charge for congestion in the transmission system. The Federal Energy Regulatory Commission (FERC) is proposing that states through various regional systems (Independent System Operators or Regional Transmission Organizations) adopt a Standard Market Design that would include location-based marginal cost pricing of transmission. Under FERC's proposal, transmission congestion would be priced. These prices could be quite high in some locations during some hours, and will be in constant flux as new investments are made and demand patterns change. As a result, wholesale electricity prices are likely to fluctuate significantly under this new regime. If the FERC changes are adopted, they could provide opportunities for investors in distributive technologies to profit. To seize advantage of these opportunities, investors will have to look at power markets in a much more sophisticated fashion than in the past. This will require running multiple simulations and examining the probabilities of various pricing scenarios.

While more analyses are needed to quantify and characterize the potential of each of the four niche markets, they do represent opportunities for distributive technologies—opportunities that are likely to become significantly larger if and when electricity systems are restructured and a standard market design for the new competitive industry is adopted. Adoption of congestion tariffs for transmission and real time pricing for power sites may expand these opportunities further still.

## **SUMMARY AND REMAINING QUESTIONS**

The conclusion from the above analysis is that, while there are several promising niche markets, for distributive generation to emerge as a competitive option in the electricity commodity market, its comparative economics—as well as its technology—must improve.

As a start, distributive generation options must improve their efficiency levels to at least about 45%. However, even in this instance it is not clear that it will be more economical for the users to buy power from small distributive generators (under 200 kW) than from central generators. In fact, if one looks at the figures in this paper, even at very high efficiency levels, the cost of power from distributive generation could be twice that from central generators, and thus the competitiveness of distributive generation will depend on the value of avoided network costs, gas rates, and capital and operating costs. Bypassing network costs will be politically difficult, as regulators and existing utilities will fight to maintain them. Distributive generators cannot capture the economies of scale enjoyed by the larger facilities, and they face higher gas prices. A new gas combined cycle can be financed and built for \$500 to \$600 per kilowatt, while most gas-fired distributive technologies are looking at capital costs above \$1200 per kilowatt. This differential could be overcome if other operating costs were lower than those for central generators, but the opposite is true. Unless these factors change, it is hard to see a situation where the decentralized grid model begins to displace the present centralized model.

Past studies on the future of energy technologies are fraught with uncertainty. The purpose of this paper is not to endorse one electricity-generating technology over another, but simply to advance the understanding of the factors that will shape the dynamic marketplace in which these technologies will be competing. There remains, however, unanswered questions that should be explored in future studies of distributive generation.

- Will the fuel cell technologies now being developed and demonstrated be competitive with grid based technologies in 2010 and beyond? Such a study will require an examination of both fuel-cell generators and the evolution of central station generators.
- How will the new regulatory regime affect niche markets for distributive power? Regulators at both the federal and state level are grappling with creating new rules for the electricity network – Standard Market Design. Whatever regime(s) they establish will create incentives – not only to the developers and operators of the network, but also to those who propose alternatives to supplement or complement the network. Analysts should look at how these incentives might affect the niche markets for distributive power technologies.
- How will generation options be affected by changes in the natural gas distribution system? Dissemination of fuel cell generation will require investments in upgrading



the natural gas distribution system. Analysts should look at the scope and potential cost of improving the urban gas infrastructure.

- How will consumption decisions be affected by real-time pricing? This paper, as well as most existing studies, has not adequately considered the volatility of a competitive electricity marketplace. Most consumers have this volatility hedged for them by their electric utility companies, and thus never experience actual hourly or daily costs. If this situation was to change, and mid-sized to large commercial and industrial consumers found their hourly rates changing by a factor of 5 or more, and if they were informed of these changes prospectively or at least in real-time, would they look at their investment choices differently? Would their assessment of the option value of distributive technologies change?

None of these questions is easy and all will require analysts to consider not only particular technologies, but more importantly, the marketplace in which these technologies will compete. One of the major deficiencies in the existing panoply of studies of distributive generation is that they assume that the marketplace, public policies, and competitive technologies will remain unchanged. This is almost never the case.



## APPENDIX A

This Appendix calculates the cost of purchasing electricity from the grid and the cost of generating electricity by using microturbine for a medium commercial customer in the states of Ohio and California.

