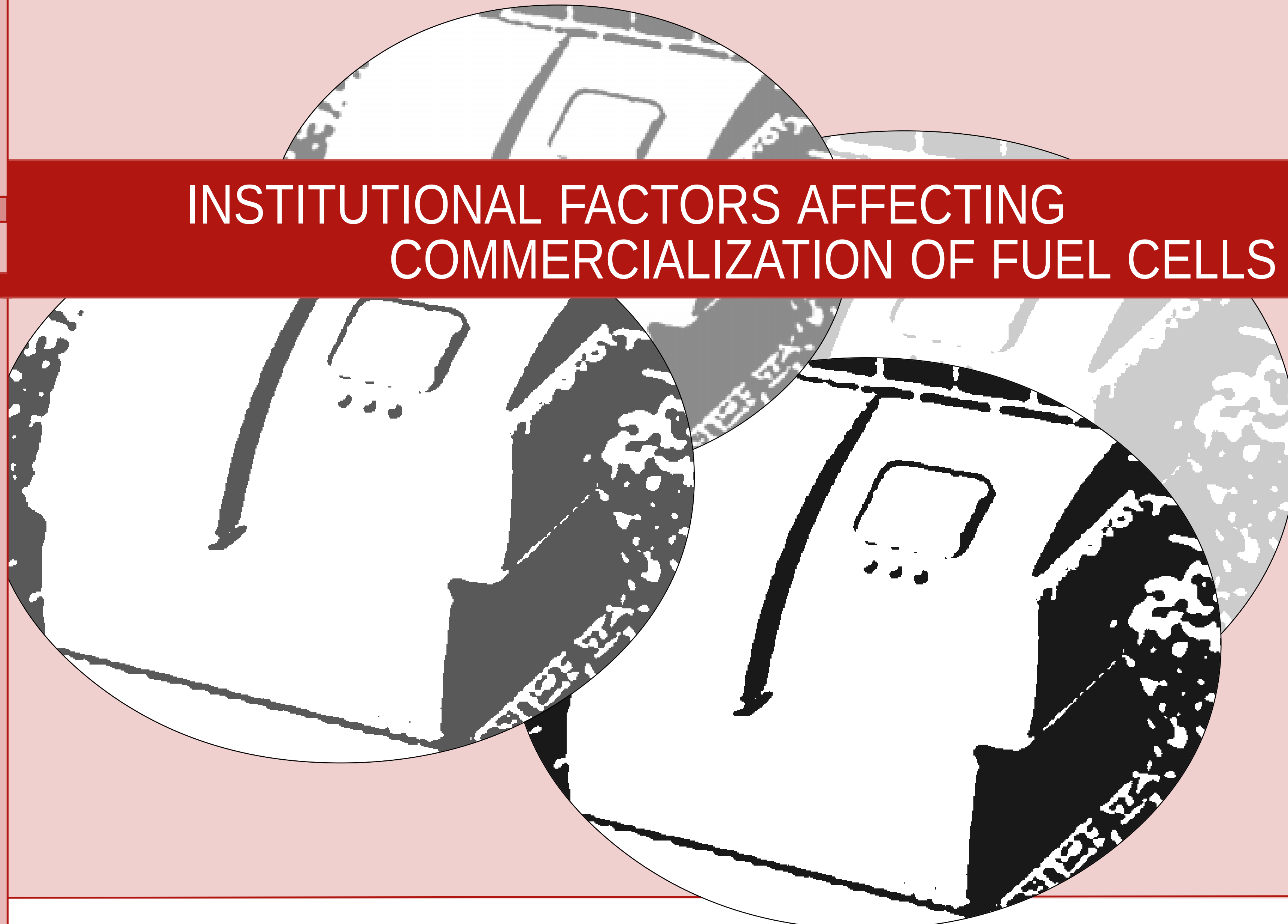
INSTITUTIONAL FACTORS AFFECTING COMMERCIALIZATION OF FUEL CELLS



U.S. Department of Housing and Urban Development
Office of Policy Development and Research

PATH

PATH (Partnership for Advancing Technology in Housing) is a new private/public effort to develop, demonstrate, and gain widespread market acceptance for the "Next Generation" of American Housing. Through the use of new or innovative technologies, the goal of PATH is to improve the quality, durability, environmental efficiency, and affordability of tomorrow's homes.

PATH, initiated jointly by the Administration and Congress, is managed and supported by the Department of Housing and Urban Development (HUD). In addition, all Federal Agencies that engage in housing research and technology development are PATH Partners, including the Departments of Energy and Commerce, as well as the Environmental Protection Agency (EPA) and the Federal Emergency Management Agency) FEMA). State and local governments and other participants from the private sector are also partners in PATH. Product manufacturers, home builders, insurance companies, and lenders represent private industry in the PATH Partnership.

To learn more about PATH, please contact:

PATH

451 7th Street, SW, Suite B 133
Washington, DC 20410
202-708-4250 (fax)
e-mail: pathnet@pathnet.org
website: www.pathnet.org

Visit PD&R's Web Site
www.huduser.org
to find this report and others sponsored by
HUD's Office of Policy Development and Research (PD&R).
Other services of HUD USER, PD&R's Research Information Service, include listservs; special interest, bimonthly publications (best practices, significant studies from other sources); access to public use databases; hotline 1-800-245-2691 for help accessing the information you need.

INSTITUTIONAL FACTORS AFFECTING COMMERCIALIZATION OF FUEL CELLS

Prepared for
U.S. Department of Housing and Urban Development

Prepared by
NAHB Research Center, Inc.
400 Prince George's Boulevard
Upper Marlboro, MD 20774-8731

December 6, 2000

Acknowledgements

The principal author of this report was Burt Goldberg with technical and editorial support from Chris Fennell, Jeannie Leggett Sikora and Joe Wiehagen. A special appreciation is extended to the staff of Energy Partners, LLC for their support and review.

CONTENTS

INTRODUCTION

Distributed generation (DG) involves the placement and use of small, modular electric generation, either integrated or stand-alone, close to the point of consumption. Fuel cells are poised to become an important component of DG in stationary applications involving commercial and residential buildings. Still under development and in the initial stages of commercialization, fuel cell technology competes with other DG technologies. These technologies include conventional small gas turbines and internal combustion engines, renewable energy generators such as photovoltaics (PV) and wind, as well as emerging microturbine technology. This report seeks to gain an understanding of the institutional and policy issues that provide barriers or opportunities for the commercialization of DG in general and fuel cells in particular in buildings. An intial review of the economics and regulatory evolution of stationary generation of electric power in the United States explains the origin of some of the barriers and opportunities that confront the commercialization of DG.

BACKGROUND

Evolution of Traditional Electric Utilities

The initial spread of electric energy occurred in a very open and competitive market, with many small utilities vying to supply energy to a specific customer in a given location. For example, at the beginning of the nineteenth century, Chicago had almost 50 utilities providing electric energy in many of the individual neighborhoods of the city.[1]

Eventually, however, electric utilities evolved into a highly monopolistic industry composed of a few hundred investor-owned firms. Technical factors were principal contributors to this change. The introduction of more efficient, big steam turbines and electric generators led to the construction of large, electric generation stations. The adoption of alternating current instead of direct current allowed transformers to step-up power from the central plant for long-distance transmission of electric current over high voltage overhead lines without experiencing significant losses. High voltage transmission permitted location of centralized power stations distant from the customer. Receiving and distribution substations then stepped-down high-voltage power and fed it to customers over local distribution lines.

The monopolistic tendencies of centralized production of power continued unabated as financial pyramid schemes resulted in utilities in many areas coming under the control of a small number of holding companies. Utility holding companies directly or indirectly held 10 percent or more of the outstanding securities of utilities on the public market. The Public Utility Holding Act (PUHCA) of 1935 broke up the very large trusts that controlled the nation's gas and electric distribution networks. Consequently, during the late 1930s and early 1940s, utilities underwent a major restructuring to prevent further exploitation of utilities and ratepayers by large holding companies.

Concurrently, in the period from 1930 to mid-1970, major advancements in technology, together with economic factors and high electricity demand fostered continued growth of larger centralized power plants. At that time, economies of scale offset large investments in big electric generators, since the unit cost of the investments in dollars per kilowatt-hour ($/kW) declined with increasing size of plants. Because of long distances between customers and power sources, electric power producers built their own transmission lines. Because they owned the transmission lines, electric power producers allowed no other producer to sell energy in their particular areas without their permission, exercising monopolistic control over their energy markets. Producers often made arrangements to sell excess energy to other monopolistic companies. This situation resulted in the creation of vertically integrated private utility companies that directly owned and operated generation, transmission, and distribution of electric energy.

Regulation of Utilities

The public sanctioned investor-owned utilities' monopoly status through a regulated system of profit, electricity prices, and production encouraged investment in large centralized power

[1] Dufour, Angelo U., "Fuel Cells – a new contributor to stationary power," *Journal of Power Sources*, Vol. 71, (1998). p. 20.

plants. Most utilities' rate of return was regulated under a cost-of-service (COS) approach. The COS approach guaranteed utilities' rates of return based on their "prudent" investment in plant and equipment, their so-called rate bases. Investment in large power plants, transmission and distribution facilities contributed to larger rate bases, which resulted in greater profits. This encouraged utilities to over-invest in their system despite regulators' efforts to require that they invest prudently. At the same time, regulations allowed thirty-year depreciation schedules on power plants which encouraged utilities to hold on to outdated investments in large centralized power plants and discouraged cost-saving innovation when adding new capacity. A few utilities adopted performance-based ratemaking (PBR), which takes into consideration fixed and variable costs in determining revenues, but often incorporating caps on price or revenue. Under the PBR approach, utilities had a stronger incentive to reduce costs rather than invest to obtain profits.

Period of Transition

During the 1970s, energy prices began to rise due to constraints on the availability of fuel resources and a number of environmental issues. Over time, the public became more concerned with the monopolistic power of utilities and confronted them with contentious issues related to their investment in costly nuclear power plants, storage of nuclear waste, and the pollution generated by fossil-fuel power plants. Pollution control devices required large amounts of money, which could only be offset by increasing the cost of energy to the consumer. Obtaining regulatory approval for large-scale power stations or rights-of-way for high-tension power lines was becoming increasingly difficult. The visual effects of high-tension power lines and substations as well as controversy over the biological effect of electromagnetic fields led to public resistance to expansion, which still exists today. Consequently, it was and still is extremely expensive and can take years of design, approval, and installation to build a traditional central plant generation, transmission, and distribution capacity. Because of increasing public concern over the cost of energy, a number of states required public programs to foster research, energy conservation, and affordable energy prices for the poor.

At the same time, despite the increasing use and application of electricity, a serious energy crisis spurred greater efficiencies in electric appliances and consumer energy consumption, lowering electricity's rate of growth.[2] Consequently, utilities found themselves with large investments in expensive plants operating less efficiently below full capacity. This forced utilities to be more cautious in their estimate of future electricity usage and to forestall investment in new generating plants. Also, during this period, utility economics began to favor economies of mass production over economies of scale. Technological advances in the aircraft industry fostered high volume fabrication of gas turbines driving down their cost and improving their performance. As a result of the increased efficiency and lower cost of smaller, reciprocating gas engines and gas turbine technologies, distributed generation (DG) began to emerge with the potential to become competitive with large central power stations.

Regulatory Reform

Partly a result of these issues, increasing energy prices, and a relatively stagnant electric utility generating capacity, the U.S. Congress passed a number of regulatory reforms. The Public Utilities Regulatory Act (PURPA) in 1978 established a precedent for establishing grid connections with nonutility, independent power producers (IPPs). PURPA granted special rights to sell power under protected contracts to so-called Qualifying Facilities (QFs) that met certain requirements in regard to operation, efficiency, fuel, size, and ownership. Also, utilities were required to buy power from QFs at the utility's cost of producing that power – known as avoided cost. Avoided cost is equivalent to the utility's cost of providing power, which is much lower than the retail rate they normally charge customers.

Some QFs were so-called Small Power Producers (SPPs) that were required to generate at least 75 percent of their power from renewable resources such as PV. Many QFs, however, were industrial cogeneration projects that provided combined heat and power (CHP), typically large, custom facilities ranging in size from five to 50 MW.[3] Cogeneration is an efficient process that generates steam and electric power from the same energy source. For example, waste heat from turbine exhaust gases that normally is released into the atmosphere in conventional plants is efficiently recovered to generate large volumes of steam. The steam, in turn, is used to provide space or process heat before being changed back to water and reused. The generation of two energy products from one fuel input generally lowers the cost of providing both energy products.

The use of cogeneration and renewable energy sources by private entities independent from utility power plants provided an excellent laboratory to resolve the issues involved in interface with the grid, especially as they apply to net metering (see discussion below). It opened utilities to partial competition and

[2] From 1978 to 1997, the increase in the number, size of housing units, and proportion of larger housing units in the United States resulted in an increase in the percentage of all residential energy provided by electricity from 23 to 35 percent. Despite this rise, in the same period, total residential energy consumption in millions of Btus per household decreased by 27 percent. All of the decrease occurred in the 1978-1987 period, with Btu consumption unchanged since then. From U.S. Department of Energy, Energy Information Agency, *Residential Energy Consumption Survey – Two Decades*.
[3] *Ibid.*, p.13.

established a precedent for the use of DG. It forced utilities to compare the costs of independently produced energy with costs of building new centralized power plants. Also, deregulation of natural gas lowered prices of gas an important fuel source for turbines and fuel cells. By the 1990s, expectations in regard to future long-term demand changed and electricity consumption was forecast to grow faster than originally projected. Many industrial consumers noted trends of competitive marketing in other regulated industries, and wanted to select electrical suppliers that would meet their requirements economically, reliably, and efficiently. Moreover, consumers began to chafe at the large regional variations in electricity prices. Consequently, these issues led to passage of the Energy Policy Act (EPACT) of 1992, which instituted deregulation, setting in motion fundamental changes to the structure of the electric utility industry.

Deregulation

The 1992 EPACT provided the broad framework for breaking up the utility monopoly, unbundling ownership of power generation, transmission, and distribution into separate entities. At the same time it set the stage for creating a more competitive wholesale market for power by giving buyers and sellers open access to the national transmission system. In the absence of a national law detailing a schedule for restructuring, most of the initiative for establishing retail choice has devolved to the states. The Federal Energy Regulatory Commission's (FERC's) order 888 in 1996 provided guidelines designed to encourage wholesale competition. By September, 2000, 25 states including Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, and West Virginia had passed legislation establishing retail competition.[4] The public utility commission in New York issued a comprehensive regulatory order introducing retail competition. Legislation is pending in Alaska and South Carolina. States that have obtained consensus with stakeholders on how stranded costs (the values of assets, which are no longer economic as a result of deregulation) should be determined and who should pay for them have a good chance of success in implementing deregulation.

Progress in the implementation of state acts, however, has been slow. Like other state rating systems, the rating of state progress in regard deregulation has its critics. Despite criticisms, the Center for the Advancement of Energy Markets (CAEM) published a national Retail Energy Deregulation (RED) Index that measured the progress that individual states made as of 1999 in moving from the monopoly model of public utility regulation to the competitive model.[5] Only a few states— in ranking order Pennsylvania, New York, Nevada, Maryland, Maine and Massachusetts— scored above 50 on a scale of 0 (no progress) to 100 (completely competitive).

Some states are adopting a wait-and-see attitude, expecting to learn from the progress and mistakes of so-called "early adopters" of deregulation, while others fear that relatively low electricity rates may rise if deregulation is implemented. Indeed California, the first state to address deregulation when the California Public Utility Commission issued its proposal to radically restructure its electricity markets in April 1994, did not implement deregulation until March 1998 after two years of debate and appears to have encountered some problems. It's rated only 11th in the nation by the RED index. Clearly, the nation is in transition in implementing deregulation, since the average index for the nation, as a whole in 1999 was only 18, while the median was 7 (out of 100). Consequently, a variety of organizations, including those still regulated under the old system and those that are emerging under the new system exist to install or service DG in homes.

