Critical Electric Power Issues in Pennsylvania:

Transmission, Distributed Generation and Continuing Services when the Grid Fails

Produced by the Carnegie Mellon Electricity Industry Center for the Pa. Department of Environmental Protection Feb. 2005

Edward G. Rendell
Governor

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Rachel Carson State Office Building
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December 1, 2004

Secretary 717-787-2814

Dear Friend:

On behalf of Governor Rendell, I am pleased to introduce to policy makers in government and the electric power industry this report on critical electric power issues that exist in Pennsylvania. The power industry in the Commonwealth is the second leading generator of electric power in the nation, and Pennsylvania is home to abundant indigenous fuel sources such as wind, biomass, solar and waste coal that can supplement electricity generation, keep energy dollars inside Pennsylvania and decrease our dependence on foreign fuels.

To reap the benefits of these indigenous energy sources, the General Assembly recently passed legislation creating the Commonwealth's Alternative Energy Portfolio Standard, which requires 18% of the electricity sold at retail in the Commonwealth to come from designated alternative energy sources in 15 years. This legislation also calls for the Pennsylvania Public Utility Commission to promulgate regulations to ease the implementation of small-scale distributed power generation of up to two megawatts per system.

However, the Commonwealth faces many obstacles to the transmission of that power, including a lack of adequate transmission capacity to meet demand and a vulnerability – particularly to critical systems – should the electric grid fail. Pennsylvania also faces regulatory and economic obstacles that discourage the deployment of distributed power generation technologies that can provide electric security both as a back-up power source to the grid and as a safe primary source of power for a variety of customers.

In this age of heightened homeland security and increased demand for electricity on the part of consumers, the Pennsylvania Department of Environmental Protection (DEP) believes we must examine these issues. DEP intends to place priority attention on these matters in order to counter the threats that exist should a homeland security event or a blackout occur, as demonstrated by the 2003 blackout in the Northeastern United States and Southeastern Canada.

This report, commissioned by the DEP and produced by the Carnegie Mellon Electricity Industry Center, details the issues and provides a road map to increased electrical security by providing numerous recommendations to improve the performance of the grid both in terms of operations and infrastructure improvements, improve the regulatory environment in order to foster the deployment of distributed generation, and increase the survivability of critical systems in the event of a grid failure.

By following this road map, we can find our way not only to increased security, but increased efficiency in electricity generation and transmission as well, resulting in a real energy cost savings for ourselves and future Pennsylvanians. This will help ensure a brighter future for the Commonwealth and will secure Pennsylvania's role as a national leader in secure and efficient electricity generation and transmission.

Sincerely,

Kathleen A. McGinty
Secretary

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by

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Carnegie Mellon Electricity Industry Center

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STUDY SCOPE

The Office of Energy and Technology Development, Pennsylvania Department of Environmental Protection requested that the Carnegie Mellon University Electricity Industry Center study three areas critical to the future of electric power in the Commonwealth. The study began December 15, 2003 and this report was submitted on July 30, 2004. The Commonwealth requested the following studies:

1. Power grid construction

1.1, Quantitative assessment of transmission line demand and siting difficulties. Rank Pennsylvania's demand for transmission and difficulties of siting new lines in a national context, and indicate the perceptions of difficulties perceived by various stakeholder groups nationally.

2. Regulatory requirements for distributed generation technology adoption

2.1, Review of the existing regulatory environment for micro-grids. Prepare a policy summary review of the environment for micro-grids nationally and in Pennsylvania.

2.2, Model legislation for enabling micro-grids. Include guidelines for draft legislation which enables a favorable regulatory environment for micro-grids, previously developed by the Carnegie Mellon Electricity Industry Center.

3. Survivability of critical missions normally served by the electric grid

3.1, Identification of missions which must survive when the grid is disrupted. Construct a preliminary taxonomy of life-critical and economically important functions and services which are provided by electric power, together with a list of outcomes that have important socio-economic consequences (such as inducing terror). In parallel define several "reference power disruptions" (length and geographic extent).

3.2, Exploratory analyses of barriers to and incentives for survivability. To implement survivability strategies, a number of legal, regulatory or other changes may be required. Incentives will have to be aligned so that private investors see benefits in investing in activities that serve the collective interests of increasing service and system reliability. With greater use of distributed resources, questions of how load is smoothly transferred back and forth between the grid and local generation must be considered, as must questions about how these capabilities might positively and negatively impact power grid stability.

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EXECUTIVE SUMMARY

1. The Power Grid

The electric power grid in Pennsylvania is both a critical infrastructure upon which virtually all residents and parts of the economy depend and a significant industry. The Commonwealth ranks second in the nation in the generation of electric power, exporting 31% of the net electricity generated in the state.[1] The annual wholesale value of these exports is approximately $3 billion.

Much of the power generated in the Commonwealth flows through lines operated under the authority of the PJM Interconnect. While PJM is one of the exemplary transmission systems in the nation, the performance of the electric grid can be improved both by introducing operations changes and by strengthening existing transmission infrastructure. The Commonwealth may have opportunities through discussions with transmission systems operators, regulation, and participation in federal forums to influence the adoption of modern transmission operations principles. Significant improvements to grid operations are possible within the next few years.

Nationally, the capacity of the United States transmission grid has not kept up with the increase in electric generation capacity. The power carried by the transmission system has increased rapidly since the Federal Energy Regulatory Commission (FERC) Order 888 in 1996 opened the system to customers buying power from remote generators. Industries can buy power from plants hundreds of miles away, putting major burdens on the transmission system, but providing customers for generators in Pennsylvania and other power exporting states. The transmission system was not designed for this competitive wholesale market. Sharp rises in transmission congestion are a leading indicator of potential problems, which may include barriers to Pennsylvania power sales, and blackouts.

While Pennsylvania could benefit from new transmission construction, no new long transmission lines have made it through the approval process in the Commonwealth for nearly two decades. To facilitate electricity exports and promote reliability and security, Pennsylvania should assess its transmission needs and find the most cost-effective ways of satisfying them, including new transmission lines, upgrading the voltage in existing lines, and adding advanced transmission technology to the lines. The Commonwealth must examine the regulatory climate for these investments to ensure that socially beneficial investments are made.

The perceptions of transmission siting difficulty and the causes of siting difficulty vary dramatically among different agencies and stakeholder groups. Although Pennsylvania is ranked 22nd in perception of siting difficulty by all stakeholder groups taken as a whole, it is second only to Maryland in difficulty of siting as perceived by government regulatory agency respondents. Addressing these perceptions is a cost-effective method of removing one barrier to transmission siting in Pennsylvania.

2. Distributed Generation Technology Adoption

Pennsylvania and California were the first states to restructure their electricity systems. One of the potential benefits of restructuring is creation of an environment in which new models of electric service can grow. The technology for economic generation of electricity close to its use (termed “distributed generation” or DG) is becoming mature.

Distributed generation can offer greater efficiency, lower costs, greater reliability, greater security, and reduced need for transmission. The efficiency increase come from productive use of the 2/3 of the fossil energy that is “waste heat.” Co-generation or combined heat and power can use this waste heat for space heating, water heating, and process heat.

Distributed generation can also increase power adequacy (the ability to meet power needs), potentially decreasing the magnitude of outages by more than a factor of ten over central generation. However, significant system-wide operations issues can be introduced by distributed generation. It appears that grouping distributed generators into units such as micro-grids with advanced controls and equipment can lessen or eliminate some of these problems.

A micro-grid is a small-scale power generation and distribution network serving multiple customers, with generators near or on the same site as the customer. Most micro-grids are interconnected with the grid, but can be operated independently when the grid fails. A shopping center, hospital complex, or industrial park may choose to implement a micro-grid to serve its loads at lower cost or higher reliability than is available through the grid. Micro-grids serve part or all of the local load, and generally incorporate energy storage for brief interruptions during switching of power sources. Some micro-grids produce more power at times than is required by their load, and may sell this surplus power to the grid.

The Commonwealth can facilitate distributed generation and micro-grid market growth through three basic actions: 1) adopt standardized and transparent interconnection procedures, applications, and model designs for all distributed generation customers; 2) formalize the definition and legal status of micro-grids and adopt standardized operating rules; and 3) allow or require appropriate natural gas tariffs for DG customers.

California and New York have begun listing pre-approved equipment that can be used by DG customers for expedited interconnection procedures. These states either conduct testing or follow testing by nationally recognized laboratories and use this information to determine which off-the-shelf systems or models are low-risk and reliable. Pennsylvania could simplify the interconnection process by adopting similar procedures.

One important issue that will arise in the development of a special symmetric tariff governing bilateral transactions between large micro-grid systems and the legacy distribution utility is that of location specificity. Micro-grids located in some places could prove highly beneficial to the operation of the legacy distribution system by relieving congestion and providing needed system support. Location in other places could impose costs on the distribution system.

We believe that the basic tariff should not be made location specific because over time the result of a series of location specific tariffs could grow into a path-dependent tangle of different rates. Instead, we recommend a fixed set of basic rates to which both parties must adhere in the absence of any other agreements

3. Survivability of Critical Missions Normally Served by the Electric Grid

Electric power outages black out customers several times each year for periods of several hours. Longer outages affecting tens of thousands of customers occur every few months. Designing an electrical power system to be invulnerable is both economically impractical and impossible. While all vulnerabilities cannot be avoided, important parts of the power system can be made survivable. Survivability is the ability of a system to fulfill its missions in a timely manner in the presence of attacks, failures, or accidents. Continuing essential services in the face of a power failure is both possible and practical for vital public and private services.

Ensuring the fulfillment of critical missions is different from either a traditional vulnerability assessment approach, or the approach of making the electricity delivery system 100% reliable. Invulnerability is not only very expensive, it is also impossible to test and probably impossible to achieve for a complicated system like the electric grid.

An in-depth study was conducted for Pittsburgh of emergency services, public utilities, private services, fuel supply, ground transportation, and the Pittsburgh International Airport. The study found that while operators of some important services, such as hospitals and 911 emergency response, have taken measures to ensure that service will continue during a blackout, other critical services, such as some police zone stations and traffic control, are unprotected from electricity outages.