### OHIO

#### **Case 1: Cost of buying electricity from the grid**

The average cost of purchasing electricity from the grid, based on commercial customers comparison of utility bills as per Ohio Utility Rate Survey dated 8/6/01, is **\$0.08878/kWh**.

#### **Case 2: Cost of producing electricity by using microturbine**

The cost for generating electricity is calculated for a Capstone Microturbine Model 330. It is assumed that the gas for operating the microturbine would be procured from the local distribution company as per published rates. The microturbine user's volume usage is probably not high enough for the utility to set up long-term contracts at the lower rate.

The specifications for Capstone Microturbine Model 330 are:

28 kW (+/- 1)

26% efficiency

[13,000 Btu/kWh heat rate (LHV)]

Fuel flow (NG-HHV): 420,000 Btu/hr = 15,000 Btu/kWh (at full load)

At 26% efficiency output would be 7.618 kWh/therm

Fuel Cost per kWh:

As per the Ohio Utility Rate Survey dated 8/6/01, the average cost of purchasing gas from the local distribution company for commercial customer on survey is \$8.4/Mcf. An industrial customer would pay \$8/Mcf.

For a commercial customer the fuel cost in terms of \$ per therm would be:

$$\begin{aligned} &= \frac{\$8.4/\text{Mcf} \times 1 \text{ Mcf}/1000 \text{ ft}^3}{1030 \text{ Btu}/\text{ft}^3 \times 1 \text{ therm}/100000 \text{ Btu}} \\ &= \$0.8155/\text{therm} \end{aligned}$$

Fuel cost per kWh for an Efficiency of 26 % and output of 7.618 kWh / therm

$$\begin{aligned} &= \frac{\$0.8155/\text{therm}}{7.618 \text{ kWh} / \text{therm}} \\ &= \$ 0.1070/\text{kWh} \end{aligned}$$

Capital Cost of using microturbine per kWh:

Capital Cost of a Capstone Microturbine: \$40,000 (installed)

Design life: 40,000 hours

Assuming 8% interest rate and lifespan of 4.5 years for the microturbine,  
Capital Recovery Factor (CRF):

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} = \frac{.08 (1.08)^{4.5}}{(1.08)^{4.5} - 1} = 0.27330$$

Assuming full load operation of 28 kW and utilization rate of 90% (7884 hours per year), the Capital Cost of using microturbine per kWh of electricity generation is

$$\begin{aligned} &= \frac{40000 \times 0.27330}{28 \times 7884} \\ &= \$ 0.0495216/\text{kWh} \end{aligned}$$

Operation and Maintenance Cost of microturbine (excluding fuel) = \$0.01/kWh

Total cost of producing electricity from the microturbine  
= CAP COST + O&M COST + FUEL COST  
= 0.0495 + 0.01 + 0.1070  
= **\$ 0.1665 / kWh**

## **CALIFORNIA**

### **Case 1: Cost of buying electricity from the grid**

Here we consider that the customer purchases electricity from Pacific Gas & Electric Company (PG&E), which is one of the major Electricity and gas utility in California.

Assume customer consumes 28 kW (constant load).

For this load the annual consumption of electricity is 28 kW x 8760 hr/yr  
= 245,280 kWh/yr

As the annual consumption of electricity for constant load of 28 kWh is more than 50,000 kWh/yr, we adopt the electricity rates in Schedule A-10 (Medium General Demand-Metered Service, effective 7/01/01) in addition to Schedule E-EPS (Energy Procurement Surcharges, effective 6/01/01) of the PG&E for the purpose of calculations. Assume secondary voltage level.