To develop a competitive market for power, utility generating assets are being separated from distribution and transmission. Although the transition has been slow, some progress has been made. In 1998, 239 investor-owned utilities (IOUs) comprised only about eight percent of the more than 3,000 utilities regulated under the U.S. Code of Federal Regulations, but comprised 73 percent of the generating capacity of all utilities and 75 percent of all utility electricity sales.[6] The federal government, local public jurisdictions, and cooperatives own the other utilities. Prior to deregulation, IOUs were vertically integrated utilities owning generation, transmission and distribution assets. From 1997 to September 1999, however, 51 IOUs or 32 percent of all IOUs owning generating capacity in the United States divested or were in the process of divesting 17 percent of the total U.S. electric utility capacity.[7]

During the transition, as of 1998, regulated vertically-integrated utilities that generate, transmit, and distribute power comprised only about 59 percent of all 239 IOUs. They exist together with IOUs that only generate and distribute power (DisCos), comprising 11 percent of all IOUs, and wires companies that only own and operate distribution lines, about 14 percent of all IOUs. In some case, affiliates or subsidiaries of IOUs own and operate transmission companies, about three percent of all IOUs (See Table 1).

---

[4] Energy Information Agency, U.S. Department of Energy, "Status of the Electric Power Industry: Industry Restructuring Activity as of September 2000."p.1.
[5] Center for the Advancement of Energy Markets, *RED Index 2000*, http://www.caem.org/red_index_2000.htm, 1999, updated March 14, 2000.
[6] Energy Information Agency, U.S. Department of Energy, "Electric Power Industry," January 2000, pp.1-11.
[7] Energy Information Agency, U.S. Department of Energy, "The Changing Structure of the Electric Power Industry1999: Mergers and Other Corporate Combinations," December 1999, Chapter 6, p.1.

Wires-only companies or DisCos step-down power from high voltage transmission lines over local distribution lines (wires) for distribution to final customers and energy service providers (ESPs) or energy service companies (ESCOs) (see discussion below). Wires-only companies charge customers for use of distribution lines. In addition to performing distribution functions wires-only companies also sell electricity to end-use customers. So-called nonutility or independent power producers (IPPs) also sell power at wholesale prices to vertically integrated utilities, DisCos, or energy service providers such as ESPs and ESCOs.

In 1998, about 400 ESPs or ESCOs–new classes of power marketers–sold electricity and provided ancillary energy services to end use customers. Such services can include energy project development and operation, management of energy facilities, risk management, and financing. As market makers for distributed generation they can provide these functions from either the system or customer side of the meter. At the option of customers, ESPs and ESCOs may charge for other ancillary services such as assuring power reliability, providing emergency back up power, and offering demand side management (DSM).

To aid in assuring equal access to wholesale markets, FERC Order 888 enunciated principles for the formation of Independent System Operators (ISOs).

Functions	IOUs		Other Utilities*		Total		Non-Utilities**	
Vertically Integrated	No.	% Total	No.	% Total	No.	% Total	No.	% Total
Generate & Transmit, Only	140	58.6	155	4.6	295	8.2		
Transmit & Distribute, Only	10	4.2	79	2.3	89	2.5		
Generate & Distribute, Only	6	2.5	133	3.9	139	3.9		
Generate Only	25	10.5	428	12.7	453	12.6	1,930	100.0
Transmit Only	11	4.6	13	0.4	24	6.7		
Distribute Only	7	2.9	27	0.8	34	9.4		
Other	34	14.2	2,522	74.9	2,556	70.9		
Total	239	2.5	10	2.9	16	0.4		
Power Marketers	400	100.0	3,367	100.0	3,606	100.0	1,930	100.0

*Publicly Owned (2,009), Federally Owned (10), Cooperatively Owned (912) ** Cogenerators (QF or Non-QF), QF Small Power Producers, non-QF other or independent power producers (IPPs)

Source: Energy Information Agency, U.S. Department of Energy, *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations,* Chapter 2,Organizational Components of the Electric Power Industry.

Table 1: Investor-Owned Utilities (IOUs), Other Utilities, and Non-Utilities by Function, 1999

ISOs are regional entities subscribed to by collaborating utilities, but authorized under State legislation and approved by FERC. ISOs manage and operate the transmission grid owned by one or more electric generation companies. They are designed to assure equitable access to the transmission grid. It is the intention that ISOs also should improve the operating efficiency by creating uniform transmission rates and providing market-oriented approaches to more efficient pricing methods. They are also charged with ensuring the short-term reliability of grid operations by making planning decisions in regard to peak power requirements, implementing emergency power programs, and defining and valuing ancillary services. In this regard, they must comply with relevant standards set by the North American Electric Reliability Council (NERC), which was created in 1968 as a result of the large Northeast and Canada blackout, to assure the long-term reliability of the grid.

As of March 31,1998, only four ISOs, California, New England, Pennsylvania, New Jersey, and the Electric Reliability Council of Texas had started operation of ISOs, while seven others are in the planning stages.[8] The Midwest ISO has an application pending with FERC, while no ISO has been proposed for the South. Although ISOs have some momentum, utility participation is fragmented, and

[8] Energy Information Agency, "The Changing Structure of the Electric Power Industry: Selected Issues, 1998, Executive Summary," pp. 2 –3.

[9] Dynegy, Inc., traditionally a seller of natural gas liquids, now obtains more than half its earnings from selling natural gas and electricity in the deregulated market. It acquired the electric utility Illinova, Inc., in February 2000. Federal regulators wanted Illinova's transmission facilities, serving 650,000 gas and electric customers in Illinois, to be controlled by neutral entities. Consequently, Illinova planned to have Dynegy remain as part of a non-profit Midwest Independent System Operator (ISO). Dynegy, however, wants Illinova's network of high-voltage transmission lines and substations transferred to a for-profit transmission company.

many disputes regarding ISO decisions remain unresolved.[9]

In summary, the following components are embedded in retail electricity prices charged by DisCos, wires companies or ESPs:

- sale charges consist of negotiated wholesale price for power plus margin;
- charges imposed for use of transmission lines regulated by ISOs, which can include a reasonable margin as determined by the ISO when the transmission line is owned and operated by utility;
- wire charges for use of local distribution wires plus margin; and
- transition costs (see discussion below) incurred by the utility for assets made obsolete or redundant by deregulation.[10]

In addition to the existing IPPs that generate energy from CHP and renewable resources such as PV under PURPA, FERC Order 888 provided opportunities for the use of bulk power transmission grid to suppliers other than utilities, such as independent large conventional power generators as well as DG energy providers. These new nonutility IPPs can sell power to distributors, who make use of third parties' grids between the IPP energy production sites and the final customers. The ISOs ensure that owners of the transmission lines provide IPPs equitable access to the grid. In 1993, IPPs generated a small, but significant amount of the nation's total energy generation, about seven percent.[11] By 1998, however, the nonutility share of total industry capacity rose to 12 percent, while the number of IOUs decreased by nearly eight percent and their (nameplate) capacity decreased by five percent, largely through divestitures of generation facilities as a result of deregulation.[12]

> *"Deregulation, now underway in half the country and functioning nationally at the wholesale level, allows new players – some affiliated with utilities, some not – to build power plants and sell electricity. Prices are supposed to be set by competitive markets. Risks are borne by investors not ratepayers. At the same time, utilities are surrendering control of long haul transmission lines to new nonprofit operators, …which are supposed to ensure fair access to the grid—the multistate system of high voltage lines. Under this new regime, energy prices should have dropped as companies raced to compete with one another. But the massive U.S. energy infrastructure wasn't designed to serve as the backbone of a free market. On hot summer days, when there's little or no surplus electricity in the nation's most populous regions, generators can charge prices far in excess of their production costs and be confident they'll be tapped for service by grid operators who must keep the lights on at any cost. Utility holding companies that still control transmission lines have an added advantage: They can effectively lock out cheaper competitors. The new regional grid operators, called independent system operators or ISOs, eventually will be in charge of preventing manipulation. But as nongovernmental organizations, they won't have the basic investigative tools, like subpoena powers or the ability to impose significant penalties. FERC, which does have those powers, rarely uses them, preferring to let the market discipline itself."*
>
> ***Rebecca Smith, "Power Deregulation Opens New Lines to Profit," Wall Street Journal, August 4, 2000***

Impact of Deregulation on Distributed Generation

In view of these trends, some expect strong interest among ESPs, distribution companies, and manufacturers in DG and see increase in DG based on the following:[13]

- "ESPs are interested in installing DG and DSM on the customer side of the meter. This includes self-generation service, microgeneration, dispatchable load management, and energy efficiency improvements.
- ESPs are also interested in connecting DG to the system side of the distribution system to provide direct access energy and ancillary services. Such DG technologies include gas turbines, fuel cells, reciprocating engines, photovoltaics, and storage.
- Electric distribution companies are exploring or have begun using DG such as gas turbines or flywheel storage on T&D [Transmission and Distribution] site (such as substations and distribution poles) or on customer sites, as a substitute for T&D expansion, to serve congested areas, to provide reliability and other ancillary services, and to avert bypass. Distribution companies are also interested in DSM measures for these reasons.
- Nationally, electric utility affiliates are exploring installing distributed generation such as gas turbines on customer sites as an alternative to T&D expansion, bypass or loss of sales to competing ESPs.
- Some gas distribution companies or affiliates are exploring offering distributed generation such as gas turbines on customer sites as a competitive alternative to service through the electric distribution system.

[10] Gas Research Institute, *The Role of Distributed Generation in Competitive Energy Markets*, Distributed Energy Forum, March 1999, p. 11.
[11] *Op.Cit.*, Dufour, p.21.
[12] *Op.Cit.*, "Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations," Chapter 6, p. 6.
[13] Letter to Richard Bilas, president, California Energy Commission, June 5, 1998, p.3.

- Makers of DG hardware seek to sell it to ESPs, end users and distribution companies."

Empowerment of IPPs and DG energy providers, however, does not guarantee implementation and many of these options will be examined below.

Under the new competitive market conditions, previous state regulations that required utilities to administer public interest programs such as research and development, energy conservation, support for renewables, and social programs are no longer required. In the new competitive market, electric power is a commodity product. Producers can therefore avoid risks in the marketplace by focusing on low cost, reducing the level of capital investment, and providing for short lead times when adding capacity. Many states are evaluating new mechanisms to maintain these programs.

Under deregulation, IPPs providing DG based on emerging, energy efficient fuel cells, existing renewable energy resources, or gas turbines can offer economic benefits that have the potential to reduce market risks for producers and DisCos. Deregulation, however, is a work in progress and, as will be discussed below, many economic and institutional issues in regard to fuel cells as a form of DG in a deregulated environment remain to be resolved.

ECONOMIC OBSTACLES TO COMMERCIALIZATION

Introduction

Barriers to commercialization of fuel cells occur at two levels. The discussion that follows focuses on the basic economic and institutional obstacles common to DG in residential markets and, therefore, also apply to fuel cells. These barriers are addressed before considering, in another report, a second, more detailed level of barriers, based on technical attributes of fuel cells as they affect economics in competition with other distributed sources of energy.

Builders are key decision-makers in commercialization of innovative products in the residential segment of the construction industry.[14] The discussion therefore considers their points of view, organized around the basic question: "Why should builders consider DG in a new homes or subdivisions?" This fundamental question leads to related, more specific questions builders are likely to ask:

- Where or at what point in the system will DG be installed?
- Who will install and pay for DG?
- How does DG benefit potential customers?
- Will DG help builders market new homes?
- How will DG impact builders' costs of construction?

Stand-Alone Distributed Generation

One option is to install DG on a customer's site at the customer's side of the meter as a stand-alone source of power independent of the power grid. This option is quite popular accounting for a substantial portion of DG that exists today. Since the decision to install and use DG is entirely up to the customer, it apparently encounters little in the way of institutional obstacles. Three general variations of this option are possible:

- In one variation, DG provides all customer requirements for power (baseload), generating power alone or through CHP. This is a very practical alternative in rural locations where no power distribution lines exist and where the cost of connection from the nearest utility would be prohibitive. In this case the utility infrastructure is not used at all.
- In another variant, DG is installed at the customer's site with no connection to the utility and is only used as backup supply, should utility power fail or not be able to meet peak demand. Customers often install small, low-cost DG such as diesel gas generators to provide this kind of power. This type of DG probably accounts for a substantial portion of DG in use today. In certain geographical areas where power capacity is constrained, utilities may offer the customer incentives for the use of this type of DG under conditions of peak demand, because it relieves load on the system thereby preventing "brown-outs" or power outages.
- In another alternative, customers install DG with no feedback connection to the utility, but DG supplies all or substantial portion of energy demand and the customer uses the utility only in emergencies when DG fails to provide power. Certain industrial or institutional users that place a high value on power reliability may find it economical to make a substantial investment in DG, especially in geographic areas with

[14] NAHB Research Center, *Diffusion of Innovation in the Housing Industry*, report prepared for the U.S. Department of Energy, November 1989.

frequent power outages. Small losses of power, even though intermittent, can cause substantial economic loss for certain industries that, therefore, require an uninterruptible source of power. If a number of large customers turn to DG for all of their power, however, some problems may occur. If, for any reason, one large customer or a number of customers have to return to the grid for all their power needs, a large surge in power demand may disrupt the grid. Also, if a significant number of large customers rely on DG in a given area they would not generate sufficient revenue for the utility or distribution company to maintain and service the grid.

Stand-alone DG is likely to continue to increase. For the most part DG demand for emergency purposes is for smaller, low-cost generating technologies. In addition, the present market appears favorable to this type of DG, especially if price of power escalates and reliability continues to decline because of capacity constraints. Installation is more likely to occur, however, in commercial buildings than in residential buildings. If stand-alone DG is installed in residential buildings, it will most likely function as back-up power for existing homeowners who see it as a solution to frequent power outages in their areas. Installers will have to comply with local building codes and permitting procedures.

"Oracle Corp., for one isn't taking any chances. Shaken by the huge power failure in August 1996, the big software company has spent more than $6 million to build its own electrical bunker, completed with a substation and generators capable of supplying thousands of servers with electricity at its headquarters in Redwood Shores, Calif. While giant manufacturers have done this for decades, other commercial users are starting to follow suit. "What's the self-sufficiency worth to us?" asks Jeffrey Byron, Oracle's energy director. "Millions of dollars per hour. It's so important, you almost can't calculate the value, to us and our customers." The problem facing Oracle and others isn't likely to go away soon. The incomplete nature of deregulation has produced planning paralysis that could have long term consequences. Old-line utilities shied away from adding capacity, worried they wouldn't be able to rcoup their investments in a truly competitive energy market. Independent generators, who were supposed to fill the need, mainly held back held back until they could figure out which markets would be most lucrative. Regulators, who were often confused as to whether they should be enforcing the old rules or help tear them down, let things slide."

Rebecca Smith, "New Rules, Demands Put Dangerous Strain on Electricity Supply," Wall Street Journal, May11

There is some concern, however, whether the current window of opportunity for DG that results from inadequate utility reserves and contributes to poor reliability will last, especially if existing planned capacity comes on-line and deregulation stabilizes. According to the NERC, "plans have been announced for construction of about 51,600 MW merchant generation by the end of 2001. By the summer of 2001, demand is projected to grow by 27,500 MW. More than half of the announced generation will be needed to keep pace with demand growth in the next two years." [15] The drop in capacity margins from projected levels over the last three years has been "disconcerting," but if the additional capacity comes on-line during the next 18 to 24 months and NERC demand projections hold, the margins will stabilize.[16] However, if demand grows at the historic growth rate of 2.6 percent, capacity margins could drop by another four percent.