Obtaining the information necessary to assess the vulnerability of important services in the face of power outages and propose solutions is at odds with the natural desire of many organizations, especially those involved with homeland security, to keep information about vulnerabilities out of the public domain so that pernicious persons or groups cannot exploit those vulnerabilities. If groups performing system-level analysis for state or local governments cannot access important information, it is extremely difficult for policy makers to develop rational policies to reduce future vulnerabilities. Significant information barriers were identified. These will require an inter-agency effort to overcome.

The following are options which the Commonwealth and local governments might pursue to encourage or require <u>private parties</u> to improve the reliability of important social services:

- Modify electricity tariffs to permit electric utilities to recover costs associated with designing, installing, testing, and maintaining backup on-site power systems.

- Provide information and advice to private parties to help them assess the benefits of making the services they provide more robust in the face of power outages. For example, once they think about it, a multi-story retirement home that installs backup power for its elevator might find that advertising this fact provides it with a comparative advantage.

- Encourage firms to offer “preferred customer” services which assure continued availability of services such as access to gasoline and ATM machines to those customers who have paid a fee that allows the companies to make the necessary additional investments.

- Require organizations to post public information on whether services such as elevators or gasoline pumps will be functional in the event of a power disruption.

- Make changes in building codes and other legal requirements for business practice. For example, a decade ago Pittsburgh adopted a building code that requires elevators in newly constructed buildings of more than seven stories to have backup power.

- Provide tax incentives, subsidies or grant programs to support the development of needed facilities. Given limited resources, this option should be used sparingly, but there might be some circumstances, such as certain upgrades in the emergency rooms of private hospitals, which warrant modest assistance.

Pennsylvania may wish to study whether promoting survivable mission activities or funding would be justified as an attraction for businesses to thrive in the global economy.

The following are options which the State and local governments might pursue to encourage or require public and non-profit parties to improve the reliability of important social services.

- Provide information which allows the identification of win-win situations. For example, LED traffic lights require far less power than conventional traffic lights. Cities and towns could be encouraged to covert to LED systems and add trickle charge battery back-up.

- Offer selective State subsidy programs, or lobby for the creation of selective Federal subsidy programs, to cover just the *incremental* cost of making systems such as ventilation fans for tunnels more robust.

All of the preceding options are focused on making services more robust in the face of a supply outage from the power company. However, since most power outages arise from failures in the local distribution system, some jurisdictions have adopted regulatory requirements to foster retail competition based on reliability. This is most prevalent in New Zealand and Australia, where up-to-date reliability indices are posted on utility and government websites.[2] [3] Transparency of this sort aids consumers, but is uncommon in the US. Pennsylvania does not currently require that utilities publish their reliability statistics;[4] we recommend that the Commonwealth do so.

INTRODUCTION – Infrastructures and the Services they Provide

The Focus on Critical Infrastructure

American society is dependent on a web of complex infrastructures. The electric power grid, gas and other fuel supply networks, computer and communication systems, transportation systems including road, rail, airports and air traffic control, water supply and sewer, are all essential to the smooth operation of the nation. Because many of these systems are complex, and because the operation of one often depends on the operation of others, the federal government, the research community, and industry have long studied vulnerabilities and searched for cost-effective ways to improve reliability in the face of accidental and intentional disruptions.

In October 1997 the President's Commission on Critical Infrastructure Protection (PCCIP) issued its report "calling for a national effort to assure the security of the United States' increasingly vulnerable and interconnected infrastructures, such as telecommunications, banking and finance, energy, transportation, and essential government services[5]." The efforts of this Commission prompted a series of assessment and other activities, including an assessment of cyber security by the Pittsburgh based CERT Coordination Center of the Software Engineering Institute[6] and a set of modeling studies of interdependencies among infrastructures by Sandia National Laboratories.[7]

On the basis of the PCCIP report, in May of 1998 President Clinton signed Presidential Decision Directive 63 titled "Protecting America's Critical Infrastructures." PDD 63 focused on reducing "cyber and physical infrastructure vulnerabilities of the Federal government by requiring each department and agency to work to reduce its exposure to new threats" and called on industry to undertake a similar effort on a voluntary basis.[8]

The terrible events of September 11, 2001 highlighted this dependency and resulted in an increased focus on infrastructure vulnerability. In October 2001 President Bush issued Executive Order 13231, "Critical Infrastructure Protection in the Information Age", creating a National Infrastructure Advisory Council.[9] In the aftermath of suicide attacks, the National Academies used their own internal resources to quickly mount a comprehensive study of the role of technology, both in making the nation vulnerable and as a tool to make the nation safer. The resulting report *Making the Nation Safer: The Role of Science and Technology in Countering Terrorism*[10] placed considerable focus on critical infrastructure, as have a series of follow-up activities at the academies[11] and in academia.[12]

In 2002, the Congress approved the creation of the Department of Homeland Security (DHS). Among its various responsibilities, "DHS is responsible for assessing the vulnerabilities of the nation's critical infrastructure and cyber security threats and will take the lead in evaluating these vulnerabilities and coordinating with other federal, state, local, and private entities to ensure the most effective response.[13]"

Critical Electric Power Infrastructure

Electric power generation in the United States in the period 1949 through 1973 increased exponentially (at the compounded rate of 7 ¾ % per year), and linearly since 1973 (with annual increases of 70 billion kilowatt-hours per year, the equivalent of roughly 15 new large generation plants per year); see Figure 1.

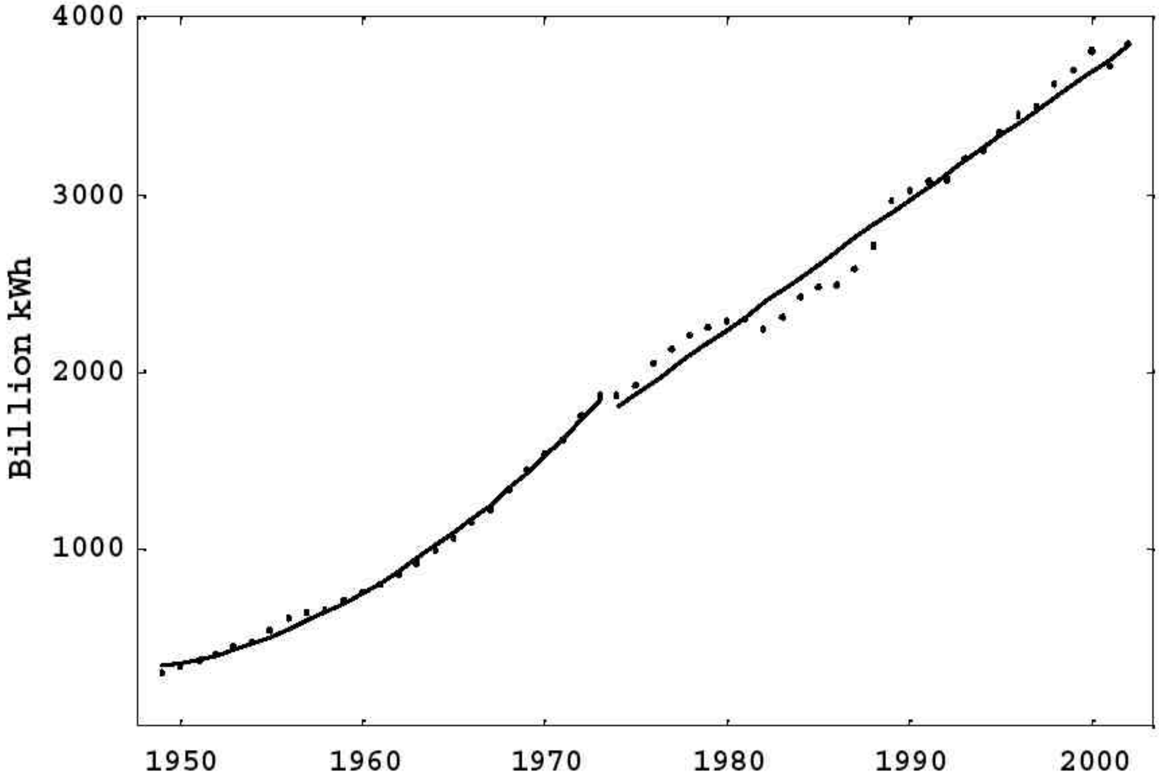


Figure 1. Net electric power generation in the United States.[14] Growth was exponential until 1973, and has been linear since.

Consumption of electricity in the Commonwealth of Pennsylvania has generally followed that in the nation (Figure 2). State figures are available for the period from 1990 through 2003. From 1990 – 1995, the use of electric power in Pennsylvania and in the US as a whole grew at the same rate. The technology boom of the late 1990's caused increased use outside the Commonwealth, but the use in the most recent three years has again generally reflected the national pattern.

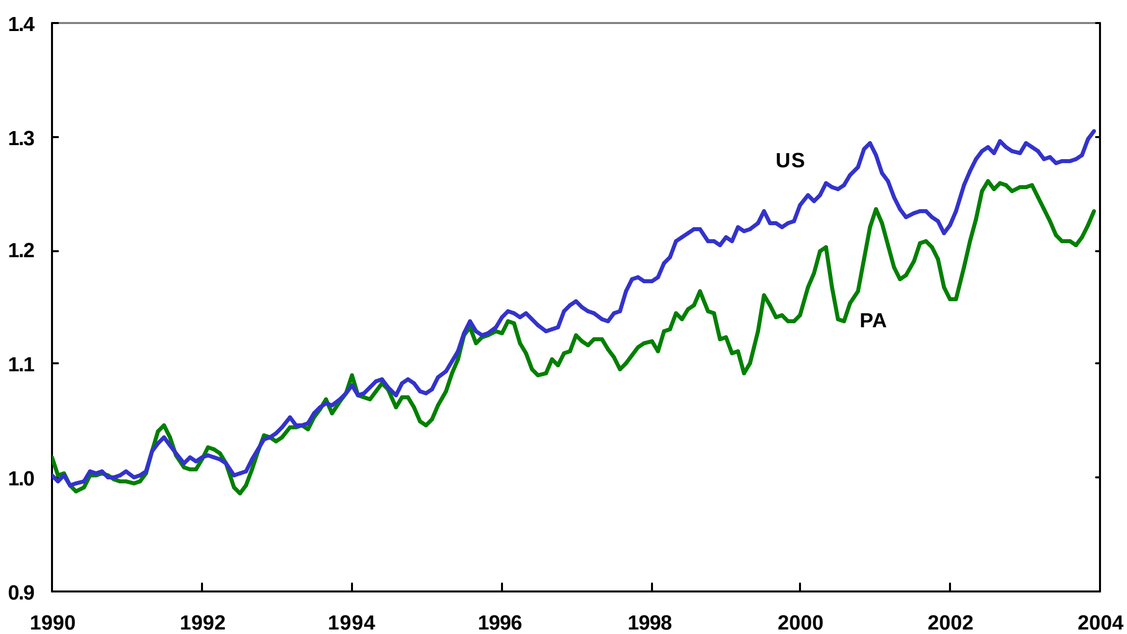


Figure 2. Pennsylvania and national monthly electricity megawatt-hour sales (all sectors), 1990 – 2003, normalized to average of 1990, with seasonal periodicities removed.[15]

This use is accompanied by occasional outages. According to figures compiled by Rodentis[16] in 1999, electrical power interruptions affect 70% of all US businesses (Figure 3).