As per these schedules the summer tariff for a medium general demand metered service would be:

energy charge:	\$0.08915/kWh
demand charge:	\$6.70/kW-month
customer charge:	\$75/meter-month
surcharge:	\$0.01/kWh
bundled surcharge:	\$0.06042/kWh

Cost of purchasing power from the grid

$$= 0.08915 + \frac{6.70}{730 \text{ hr/month}} + \frac{75 \times 1 \text{ meter}}{28 \text{ kWh} \times 730 \text{ hr/month}} + 0.06042 + 0.01$$

$$= 0.08915 + 0.009178 + 0.003669 + 0.06042 + 0.01$$

$$= \text{\$0.1724/kWh [summer]}$$

The Winter tariff would be:

energy charge:	\$0.07279/kWh
demand charge:	\$1.65/kW-month
customer charge:	\$75/meter-month
surcharge:	\$0.01/kWh
bundled surcharge:	\$0.02888/kWh

Cost of purchasing power from the grid

$$= 0.07279 + \frac{1.65}{730 \text{ hr/month}} + \frac{75 \times 1 \text{ meter}}{28 \text{ kWh} \times 730 \text{ hr/month}} + 0.02888 + 0.01$$

$$= 0.07279 + 0.00226 + 0.003669 + 0.02888 + 0.01$$

$$= \text{\$0.1175/kWh [winter]}$$

## Case 2: Cost of producing electricity by using microturbine

We consider that electricity is produced using a Capstone Microturbine Model 330 (specifications as mentioned above) and gas for operating the microturbine is obtained from the distribution network of Pacific Gas & Electric Company (PG&E). We consider a constant load of 28 kW and a utilization rate of 90% (7884 hours per year).

Fuel cost per kWh for purchasing gas from Pacific Gas & Electric:

At 26% efficiency output would be 7.618 kWh/therm

For a constant load of 28 kW, the customer will use 2683 therms/month (20440 kWh/month / 7.618 kWh/therm) to operate the microturbine full-time. Thus, he qualifies as a small commercial customer. Hence, I adopt the gas rates in Schedule G-NR1 (Gas Service to small commercial customers effective 8/7/01) of the PG&E.

As per the G-NR1 schedule, the summer tariff for procuring gas would be:

$$\begin{aligned} \text{Customer charge} &= \$ 13.42/\text{month} \\ \text{Procurement \& transportation charge} &= \$ 0.65403/\text{therm} \\ \text{Fuel cost per kWh} &= \frac{13.42}{28 \text{ kWh} \times 730 \text{ hr/month}} + \frac{0.65403}{7.618} \\ &= \$ 0.0865 \end{aligned}$$

Winter tariff (Using G-NR1 schedule) for procuring gas would be:

$$\begin{aligned} \text{Customer charge} &= \$ 13.42/\text{month} \\ \text{Procurement \& transportation charge} &= \$ 0.73392/\text{therm} \\ \text{Fuel cost per kWh} &= \frac{13.42}{28 \text{ kWh} \times 730 \text{ hr/month}} + \frac{0.73392}{7.618} \end{aligned}$$

$$= \$ 0.0969972$$

Capital Cost of using microturbine per kWh of power generation:  
\$ 0.0495216/kWh (as calculated above)

Operation and Maintenance Cost of microturbine (excluding fuel):  
\$ 0.01/kWh (as calculated above)

Total cost of producing electricity from microturbine  
= CAP COST + O&M COST + FUEL COST

During Summer:  
 $0.0495 + 0.01 + 0.0865 = \$ 0.1460 / \text{kWh}$

During Winter:  
 $0.0495 + 0.01 + 0.0970 = \$ 0.1565 / \text{kWh}$

**Thus, in case of Ohio the average cost of purchasing electricity from the grid is 8.87 cents per kWh while cost of generating electricity from microturbine is 16.7 cents per kWh. In case of California: during summer, the cost of purchasing power from the grid is 17.2 cents per kWh and the cost of generating power using microturbine is 14.6 cents per kWh, and during winter, the cost of purchasing power from the grid is 11.7 cents per kWh and the cost of generating power using microturbine is 15.7 cents per kWh.**

## APPENDIX B

This Appendix calculates the efficiency levels of producing electricity that the microturbines must achieve in order to break even with the cost of purchasing power from the grid for the states of Ohio and California.