Also, since DG is unable to receive economic return from a connecting utility for the excess energy it might produce, it is more difficult to economically justify DG stand-alone options. Moreover, the cumulative impact of a large shift to DG using natural gas as a source of power may cause pollution problems, resulting in Environmental Protection Agency (EPA) restrictions that thwart further expansion. Fuel cells, because of their low emissions, may have an advantage in this regard, but at present it remains a high-cost alternative.

Distributed Generation Connections with Utilities

Connecting DG with utilities presents an entirely different set of options and numerous economic and institutional challenges that are a subject of the remainder of this report. Advantages in connecting DG with the utilities are the ability to use all the energy that DG is capable of producing and at the same time such use provides revenue that helps to make DG economically feasible.

Connecting DG to the electric grid is likely to involve other major players such as builders, utilities, and other parties as well as the customer. DG is likely to be installed:

- At DisCo sites such as substations or power poles – In this case DG is used as part of the utility infrastructure near

[15] North American Electricity Reliability Council, "Reliability Assessment, 1999-2008." May 2000, p.6
[16] *Ibid.*, pp.9-11.

the point of use. DG may service a group of homes in residential developments ranging in size from a few homes to hundreds of homes.

- At the utility- or system-side of the meter at the individual customer's home
- At the individual customer's home on the customer's side of the meter, either:
  - providing the entire home's electrical demand using the connection to electric utility grid only as back-up supply to the fuel cell, if the fuel cell should fail, or
  - supplying only a portion of the home's electrical demand with the remaining demand serviced by the electric utility system.

DG located at the utility side of the meter either at the substation or at the customer's location is not likely to be of concern to builders, since the utility bears the cost of installation. It is assumed that if a utility makes the decision that DG is the most economical solution to expanding power to homeowners, it will ultimately benefit and make economic sense to homeowners as well. The builder will want to be convinced, however, that a utility or other provider installing DG on the system side of the meter at the customer's site will not add to construction costs, impose health and safety hazards to customer, and will properly install, maintain, and service DG.

These same builder concerns apply to installation of DG at the customer's site on the customer's side of the meter. If a vertically integrated utility producing electricity at some remote location or wires-only company is unlikely to install DG on the customer's side of the meter, the decision to install DG on the customer side of the meter becomes an option for the ESP, builder, or the prospective homeowner. In considering such an option, the builder will have additional concerns regarding the economic feasibility and benefits of DG that might accrue to the builder or homeowner and who will be responsible for installation and maintenance of the DG.

A variety of entities exist that can install DG for builders:

- DisCos, that own generation and distribution;
- Wires-only companies that own only distribution assets and do not generate electricity, but charge for the delivery of electricity to customers;
- ESPs and ESCOs that sell retail electricity and other energy-related services to customers; and
- Manufacturers' distributors, qualified retailers or dealers, or other certified installers in the private sector.

According to a general model that uses industry available data with supporting assumptions, a typical DG system produces power at a cost of between $0.07 and $0.15 per kWh.[17] The range reflects variations in the fixed cost of particular DG technologies as well as any costs related to secondary distribution lines if the DG is installed on the utility side of the meter.

Installations on the Customer Side of the Meter

Economic and institutional obstacles deter DisCos or vertically integrated utilities and wires-only companies from installing DG on the customer side of the meter because:

- Customer-side DG decreases metered energy demand, thereby reducing utility revenues and profits and therefore is an unlikely option for a vertically integrated DisCo or other utility.
- A wires-only company, for example, delivers but does not generate or sell energy. It is responsible, however, for metering a customer's retail power consumption and using the measured consumption as a basis for its delivery charges. DG installed on the customer's side of the meter will reduce the customer's metered energy and therefore the wires company's charges for the use of wires. Consequently, a wires-only company is unlikely to be motivated to install DG on the customer's side of the meter.
- Both utilities and wires-only companies are more likely to install DG on the customer-side of the meter if they are allowed to charge for the energy it produces. However, this would reduce the benefits of DG to the homeowner and the incentives for customer-side installation.

Installations on the Utility Side of the Meter

Installations on the utility side of the meter are of interest to manufacturers of DG because utility-side installations could provide an important market for DG and could be instrumental in facilitating DG's commercialization. Such utility-side installations will depend on the adequacy of utility's generating or transmission and distribution (T&D) capacity to accommodate downstream peak loads in areas where builders are erecting new homes. With no constraints on T & D capacity, the utility has adequate capacity and can use existing infrastructure by only increasing variable operating costs (such as fuel costs) to increase generation. When constraints exist, however, the capacity of utility infrastructure is inadequate to accommodate increased demand, requiring investment in the fixed cost of physical facilities in addition to the necessary increase in operating costs.

Whether a vertically integrated utility or DisCo finds it economically feasible to install DG at a new home at the utility side of the meter depends on the extent and type of capacity related constraints that exist in the utility's system (See Table 2):

- Installation of DG at the utility side of

[17] Arthur D. Little, *Distributed Generation: Understanding the Economics*, An Arthur D. Little White Paper, 1999.

the meter at builders' new home locations may be feasible if inadequate utility capacity exists for both generation and T&D or T&D alone. In such cases, the utility's added fixed and variable costs to provide both generation and T&D or T&D alone would be comparable to or exceed the costs of installing DG, making a DG option at the utility side of the meter competitive.

- If only the utility's generation capacity is constrained, the estimated fixed and operating cost of adding new central generation capacity would be less than the cost of DG and the utility would be unlikely to install DG.
- The estimated added operating expense for generation and T&D to meet increased demand when the utility has no capacity constraints, would also be less than the DG installation, thereby deterring the utility from installing DG.

Wires-only companies are not concerned with generation capacity, but the following situations in regard to T&D capacity constraints affect installation of DG at a new home at the utility side of the meter (see Table 2):

- When no capacity-related constraints exist at the builders' location the wires-only company's estimated added cost of providing T&D (less than a $0.01 per kWh) would be miniscule compared to the installation of DG, making it an unlikely option.
- If the wires-only company finds that the capacity of T&D in the area where the builder is constructing new homes is inadequate, estimates indicate that the added fixed cost of extending T&D would be about the same as installing DG. As a result, it may be cost effective to install DG.

"San Diego is a good illustration of how deregulation isn't working out as expected. The flourishing city, home to cell-phone suppler Qualcomm Inc. and a slew of other high tech firms, doesn't have enough local generating plants to meet its growing needs. It also is poorly connected to plants elsewhere in the region. The transmission lines simply aren't numerous enough to allow San Diego Gas & Electric Co., a unit of Sempra Energy, Inc., to import enough juice, according to California Independent System Operator, a nonprofit corporation that manages the state's electric grid. That leaves San Diego dependent on the two existing generators, Dynegy Inc. and Duke Energy Corp. that recently bought the plants from San Diego Gas & Electric. More plants are needed, but many generators want a special price zone set up before they will build within San Diego, because its transmission problems limits their ability to sell power outside the area. Economists believe, however, that such a small market wouldn't have enough bidders to produce competitive prices, says Severin Borenstein, director of the University of California Energy Institute at Berkley. Because demand for energy isn't as sensitive to price as most commodities, generators could raise prices by almost 30-fold whenever demand peaks, while staying within a statewide price cap."

Rebecca Smith, "New Rules, Demands Put Dangerous Strain On Electricity Supply," Wall Street Journal, May 11, 2000

Stakeholders	Range of Utility Cost ($/kWh) to Meet New Demand under Alternative Constraints: Generation + T&D	Generation Only	T&D Only	No Constraints
Vertically Integrated Utility	.09 to .22	.04 to .07	.07 to .18	.02 to .04
Wires-Only Co.	NA	NA	.05 to .16	< .01
DG Option	.07 - .15			

Source: Arthur D. Little, *Distributed Generation: Understanding the Economics, An Arthur D. Little White Paper,* 1999, pp. 8-9.

Table 2: Range of Utility Cost ($/kWh) to Meet New Demand under Alternative Constraints, Compared with DG Option

Institutional Obstacles

Even in situations where utility-side DG is economically feasible, however, vertically integrated utilities or DisCos might still prefer to invest in additions to existing T&D rather than DG under the cost of service (COS) method of pricing permitted by regulations. The larger investments in existing facilities under this costing procedure offer greater profits in the long term. Also, a major aim of deregulation is to break up the utility monopoly by separating the generation of power from its transmission and distribution. DisCos would be in a good position to determine when and where T&D capacity is needed. Many stakeholders, however, view any decision by DisCos to install DG on the utility side of the meter as anti-competitive, since they would be generating electricity in addition to their T&D functions.

Other Options

ESPs and ESCOs

Adding DG to homes on the customer's side of the meter may offer newly created

ESPs or ESCOs in a deregulated environment more flexible DG opportunities for the following reasons:

- They are not saddled with COS requirements of regulated utilities or DisCos.
- They do not have a vested interest in maintaining utility revenues by installing DG on the utility side of meters. In fact, those that are market makers can negotiate directly with producers of electricity to obtain favorable wholesale prices in direct competition with DisCos.
- ESPs and ESCOs are capable of assembling an integrated package of services for potential customers such as determining economic feasibility and technical requirements for DG, executing Demand Side Management (DSM), and performing installation and subsequent servicing of DG. Incorporating such high-value services may provide ESPs with the opportunity to garner more profit than the pure-play strategy of utilities that supply only energy.
- Many new ESPs and ESCOs, however, are formed as affiliates or subsidiaries of integrated utilities.[18] Consequently, it is unlikely that these ESPs will install customer-side DG in its parent company's area of distribution where it will result in a revenue loss for the parent company. Such an installation may occur, only if it is part of a system wide expansion sponsored by the parent company. This does not prevent ESPs, however, from performing such installations in another integrated utility's jurisdiction.

Builder ESPs

The feasibility and/or profitability of ESPs installing customer-side DG for builders in individual homes compared with the installation of DG for a large number of individual homes in a new subdivision has not been determined. At the subdivision level, for example, DG can occur as a micro-grid–one installation of large capacity positioned at a substation, or a large number of installations of smaller capacity in individual homes. It may be possible for builders or developers of a subdivision to become ESPs by hiring subcontractors or forming subsidiaries to install, service, and maintain DG and by eventually marketing and selling DG energy to others on the grid. Builder-ESPs could develop home marketing programs highlighting energy-efficient subdivisions of new homes, coordinating DG activities with building energy conservation measures and demand side management. Benefits could accrue to customers in the form of energy savings and reliable power and to the builder in terms of long-term cash flow or profit.

The feasibility of a builder-owned and -operated micro-grid would depend on whether the builder's financial strategy favors a quick return on capital or long-term cash flow. Builder involvement has a number of advantages and disadvantages. The major advantage of such an operation is its potential to provide greater margins and a consistent, long-term cash flow that could overcome the cyclical variations that have plagued and deterred investment in home building. The major disadvantage is that the builders would be saddled with a long-term investment in the complex economics of an unfamiliar technology. Builders and/or their subcontractors would be acting as brokers, negotiating directly with utilities on behalf of homeowners in a spot market for energy that is complicated by an industry in transition as a result of deregulation. Builders could be in direct competition with utilities that could have a competitive advantage in being able to serve the micro-grid more efficiently with existing generation facilities.

Customer Benefits and Costs

The assessment of opportunities to install DG thus far discussed the installed cost of DG only from the utility's point of view in terms of $/kWh of electricity produced. Potential energy savings and other benefits of DG have yet to be considered from the builder's or homeowner's point of view, comparing benefits to a customer with the installed, operating, and maintenance costs of DG of a given kW capacity. If builders and their potential customers could realize and be convinced of the tangible benefits from DG, builders might encourage the installation of DG. For enlightened builders, DG could be an important tool in improving their competitive position and expanding their market by differentiating their product, eventually resulting in increased revenue and profits.

The specific application of DG in providing energy to the home can influence the amount of benefit and cost that accrues to the customer. DG could provide:

- peak shaving - provide customers with energy during peak periods of demand, providing the customer with an alternative to paying for higher cost energy during peak hours, if time-of-use rates are in effect;
- grid support – reduce utility line losses to the customer in remote or congested portions of the T&D system;
- combined heat and power (CHP) – produce electricity and useful heat at the same time, providing low cost energy to the customer and increasing efficiency and cost-effectiveness of DG; and
- standby power – provide customers with reserve capacity and improved reliability during peak periods or possibly in outages.

---

[18] An affiliate company is one in which parent company has direct or indirect ownership of five percent or more of the voting stock. A subsidiary corporation, on the other hand, is one in which the parent corporation owns at least a majority of the shares, and thus has control. (Black's Law Dictionary, 5th Ed.)

The attractiveness of applications can vary according to the type of customer. For example, some commercial customers may place a high value on standby power for the conduct of their business and are willing to pay for it while residential customers may be relatively indifferent to this application of DG.

Customer Gross Energy Savings

Regulated utilities, along with their primary responsibility of producing and distributing energy, were formerly responsible for providing in one-package applications relating to reserve backup or standby power and power factor correction and voltage support in the interests of maintaining power reliability and quality (See Glossary). Under deregulation many of these applications are being unbundled as ancillary services and priced separately. Some DG technologies may have the capability to provide several applications simultaneously, providing multiple monetary benefits to the customer. For example, DG could provide baseload power to customers throughout the day, allowing them not only to save energy during peak hours, but also to sell unused off-peak energy to the grid, reducing utility line losses and relieving T&D congestion.

The monetary benefit of DG to homeowners depends upon a number of factors:

- If the utility adopts time-of-use rates or demand charges that impose higher retail prices for energy during peak periods, homeowners will save a larger amount of money using DG than if a utility charged a flat rate all day. Not all utilities impose time-of-use rates, but under deregulation it is anticipated that most will.
- The monetary value of energy savings to the homeowner will be greater or less depending upon the rates the utilities or others on the grid compensate homeowners for the energy they return to the grid. Homeowners will incur greater benefits if utilities compensate them with the same high retail prices that utilities usually charge other customers for energy, but if the utilities pay the homeowner for energy based on lower wholesale prices or so-called avoided costs of producing energy, monetary benefits will be lower.

Balanced against the gross monetary benefits to the consumer, the customer incurs costs related to DG operation and maintenance as well as installation.

> *"Where people have a power quality need, price is not an issue," Mr. Wilson (director of strategic panning for Caterpillar) said. He predicts strong growth for Caterpillar's generator sales to a "premium" market of users for whom price is no object when it comes to reliable backup energy. Such users are willing to pay the equivalent of $20 per [kwh] for backup supplies, compared with about seven cents a kilowatt, on average, for electricity drawn directly from the utility grid. Although it varies by state around the nation, utility regulators generally define a momentary power loss as one lasting one to five minutes. Such interruptions can cause havoc in stock-trading systems, automated paper mills, and other computer-driven processes unless there is backup power generators and equipment to switch them seamlessly. Addressing the new economy's power needs, however, is not simply a matter of improving the utility grid. Studies show that 70 percent of disruptions originate from electrical problems at customer sites, according to Richard P. Bingham, manager at Dranetz-BMI, a power quality product and consulting company, in Edison, N.J. "Laser printers often take out computers when the heater comes on," said Mr. Bingham, citing but one example. Electronic ballasts in overhead lighting and compressors in soda machines also cause unexpected loads. And electronic devices, like drives that adjust speed on motors to save energy, generate electrical interference on lines that power them. The interference can trip up other equipment unless it is cancelled by filtering devices.* ***Barnaby J. Feder, "Digital Economy's Demand for Power Strains Utilities", The New York Times, July 3, 2000, p. C1.***

Operating and Maintenance Costs

To derive the true or net energy savings to the customer, the annual operating costs associated with DG must first be subtracted from the annual value of benefits a customer might receive from reduced energy purchases or sales of energy to the grid. Annual operating costs consist of fuel costs as well as operating and maintenance costs. Fuel costs, in turn, are a function of the efficiency of the DG technology under consideration as well as fuel prices, which may vary according to the market and local conditions.