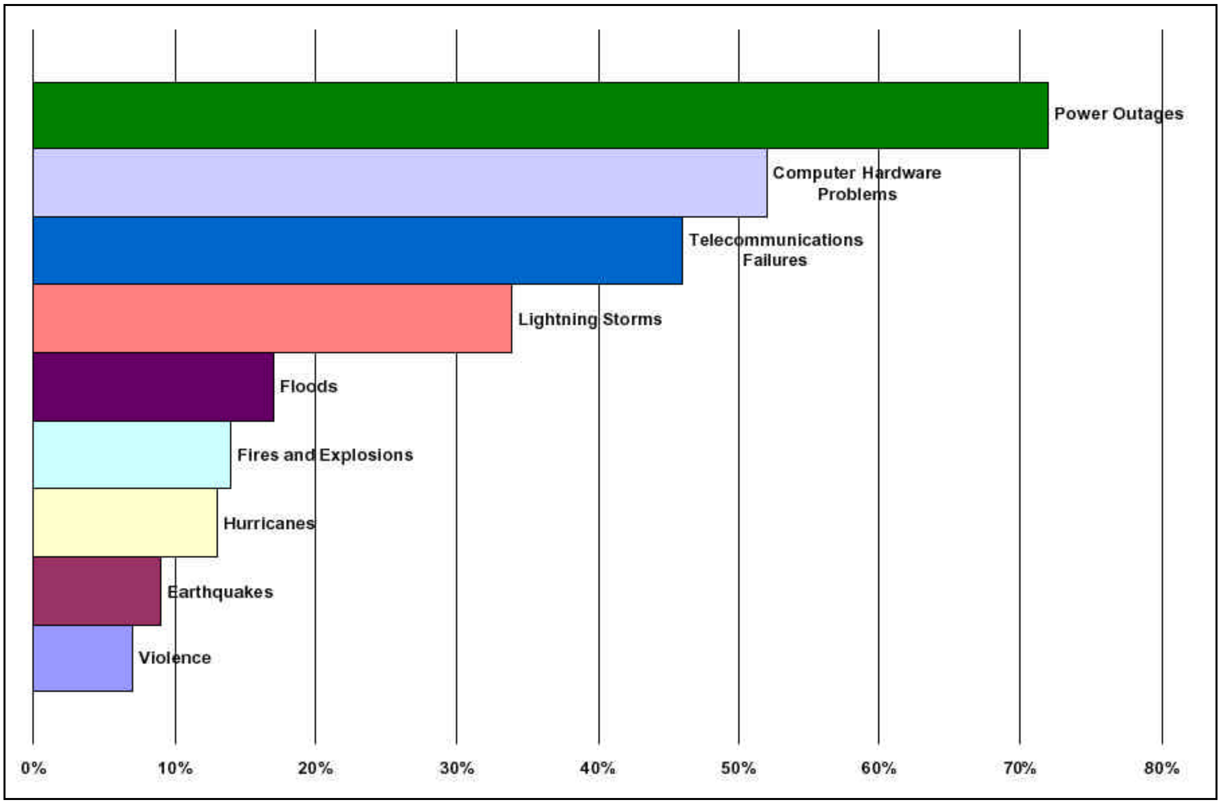


Figure 3. Fraction of US businesses affected by natural and human-caused factors.[16]

Most power outages are brief. In the US, customers lose power a few times a year for periods of between 2 and 8 hours.[17] However, large and long blackouts are not rare. Examples of recent large blackouts include:

•	11/9/65	Northeast US	30 million people affected
•	6/5/67	Pennsylvania-NJ-MD	4 million
•	7/13/77	New York City	9 million
•	3/27/82	Western US	1 million
•	3/13/89	Québec	6 million
•	12/14/94	Western US	2 million
•	7/2/96	Western US	2 million
•	8/10/96	Western US	7.5 million
•	1/5/98	Québec	2.3 million
•	8/14/03	Great Lakes-NYC	50 million
•	9/18/03	Southeast US	4 million
•	9/23/03	Denmark & Sweden	4 million
•	9/28/03	Italy	57 million
•	11/7/03	Chile	15 million
•	7/12/04	Athens	7 million

The North American Electric Reliability Council (NERC) lists 533 transmission or generation related outages over the period 1984 through 2000 (Figure 4). These are not distribution system losses; users were affected because the generation and transmission system failed. Forty-six of the events, or nearly three per year, are losses of 1,000 MW or greater (about the size of the load in the city of Pittsburgh).

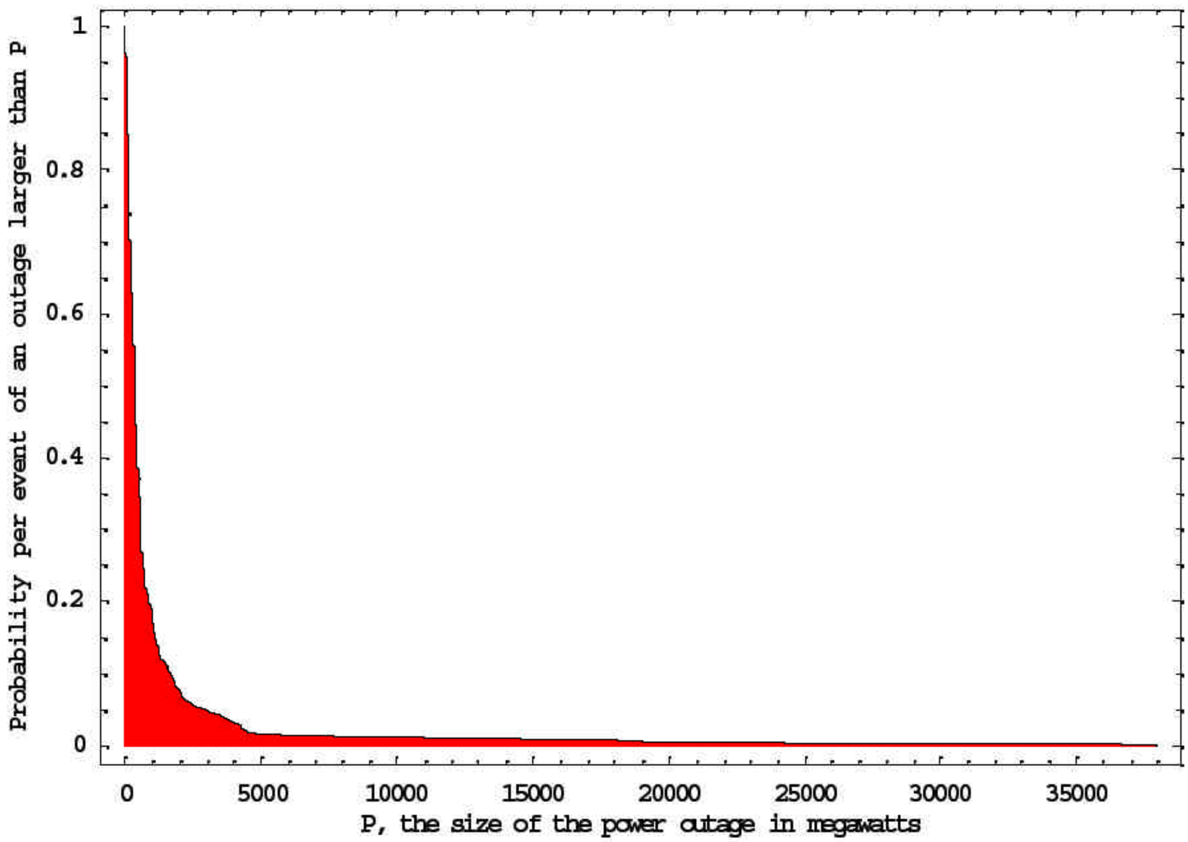


Figure 4. Probability of transmission- and generation-related failures that exceed a particular size.[18]

About every four months, the United States experiences a blackout large enough to darken half a million homes. In 1965, a massive blackout in New York captured the nation's attention and started remedial action. But that was almost 40 years ago, and still we have not ended blackouts, nor even reduced their frequency significantly.

Predicting the evolution and effects of electrical failures which cascade into blackouts has proven difficult. The difficulties have four sources. First, cascading failures are hybrid phenomena; their dynamics involve periods of continuous change punctuated by switching operations that produce discontinuities. Second, the evolution of any cascading failure depends on the initial conditions of the network, and there are a great many possibilities for these conditions. Third, electric grids contain many nonlinearities, such as power flows (products of voltage, current, and the cosine of the included angle) and saturation effects in transformers. Fourth, there are profound uncertainties in the grid's response, such as the uncertainties in the reliability and thresholds of protective devices, in hidden failures, and in the interventions of human operators. The response of the grid is exquisitely sensitive to some of these uncertainties. A slight lowering of the threshold of a single protective device, causing it to operate when otherwise it would not, can completely change the course of a cascading failure.

There are two classes of methods for dealing with hybrid phenomena: analytical methods and simulation methods. Both classes have limitations. The analytical methods can handle the multitudes of initial conditions reasonably well but not the nonlinearities and uncertainties. The simulation methods can handle the nonlinearities well, but not multitudes of initial conditions, or uncertainties.