### OHIO

#### **Cost of generating electricity from Capstone microturbine Model 330**

(Specifications as in APPENDIX A)

Assuming 8% interest rate and lifespan of 4.5 years for the microturbine, Capital Recovery Factor = 0.27330

Assuming full load operation of 28 kW and utilization rate of 90%<sup>29</sup> (8760 hours per year), the Capital Cost of using a microturbine per kWh of electricity generation is

$$\begin{aligned} &= \frac{40000 \times 0.27330}{28 \times 7884} \\ &= \$ 0.0495216/\text{kWh} \end{aligned}$$

Operation and Maintenance Cost of microturbine (excluding fuel)  
\$ 0.01 /kWh (As in APPENDIX A)

Fuel cost per kWh of electricity production from Capstone Microturbine:

Assuming that the output is proportionately related to Efficiency  
At Efficiency ( $\eta$ ) = 0.26, Output = 7.618 kWh / therm

$$\text{For any Efficiency } (\eta), \text{ Output} = \frac{7.618 \times \eta}{0.26} \text{ kWh / therm}$$

Assume, as in APPENDIX A, that the gas for operating the microturbine is procured from the local distribution company. Adopting the average cost of purchasing gas from the local distribution company for commercial customer on survey of \$8.4/Mcf as per the Ohio Utility Rate Survey dated 8/6/01; the fuel cost in terms of \$ per therm would be:

$$\begin{aligned} &\$8.4/\text{Mcf} \times 1 \text{ Mcf}/1000 \text{ ft}^3 / (1030 \text{ Btu}/\text{ft}^3 \times 1 \text{ therm}/100000 \text{ Btu}) \\ &= \$0.8155/\text{therm} \end{aligned}$$

Hence, the fuel cost per kWh of electricity produced

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<sup>29</sup> If we instead assume 100% utilization rate, the efficiency numbers change slightly to 81.4% (Ohio), 19.1% (California during summer), and 40.2% (California during winter).

$$\begin{aligned}
&= \frac{0.8155\$ / \text{therm}}{\left( \frac{7.618 \times \eta}{0.26} \right) \text{kWh}} \\
&= \frac{0.027832}{\eta} \$ / \text{kWh}
\end{aligned}$$

Cost of generating electricity from microturbine:

$$\begin{aligned}
&= \text{CAP COST} + \text{O\&M COST} + \text{FUELCOST} \\
&= 0.095216 + 0.01 + \frac{0.027832}{\eta}
\end{aligned}$$

$$= 0.0595216 + \frac{0.027832}{\eta}$$

#### **Cost of getting power from the grid**

\$ 0.08878 / kWh (As in APPENDIX A)

For breakeven:

Cost of getting power from the grid = Cost of generating power from microturbine

$$0.08878 = 0.0595216 + \frac{0.027832}{\eta}$$

Efficiency at Break-even ( $\eta$ ) = 0.9512 or **95.12 %**

### **CALIFORNIA**

#### **Cost of generating electricity from Capstone microturbine Model 330**

(Specifications as in APPENDIX A)

Assuming 8% interest rate and lifespan of 4.5 years for the microturbine, Capital Recovery Factor = 0.27330

Assuming full load operation of 28 kWh

Capital Cost of using microturbine per kWh of electricity generation  
= \$0.04457/kWh (As above)

Operation and Maintenance Cost of microturbine (excluding fuel)  
= \$0.01/KWh (As in APPENDIX A)

Assuming output is proportionately related to Efficiency

At Efficiency ( $\eta$ ) = 0.26, Output = 7.618 KWh / therm

For any Efficiency ( $\eta$ ), Output =  $\frac{7.618 \times \eta}{0.26}$  kWh / therm



Assume, as in APPENDIX A, that the gas for operating the microturbine is obtained from the distribution network of Pacific Gas & Electric (PG&E). We adopt the gas rates in Schedule G-NR1 (Gas Service to small commercial customers effective 8/7/01) of the PG&E.