Fuel Costs

Aside from maintenance costs and DG efficiencies, a principal variable determining DG operating cost is fuel cost, which is a function of variation in fuel prices in geographical areas and type of fuel.[19] For example, one study examined how variation in fuel prices affected changes in annual energy savings of a 50 kW microturbine for a commercial customer, using avoided electricity cost and simple payback as investment-return criteria.[20] It

[19] Fuel costs are zero for Solar Electric DG Systems.
[20] *Op. Cit.*, Arthur D. Little, *Understanding Economics*, pp. 13-16.

determined that DG would be successful in states where high electricity prices and low gas rates coexist such as California, Illinois, and New York.

The economic feasibility of fuel cells and other DG that rely on natural gas are heavily influenced by fluctuations in the price of natural gas. The market for natural gas has typically been subject to considerable price volatility, facilitating the development of financial markets that trade in natural gas and hedge against variation in prices.

Although the Energy Information Administration (EIA) acknowledges, "uncertainty with regard to estimates of the nation's natural gas resources has always been an issue in projecting production, and could affect prices," it is relatively optimistic concerning the supply of natural gas resources. [21] It bases its positive outlook on increased imports from Canada and technology advances that have both reduced effective exploration and development costs, and increased the recoverability of in-place resources.

Prices of natural gas actually declined from 1997 to 1998. [22] Mild weather lowered demand. Lower prices from competing fuel such as oil as well as availability of abundant gas supplies from domestic as well as foreign sources also contributed to declines. In contrast, the average wellhead price of gas in the summer of 2000 represented the highest annual wellhead price on record in nominal terms and the highest annual average price since 1985 in real terms, according to the EIA.[23] Moreover, "U.S. natural gas consumption is expected to grow 1.8 percent annually from 1998 to 2020 — faster than any other major fuel sources, mainly because of the growth in gas-fired electricity generation."[24] High demand combined with a low level of storage is expected to contribute to higher prices for the remainder of 2000. Since producers will not immediately be able to meet demand increases, EIA foresees higher prices continuing in the short term, and declining prices in the longer term before rising again in 2020.

The timing of a projected long-term decline in natural gas prices relative to the period of fuel cell commercialization can have a major impact on the economic feasibility of fuel cells. Moreover, the increased use of DG dependent on natural gas combined with the expected increase in electricity generation based on gas turbine technology could generate higher than expected demand, putting an upward pressure on gas prices. Even if DG could succeed in substituting for a significant portion of planned large generation facilities, the positive or negative impact on the overall consumption of natural gas remains an issue that is subject to further investigation.

Other Operating and Maintenance Costs

Table 3 indicates the relative efficiency as well as operation and maintenance costs for a variety of DG technologies, independent of variable fuel prices. Fuel cell operating costs are comparable to DG diesel engines and gas microturbines, higher than PV and simple-cycle gas turbines, and lower than DG gas engines.

Installed Cost

In addition to bearing the operating and maintenance costs of DG, customers can also incur costs related to the purchase and installation of DG. DG installed cost not only includes the capital cost of DG equipment, but the related interconnection, construction, permitting and engineering costs. These costs should also be deducted from the customer's gross energy savings in estimating the net benefit of DG to the consumer. DG capital cost related to equipment can range from $125 to $500/kW for a diesel generating package to $1,500 to $3,000 for fuel cells (See Table 4). Other costs related to construction and installation, the so-called turnkey costs, can range from $350 to $500/kW for a diesel engine set to $1,900 to $3,500/kW for fuel cells. Except for PV, fuel cells have the highest installed cost due to high equipment and construction-related costs. The cost of fuel cells, however, is based on early models of higher generating capacity and different technology than that intended for homes. Further, when fuel cells are commercialized, costs are expected to

Attribute	Diesel Engine	Gas Engine	Simple Cycle Gas Turbine	Micro-turbine	Fuel Cell	Photovoltaics
Efficiency	36 to 43%	28 to 42%	21 to 40%	25 to 30%	35 to 54%	N/A
O&M Cost ($/kWh)	0.005 to 0.010	0.007 to 0.015	0.003 to 0.008	0.005 to 0.010	0.005 to 0.010	0.001 to 0.004

Source: Gas Research Institute, *The Role of Distributed Generation in Competitive Markets*, Distributed Energy Forum, March 1999, p.4.

Table 3: Comparison of Efficiencies, Operating and Maintenance Costs of DG Technologies

[21] Testimony on Natural Gas Supply Forecasts before the Committee on Energy and Natural Resources, Statement of Mary J. Hutzler, director, Office of Integrated Analysis and Forecasting, Energy Information Administration, Department of Energy, U.S. Senate, July 26, 2000, p.14.
[22] Energy Information Administration, Office of Oil and Gas, U.S. Department of Energy, *Natural Gas 1998, Issues and Trends*, April 1999, p. 5.
[23] *Op. Cit.*, Hurtzler, p. 14.
[24] *Ibid.*

decline considerably. In contrast to gas engines and turbine technologies, however, fuel cells do not incur added installation costs when heat recovery is added in CHP applications.

Attributes	DG Technologies Diesel Engine	Gas Engine	Simple Cycle Gas Turbine	Micro-turbine	Fuel Cell	PV
Size Range (kW)	20 to 10,000+	50 to 5,000+	1,000+	30 to 200	50 to 1,000+	1+
Equipment Cost	125 to 300	250 to 600	300 to 600	350 to 750	1,500 to 3,000	N/A
Install. Cost – No CHP	350 to 500	600 to 1,000	650 to 900	600 to 1,100	1,900 to 3,500	5,000 to 10,000
Add. Install. Cost w/CHP	N/A	75 to 150	100 to 200	75 to 350	Included	N/A

Source: Gas Research Institute, *The Role of Distributed Generation in Competitive Markets*, Distributed Energy Forum, March 1999, p.4.

Table 4: Comparison of the Equipment and Installation Costs ($/kW) of DG Technologies

Economic Feasibility of Distributed Generation to Customer

The value of a customer's annual energy savings from DG and variations in operating costs are critical in determining the length of time it takes a customer to pay for the installed cost of DG. Dividing installed cost by the value of a customer's annual energy savings determines the simple payback of installation. As the margin of the value of energy saved over the annual operating and maintenance costs increases, the payback declines and economic feasibility increases. DG's economic feasibility therefore depends on a number of factors:

- Imputed value of energy saved – the value of a customer's energy savings based on the avoided or wholesale cost of energy will be lower than if the value was based on the retail cost the utility usually charges the customer. Moreover, utility retail pricing policies and wholesale costs vary by location based on local regulatory policy in regard to transition costs, and relative access to or availability of fuels. The adequacy of existing energy infrastructure in accommodating demand and degree of congestion due to local physical characteristics and growth can also affect utility pricing and, therefore, the amount of savings.
- Customer's payback preferences – the period of time that a customer is willing to wait to be paid back for the installed cost of DG can vary depending on the type of customer. Energy service companies and to some extent commercial customers who include the costs before payback as part of their cost of doing business will be more willing to wait longer to receive payback than residential customers.
- Type of DG application – In some instances, the benefits of other applications such as avoided customer downtime or increased customer reliability can be quantified and then serve as a basis for customer compensation in addition to the costs of peak energy savings. In this way a previously unattractive return on investment can become attractive.
- Local variation in operating costs - annual energy savings is determined by deducting operating costs from the amount the customer is paid for peak energy savings or other excess energy returned to the grid. As noted above, variation in local fuel costs is a principal variable determining DG operating costs.

Of course, installed cost is also a critical factor influencing DG economic feasibility. Institutional factors affecting cost of installation related to interconnection, engineering, and other regulatory imposed charges are discussed below, while equipment cost is treated elsewhere in a separate report dealing with fuel cell technology.

Added Customer Benefits

As noted above, a number of additional benefits can accrue to a homeowner that would have a positive effect on the economic feasibility of DG, but it is more difficult to impute a monetary value to these benefits, especially for residential customer. One source computed the value of these other benefits to a commercial customer of a small gas turbine at a 60 percent capacity factor.[25] The values for some of the benefits are cited below as examples of orders of magnitude, but they

[25] *Ibid.*

would probably have to be reduced somewhat for residential customers:

- CHP – DG in combination with electric power can produce heat, which reduces the cost of energy by directly providing hot water and more indirectly through further processing by providing for heating and cooling needs. The value of the additional benefit attributed to this application to a commercial customer has been estimated to be $.021/ kWh or $110/kW a year.
- Reduced price volatility – DG provides the customer with a safeguard against the uncertainty and potential harmful effects of electricity price volatility at the same time permitting the customer to be more venturesome in energy markets. The monetary value of this additional benefit to a commercial customer is estimated to be $.01/kWh or $55/kW a year.
- Increased power reliability – DG can deter or eliminate grid power outages that interrupt customer electricity service, can be detrimental to health and safety, and cause economic loss. The value of this additional benefit to a commercial customer is estimated to be $.006/kWh or $35/kW per year.
- Improved power quality – DG can reduce or eliminate variation in grid voltage or harmonics that could be harmful to a customer's sensitive electrical equipment such as computers that depend on high quality power.
- Additional sources of revenue – DG provides customers with the opportunity to sell power to the grid that is in excess of their energy needs.

A number of external economies result from DG in the form of public benefits to customers as a whole or society in general, which are more abstract and remain to be proved, demonstrated, and quantified.[26]

DG may in the long term foster a more competitive and efficient economic environment for energy resulting in reduced costs of energy to the customer. By avoiding the necessity for construction large generation facilities DG may reduce pollution associated with such facilities and help protect the environment.

Utility Benefits and Costs

The perceived or demonstrated benefits of DG to utilities are of concern to homeowner customers, since increased utility adoption of DG technologies can increase the scale of production thereby reducing the costs of DG and helping to diffuse many of DG's potential benefits to customers. Manufacturers and suppliers of DG and fuel cells in particular are caught in the typical commercialization conundrum. Low acceptance of their innovative product results in low production volumes and high prices, yet customer acceptance on a large scale is necessary to achieve the economies of mass production that result in large volumes and low cost. Consequently producers of DG seek to encourage and expand their markets regardless of who or where DG is installed. The presumed or demonstrated benefits of DG to utilities are therefore of concern to manufacturers in reducing their cost and such benefits accrue to builders and homeowners as well.

DG by providing additional sources of power at the customer's site reduces the utility's need to expand the generation, transmission, and distribution system and can defer the need for T&D upgrades. A number of subsidiary utility benefits are an outgrowth of these DG grid-related benefits:

- DG, by reducing transmission congestion at the point of consumption, may increase the capacity of T&D available for other customers.
- DG, by decreasing customer peak energy demands, reduces the level of reserve margins the utility must maintain to meet this demand
- In obviating need for additional T&D lines, DG can relieve the utility from dealing with troublesome public concerns and problems over adding additional transmission lines.

DG can also offer a number of technical benefits to the utility grid:

- DG can eliminate the electricity losses associated with long distance transport of electricity over the T&D system.
- Some DG technologies can provide reactive power (VARs) that can help utilities maintain system voltage.
- DG reduces utility costs associated with outages and providing reliable power.
- DG can improve power quality and eliminate demand that is harmful to the power quality of the grid system.
- As a dedicated auxiliary power source, DG can assist a power source's ability to reenergize lines following a power outage i.e., start up from a cold power condition to fully operational status ("black start").

The value of these benefits, however, is difficult to quantify and reflect in utility rates because many are specific to given locations. As already noted, economic and institutional considerations may prevent utilities from taking advantage of DG benefits. Utilities claim it is very difficult to incorporate customer-side benefits such as peak shaving to the grid into their long-term plans because these benefits are not under their direct control and are difficult to quantify.[27] Utilities therefore tend view DG as a short-term solution.

DG may add to utility costs due to a number concerns related to DG's impact on equipment and the grid.[28] Additional

[26] Arthur D. Little White Paper, *Distributed Generation: Policy Framework for Regulators*, 1999.
[27] *Ibid.*
[28] Arthur D. Little White Paper, *Distributed Generation: System Interfaces*, pp. 6 and 9.

DG-related costs arise from additional management and measurement equipment required dealing with:

- Quality control problems;
- Negative impacts of DG on reliability; and
- Inconsistent maintenance by owners of DG units.

Utility grid-related costs related to DG could result from:

- Reduced system protection due to reverse power flows to the grid, de-energized utility distribution lines, over/under voltage, over/under frequency, and voltage imbalance;
- Threats to the safety of workers if DG should mistakenly energize a line where workers are working; and
- Islanding, when a DG unit energizes a portion of the system that is supposed to be de-energized or isolates a portion of the electric utility system from the remainder of the utility system.

DG advocates claim that the extent of these problems and their related costs are exaggerated and that many costs are based on perceptions rather than demonstrated fact.[29] Proponents of this view have even suggested that the threat of competition from DG rather than safety and grid integrity is behind some of these concerns.[30]

INSTITUTIONAL BARRIERS TO INSTALLATION OF DG

Installed cost is a major factor affecting the payback and feasibility of DG. Reductions in the capital cost of DG equipment, one component of installation cost, can occur through technological advancements and economies in the scale of production brought about by increasing customer acceptance of DG. Costs related to other components of installed cost such as interconnection, construction, permitting, and engineering, however, remain high because of a number of institutional barriers. In addition, transition costs, such as stranded and standby costs, imposed on customers to defray the cost of capital equipment (made redundant under deregulation) also add significantly to installation cost. Explained below are the cumulative impacts of institutional barriers that can ultimately deter widespread acceptance of DG and fuel cells in particular:[31]

- system interfaces;
- electrical interconnection;
- stranded costs;
- standby charges; and
- siting and permitting.

System Interfaces

System interfaces occur where DG and the utility grid intersect. DG system interfaces are both physical and market related. Physical interfaces involve a DG unit's connection with the fuel and electrical infrastructure and includescommunication with a central body that controls or monitors the DG system.[32] Development of DG physical interfaces involves dealing with issues such as safety, protocols, system impacts, reliability, standards, and metering. Physical connections are also necessary to provide real time market data to DG so that DG owners can bid and compete with other energy sources in selling energy in the marketplace. Issues related to DG in developing market interfaces include dispatch, tariffs, pricing signals, response and business operations.

Grid Interconnection Metering

Increasing the ability of DG owners to access and sell energy to the grid would help DG to gain wider acceptance among customers such as builders and homeowners. Currently, most installed DG only supplies energy on-site and has no access to the grid, resulting in little or no complications for the grid. With completely open access to the markets for energy and ancillary services, DG could be dispatched, either individually or collectively with other DG installations, to compete in the same markets as traditional utility power plants. In this way the full potential of DG could be realized and additional benefits could accrue to builders and homeowners as customers. As an alternative to complete access, one intermediate option constrains DG's access by placing specific limits on its minimum size, bidding, and dispatch.[33] Regardless of the allowable level of DG access to the grid, however, the costs of access must be weighed against the benefits. For example, owners of DG can incur costs because the level of operational complexity increases with grid access, requiring investment in control and communications systems to maintain power quality, reliability and safety, as well as to provide information in support of market transactions.

The enactment of PURPA in 1978 established a precedent for grid connections with independent generators of power and metering.