Designing an electrical power system to be invulnerable has inherent difficulties. The problem is exceedingly large. It is not certain that the problem has any good solutions. Even if it does and someone were to propose the perfect solution, we lack the verification methods to identify it as such. An unverified solution, even one that appears to be eminently reasonable, could in some cases increase the chances of cascading failures. Finally, some measures taken to prevent cascading failures could probably be defeated by an intelligent and determined attacker.

Critical Services *versus* Critical Infrastructure

There are three strategies that can be pursued to assure that critical social services are maintained:

1. Harden the network so that it is less vulnerable to disruption;
2. Make the network more robust so that it can survive disruptions and continue to operate (perhaps with a degraded level of service);
3. Pursue alternative strategies to keep the services operating when power from the network is no longer available.

Because networked infrastructures are physically dispersed, there is no way to harden every piece against accidental or intentional disruptions. Researchers in cyber security understood this many years ago. Indeed, it was the desire to produce a computer communication system that could continue to operate when parts of it were disrupted that lead to the creation of ARPAnet, the forerunner of today's internet. Computer scientists have also recognized the need to focus on resiliency in the creation of software systems.[19]

While much of government and the research community, including many of those concerned with the electric power industry, have focused on the protection of networked infrastructure, in fact what really matters is the social services that those networks provide. For example, in the case of electricity, people need light and power for electric motors. Typically electricity from a central grid is the best way to meet these needs, and reliability of these services may be increased over today's level. But there are other ways to obtain the same services, and we examine some of those alternatives in Part 3 of this report.

In Part 1 we explore what has been done, and what still needs to be done to pursue the first two of these strategies at the level of the traditional power grid. The electric power grid as a whole requires adequate transmission capacity additions to meet the changing needs of the deregulated electric power industry, as well as growth in demand for power which exceeds the ability of local generators to meet the demand. One of the least pursued strategies for making electric power more secure is through the use of distributed resources (distributed generation and micro-grids). We explore opportunities presented by these options, together with the difficulties and obstacles they face, in Part 2. Finally, in Part 3 we turn the focus around and consider the critical services that society derives from electric power. In that section we explore a variety of strategies that might be pursued to keep those services operating if and when power is not available from the traditional power grid.

PART 1: Improving the Performance of the Grid

1.1 Improving Grid Operations

The United States has attempted to use voluntary measures to prevent electrical blackouts for much of the past century. Until recently, vertically integrated utilities planned for their own system reliability, with a few tie lines to neighboring utilities that might be helpful in some emergencies. It became clear in the 1965 Northeast blackout, when a failure in Ontario blacked out New York City eleven minutes later, that growing electric demand had made regional issues important. In the next two years, ten voluntary regional reliability councils were established to coordinate the planning and operation of their members' generation and transmission facilities. In 1968, the North American Electric Reliability Council (NERC) was formed to coordinate the regional councils. One of NERC's primary functions is development of reliability standards for the regional generation and transmission of power. According to its website, "NERC has operated successfully as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved."[20]

Consumers of electricity may have a different definition of success. Despite the voluntary standards, large blackouts unrelated to storms occurred in Pennsylvania, New Jersey and Maryland on June 5, 1967 (affecting 4 million people); Miami on May 17, 1977 (1 million); New York on July 17, 1977 (9 million); Idaho, Utah and Wyoming on January 1, 1981 (1.5 million); four western states on March 27, 1982 (1 million); California and five other western states on December 14, 1994 (2 million); the Pacific Northwest on July 2, 1996 (2 million); eleven western states on August 10, 1996 (7.5 million); and San Francisco on December 8, 1998 (0.5 million).

After the passage of the Public Utilities Regulatory Policies Act in 1978 and the Energy Policy Act of 1992, the electricity industry became a hybrid of vertically-integrated utilities and new structures of multiple forms. "Merchant generators," independent of utility companies, installed their own plants and sought customers anywhere in the country. Aggregators bargained for better rates on behalf of large numbers of customers. Energy brokers used the open market and long-term contracts to buy and sell power.

Restructuring has transformed the operation of the electricity system. Utilities formerly transmitted power from a nearby generation plant to customers. Now, industrial customers can buy power from plants hundreds of miles away, putting major burdens on the transmission system and increasing the likelihood of a blackout. Electricity flows from high to low voltage points over the path of least resistance, not over paths specified in a contract. This property (expressed in Kirchoff's Laws) means that the laws of the market may put stress on the system for which it was not designed.

That has made an immense difference: The number of times the transmission grid was unable to transmit power for which a transaction had been contracted jumped from 50 in 1997 to 1,990 in 2003. Restructuring has done little to improve the physical system of transmission or its control systems.

No organization that generates, transmits, or distributes electric power wants low reliability. But in a deregulated, competitive electricity market, companies have to pay for investments out of the revenues they earn. Unless companies can find a way to bill customers for reliability, or unless regulators mandate reliability investments and ensure that they are reimbursed, no investments will be made. None of the nineteen states that have implemented electric restructuring has figured out how to pay for investments to prevent low-probability events such as blackouts.

Eight years ago, reacting to that summer's two large outages in the West, NERC's CEO wrote "[a new model] must include universal participation, more detailed and uniform reliability standards that can be put in place quickly, independent monitoring of reliability performance, and the *obligation* to support, promote, and comply with NERC's Policies." In 2002, NERC incorporated many of the new market participants that emerged after restructuring (such as brokers and aggregators) in developing its voluntary reliability standards. In 2003, NERC stated that "the existing scheme of voluntary compliance with NERC reliability rules is no longer adequate for today's competitive electricity market." However, both a 1998 Department of Energy report and a complaint to FERC in 1997 question NERC's authority to make its standards mandatory.

NERC has supported federal legislation that would establish an Electric Reliability Organization (ERO) with authority to establish and enforce mandatory standards. A NERC panel put forward this proposal first in January 1997. Eight months later it was endorsed by a task force chartered by the Department of Energy as a response to the 1996 blackouts. It was part of the energy bill that passed the House on April 11, 2003, and subsequently appeared in Section 1211 of the conference committee language. The proposed ERO would be industry-led and could level penalties for violations of standards, but its authority over grid operations (as distinct from planning standards) is still to be defined.

Significant improvements to grid operations are possible within the next few years. Some elements of such a near-term plan were proposed in 2004 by the Carnegie Mellon Electricity Center.[21]

National standards for telemetry data on power flows and transmission system components are required. Competitive pressures and changes in the way the grid is used have led to a very sparse data system, and market pressures are not likely to improve matters. Operators can no longer be expected to make the right decisions without good data. Control centers must have displays and tools that allow operators to make good decisions and to communicate easily with operators in different control areas. There must be backups for power and data, and clear indications to all operators that data are fresh and accurate. The emphasis should be on data and presentations that support decisions. The present representations of system state, particularly indicators of danger, are too complex. They stress accuracy over clarity. Grid operators need much clearer metrics of danger and suggestions for action (like collision avoidance alarms in aircraft and in air traffic control centers) even if they are a little less accurate. If the existing 157,000 miles of transmission lines in the United States were fitted with $25,000 sensors every ten miles, and each sensor were replaced every five years, the annual cost would be $100 million. This would increase the national average residential electricity bill (now 8.41 cents per kilowatt-hour) to 8.413 cents per kWh. The total would be roughly one-tenth the estimated annual cost of blackouts. Even this estimate may be too high, since many of the sensors already are in place and need only additional communications to be useful for real-time operations.

All grid operators must be trained periodically in contingency recognition and response using realistic simulators. These simulations must include all operations personnel in a way that exposes structural deficiencies such as poor lines of authority and insufficient staffing. The goal should be to recognize and act upon signs of extreme system stress that may be well outside daily operations experience. Only realistic simulation, using the displays and staffing used in each control center, can provide the training which prepares operators for once-in-a-career events. Federal standards for training, licensing, and certification of grid operators and control centers are warranted to ensure that a single weak control center does not bring down a large area. No federal entity now mandates such realistic training for grid operators, but the owners of nuclear generation plants proved (after Three Mile Island) that it can be done. Simulator training has also become routine for personnel in many other industries such as for commercial aircraft pilots and the operators of large ships.

Operations control centers must be able to control. The present patchwork ability to shed load is not appropriate to the current interdependent transmission grid. Some systems do it automatically, but some cannot even do it manually from the control center. Current practice is to allow relays to shed load only when large load-generation imbalances are perceived (when an under-frequency condition is sensed). As the scale of the US power system grows, imbalances will become increasingly difficult to detect locally. Allowing relays to drop some load on under-voltage conditions is a necessary first step toward improving the systems ability to react to disturbances. In the near term, load-shedding, will probably be in the form of blacking out large areas (such as a neighborhood) regardless of customer reliability preferences and costs. Some power companies have customers who have agreed to be blacked out in emergencies, but this practice is not uniform. A decade hence it may be possible on a large scale to provide signals to consumers to shed parts of their load in exchange for lower tariffs, but this partial load reduction solution has not been economically feasible with current systems.

Sensors, load-shedding devices, and other system components must be checked on a much more systematic basis than they are at present. In a competitive environment, chief financial officers will frown upon such periodic testing, which is why it should be mandated by national standards.

Industry standards for such items as tree-trimming under transmission lines must be set with the costs of failures in mind, not just by the competitive constraints of the immediate marketplace. Companies that do not comply should be penalized. These standards will vary by region, and should be set by regional bodies such as the Regional Transmission Operators.

A national grid coordination center should be established and run as a national asset by a private body. It would stimulate R&D for the data needed for grid monitoring. It would also monitor the situation at regional and larger levels, provide national flow control, and perhaps act as a backup for computer failures in individual control regions. As in air traffic control, the roles and responsibilities of the local and national centers will be neither perfectly optimum nor static, but they will complement each other so that we can avoid the complete lack of situational awareness seen in so many blackouts.

A permanent government investigation body, including professional accident investigators who are trained to look for systemic as well as discipline-related causes, should be an entity separate from the operators or regulators of the grid.

1.2 Transmission Demand and Siting Difficulty in Pennsylvania

The performance of the electric power transmission grid is important for both the reliable supply of electricity to businesses and residents of the Commonwealth and for the economically important export of power from Pennsylvania generation units to customers in other states.