During summer

Fuel Cost per kWh of electricity production from Capstone Microturbine:

= Customer charge + procurement and transportation charge

$$= \frac{13.42}{28 \text{ kWh} \times 730 \text{ hr/month}} + \frac{0.65403}{7.618\eta / 0.26}$$

$$= 0.000657 + \frac{0.02232}{\eta}$$

Cost of generating electricity (per kWh) from microturbine during summer

= CAP COST + O&M + FUELCOST

$$= 0.0495216 + 0.01 + 0.000657 + \frac{0.02232}{\eta}$$

$$= 0.0601786 + \frac{0.02232}{\eta}$$

Cost of purchasing power off the grid from PG&E:

= \$0.172417 / KWh (As in APPENDIX A)

For breakeven:

Cost of getting power from the grid = Cost of generating power from microturbine

$$0.172417 = 0.0601786 + \frac{0.02232}{\eta}$$

Efficiency at Break-even ( $\eta$ ) = 0.1989 or **19.89 %**

**During winter**

Fuel Cost per kWh of electricity production from Capstone Microturbine:

= Customer charge + procurement and transportation charge

$$= \frac{13.42}{28 \text{ kWh} \times 730 \text{ hr/month}} + \frac{0.73392}{7.618\eta / 0.26}$$

$$= 0.000657 + \frac{0.025048}{\eta}$$

Cost of generating electricity (per kWh) from microturbine

= CAP COST + O&M + FUELCOST

$$= 0.0495216 + 0.01 + 0.000657 + \frac{0.025048}{\eta}$$

$$= 0.0601786 + \frac{0.025048}{\eta}$$

Cost of getting power off the grid from PG&E:  
= \$ 0.1175 / KWh (As in APPENDIX A)

For breakeven:

Cost of getting power from the grid = Cost of generating power from microturbine

$$0.1175 = 0.0601786 + \frac{0.025048}{\eta}$$

Efficiency at Break-even ( $\eta$ ) = 0.4370 or **43.70 %**

**Thus, taking into account the prevailing tariff for power and gas, in the case of Ohio, the microturbine must achieve an engineering efficiency level of 95.12% to breakeven with the option of purchasing power from the grid. In the case of California, keeping in view the different tariff of power and gas during summer and winter, the microturbine must achieve an engineering efficiency level of 19.89% and 43.70% during summer and winter respectively.**

## APPENDIX C

This Appendix examines the use of microturbines for generating and selling electricity during peak price hours of, i.e. when the price of electricity from the grid is above the price of generating the electricity with microturbines.

We assume that a microturbine used in this non-continuous mode has a life expectancy that is twice that when used in continuous mode, i.e. 9 years.

Assuming a discount rate of 8%, the capital recovery factor for the investment is

Capital Recovery Factor (CRF):

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} = \frac{.08 (1.08)^9}{(1.08)^9 - 1} = 0.16008$$

Assuming full load operation of 28 kW and utilization rate of 400 hours per year (peak price hours), the capital cost of using microturbine per kWh of electricity generation is:

$$\text{Capital Cost} = \frac{40000 \times 0.16008}{28 \text{ kW} \times 400 \text{ hrs}} = \$0.5717/\text{kWh}$$

We further assume that Operation and Maintenance Costs are the same as assumed in Appendix A:

$$\text{Operation and Maintenance Costs (excluding fuel)} = \$0.01/\text{kWh}$$

Therefore even without the cost of fuel, the cost of using the microturbine in this fashion amounts to approximately 58 cents per kilowatt-hour.

Even in the high price market of California in the summer of 2000, electricity prices exceeded 58 cents for only approximately 60 hours.

As the number of high price hours increases, the capital cost of using the microturbine decreases. In the event where the turbine can be used 1200 hours, the capital, operation and maintenance costs per kWh of electricity produced decreases to:

$$\begin{aligned} \text{Capital, Operation and Maintenance Costs} &= \frac{\$40000 \times 0.16008}{28 \text{ kW} \times 1200 \text{ hrs}} + \$0.01/\text{kWh} \\ \text{Capital, Operation and Maintenance Costs} &= \$0.2006/\text{kWh} \end{aligned}$$

However, even this much lower cost of production was only exceeded for approximately 850 hours during the summer of 2000 in California, and is still well above wholesale market prices in the New England ISO market during 2000 and 2001.

Moreover, this cost of production doesn't include the cost of fuel. Given the smaller consumption compared to the continuous use of the microturbine, fuel costs will likely exceed even the minimum 8 cents per kWh (summer tariffs in California, Appendix A), thus bringing the cost of electricity closer to 28 cents per kWh.

The chart below presents a comparison of the cost of capital, operation and maintenance (excluding fuel costs), and ex-post wholesale electricity prices in the California ISO and ISO-New England markets in 2000 and 2001.