---

[29] Thomas J. Starrs and Howard J. Wenger, *Policies to Support A Distributed Energy System,* 1997.
[30] *Ibid.,* p. 10
[31] *Op. Cit.*, Arthur D. Little, Policy Framework for Regulators
[32] *Op. Cit.*, Arthur D. Little, *System Interfaces,* p. 3.
[33] *Op. Cit.*, Arthur D. Little, Policy Framework for Regulators, p. 12.

Dual Metering

Most PURPA qualifying facilities (QF), including large-scale cogeneration and smaller renewable energy projects, has net purchase and sale agreements with utilities. These agreements require use of dual meters, one that measures the electricity flowing into the building and the other that measures the flow of electricity out of the building and into the grid. Under this type of agreement, customers purchase energy from the utility at the retail rate, but the electricity not immediately used is sold back to the utility at the lower avoided or wholesale cost. Under this arrangement it is advantageous for customers to use all the DG electricity as it is generated rather than selling it at avoided cost to the utility, since their immediate use of energy is equivalent to replacing electricity which they would normally have to buy at the retail rate.

Net Metering

Net metering of DG can be beneficial to the DG owner. In net metering, the meter spins forward when energy from the utility is flowing into the building and moves backward when energy flows from the building to the utility. At the end of the billing period the customer is charged for net energy consumed.

Benefits of Net Metering

Proponents claim customer benefits of net metering include:

- Compensation for customers at the retail rate for the energy DG provides regardless of whether they immediately use the energy.
- Elimination of the requirement for a second meter and the need for the utility to purchase power, which entails time-consuming and costly paperwork and processing.

In 1998, small-scale renewable projects in 23 states[34] were eligible to use a more favorable net metering approach in which customers can connect to the grid using their existing meter. Twelve of 23 states with regulations or laws on net metering limited net metering to renewables and cogeneration, while most of the remaining states excluded cogeneration, limiting it specifically to solar or some combination of solar with wind or hydroelectricity. Two states had no restrictions on allowable customers.

Criticism of Net Metering

Since the scale of DG required for homes would be similar to that of small renewable projects, net metering might be particularly applicable to other forms of DG, but utilities have leveled a number of criticisms against the use of net metering:[35]

- On the abstract level, net metering is contrary to competition, which involves the market pricing of wholesale energy.
- Critics object to customers using surplus energy generated at one point in time to compensate for energy the utility dispatches and delivers at another point in time.
- Customers are, in effect, getting a free ride by being allowed to use the distribution system to store their surplus energy without paying the distribution utility for this service.

Others counter that:

- The utility merely shunts the DG surplus energy to another customer and charges that customer the retail price without having incurred the expense of generating the power.
- As long as the power fed back to the utility is miniscule relative to the power flowing through distribution system, net metering should have little effect on utility operations.[36]

Existing Limits on Net Metering

A real concern exists, however, that if net metering were allowed to expand its penetration of the market to cover all types of DG, at some point so many customers would be free-riders that there would not be enough revenue left to pay for cost of maintaining the distribution network. Consequently, several states have adopted constraints[37] on the use of net metering by limiting the amount of net metered generating capacity or the number of generating systems so that when the limit is reached the revenue impacts would be insignificant. The following are existing limits on net metering:

- Capacity limits are often expressed as a percentage of each utility's peak demand and can range from a low of 0.1% in California, New York, and Washington to a high of 1% in Vermont.[38]
- The largest proportion of the states with regulation of net metering, almost 30 percent, limit the allowable generator capacity to equal or less than 100 kW.
- Almost half of these states require that the net excess generation of electricity by the customer's generator must be purchased at the avoided cost.

Electrical Interconnection

A DG unit often requires an electric interface to make a connection to an external utility power system or grid simultaneously as it generates electricity. For this reason the term interconnection is often synonymous with the terms "synchronized operation" or "parallel operation." DG electrical interfaces are non-existent in remote, isolated grid applications, but become more complex as the requirements for interaction between DG units and electric utility/distribution companies increase. Average costs for larger QFs' interconnection under PURPA range from \$50/kW to \$200/kW, but smaller units often have higher costs.[39] The main issues in regard to electrical interconnection arise from the complex

[34] *Op. Cit.*, Starrs, p. 4.
[35] *Ibid.*, pp. 5-6.
[36] *Ibid.*, p. 6.
[37] *Ibid.*, p. 6.
[38] *Ibid.*
[39] *Ibid.*, p. 4.

technical requirements and processes that utilities impose for safety and reliability on the one hand and the contention of DG producers and owners that these costs are too high and inequitable, posing serious obstacles to commercialization. Photovoltaics (PV), a unique DG technology, has already confronted many of these issues and its experience foretells many of the problems that small DG units will encounter and may exacerbate in the future as their numbers increase.

Based on the PV industry experience, electrical interconnection issues have evolved around:

- the technical elements of interconnection;
- standardization of technical requirements for interconnection;
- complexity of power purchase agreements; and
- the relevance of various engineering fees and other charges related to interconnection.

Technical Elements of Interconnection

Electrical interconnection typically involves three types of equipment:[40]

- Control equipment to regulate the output of DG;
- Circuit breakers or switches to isolate the DG unit from the system; and
- Relay mechanisms to protect and monitor the status of the system.

Interconnection Barriers to DG

Most equipment is protective, designed to maintain the safety, stability, and integrity of voltage and current on the grid, alleviating operational problems that might occur as a result of DG by detecting voltage faults, abnormal conditions, and de-activated distribution lines. The following interconnection requirements negatively impact the cost of DG:

- Utilities require safety measures to ensure that DG does not activate a line while workers are working on the line.
- Requirements for electrical connection are not standardized and vary not only by utility but even by project within a given utility. Lack of standardization is in part due to the fact that the type of protective equipment required can vary according to the type of DG, its size and location in the distribution system, the voltage on the system, and the configuration of the distribution network.[41] Consequently, requirements are often not well defined or, when defined, are subject to change with each interconnection.
- DG producers, who expect to achieve economies of scale through mass production of standardized products, complain that lack of interconnection standardization can add significantly to price of their products.
- Many interconnection requirements are too expensive and not suitable for smaller scale DG since the requirements are based on needs of large QFs, producing greater than 50MW of electricity.

Utilities also often require redundancy in their system by not allowing incorporation of protective equipment within an individual generator, maintaining that this is necessary to prevent system failure that might result if an individual piece of equipment fails.[42] On the other hand, DG producers, in the interest of economy, attempt to integrate protective equipment into their products. For example, a New Hampshire utility required PV customers to purchase mechanical relays to protect against variation in voltage and frequency, even though the customer's inverter already contained such relays.[43] The price of the relays added $50 per watt to the cost of PV. Moreover, since the mechanical relays were less advanced than the electronic relays in the inverter, they required annual utility calibration costing $100, which nullified half of the annual energy produced by the small-scale PV system.

Solutions Underway

Technical interconnection issues are concrete and, therefore, easier to address. Technical issues may need to be resolved before dealing with other more abstract economic and institutional issues related to the allocation of costs and benefits:[44]

- At the state and national levels, efforts are underway to develop uniform technical standards that will allow for more cost-effective interconnections of DG with the grid, at the same time ensuring the safety and reliability of the electrical system. New York, California and Texas have initiatives under way.
- The Institute of Electric and Electronic Engineers (IEEE) at the national level expects to develop, based on consensus, uniform interconnection standards by 2002.
- New technical standards for DG dispatch, metering, communication, and control based on expertise and emerging technologies in other fields such as telecommunications, remote sensing, and software design, however, may pose a more formidable problem.

Interconnection Process and Fees

Utility processes for the design, approval, and inspection of interconnection equipment are lengthy since they were designed for larger QFs. Consequently, rules are burdensome and contain requirements that are not relevant or readily understood by small-scale DG customers. The process typically proceeds as follows: [45]

1. Initial contact is made with the utility.
2. The customer and utility exchange project information.
3. Based on the information provided, the utility conducts an engineering analysis to determine the effect of the installation on worker safety, system protection, and operation.

[40] Op. Cit. Arthur D. Little, *System Interfaces,* pp. 8-9.
[41] Ibid.
[42] Ibid.
[43] Op. Cit., Starrs, p. 13.
[44] Op. Cit., Arthur D. Little, *Policy Framework for Regulators,* p. 14.
[45] Op. Cit., Arthur D. Little, *System Interfaces,* p. 11.

4. The customer then has the option of accepting or rejecting the utility's engineering design.
5. An engineering project review meeting between the utility and the customer is then convened.
6. Assuming agreement, project engineering and construction can begin.
7. At completion, the utility conducts a final inspection of the interconnection and protective equipment.
8. Minor changes to engineering plans during this process may require additional analysis and meetings resulting in further delays.

The utilities require that applicants pay a fee, often in advance, for the engineering analysis and review regardless of whether the project is completed. Sometimes, applicants are required to pay for any modifications to the utility's distribution system that is required to accommodate DG. It has been argued that such fees are discriminatory and arbitrary, citing the example of a New Hampshire utility that charged $900 for a design review of a 900-watt PV system–adding $1 per watt to its installed cost.[46]

Legal Barriers: Purchase Power Agreements (PPAs)

The interconnection agreement, or PPA, is an enforceable contract between the utility and the DG owner desiring to interconnect, specifying the terms and conditions of the two-party relationship. In addition to the technical requirements previously discussed, such agreements typically cover "metering requirements, payment for excess energy, imposition of standby charges, service interruption or curtailment, permitting and maintenance obligations, access provisions, indemnity and liability provisions, notification requirements, and non-transferability provisions."[47] For example, the PPA not only indicates the type of metering for the DG facility, but it usually requires that the DG owner be responsible for providing approved metering equipment and utility access to the meter at all times.[48] Since the complexity of these agreements is difficult to understand, small DG owners often must incur the added expense of retaining a lawyer to comprehend and negotiate a contract.

As PV experience points out, many standard contract requirements are applicable to the larger generating capacity typical of QFs under PURPA, but are inappropriate and onerous to small-scale DG. Liability and insurance may be reasonable and low for a large QF on a per kW basis, but the same insurance may be significantly higher per kW for small DG.[49] Objections were lodged against the burdensome requirements of several New York utilities requiring small net metering customers to carry liability insurance ranging between $500,000 and $1,000,000 from a utility-approved carrier.[50] In one case, the New York Public Service Commission found that such charges were too costly and impossible for residential customers to meet. It limited such charges to $100,000, an amount covered under conventional homeowner insurance policies.

Stranded Costs[51]

Investors under the old rules made investments in utility generation, transmission, and distribution with the understanding that there would be a fair return on investment. Deregulation, however, required that generation, transmission, and distribution be broken up into separate business or non-profit entities. As a result, some of these investments are no longer economic for traditional utility companies and have become redundant. States have, therefore, allowed utilities to charge customers exit fees or competitive transition charges (CTCs) to compensate investors for these uneconomic or "stranded" investments.

Exit fees are other charges for stranded costs imposed when DG customers leave the grid and reduce the utility load. The following are arguments for and against these charges:

- Utilities contend that DG imposes a burden of stranded costs on investors and non-DG customers when DG residential or other customers exit the

> *"Stripped of their monopolies, industry executives grumbled, they would never recoup the money they spent over the decades of building generation plants – including nuclear reactors – to meet demand. Competition from newer, lower-cost power producers, they complained, would force old-line utilities to eat more than $100 billion of "stranded costs" – money spent building generation plants that would be unable to pay for themselves under deregulation. Instead, the industry appears to be holding its own. Rising prices for electricity in many parts of the nation have helped make existing plants more valuable than anyone expected. Nonetheless, the utilities continue to enjoy ratepayer-financed bailouts for nuclear plants and other assets, based on a gloomy post-regulation outlook. Five years ago Moody's Investors Service, the bond rating house, estimated the industry's stranded costs at $135 billion; it now puts it at just $10 billion."*
>
> ***Richard A. Oppel, Jr., "Deregulation Has Given Power to the Power People," The New York Times, April 30, 2000***

[46] *Op. Cit.*, Starrs, p. 13.
[47] *Ibid.*, Starrs, p. 11.
[48] *Op. Cit.*, Arthur D. Little, *System Interfaces*, p. 15.
[49] *Ibid.*
[50] *Op. Cit.*, Starrs, p. 12.
[51] *Op. Cit.*, Arthur D. Little, *Policy Framework for Regulators*, pp. 16-18.

system and no longer provide the revenue necessary to compensate utilities for existing investments in generation and distribution infrastructure.

- DG advocates, on the other hand, contend that DG contributes many benefits (see above) to utilities that offset such costs. Also they assert that when DG returns energy to the grid it is shunted to other customers that pay utilities retail prices for power that utilities do not generate.

Currently, the imposition of CTCs or exit fees can negatively affect the economic feasibility of DG. Consequently, many proponents of DG argue that states should grant DG exemptions from these fees. Utilities argue exemptions for stranded costs will increase the burden of costs imposed on the rest of their customer base.

California regulations on CTCs appear to allow exemptions for residential PV applications, but are complex and somewhat ambiguous and are subject to a variety of interpretations. The following are examples of some of the consequences of CTCs:

- One study found that the added costs of standby charges, CTCs, and exit fees together with interconnection and permitting costs could lengthen the payback period for DG customers, making DG economically infeasible in all but a few states.[52]
- Another study cited the example of a 100-kW PV system for a commercial or industrial facility in which CTCs resulted in an extra expense of more than $160,000 per year.[53]
- Since most states impose CTCs for a fixed period of time, CTCs may not be a long-term threat to some DG, because of the possibility that such fees could expire before the commercialization of some emerging DG technologies, such as fuel cells. No such mitigating circumstances, however, exist for exit fees.

Standby Charges

When builders or homeowners install DG they usually want to maintain a parallel connection with the grid so that the utility can supply power during an unexpected outage or add capacity when peak demand exceeds DG capacity. A utility provides standby services when it is necessary to interconnect with customers to substitute for or add to their normal source of power. Charges for standby services differ from fees for stranded costs in that they are for particular services rather than compensation for past investments. Backup service, the most common of standby services, supplies power or additional capacity during unanticipated outages of power at the homeowner's site. When residential DG customers incur standby charges for backup power, however, they can confront the same issues of economic feasibility experienced with stranded costs.

Justification for Charges

The cost of standby service is assessed as an added charge or tariff based on power usage or demand in the homeowner's monthly bill. Utilities' justification of the charges is as follows:

- Utilities are saddled with the fixed cost and maintenance of the T&D, which is no longer fully compensated by customer user revenue due to customer's reduced reliance on the grid as a result of DG.
- A portion of the distribution infrastructure is devoted to a particular home and cannot be reallocated to other customers when not used by the homeowner.
- Without charges for standby service, fixed distribution costs would be shifted to other utility customers who do not have DG and who would, therefore, have a higher incidence of cost, in effect subsidizing DG.
- Utilities are often not compensated for higher prices of backup power they often must procure from spot markets to provide standby power.

Opposition to Charges

Advocates of DG, on the other hand, claim that:

- Since standby charges are not based on the actual cost or value of the service to the customer, they are excessive, negatively affecting the economics of DG and, therefore, its feasibility. This discourages the adoption of DG.
- Given the relatively small amounts of power involved with individual residential DG units, some supporters of DG argue for complete exemption for residential units, asserting that such revenue losses are inconsequential to utilities.
- Advocates contend further that utilities do not take into consideration the benefit of combined reliability that many DG units, dispersed over the system, offer by decreasing utility capacity constraints.