Grid performance depends on not only the operation and maintenance of existing transmission capacity as discussed in the previous section, but also on long-term planning for construction of new infrastructures. The sustainability of the grid as a whole requires adequate transmission capacity additions to meet the changing needs of the deregulated electric industry and competitive electricity markets. This section focuses on characterizing the need for additional transmission capacity and the difficulty associated with siting new lines, and evaluating the consequences of state-level variations in demand and difficulty for national energy policy. We discuss the implications of individual state-level demand and difficulty indicators within Pennsylvania and place the Commonwealth in regional and national transmission planning contexts.

Nationally, since 1982 the transmission grid capacity has not kept up with the increase in electric generation capacity, as shown in Figure 5. Although transmission was intentionally over-built in the 1970's, that excess was absorbed by 1990, and the subsequent decline reflects stress on the system.

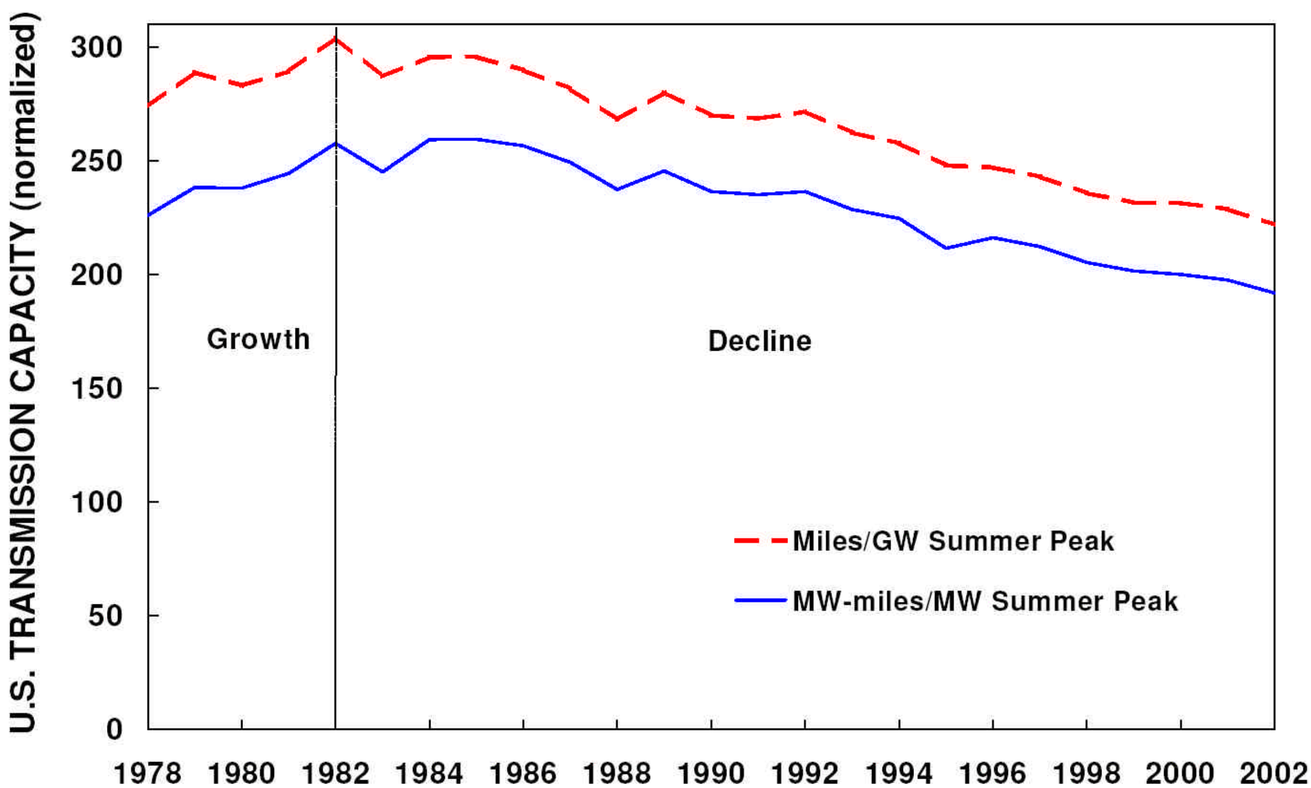


Figure 5. United States transmission (length in miles, red dashed line, and capacity in megawatt-miles, blue solid line) divided by summer peak generation capacity (megawatts) as compiled by Hirst.[22]

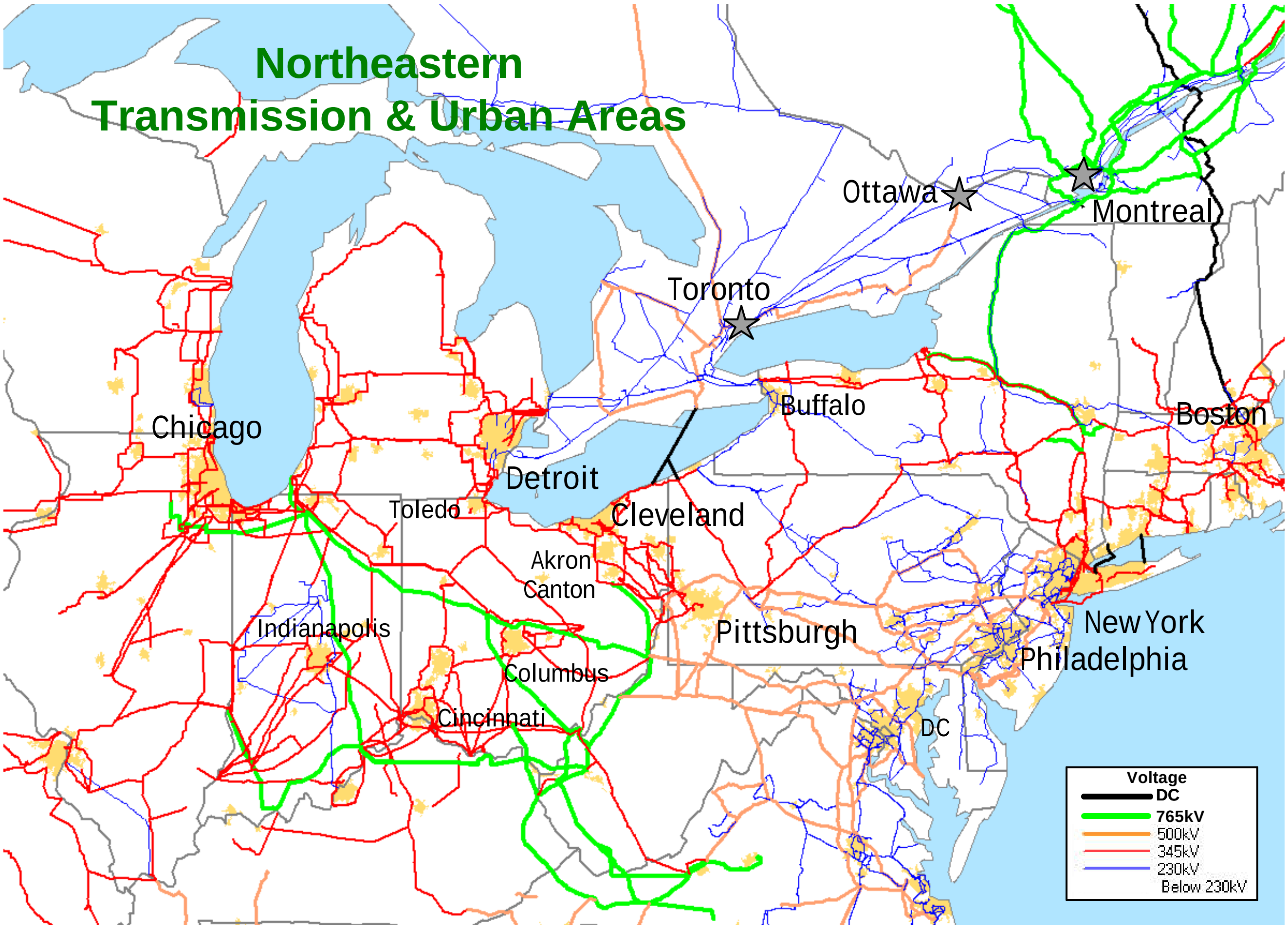


Figure 6. Electric transmission lines in the Pennsylvania region.[23]

The most advanced alternating current (AC) transmission lines operate at 765 kilovolts (kV). Higher voltage lines require fewer resources for a given transmission capacity than lower voltage lines. No lines operating at 765 kV have been constructed in Pennsylvania.

Voltage (kV)	Capital cost ($k/mile)	Capacity (MW)	Capital cost ($k/MW-mile)	Corridor width (feet)	Feet / MW
230	480	350	1.37	100	0.29
345	900	900	1.00	125	0.14
500	1200	2000	0.60	175	0.09
765	1800	4000	0.45	200	0.05

Table 1. Typical costs, thermal capacities, corridor widths, and resource requirements for transmission lines as compiled by Hirst and Kirby. [24] *Lines in heavily populated regions may be much more costly.*

The power carried by the transmission system has increased since the Federal Energy Regulatory Commission (FERC) Order 888 in 1996 opened the system to customers buying power from remote generators. Industries can buy power from plants hundreds of miles away, putting major burdens on the transmission system, but providing customers for Pennsylvania and other power exporting states. The number of times transmission owners did not transmit power for which a transaction had been contracted (called a transmission loading relief event or TLR) jumped from 50 in 1997 to 1,990 in 2003 (Figure 7).

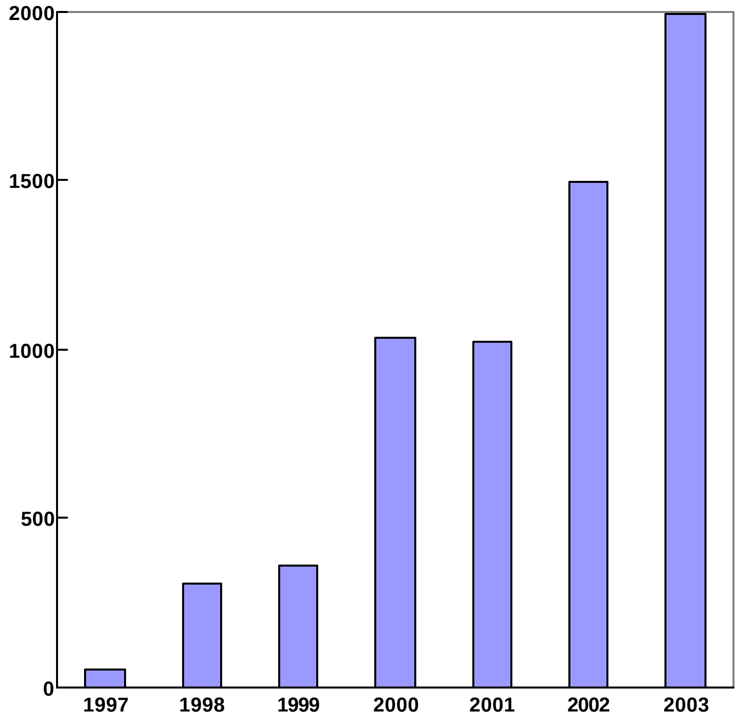


Figure 7. Yearly number of transmission loading relief (TLR) events in the United States.[25]

David Cook, general counsel of the North American Electric Reliability Council (NERC), notes that "The lack of additional transmission capacity means that we will increasingly experience limits on our ability to move power, and that commercial transactions that could displace higher-priced generation with lower-priced generation will not occur."[26]

Literature on siting focuses primarily on the individual causes of siting difficulty without any quantifiable estimates for how much each cause contributes to the collective siting problem.[27] [28] [29] As a result, data on the causes of siting problems are difficult to compile and interpret in a broader policy context.

For this reason, this study specifically focused on indicators of siting difficulty, independent from the host of actual and perceived causes of difficulty. We developed four state-level quantitative indicators of transmission demand and siting difficulty.[30]

1. An <u>economic indicator</u> based on measures of the variability of the marginal cost of electricity production. High variation in generation costs in a state relative to other states and the suboptimal dispatch of generation capacity within a state are an indication of transmission congestion. We developed this indicator by examining cost of production data for 1,500 generation plants across the US at the state level.[31] [32] [33] The median cost of baseload production for all states is $19.47 per MWh; for peak production it is $92.46 per MWh..

At an average baseload cost of production of \$21.52/MWhr, Pennsylvania is ranked 17th in the US for baseload generation cost, below both California and Texas (frequently cited as electricity comparison states in the literature). Similarly, the peak cost of production in Pennsylvania (\$82.27) is close to the US average; however, the potential savings at the peak from optimizing the allocation of generation plants is the highest in the nation. The Commonwealth has relatively weak east-west transmission links, and less expensive peaking units in the west are often unable to be used to meet peak load in the east. Pennsylvania could save 67.5% of its current peak generation costs of production, over \$125 million annually, based on the enhanced transmission scenario in this model. Table 2 presents these data for each state.

2. A geographic indicator based on the distances separating generation capacity from demand load centers. Using a geographic information systems (GIS) model for all generation plants in the United States, footprints based on 5-mile incremental radii were plotted around each plant[34]. These plant data and circular footprints were then overlaid on census zip-code population data and the total population contained within each footprint for all plants was calculated for each state (US Bureau of Census, 2000). Based on the annual power demand for each state[35], consumption per capita was used to approximate the power consumed by the population in each concentric 5-mile radius circle around each plant. The population sufficient to consume a plant's yearly output was then calculated for each footprint. Finally, the population actually served within a given radius of all plants was calculated as a percentage of the state's total population (see Table 3, where a high percentage population served within a small radius indicates a close proximity of generation plants and population loads, and suggests a low demand for transmission lines, and vice versa).

   Pennsylvania has a relatively high percentage of its population within a 25-mile radius of generating plants in the state.

   For this model, we assume that states that export electricity will first use in-state generation capacity to serve in-state demand, and that states that import electricity can never reach 100% demand served. Since this analysis focuses on the relative need for additional capacity and not the specific amounts of additional capacity, any lack of in-state generation capacity satisfied by imports is also an indicator of a need for transmission capacity.

3. A construction indicator based on differences in transmission construction relative to generation capacity construction, net generation, and sales. This indicator was calculated based on changes in total transmission capacity (circuit miles) relative to the changes in generation capacity (MW), net annual generation (MWhrs), and electricity sales (MWhrs). Generation and transmission data for these metrics were compiled for a 10-year period from 1988 to 1998,[36] [37] and normalized to one for the first year. The rate of increase from the baseline year was then calculated for transmission, generation capacity, net generation, and sales in each state.

   For the entire United States the transmission capacity increased by 1.7% per year from 1988-1998 compared to 2.5% average increases for sales. Similar data for slopes (rates of change) and the differences between slopes for transmission capacity and generation capacity, net generation, and sales in each state are presented in Table 4. Negative numbers indicate that transmission growth exceeded generation, as in Pennsylvania (as discussed above, the Commonwealth had slower growth than the nation as a whole in electricity use in the last three years of the data used for this indicator).

4. A perception indicator based on a survey of industry experts. Transmission planning and site selection are influenced not only by objective factors such as economics and geography, but also by perceptions of siting difficulty. A region known for its siting difficulty is likely to be avoided during the process of site selection;[38] therefore, it is equally important to consider indicators that capture both perceived and actual siting difficulty in any quantitative analysis.

   In order to create a perception indicator of state siting issues, an Internet survey consisting of 154 multiple choice questions was administered to siting experts and professionals across the United States to elicit respondents' experience with and opinions about siting in each of the 48 continental United States. A list of approximately 400 potential survey respondents was compiled from the EEI State-Level Siting Directory,[39] the Platt's Directory of Electric Power Producers and Distributors,[40] and industry contacts of the Carnegie Mellon Electricity Industry Center. Respondents were individually contacted by email and were provided a link to the survey website and a password to access the survey. Participants' work experience and current job descriptions ranged from environmental protection to route design, permitting, regulation, and engineering. All surveys were completed online and evaluations were collected from 55 respondents residing in 31 states. Respondents' ratings of siting difficulty in a state are weighted based on their familiarity with siting in that state, where respondents with greater siting experience in a state receive a higher weight.

   The survey results are given in Table 5. The perceptions of average siting difficulty and the causes of siting difficulty vary dramatically among respondents affiliated with different agencies and stakeholder groups.[41] Although Pennsylvania is ranked 22nd overall, it is 2nd only to Maryland in perceived difficulty by government regulatory agency respondents.

   Since respondents in each of these five categories of employment become involved in siting projects at different phases along a project timeline, the perception of the contributing factors of siting difficulty varies with exposure to and consideration of siting constraints. Although public opposition is the dominant constraint across all agencies, only 4% of respondents from public electric utilities perceive topography and environment to be the primary siting constraint across the United States, compared to 28% of respondents from government regulatory agencies. Similarly, far fewer government regulators perceive state regulation as the dominant siting constraint than do public utility respondents. These significant variations in the perception of siting constraints between the five groups of respondents (Figure 8) can be associated with an agency's control or involvement with a given constraint. For example, utility siting officials begin a siting project by eliminating economically or physically infeasible terrains or environments along a route, whereas government regulators working with topographical or environmental issues are involved in the siting process only after utilities have already selected preliminary route proposals and limited the decision options. Based on these variations, one can hypothesize that public opposition is the primary focus of media and research attention to siting constraints since public involvement occurs relatively late in all siting projects and at that point siting agencies have only limited control over the decision-making in a project.

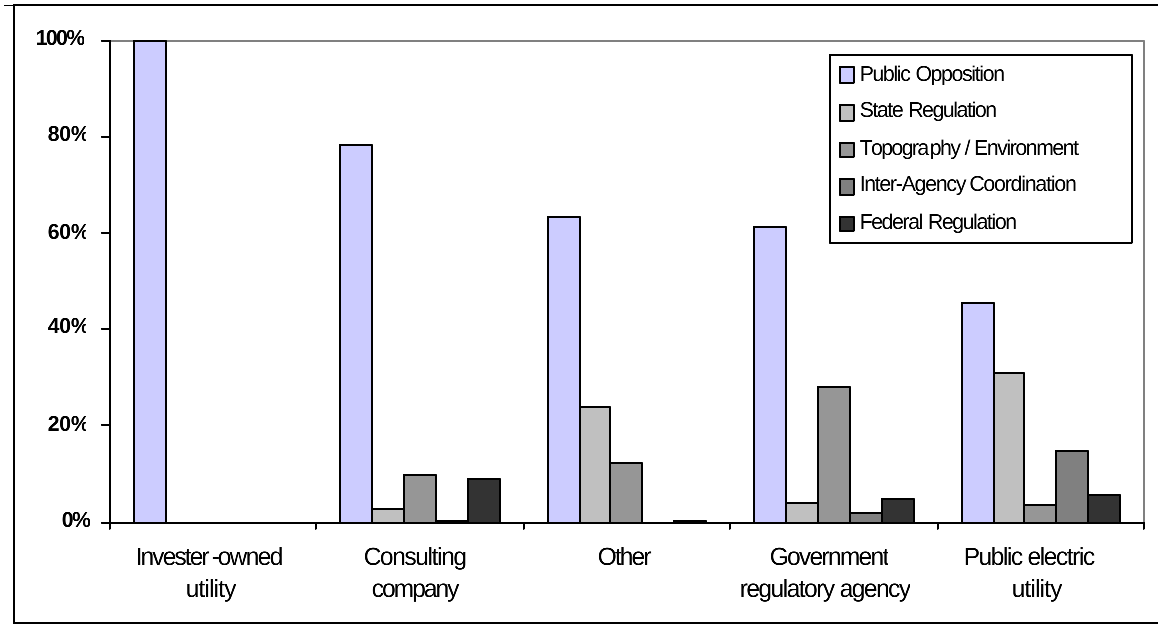


Figure 8. Agency Perceptions of Siting Constraints. The category "Other" includes respondents from electric transmission technology and manufacturing companies.