In computing a standby power rate, many utilities establish a flat equivalency between the standby charge and the capacity of the DG generator the homeowner installs, regardless of the homeowner's use of standby services.[54] For example, the rate a utility would charge a homeowner with a 4 kW generator and a peak demand of 10 kW would be based on 6 kW of backup power. As peak demand exceeds DG capacity and the 4 kW generator is insufficient, it can be argued that homeowners may want to have the flexibility of being able to rely on the utility for only a limited amount of backup power and voluntarily reduce or shed the rest of their load.[55]

---

[52] *Op. Cit.*, Arthur D. Little, *Understanding the Economics,* pp. 19-21.
[53] *Op. Cit.*, Starrs, p. 14.
[54] *Op. Cit.*, Arthur D. Little, *Policy Framework for Utilities,* p. 20.
[55] *Ibid.*

Siting and Permits

Small DG should have the advantage of not having to meet the elaborate and often onerous planning and approval requirements related to environmental and physical impacts that local jurisdictions impose on utility central power generation and T&D facilities. However, the costs of complying with local permit requirements related to the siting of DG at a particular location and the added expense of administrative delays in applying and obtaining approval for such permits can still be significant. Such costs often outweigh the impact of burdensome local permit fees and can negatively affect the economic feasibility of DG. Compared to other DG institutional issues discussed above, DG siting and permitting issues are more closely related to the characteristics of specific DG technologies. For example, deeds or community covenants that control the external appearance of homes may be important factors restricting installation of PV roof systems, but they would not be a factor for fuel cells.

General Permitting Issues for DG

Except for renewable energy technologies, the fuel for most DG systems is natural gas. One authority claims that most DG systems running on natural gas meet California emission requirements.[56] On the other hand, according to the California Energy Commission, natural gas DG combustion technologies are not land intensive, but can pose moderate to significant permitting issues (see Table 5) in the areas of hazardous material handling and storage, air quality, water use and quality, and noise and odors:

- Particularly significant are issues related to hazardous wastes and storage and air quality.
- Air quality, however, is only moderately significant for advanced gas turbines and water quality has little or no significance for simple-cycle gas turbines.
- Most evaluations in the permitting of fossil fuel DG at the local level have been based on standards developed for large commercial and institutional cogeneration projects ranging from 10 to 20 MW.[57]

One of the principal barriers to installation of DG at the local level can be state and regional air pollution regulations.[58] In this context, fuel cells have major advantages.

- Typically "emissions per unit of fuel consumed" is used as a criterion in the permitting decisions regarding new generation facilities, but an output-based standard such as "emissions per unit of power produced" would be more favorable to DG since it would better reflect inherent DG efficiencies.
- Since the Clean Air Act grandfathered many old, central power generation facilities, many sites desired for the location of DG may be off-limits because they are in so-called "non-attainment areas" where air pollution concentrations from old generating facilities exceed the Act's requirements.
- Many State Implementation Plans incorporate a system for trading emission credits for new generation facilities. Although state procedures for awarding credits vary, if utilities have a substantial share of allowable credits they have considerable market power to influence the location of DG in their area by withholding or granting credits.

Type Facility	Hazardous Materials & Storage	Air Quality	Water Use & Quality	Noise, Odors, & Visual	Land-Intensive
Advanced Gas Turbines	++	+	++	+	0
Cogeneration	++	++	++	+	0
Combined Cycles	++	++	++	+	0
Simple-Cycle Gas Turbines	++	++	0	+	0
Steam-Injected Gas Turbines	++	++	++	++	0
Fuel Cells	0	0	0	0	0

0 = no or insignificant issue; + = potentially moderate issue; ++ = potentially significant issue

Source: California Energy Commission, *Energy Aware Planning Guide: Energy Facilities,* pp. B.05 – B06.

Table 5: Significance of Permitting Issues by Type Distributed Generation Facility

Combustion-based DG technologies in California must overcome control technology requirements and emission levels to comply with air quality permits.[59] Energy projects requiring air quality permits in California are reviewed by various regional Air Quality Management Districts (AQMDs) on a case-by-case basis to account for the environmental and economic impacts as well as to determine the Best Available Control Technology (BACT) for the particular DG technology under consideration. Some air quality regulations designed for larger cogeneration projects initiated under

[56] C.J. Weinberg, "Emerging Energy Technologies", for California Energy Commission, *Energy Aware Planning Guide: Energy Facilities.*
[57] The permitting impact of large industrial or commercial DG facilities in local areas may be quite different than that of smaller DG in light commercial or residential applications. Local emission requirements are a consideration for large DG but not for small DG facilities, since large DG facilities run for longer hours.
[58] *Op. Cit.*, Arthur D. Little, *Policy Framework for Regulators,* pp. 22-23.
[59] California Alliance for Distributed Energy Resources (CADER) Siting and Environment Committee, Final Draft Action Plan, submitted to the CADER Steering Committee, June 6, 1997, p. 14.

PURPA are not appropriate for smaller DG. For example, in California regulation of generation technologies generally requires cogeneration applications with emissions of 5 parts per million (ppm) of NOx to install selective catalytic reduction (SCR) for control of emissions. The operating and maintenance costs of SCR would be prohibitive to small DG units of less than 15 MW, however, find .

Permitting Issues for Fuel Cells

Fuel cells are more flexible in regard to fuel sources than other DG technologies, offering options of using pure hydrogen or other fossil fuel derivatives. Fuel cells that use pure hydrogen and oxygen as inputs to produce energy emit no pollutants. On the other hand, except for some industrial and commercial settings, experience with storage and use of pure hydrogen is not widespread and perceptions exist that it is highly explosive. The disastrous explosion of the Hindenburg dirigible in 1938, which was filled with hydrogen, is responsible for much of the negative impressions of hydrogen. One study claims that hydrogen was not the cause of the disaster, that hydrogen will disperse much more quickly than gasoline and natural gas, and storing hydrogen can actually be safer than storage of gasoline.[60] Negative perceptions in regard to hydrogen's safety still exist, however, especially in regard to its use in homes. Furthermore, hydrogen is not readily accessible for distribution to homes and an economical and safe means of storing hydrogen in homes does not yet exist.

Fuel Cell Permitting Advantages

It is more common for fuel cells to use natural gas as a source of hydrogen, since the requirements for safe handling of natural gas are well established for commercial and residential applications. The California Energy Commission cites no significant permitting issues for fuel cells (see Table 5), a major advantage of fuel cells over other competing DG technologies:

- Natural gas fuel cells (NGFCs) have very low emissions because they rely on chemical reaction rather combustion to produce energy.
- NGFCs also produce as byproducts relatively pure water, CO_2, and relatively low levels of hydrocarbons, carbon monoxide, and nitrogen oxides.
- The California South Coast AQMD independent emissions tests of a NGFC system confirmed low levels of air pollution, granting the NGFC exemption from all air quality permitting (See Table 6).
- Nitrogen oxide emissions from fuel cells in pounds (lb.)/ BTU were 0.003 to 0.02 lb./BTU compared with 0.3 lb./ BTU for gas engines and 0.10 lb./BTU for gas turbine generators.[61]

Emission	Emission Limits [(a)]	Typical Emission Levels
NOx	0.045 (3)	1
CO	1.40 (10)	5
SOx	(b)	(b)
Particulates	(b)	(b)
Unburned Hydrocarbons	0.03 (250)	~1

(a) Numbers in parentheses are SAQMD's emission limits.
(b) Emission levels were either negligible or lower than detectable

Source: U.S. Department of Energy, Federal Technology Alerts, Natural Gas Fuel Cells, p.16

Table 6: Natural Gas Fuel Cell (NGFC) Emission Levels (units of ppmv, 15% O_2 dry)

The favorable impacts of NGFCs have been largely based on the studies of the relatively small numbers of Phosphoric Acid Fuel Cells (PAFCs) that have been installed and demonstrated in stationary applications:

- These fuel cells are easily located in urban areas serving large loads at central locations such as distribution substations, hospitals, offices and other institutions.
- Such uses are feasible because PAFCs are modular (5kW to 10 MW), can be operated from remote locations, and the amount of land used, operating noise, and emissions emitted is minimal.[62]
- Discharge water that is a byproduct of the NCFG chemical process meets sanitary discharge standards adopted by most local regulatory authorities.
- The fuel cells that have been commercialized to date have been reliable and require low maintenance.
- The California Energy Commission concludes, "there are no significant permitting issues associated with commercially-available PAFCs."[63]

Fuel Cell Permitting Obstacles

As of 1997, large size fuel cells encountered permitting obstacles in California even though technical tests indicated benign effects on the local environment.[64] The Sacramento Municipal Utility District (SMUD) and Southern California Gas required that fuel cells

[60] Ford Motor Company, "Direct-Hydrogen-Fueled Proton Exchange Membrane Fuel Cell Systems for Transportation Applications: Hydrogen Vehicle Safety Report," May 1997, pp. xii and 17-18.
[61] Distributed Power Coalition of America, "Summary of Distributed Generation Technologies," p.1.
[62] Dufour, A.E., "Fuel Cells – a new contributor to stationary power", *Journal of Power Sources,* vol. 71, 1998, p.23; California Energy Commission, *Energy Aware Planning Guide: Energy Facilities,* Appendix B-6: "Fuel Cells", p. B.6.1.
[63] *Ibid.*, p. B.6.2
[64] *Op. Cit.*, CADER, p. 14.

undergo a long permitting process that delayed installation and possibly added costs. These entities raised issues in regard to area water quality output and disposal. Since California air quality regulations provided no thresholds to determine whether fuel cells were required to have air quality permits, air quality agencies raised questions in regard to air quality that also delayed installation.

PAFCs differ in regard to operating characteristics and possible impacts compared with smaller proton exchange membrane (PEM) fuel cells under consideration for residential applications. PAFC high operating temperatures of 205° C are suitable and even advantageous for larger DG facilities, but may be dangerous and impractical in the home. PEM fuel cells share many of the same advantages outlined above for PAFCs, but their lower operating temperatures of between 70 and 80° C and their potential for achieving lower production costs may make them more favorable candidates for residential applications.

Permit and Land Development Review Process

California regulations and laws may represent an extreme case of complexity in regard to permit and approval requirements, but are cited here as an indication of the potential for complications in the permitting process. Under 1997 California laws and regulations, fuel cells sized between 2kW and 5 MW operating with natural gas, propane, and landfill gas fuel sources would be required, with exceptions noted, to obtain permits and meet requirements on the following:[65]

- Construction Permits – required by the California Uniform Building Code and administered by City and County Building Departments include the following:
  - Fire Permits – underground or overhead fire sprinklers, fire alarm, tank installation, gas detection system, site preparation, sewer and fire line permit
  - Electrical Permits – underground conduit
  - Building permits – plan check, building permit, seismic fee, plumbing and mechanical permit, and landscape
  - Land Development Review – required by local zoning and administered by City or County Building or Planning Departments, covers: review of impact on city/county services, infrastructure, traffic, sewer, water, fire, zoning, easements, etc.
  - Environmental Review and Conditional Use Permit – authorized by the California Environmental Quality Act (CEQA) and administered by City or County Planning Commission: Planning Commission acts as lead agency for CEQA review which will involve several City/County departments, the public, California State Clearinghouse, and state and federal agencies. An initial study based on CEQA guidelines with descriptive information may be adequate.
- Hazardous Materials, Emergency Response Plan – administered by the local fire department.
- Hazardous Waste Generation – administered by local City/County Health Department and California Department of Health
- Air Toxics – authorized by Bay Area AQMD regulation # 1-110.8 and administered by the Bay Area AQMD, requires a permit for any new emission source which results in a net increase in non-attainment pollutants. A project may be exempt if it emits very low levels of pollutants.
- Air Permit – authorized by South Coast AQMD under Rule 219: equipment not requiring a written permit pursuant to Regulation II, when PAFC, PEM, molten carbonate or solid oxide technologies are used.

Summary of Permitting Issues and Barriers

Based on considerable experience and research on the permitting process, California enumerated six siting and environment barriers for DG which are most likely applicable in any area of the nation:[66]

- Lack of Policy Support – policy and regulations supporting and specifically acknowledging DG are generally lacking, creating ambiguity, unnecessary approvals, which are obstacles to an efficient siting and permitting of DG.
- Lack of General Information and Understanding – ignorance and lack of general information on DG and its benefits hinders use and acceptance of DG in the permitting and siting of DG projects, adding unnecessary, costly delays.
- Lack of Information on Technology of DG – lack of research or information on the results DG testing and applicable standards can lead to mistaken perceptions, inappropriate application of DG, delay and slow the regulatory process, and prevent approval of projects.

---

[65] *Op. Cit.*, CADER, pp. 27-28.
[66] *Op. Cit.*, CADER, pp. 2-13.

- Lack of Community Planning Related to DG – the acceptability of DG in terms of its impact on the community's environment and infrastructure is not established in advance as part of the community's planning process, resulting in negative perceptions and its being opposed as an incompatible land use.
- Inconsistent Regulatory and Technical Standards – permit requirements, technical standards, and levels of exemptions are inconsistent and overlap across multiple jurisdictions resulting in tortuous, inefficient regulatory process that is costly to the DG customer as well as to the government.

SUMMARY OF FINDINGS

Deregulation of the production and distribution of power provides a particularly opportune time for the commercialization of DG and fuel cells in particular. Independent entrepreneurs given access to the market under deregulation exist side-by-side and compete in the wholesale power market with regulated utilities that maintain their monopoly status and operate under different rules. The current transitional and fluid state of the electricity industry leads to uncertainty that may make it difficult to maintain necessary levels of generation capacity. In the interest of protecting the public from unreasonable price increases, state regulatory interventions distort market price signals that would ordinarily provide incentives to increase system capacity and reliability. Economic prosperity and population growth in certain areas encourages independent distribution companies to revive once discarded plans for expansion of transmission and distribution lines, but public opposition thwarts implementation for environmental and other reasons. As a result, generation and system capacity margins are declining, creating potential for increased power outages and less system reliability in the future.

Many of the problems related to high installed cost, a principal disadvantage of fuel cells in residential building applications, can deter commercialization.[67]

- Taking advantage of the economies inherent in mass production can reduce fuel cell installed cost, but is not economically feasible without a significant expansion of the customer base for fuel cells.
- As cited above a number of "external" institutional and economic barriers to reducing high costs hinder creation of an expanded market for fuel cells and successful commercialization. High labor and other costs incurred during installation, for example, are the result of institutional impediments associated with establishment of system interfaces, variation in standards for electrical connection with the utility grid, imposition of stranded and standby costs, and onerous siting and permitting regulatory procedures and fees.

Problems and Opportunities for Fuel Cells in the Existing Market

The imperfect market that now exists for DG under deregulation provides both opportunities and obstacles for the commercialization of fuel cells:

- About 45 percent of consumers would be interested or very interested in a generator about half the size of a refrigerator that could be bought for about $400 and saved about 20 percent of their electric bill, according to a nationwide survey of 600 consumers in 1999.[68] If any significant portion of these interested consumers purchased DG, it would have dramatic implications for the electric power industry, concluded the sponsor of the survey. Potential energy savings depends on DG efficiency, the pattern (peaks and valleys) of residential load profile, whether the application allows the consumer the option of selling unused energy, and the method utilities use to charge consumers. *The energy savings fuel cells offer residential customers*

[67] Advances in technology that reduce fuel cell equipment costs can also contribute substantially to decreased installed cost, but are not a focus of this report.
[68] "Consumer Uninformed about Deregulation, Enthusiastic About On-Site Generation", *Deregulation Inc.* Webzine: *1999 Deloitte & Touche Consumer Awareness Survey of Electric Deregulation,* conducted by International Consumer Research, Inc., Media PA, November 5-9, 1999.

has yet to be demonstrated, but fuel cell efficiency is relatively high compared to other DG (See Table 2). The estimated installed cost of fuel cells, which is significantly higher than other DG options, substantially exceeds residential consumers' cost goal, while the less environmentally compatible diesel generator is the only other DG technology that meets customer cost criteria (See Table 3).