Each of these indicators captures a different aspect of the siting problem. Transmission line siting is a complex problem, and no single metric is perfect. All of these indicators focus on both the state-level need for transmission capacity and siting difficulty. Because each has its own limitations, we combined the selected metrics using statistical techniques to form an overall indicator[42]. We have found significant variations in demand and difficulty across states and regions.

In order to illustrate the results of this demand-difficulty factor analysis for the US, the scores for each state were calculated and plotted with demand on the x-axis and transmission siting difficulty on the y-axis. As shown in Figure 9, each point on the factor score plot is a state, and states can be grouped into four categories of transmission demand and siting difficulty based on the four quadrants of the graph.

Figure 10 is a map of this plot that shows the geographic variations in transmission demand and siting difficulty by state. States like California with both above-average transmission demand and siting difficulty appear in the darkest color on the map, while states like Nevada with below-average difficulty and demand appear in the lightest color.

Pennsylvania has both above-average demand for transmission and above-average difficulty of siting new transmission lines.

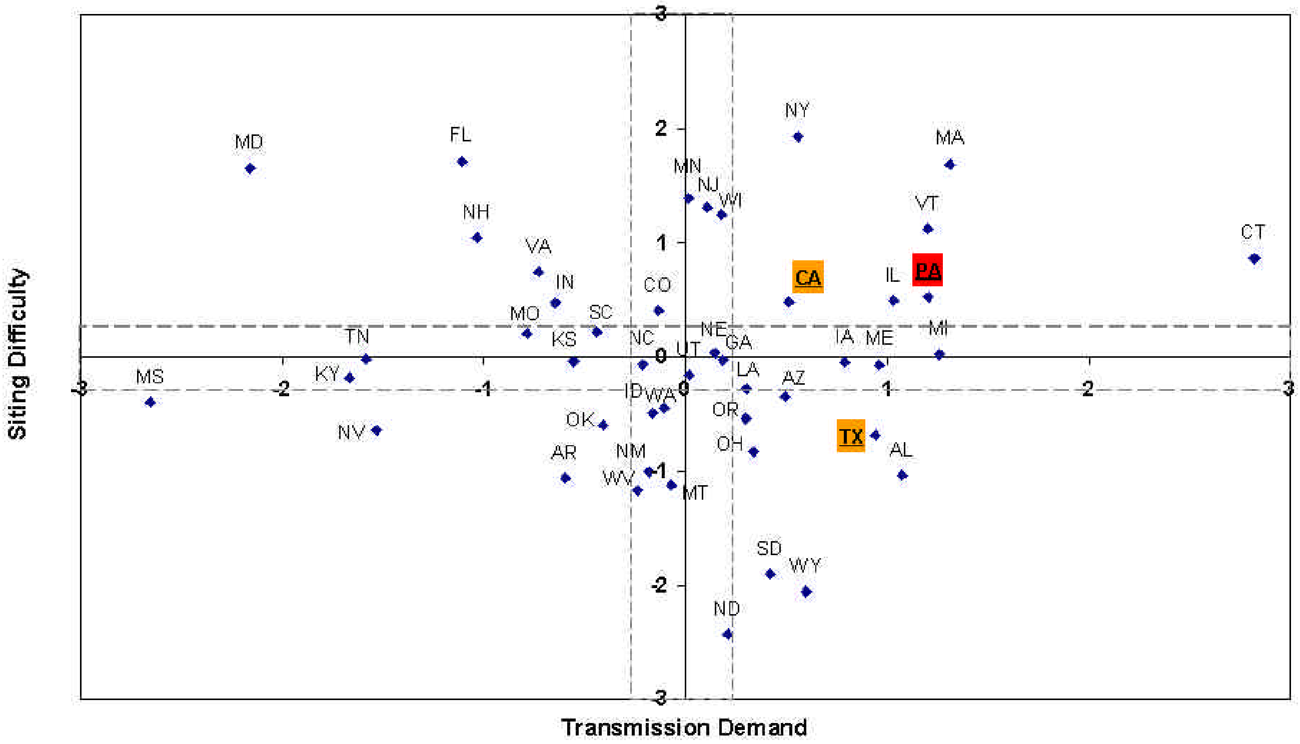


Figure 9. State transmission demand and siting difficulty scores.

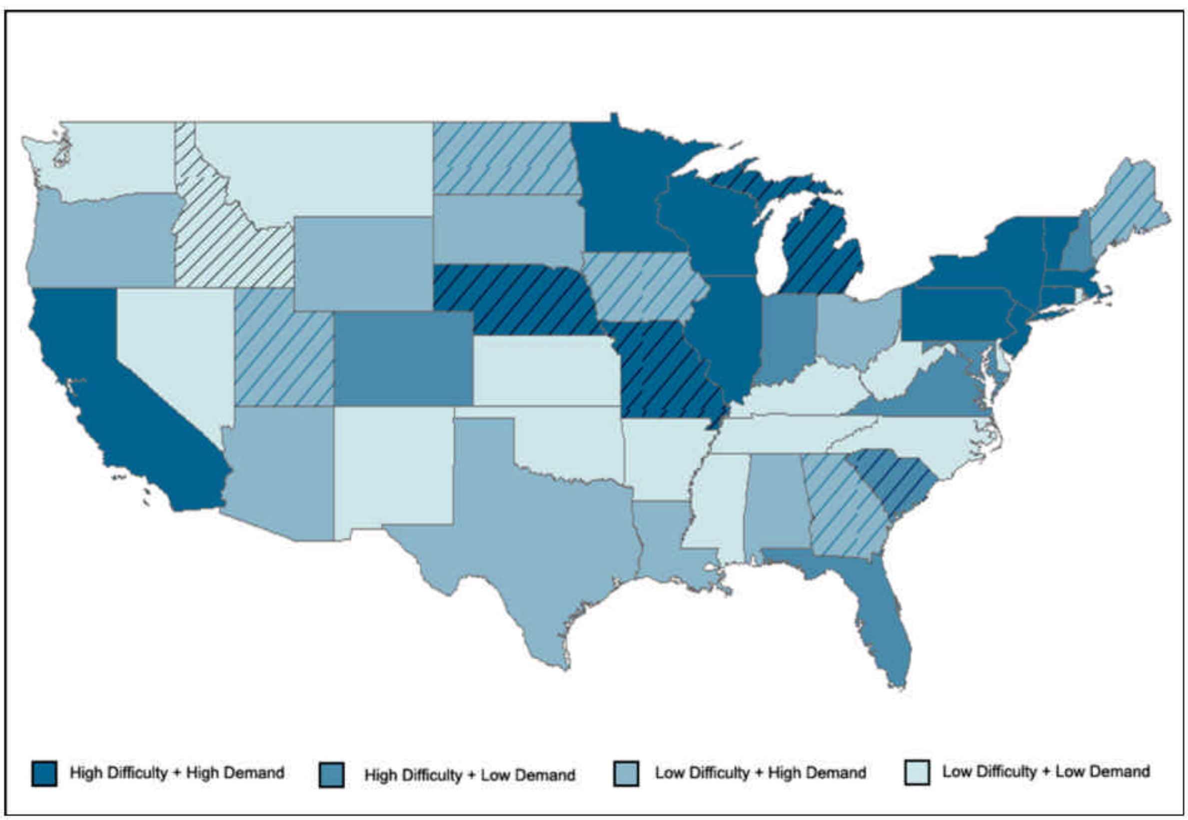


Figure 10. National map of state-level transmission demand and siting difficulty.

State	Baseload Cost of Production ($/Mwhr)				Peaker Cost of Production ($/Mwhr)			
	Mean	Standard Deviation	IQR	Opt. Dispatch Savings (%)	Mean	Standard Deviation	IQR	Opt. Dispatch Savings (%)
Alabama	14.74	6.97	9.41	0.0%	40.47	5.85	-	0.0%
Arizona	26.82	16.13	15.28	0.0%	198.18	236.58	260.82	12.8%
Arkansas	21.56	3.07	5.25	0.7%	76.40	50.87	-	3.5%
California	22.97	12.46	9.39	0.8%	165.52	305.64	100.09	33.8%
Colorado	18.50	6.52	9.72	1.6%	219.01	259.93	412.36	42.5%
Connecticut	34.07	12.72	17.35	0.0%	216.75	111.27	162.62	9.8%
Delaware	-	-	-	0.0%	387.51	377.45	582.34	8.6%
Florida	24.68	5.94	8.83	1.0%	276.77	941.38	36.20	10.3%
Georgia	19.41	4.89	6.19	0.0%	61.80	22.63	16.17	3.3%
Idaho	16.06	10.64	16.91	0.0%	-	-	-	0.0%
Illinois	28.42	15.51	15.66	0.3%	117.54	67.26	66.10	30.9%
Indiana	19.51	6.20	6.69	0.1%	80.06	54.81	61.29	3.6%
Iowa	22.29	14.03	12.58	1.5%	77.14	32.24	54.76	4.3%
Kansas	17.17	4.69	9.28	0.5%	75.04	51.13	40.76	14.0%
Kentucky	14.80	3.79	4.49	0.5%	87.82	68.84	37.78	5.6%
Louisiana	25.94	6.05	10.15	1.8%	183.73	25.38	-	0.0%
Maine	17.27	11.20	20.93	0.0%	1125.20	-	-	0.0%
Maryland	19.27	3.45	5.25	0.1%	73.16	25.85	45.63	0.5%
Massachusetts	34.03	18.18	31.56	0.0%	213.92	214.64	252.82	37.7%
Michigan	21.29	5.69	7.96	0.2%	119.99	109.65	51.57	17.6%
Minnesota	26.19	15.16	19.78	0.2%	159.14	168.00	101.83	16.3%
Mississippi	20.25	3.61	6.65	0.9%	152.58	254.73	51.66	3.8%
Missouri	17.67	5.34	10.61	0.5%	89.65	58.08	45.79	22.0%
Montana	12.07	6.16	8.90	0.0%	38.73	4.23	-	0.0%
Nebraska	16.14	9.42	15.54	0.9%	72.64	42.09	32.13	8.2%
Nevada	18.68	3.07	6.12	0.3%	78.80	35.04	67.19	0.0%
New Hampshire	20.01	5.57	9.97	0.5%	332.84	167.09	308.73	6.2%
New Jersey	28.76	8.30	15.33	0.4%	105.42	66.51	82.74	12.3%
New Mexico	27.26	7.23	12.85	0.0%	54.14	-	-	0.0%
New York	27.81	19.68	18.14	2.2%	351.20	801.97	61.14	13.6%
North Carolina	15.42	8.23	10.39	0.4%	103.30	46.84	73.00	2.4%
North Dakota	16.00	5.26	8.34	0.0%	92.46	-	-	0.0%
Ohio	18.94	4.51	5.40	0.7%	175.33	117.41	128.24	5.1%
Oklahoma	20.55	6.75	10.00	0.9%	49.60	7.09	13.68	0.0%
Oregon	18.79	10.20	15.25	0.0%	45.87	-	-	0.0%
Pennsylvania	**21.52**	**7.54**	**8.20**	**0.1%**	**82.27**	**49.21**	**39.71**	**67.5%**
Rhode Island	32.26	-	-	0.0%	-	-	-	0.0%
South Carolina	18.91	6.61	9.54	0.2%	96.94	30.73	45.40	6.4%
South Dakota	14.45	8.16	15.66	0.0%	66.21	22.71	32.50	2.1%
Tennessee	13.46	6.48	7.57	0.2%	58.25	18.51	36.34	0.0%
Texas	22.52	7.08	11.23	0.9%	196.95	393.23	73.70	42.4%
Utah	19.47	7.66	12.52	0.1%	-	-	-	0.0%
Vermont	21.65	14.22	28.24	0.0%	119.43	34.73	58.61	0.4%
Virginia	18.37	4.32	7.06	0.1%	82.19	30.25	59.41	0.6%
Washington	14.67	6.29	8.93	2.0%	32.72	7.92	-	0.0%
West Virginia	15.51	1.05	1.71	0.1%	-	-	-	0.0%
Wisconsin	20.59	7.69	15.61	0.4%	90.25	74.04	53.97	8.7%
Wyoming	12.69	2.73	5.25	0.1%	-	-	-	0.0%