- A large majority of consumers are uninformed about the changes underway in the electric industry and are evenly split as to whether such changes will increase or decrease electricity price.[69] Moreover, large numbers of residential customers are not switching to new electric power providers because customers are much more sensitive to price and are not being offered price discounts, according to another survey.[70] For example, 20 percent of residential customers would switch if offered a ten percent discount with other non-price attributes remaining the same, while only five percent would switch if reliability is less assured, and no one would switch if reliability and customer service were likely to diminish. *Given these conditions, fuel cells can compete with other DG in the broad residential market only if they become less expensive or serve niche markets that highly value reliability and environmental compatibility.*
- In the absence of residential consumers, business attitudes can provide a foretaste of behavior in the deregulated market. More than half of U.S. businesses are distrustful of energy suppliers, stating that information they received from their suppliers is self-serving or confusing.[71] If businesses do not get expert guidance from utilities they are prepared to switch. Businesses rank reliable supply, 24-hour customer service, and power delivery ahead of low prices, according to a recent survey and focus groups. *Despite the apparent readiness of businesses to switch, the study finds that IPPs and energy brokers that could promote fuel cells are not as aggressive as natural gas companies in soliciting key business customers, suggesting that they also might not be aggressive in promoting fuel cells in the residential market.*
- State regulators find it difficult to let the free market determine energy prices for residential consumers and are not ready to embrace deregulation by opening up the market to deregulated energy providers that might install DG.[72] For example, the regulated price structure in Massachusetts makes it hard for outside retailers to be price competitive with existing utilities in the residential market. E*ntrepreneurial IPPs that might install DG such as fuel cells find it difficult to be price competitive in California, since a very large share of the market is held by traditional utilities with cash reserves from recovered stranded costs and where the Public Service Commission has already reduced electric bills by ten percent.*
- Very large consumer price increases during the peak summer months have led many states to wrestle with establishing a maximum wholesale price they will allow ISOs or distribution companies to pay for power.[73] States such as California consider such price caps necessary since there are not enough generators bidding against one another to produce competitive prices. For example, in a recent five-day heat wave in California, distribution companies paid three times as much for power on the wholesale market as they did in the costliest week in 1999. This amount included substantial funds from the California ISO to stabilize the system. The San Francisco area's power system came dangerously close to collapse and rolling blackouts were ordered throughout the area. *Market opportunities might exist for entry of IPPs promoting DG such as fuel cells if shortages of power and market imperfections persist, and if, as promised, the majority of generators should remove themselves from the California market when and if caps are reduced.*
- Despite the reported reluctance of some portions of the market to switch to deregulated energy providers, three million customers use non-regulated utility suppliers for natural gas and electricity.[74] Moreover, five retail companies catering to these customers represent 60 percent of this market. Each has 300,000 customers, a scale sufficient to reduce the cost of marketing and customer service and remain profitable. *The retailers' focus on wholesale commodity markets together with energy infrastructures and utility interfaces suggest priorities that might serve as a model for successful commercialization of fuel cells in the residential market.*
- The current capacity of the T&D system is constrained in many areas. Institutional obstacles related to permitting rather than technical factors result in growing opposition to new substation and T&D infrastructure despite the proposed new lines' demonstrated electrical need, economic feasibility, and environmental compatibility.[75] Aside from reported problems regarding electromagnetic fields, environmental impact, and declines in property values attributed to proposed power lines, local entities are concerned that new lines will import power, thereby diminishing jobs at local power plants or the amount of local resources used for fuel at plants. Some claim that

[69] *Op. Cit.*, "Consumer Uninformed..."
[70] W. Causey, "What Prevents Customers from Switching", *Electrical World*, March/April 2000, p. 47. (A study by National Economic Research Associates, San Francisco).
[71] RKS Research & Consulting, "Study Reports Fragile Relationships Between U.S. Businesses and Electricity Suppliers," *Business Wires*, March 30, 2000.
[72] *Ibid.*
[73] R. Smith, "California Ponders Lowering Price Cap as Hot Spell Raised Temper," *Wall Street Journal*, June 26, 2000.
[74] J.D. Pine, "Report Says Number of Consumers Embracing Retail Choice is Snowballing," *Deregulation Inc. Webzine*, 1999.
[75] M. Janick, "Siting Lines and Substations Gets Harder as Opposition Gets Savvy," *Electrical World*, March/April 2000, p. 15.

existing transmission lines were not designed to accommodate the increasing number of independent generation and cogeneration projects being built and proposed as a result of deregulation.[76] *Other studies discussed above claim, however, that customer-side DG such as fuel cells provides a cost-effective and environmentally compatible approach to relieving congestion and circumventing some of these problems. DG also provides a local sense of ownership and connection with power lines that is now lacking and thwarts new construction of T&D.*

Public Intervention on Behalf of Fuel Cells

A number of general recommendations for overcoming the hurdles that contribute to the high installed cost of fuel cells and DG in general depend on public funding. Public involvement is based on the following:

- Government expects significant public benefits from its programs in the form of reduced impacts on climate change, reduced air pollution, substantial increases in energy efficiency, and reduced dependency on petroleum.
- The government may seek to redress unfair competitive advantage of traditional utilities and distribution companies in the imperfect market under deregulation that nullifies many of the inherent advantages of DG technologies and discourages IPPs from promoting them.

Some experts are skeptical concerning the value of direct public support for DG, claiming that:

- Sufficient incentives exist for the private sector to invest in the R&D and commercialization of new, efficient, and cost-effective technologies with new entrepreneurs emerging from utility restructuring under deregulation, the trend of increasing fuel prices, and the capacity constraints that now exist in the electric power system.
- The artificial price signals resulting from public subsidies prevent the market's evaluation of the real efficiencies and costs of competing DG technologies.
- Public programs give some DG technologies that might not make it on their own an unfair competitive advantage.

A number of general policy recommendations aimed at federal, state, and local government entities could provide a context for reducing costs, increasing consumer incentives, and elevating the economic feasibility of fuel cells:[77]

- Continue government-funded research and development (R&D) and demonstrations of equipment performance under real operating conditions for PEM and other types of fuel cells now in the early stages of commercialization.[78]
- Require utilities to offer net metering for DG and fuel cells. Such a requirement should include a formula that provides a cap on the amount of net metering allowed on an individual utility's system. The cap should be sufficiently high to provide incentives to install fuel cells, but small enough not to significantly impact the utility's revenue.
- Mandate or facilitate agreement among utilities to provide standardized technical requirements for interconnection of DG and fuel cells, limiting utilities' discretion to accept or modify standards. Such procedures would allow manufacturers to offer more affordable, standardized plug and play products.
- Require utilities to provide simple, easy to understand contracts appropriate for customers installing small DG systems such as fuel cells.
- Reduce or waive various fees and charges associated with permitting, installing and/or operating DG and fuel cells.
- Adopt new federal legislation that restructures the utility distribution system and incorporates new procedures to remedy some of the market imperfections and unintended consequences of EPACT. In the process, review the equity and justification for recovering stranded costs and allow more flexible standby charges. Provide direct and indirect government aid that induces utilities to adopt DG and fuel cell technologies in later stages of commercialization. Such incentives would make fuel cells and DG more competitive. Incentives could include buy-downs, tax credits, special fuel tariffs, or subsidized loans.[79]
- Develop uniform, efficient permitting requirements and processes that balance environmental concerns and concerns about the local impact of DG with DG's broad benefits to the public. Allow independent laboratories to test and pre-certify fuel cells to ensure that they meet uniform, minimum regulatory requirements for installation.
- Provide regulatory or financial incentives for the creation of distribution level power markets that allow DG and fuel cells to execute bids and bilateral contracts in a DG power exchange, thereby competing more directly with central power plants and other sources of power through real-time pricing.

Prospects for Residential Fuel Cells

A very optimistic future has been forecast for fuel cells in stationary markets. A relatively modest projection

[76] *Ibid.*
[77] *Op. Cit.*, Starr, pp. 24-26.
[78] NAHB Research Center, for Partnership for Advancing Technology in Housing (PATH), *Task 1.0 Interim Report Background Literature Review of Fuel Cell Firms, Products, and Research and Development*, March 17, 2000.
[79] *Op. Cit.*, Arthur D. Little, *Policy Framework for Regulators*, p. 26.

still expects fuel cells in stationary applications to grow substantially from a revenue base of $20.9 million in 1998 at a compound annual growth of 49.6 percent by 2005.[80] The high-tech, health care, and financial segments of the non-residential sector need and can pay for high quality, stand-by, and uninterrupitible power and are likely to drive growth. However, the prospects for growth may be much more narrow and specialized in the residential sector. Fuel cells will have to compete with other DG technologies in entering the residential market. Assuming that the fuel cell's small footprint, noiseless operation, low maintenance requirements, and negligible pollution levels are particularly desirable in the residential market, it should have an advantage over other DG technologies in this sector. It has been suggested, however, that the fuel cell's chief competitor among DG technologies might be the gas microturbine and that opportunities for installation of fuel cells exist only in some small segments of the residential market where price is less of an issue such as: [81]

- luxury homes that can afford the high cost of fuel cells;
- homes located in remote areas where power infrastructure is lacking, making conventional connections to the grid extremely costly, but homes will still have to be provided with fuel;
- homes in areas subject to frequent and severe weather disturbances that contribute to frequent outages and where price is secondary to good power quality and reliability.

An indeterminate number of homes may be increasingly sensitive to frequent outages and poor power quality, especially when exacerbated by severe capacity constraints on the generation and distribution of energy in their areas. Recent trends in usage of electricity increase the sensitivity of this residential market to the quality of power, adding it to the list of potential markets for fuel cells:

- The increasing importance of computers and other digital appliances in the home for general access to the Internet as well as entertainment and home automation;
- The increasing proportion of households that telecommute or work at home and depend on home computers for their livelihood; and
- The increasing use of microchips or electronic devices for control in appliances, electric light ballast, and variable speed motors in compressors for energy efficiency.

Increases in use of digital equipment and electronic control of devices can contribute to a number of negative impacts that may influence this segment of the residential market to add DG as an auxiliary source of power:

- An increase in the density of residential demand in watts per square foot can place more strain on a constrained utility system and can increase the probability of outages.
- Digital appliances and computers are extremely sensitive to lapses of power as small as one to five minutes, which can cause major disruptions.
- Electronic controlled devices can provide interference or harmonic signals that can negatively affect the grid and other equipment in the home unless cancelled by filtering devices.
- Poor power quality resulting from as much as a ten percent voltage dip in less than a second can cause problems in the operation some types of digital equipment.

Builders and the Potential of Micro-grids

Some claim that the course of deregulation of telecommunications industry a decade ago and the rise of the Internet are analogous to deregulation of the power industry and the rise of DG, providing a foretaste of what might happen to emerging DG technologies under deregulation of the power industry. Some of the impacts of deregulation of telecommunications industry and the Internet as they relate specifically to the homebuilding industry may therefore serve as a model for the impact of DG on home building in a deregulated environment.

An increasing number of homeowners desire high-speed Internet access, but developers and builders of subdivisions and planned communities in the suburbs own the land and easements necessary to carry the structured wiring that provides broadband access to individual homes. Builders have been taking advantage of this monopoly on real estate, the so-called "first mile," either by building and owning neighborhood networks that offer Internet access bundled with cable and phone service or by joining with telecommunication companies to provide such access.[82] Such service is being offered at up to $20 dollars below cost. Moreover, homeowners can pay one fee for Internet and cable through a homeowner association instead of receiving different bills. In effect, builders are either competing with regional phone companies, cable companies, and other service providers, or are joining with them to share in continuing revenue resulting from the market for new technologies.

Production builders are establishing relationships with the high tech telecommunications industry because they are seeking sources of stable, long-term cash flow. Despite the prosperity of home building in recent years, publicly traded homebuilding stocks are trading at prices of only five to eight times earnings and at values below prior years when they were less profitable.[83] One of the reasons for this anomaly is that the industry in the

[80] "A Sober Look at Fuel Cells in the New Millennium" *Deregulation Inc. Webzine,* citing Frost & Sullivan, "Stationary Fuel Cell Markets".
[81] *Ibid.*
[82] R.A. Oppel Jr., "Internet-Ready Houses are Finding a Home," *The New York Times,* May 26, 2000, p. 1.
[83] P.O. O'Toole, "Out of Whack on Wall Street," *Professional Builder,* April 2000, pp. 128-134.

past has proven to be very cyclical–one of the first sectors to feel the impact of rising interest rates. Another reason is that industry has the reputation of being "low-tech" and does not have the positive connotations for investors that the current high-tech sector enjoys. Expansion into telecommunication also gives some homebuilders an opportunity to differentiate their product in competition with other builders and garner a share of the profits in the rapidly growing high-tech industry.

Large builders are making a concerted effort to partake in the ownership of the revenue streams flowing into the Internet, the cable, the telephone lines after the sale of the house is completed. This effort takes many forms, some of which may possibly serve as models for local energy micro-grids:[84]

- Toll Brothers, a builder of luxury homes in Huntington, Pennsylvania has formed its own subsidiary to build and own broadband networks in its developments. It recently formed a unit, Advanced Broadband to wire two new developments in Florida and one in Virginia.
- Also Toll Brothers and other builders such as Kaufman & Broad are evaluating revenue-sharing deals with companies to install wiring in new communities
- Service providers such as SBC Communications, U.S. West, and Cox Communications are looking for builders to wire their planned communities
- R. Horton, a builder headquartered in Arlington, Texas, is partnering with a Santa Monica-based venture capital firm to create a $100 million fund desiring to invest in e-commerce and Internet opportunities that relate to real estate and home building industries.[85]
- Estridge Companies, a builder of Centennial homes outside of Indianapolis, has formed a company with another investor, First Mile Technologies, to wire new developments. It expects to negotiate deals with other developers, granting them up to ten percent of the revenue from services that it sells their homebuyers and expects that such services would be 15 percent or more less expensive for the homeowner.
- Although Centex Corporation in Dallas has not yet invested in broadband services, it is seeking to augment its cash flow by diversifying into areas such as lawn care and home security.

As noted above, the construction of a miniature electric grid or a so-called micro-grid based on fuel cell technology, combined with other energy saving construction measures, offers builders an opportunity to obtain long-term cash flow based on highly-valued services that also provide the builder with potential for higher margins. A number of alternatives exist for spreading the burden of fuel cells' high installed cost among a large number of homeowners in subdivisions:

- A builder could install, own, and operate a larger capacity fuel cell at a substation that supplies power to individual homes within a subdivision development and interconnects with the utility grid for the sale of excess power and receipt of standby power.
- A builder could install, own, and operate small fuel cells at the customer side of the meter in all individual homes offered for sale in a subdivision of homes and would connect these units to a utility substation within the subdivision. In this alternative, the small footprint and benign noise and air pollution attributes of fuel cells along with low maintenance requirements provide an advantage over other DG technologies. The high installed cost could be offset by discounts from the manufacturer based on the economies of scale from large volume production.

In each of the above alternatives:

- A subsidiary construction company or ESP, independent ESP or one that is an affiliate or subsidiary of a utility, or IPP could install, operate, and maintain the fuel cell and micro-grid system. Depending on contractual arrangements and negotiations they could share in ownership and revenues with the builder.
- The margin of benefits over cost is assumed to be sufficient to provide revenue incentives for builders as well as reduced energy costs and high quality, reliable energy for prospective homeowners.
- Negotiations with a utility, DisCo, or a wires company would be necessary for electrical connection with the grid. Negotiation is most likely to proceed favorably if the subdivision development is located in an area where constraints exist on either generation and T&D or T&D alone.
- Along with the potential for increased margins and cash flow, the builder ESP and/or subcontractor must also bear the increased risk associated with participation in the very fluid energy market fluctuating prices for power as well as fuel. (See discussion above).

---

[84] *Ibid.*
[85] *Op. Cit.*, O'Toole, p. 130.

GLOSSARY

Ancillary Services – Generation, storage and generation-like services that complement electricity generation and support the quality and stability of the grid including, but not limited to, reliability services such voltage support, reactive power, black start, spinning and non-spinning reserve, and generation of services in areas with power supply capacity constraints (see definitions below).

Avoided Cost – Equivalent to the utility's cost of providing electricity service, which is much lower than the retail rate and is used as a basis for compensating cogenerators (See Cogenerators and CHP) and Small Power Producers (See SPPs) under the Public Utility Regulatory Policy Act (See PURPA and QFs).

Baseload – The minimum amount of electric power delivered or required over a period of time at a steady rate. Baseload capacity consists of generating equipment normally operated to serve loads continuously.

Black Start – A power source's ability to power up from a cold shut down condition to a fully operational status through a dedicated auxiliary power source that is totally independent of external systems. It is the net capability of generating units that carry load or have quick-start capability. In general, quick-start capability refers to generating units that can be available for load within a 30-minute period.

CHP – Combined Heat and Power – (See Cogeneration) Projects that use cogeneration to generate heat and power from the same energy source. For example, waste heat that is normally released into the air is efficiently recovered to generate large volumes of steam, which is used to provide space or process heat before being changed back to water and reused. The generation of two energy products from one fuel input generally lowers the cost of providing both products.

Cogeneration – **(**See CHP) The production of electricity and, in sequence, another form of useful thermal energy for general heating and cooling purposes or steam for industrial processes. Many nonutility electricity-generating companies own cogeneration facilities, and have status under the Public Utilities Regulatory Act (See PURPA) of 1978 as Qualifying Facilities (See QF below), which allows them to sell excess power back to utilities at avoided cost (See Avoided Cost). Other cogenerators produce power for their own use and do not qualify as facilities under PURPA.

Congestion – The condition that exists in a portion of the transmission and distribution (See T&D) system where T&D capacity is inadequate to accommodate the downstream peak load with generation from an upstream central facility. Congestion may be relieved by redispatch of the upstream generation, downstream generation or storage, by demand side management (See DSM), distributed generation (See DG), or by expanding the T&D.

CTCs – Competitive Transition Charges – (See Stranded Costs) CTCs refer to charges that offset uneconomic investments as a consequence of deregulation.

Cooperative Electric Utilities – Utilities that are owned by members and established to provide electricity to those members. Cooperative electric utilities operate in rural areas with low concentrations of consumers because these areas historically have been viewed as uneconomical operations for IOUs (See IOUs).

COS – Cost-of-Service – An approach used to regulate utility rate of returns in which a utility's rate of return is guaranteed based on their "prudent" investment in plant and equipment—the so-called rate base. Under this approach, investment in large power plants, transmission, and distribution facilities generally contribute to larger rate bases, which result in greater profits.

DSM – Demand-Side Management – The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. DSM refers only to energy and load-shape changes arising from the normal operation of the marketplace or from marketplace or government–mandated energy–efficiency standards. DSM covers the complete range of load-shape objectives, including strategic conservation and load management, as well as load growth. In essence it encompasses measures that reduce or shift the customer's energy load in the interest of energy conservation and efficiency. For example, DSM can manage energy dispatched over the grid and/or non-dispatchable energy used entirely within the home by providing for interruption of customer energy service.

DisCos – Distribution Companies – Investor-owned utilities (see IOUs) that own and operate generation and distribution facilities and may also be a retail supplier of electricity.

DG – Distributed Generation – The placement and use of small, modular electric generation, either integrated or stand-alone, close to the point of consumption. A fuel cell is one example of a distributed generation technology that can be used in commercial and residential buildings.

Electric Energy – The amount of work that can be done by electricity. The unit of measure for electric energy is a watt-hour. Electric energy is measured over a period of time and has a time dimension as well as an energy dimension. The amount of electric energy produced or used during a specified period of time by a piece of electrical equipment is referred to as generation or consumption.

Electric Power – The rate at which electricity does work – measured at a point in time, with no time dimension. The unit of measure for electric power is a watt.

EPACT – Energy Policy Act of 1992 (Public Law 102-486) – EPACT contains two provisions that enabled deregulation: (1) the creation of new class of non-utility electric power producers, including public utility holding companies, that could develop and operate independent power projects anywhere in the world, and (2) the broadening of the authority of FERC (See FERC) to order a transmitting utility to provide transmission service, including building of facilities needed to provide transmission, at the request of any electric utility, federal power marketing agency, or business generating electricity at wholesale. Together, these two provisions opened up the industry so that virtually any business could generate electricity and sell it at wholesale.

ESPs or ESCOs – Energy Service Providers or Energy Service Companies – Retail companies that buy power at wholesale prices and sell it, ancillary services, or other services to end use customers from either the system side or the customer side of the meter. Services on the customer side of the meter may include billing, energy auditing, load management, distributed generation (See DG) or cogeneration. Such companies may be utility affiliates. At the option of customers, the companies may charge for other ancillary services (See Ancillary Services) such as assuring power reliability (See Reliability), providing emergency back up power, and offering demand-side management (See DSM). Service may also include energy project development, risk management, or operation and management of energy facilities.

Electric Utility – A corporation, person, agency, authority, or other legal entity or instrumentality that owns and operates facilities within the United States for the generation, transmission, distribution, or sale of electric energy primarily for the use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Independent Power Producers (See IPPs) or facilities that qualify as cogenerators (See Cogenerators) or Small Power Producers (See SPPs) under the Public Utility Regulatory Act (See PURPA and QFs) are not considered electric utilities (See Non-Utilities).

Exit Fees – (See Stranded Costs) Fees imposed on DG customers when they leave the grid, reducing the utility load and making portions the utility infrastructure uneconomic.

FERC – Federal Energy Regulatory Commission – A quasi-independent regulatory agency within the U.S. Department of Energy (DOE) having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Fuel Cells – Electrochemical devices that can continuously convert the chemical energy of a fuel and oxidant to electrical energy. The fuel and oxidant are typically stored outside of the cell and transferred into the cell as reactants are consumed.

Gas Turbine Plant – An electric-generating plant in which the prime mover is a gas turbine. A gas turbine typically consists of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine, in which hot gases expand to drive the generator and are then used to run the compressor.

Interruptible Load – Program activities (See DSM) that, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions. For example, loads that can be interrupted to fulfill planning or operation reserve requirements are reported as Interruptible Load, and excludes Direct Load Control and other load management methods of controlling demand. This definition is synonymous with Interruptible Demand as reported to the North American Electric Reliability Council (See NERC) on the voluntary Office of Emergency Operations Form OE-411, "Coordinated Regional Bulk Power Supply Program Report."

IOUs – Investor-Owned Electric Utilities – Privately owned entities that have the fundamental objective of producing a return for their investors. IOUs either distribute profits to stockholders as dividends or reinvest profits. IOUs are granted service monopolies in certain geographic areas and are obliged to serve all consumers. As franchised monopolies, IOUs are regulated and required to charge reasonable prices, to charge comparable prices to similar classifications of consumers, and to give consumers access to service under similar conditions. Most IOUs are operating companies that provide the basic services for generation, transmission and distribution of electricity.

IPPs – Independent Power Producers – Nonutility companies (See Nonutility Power Producers) that generate power for their own use and/or for sale in wholesale power markets. IPPs can operate entirely independent of traditional, regulated, vertically integrated utilities (See Vertically Integrated Utilities), or independently as wholly owned subsidiaries of utility holding companies. Independent System Operators (See ISOs) assure IPPs access to the grid to sell electricity at wholesale prices to utilities, DisCos, ESPs or ESCOs. IPPs can use distributed generation (See DG) or combined heat and power (See CHP) to produce energy. Utilities are required to buy IPPs' excess power at avoided cost if, under PURPA, they qualify as a cogeneration facility (See QFs) or they qualify as a small power producer (SPP) that generates at least 75 percent of their power from renewable resources (See SPP and QFs). Under deregulation, the unbundling of electricity supply from transmission and distribution has opened wholesale power markets to competition and spawned the growth of non-QF IPPs that produce and sell power at market wholesale prices or for resale and do not possess transmission facilities or sell electricity on the retail market.

ISOs – Independent System Operators – A regional organizational entity that plans and operates a transmission system but is not its owner, a generator, or service provider. Prior to deregulation vertically integrated utilities formed regional power systems that decided on peak power requirements and implemented emergency power programs. ISOs assume many of these decision-making functions and in addition operate the new competitive power market, defining and valuing ancillary services and creating rules that assure DG access and participation in the power market. Utilities usually voluntarily join ISOs in their own self-interest, thereby obviating possible imposition of federal rules, but some opt out when they disagree with rulings. The Federal Energy Regulatory Commission (FERC) approves acquisition and mergers on condition that the entities involved join a regional ISO.

Islanding – Operation of a non-utility power source with or without a portion of the utility system isolated from the remainder of the utility system.

Load (Electric) – The amount of electric power delivered at any specific point or points on a system. The requirement originates at the energy-consuming equipment of consumers.

Megawatt (MW) – One million watts (See Electric Power).

Net Metering – A type of metering of electricity in which the meter spins forward when energy from the utility is flowing into a building and backward when energy flows from a generator (usually a photovoltaic system) in a building to a utility. At the end of the billing period the customer is charged for net energy consumed.

Nonutility Power Producers – Corporations, persons, agencies, authorities, or other legal entities or instrumentalities that own electric generation capacity and are not electric utilities. Nonutility power producers are synonymous with independent power producers (See IPPs) and include qualifying cogenerators, qualifying small power producers, and other nonutility generators without a designated franchised service area.

NERC – North American Electric Reliability Council – Voluntarily formed in 1968 by the electric utility industry as a result of the 1965 power failure in the Northeast, NERC has responsibility for overall reliability planning and coordination of interconnected power systems. NERC's nine regional councils cover 48 contiguous states, part of Alaska, and portions of Canada and Mexico. The councils are responsible for overall coordination of bulk power policies that affect the reliability and adequacy of service in their areas.

PBR – Performance-Based Ratemaking – An approach used in regulating utilities that takes into consideration fixed and variable costs in determining revenues, often incorporating caps on price or revenue. Under this approach, utilities generally have a stronger incentive to reduce costs rather than invest in their system to obtain profits.

Power Reliability – The ability of the power system to perform a required function under stated conditions for a stated period of time. Power reliability can be measured most generally by the percentage of the total time the power system is available for operation or by the forced outage rate, the percentage of the time the system is not available for operation due to unplanned factors or the mean time between forced outages. A power plant can be deliberately taken out of service at a specific time for construction, repair or maintenance. Consequently, a scheduled outage factor measures the percentage of time set aside for planned maintenance.

Publicly Owned Electric Utilities – Nonprofit local government agencies established to provide service to their communities and nearby consumers at cost, returning excess funds to consumers in the form of community contributions, increased economies and efficiencies in operations, and reduced rates. They include municipals, public power districts, state authorities, irrigation districts, and other state organizations.

PURPA – Public Utilities Regulatory Act of 1978 – Act which granted special rights to sell power under protected contracts to qualifying independently owned industrial and institutional cogeneration projects that provide combined heat and power or Small Power Producers (See SPP) that generate power from renewable resources (See QFs and IPPs).

QFs – Qualifying Facilities – Independent generators or producers of power (See Nonutility Power Producers and IPPs). Authorized under PURPA, many QFs are industrial cogeneration (See Cogeneration and CHP) projects that must meet certain requirements in regard to operation, efficiency, fuel size, and ownership. Qualifying facilities are typically large, custom facilities ranging in size from five to 50 MW. They are allowed to sell power that utilities must purchase at avoided cost (See Avoided Cost). Other QFs are Small Power Producers (See SPPs) that rely on renewable energy as sources for power.

Rate Base – The value of property upon which a utility is permitted to earn a specified rate of return as established by regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or combination of the following methods: fair value, prudent investment, reproduction cost, or original cost.

Reactive Power (VAR) – A unit of reactive power in a circuit carrying a sinusoidal current. A VAR equals the amount of reactive power in the circuit when the product of the root-mean-square of the Volts (Voltage) by the root-mean-square of the current (amps) and the sine of the phase angle between the voltage and the current equals one.

Reserve Power or Margin (Operating) – The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.

Retail – Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes such as agriculture and street lighting are included in this category.

Spinning Reserve – Reserve generating capacity running at zero load and synchronized to the electric system.

SSP – Small Power Producer – A small power production facility or producer generates electricity using waste, renewable (water, wind, and solar), or geothermal energy as a primary source of energy, qualifying under the Public Utility Regulatory Act (See PURPA and QFs). Fossil fuels can be used but renewable resources must provide at least 75 percent of the total energy input. (See Code of Federal Regulations, Title 18, Part 292.)

Standby Power – Power provided to consumers by generators on a customer's site (See DG) or during power outages due to storms or accidental damage to overhead T & D systems.

Standby Service – Service that is available, as needed, to supplement a consumer, a utility system, or to another utility if a schedule or agreement authorizes the transaction.

Stranded Costs – Investments that are no longer economic and have become redundant as a result of breakup of utility functions under deregulation and when customers leave the grid. States have allowed utilities to charge customers competitive transition charges (See CTCs) and exit fees (See Exit Fees) to offset these costs.

Substation – Facility equipment that switches, changes, or regulates electric voltage.

Switching Station – Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between circuits.

Transformer – An electrical device for changing the voltage of alternating current.

T & D – Transmission and Distribution – An interconnected group of electric lines and associated equipment for moving or transferring electricity in bulk between points of supply and points at which it is transformed for delivery over the distribution lines to consumers. The transmission line is that part of the grid that typically transmits energy across state boundaries that is sold at wholesale prices (so-called interstate wheeling) and therefore is under the Federal Energy Regulatory Commission and ISO (See ISO) jurisdiction. The distribution portion of the grid includes local transmission and radial feeder lines that transmit electricity, once it is transformed to voltages usable in residences, at retail prices to consumers and is therefore under state rather than federal jurisdiction.

Unbundling – Separating generation, transmission, and distribution that function together as a monopoly service in a vertically integrated utility (See Vertically Integrated Utility) so that they function as individual services under independent entities with competitive rates.

Vertically Integrated Utilities – An arrangement whereby the same company owns all the different aspects of making, selling, and delivering a product or a service. In the electricity industry, it refers to the historically common arrangements whereby a utility owns its own generating plants, transmission system, and distribution lines to provide all aspects of electric service.

Voltage Reduction – Any intentional reduction of system voltage by three percent or greater for reasons of maintaining continuity of service of the bulk power supply system.

Wheeling Service – The movement of electricity from one system to another over a transmission network of interconnected systems. Wheeling service contracts can be established between two or more systems.

Wholesale Sales – Energy supplied to other electric utilities, cooperative, municipals, and federal and state electric agencies for resale to ultimate consumers.

Wires Companies – Companies that own and operate only distribution lines, provide delivery services to consumers, generators of power, marketers or retailers, and that charge customers for energy only as a pass through. In some cases DisCos and private, for-profit distribution or wires companies may be retail suppliers of electricity to customers in addition to performing distribution functions.

U.S. Department of Housing and Urban Development
HUD User
P.O. Box 6091
Rockville, MD 20849

Official Business
Penalty for Private use $300

Return Service Requested

FIRST-CLASS MAIL
POSTAGE & FEES PAID
HUD
Permit No. G-795

December 2000