Table 2. Economic indicator of potential savings from optimal economic dispatch of baseload and peak generation units if transmission were available. The median cost of baseload production for all states is $19.47 per MWh; for peak production it is $92.46 per MWh..

	Percent of Total Population Served within Footprint Radius					
State	**1 mile**	**5 mile**	**10 mile**	**15 mile**	**20 mile**	**25 mile**
Alabama	0.4%	7.4%	30.0%	56.6%	74.7%	87.3%
Arizona	0.9%	4.7%	5.9%	59.8%	60.7%	61.7%
Arkansas	0.5%	4.7%	14.9%	37.1%	56.9%	82.6%
California	0.7%	14.2%	23.0%	31.3%	49.1%	55.4%
Colorado	0.8%	10.4%	19.7%	26.6%	51.1%	92.6%
Connecticut	1.9%	32.5%	47.8%	81.9%	98.2%	99.2%
Delaware	1.5%	26.8%	44.6%	83.9%	99.2%	100.0%
Florida	1.2%	17.2%	49.6%	62.9%	87.1%	90.3%
Georgia	0.6%	10.0%	37.5%	57.2%	88.0%	94.3%
Idaho	0.1%	3.9%	13.1%	24.5%	44.6%	85.1%
Illinois	0.9%	11.5%	32.7%	86.0%	95.2%	98.8%
Indiana	0.6%	12.7%	19.4%	68.9%	80.6%	91.4%
Iowa	0.9%	11.8%	26.0%	68.3%	83.0%	89.0%
Kansas	1.0%	17.2%	38.4%	56.9%	89.2%	95.7%
Kentucky	0.7%	15.3%	38.7%	48.4%	55.2%	81.5%
Louisiana	0.9%	19.3%	47.9%	61.9%	80.2%	87.7%
Maine	0.4%	8.4%	30.4%	40.1%	74.4%	82.8%
Maryland	1.7%	22.1%	46.1%	74.2%	95.1%	97.5%
Massachusetts	2.4%	30.9%	50.0%	72.1%	91.5%	95.6%
Michigan	1.1%	13.9%	37.2%	89.3%	96.6%	96.8%
Minnesota	1.4%	13.9%	44.7%	75.5%	87.9%	91.3%
Mississippi	0.3%	6.7%	18.6%	38.9%	51.3%	62.7%
Missouri	0.9%	15.4%	40.7%	73.8%	81.4%	91.5%
Montana	0.1%	5.1%	13.3%	18.0%	30.6%	48.4%
Nebraska	0.9%	5.8%	48.0%	72.4%	83.8%	91.5%
Nevada	1.1%	11.1%	34.3%	39.2%	58.0%	71.5%
New Hampshire	0.6%	11.0%	42.4%	79.7%	99.2%	100.0%
New Jersey	2.2%	19.9%	51.2%	81.0%	98.4%	99.3%
New Mexico	0.3%	2.4%	4.6%	7.3%	12.2%	14.9%
New York	5.7%	24.7%	48.3%	78.7%	94.7%	95.8%
North Carolina	0.7%	11.5%	40.0%	67.4%	86.5%	92.7%
North Dakota	0.1%	1.9%	8.8%	15.5%	19.3%	38.8%
Ohio	0.9%	6.9%	31.2%	56.5%	87.0%	91.2%
Oklahoma	0.7%	12.7%	22.0%	40.9%	52.0%	87.2%
Oregon	0.1%	1.8%	6.4%	14.1%	38.7%	50.6%
Pennsylvania	**1.5%**	**15.8%**	**58.4%**	**89.1%**	**95.5%**	**98.4%**
Rhode Island	2.3%	45.2%	80.0%	84.2%	98.5%	100.0%
South Carolina	0.9%	9.4%	31.2%	78.7%	94.4%	99.9%
South Dakota	0.3%	5.7%	10.5%	15.3%	30.4%	34.5%
Tennessee	0.5%	6.7%	25.9%	47.3%	66.1%	84.0%
Texas	1.1%	14.2%	37.8%	52.6%	80.0%	83.5%
Utah	0.5%	4.0%	6.1%	7.6%	88.2%	92.3%
Vermont	2.2%	13.1%	22.5%	75.9%	98.9%	99.0%
Virginia	1.3%	14.7%	36.3%	75.0%	93.4%	96.5%
Washington	0.4%	2.2%	6.1%	22.9%	38.4%	50.3%
West Virginia	0.6%	12.0%	39.5%	60.1%	72.0%	82.9%
Wisconsin	2.2%	13.7%	39.2%	83.0%	94.4%	94.8%
Wyoming	0.1%	1.4%	4.8%	11.0%	30.6%	41.1%

Table 3. Geographic indicator of transmission demand and siting difficulty. A high percentage of population served within a small radius indicates a close proximity of generation plants and population loads and suggests a low demand for transmission lines.

	Slope 1988-1998 (Avg. Annual Change)				Difference in Slopes		
State	**Transmission Capacity (Circ. Miles)**	**Net Generation (Mwhrs)**	**Generation Capacity (MW)**	**Sales (Mwhrs)**	**Net Generation-Transmission**	**Generation Capacity - Transmission**	**Sales - Transmission**
Alabama	7.06%	7.01%	1.27%	3.86%	-0.06%	-5.79%	-3.20%
Arizona	1.83%	3.43%	0.47%	4.40%	1.60%	-1.36%	2.57%
Arkansas	1.24%	2.89%	0.02%	5.62%	1.65%	-1.23%	4.38%
California	1.52%	0.36%	-0.24%	1.15%	-1.16%	-1.75%	-0.37%
Colorado	1.48%	1.99%	0.85%	3.48%	0.51%	-0.63%	2.00%
Connecticut	7.43%	-4.90%	-1.39%	0.70%	-12.33%	-8.82%	-6.74%
Delaware	14.76%	-1.48%	2.32%	3.55%	-16.24%	-12.45%	-11.22%
Florida	1.30%	3.93%	2.28%	3.99%	2.64%	0.99%	2.69%
Georgia	4.77%	2.22%	2.13%	4.66%	-2.55%	-2.64%	-0.11%
Idaho	1.54%	7.92%	1.71%	2.52%	6.38%	0.16%	0.98%
Illinois	2.35%	1.32%	0.15%	2.02%	-1.03%	-2.20%	-0.33%
Indiana	0.92%	2.95%	0.35%	3.02%	2.03%	-0.58%	2.10%
Iowa	3.50%	3.06%	0.60%	3.11%	-0.43%	-2.89%	-0.38%
Kansas	0.25%	2.78%	0.33%	3.05%	2.53%	0.08%	2.80%
Kentucky	-2.29%	2.71%	0.54%	4.31%	5.00%	2.83%	6.59%
Louisiana	2.80%	1.19%	0.48%	3.03%	-1.61%	-2.32%	0.23%
Maine	-0.16%	-4.18%	-2.01%	0.39%	-4.01%	-1.85%	0.56%
Maryland	-2.45%	2.99%	1.96%	2.21%	5.45%	4.41%	4.66%
Massachusetts	0.85%	-0.21%	0.00%	0.76%	-1.06%	-0.85%	-0.09%
Michigan	5.72%	0.35%	-0.16%	2.39%	-5.37%	-5.88%	-3.32%
Minnesota	-0.18%	0.88%	0.86%	2.61%	1.06%	1.04%	2.79%
Mississippi	-5.85%	3.62%	0.36%	4.85%	9.46%	6.20%	10.69%
Missouri	-0.70%	2.48%	0.85%	3.23%	3.18%	1.55%	3.93%
Montana	0.03%	0.80%	0.26%	0.13%	0.77%	0.22%	0.09%
Nebraska	1.93%	4.02%	0.72%	3.53%	2.09%	-1.20%	1.61%
Nevada	0.04%	3.13%	2.46%	8.16%	3.09%	2.42%	8.12%
New Hampshire	1.90%	8.60%	5.00%	0.30%	6.69%	3.10%	-1.60%
New Jersey	0.91%	-1.24%	1.03%	0.88%	-2.14%	0.12%	-0.03%
New Mexico	1.00%	1.85%	0.46%	4.27%	0.85%	-0.54%	3.27%
New York	0.84%	0.00%	1.07%	0.39%	-0.84%	0.23%	-0.45%
North Carolina	1.66%	4.24%	0.90%	3.28%	2.57%	-0.77%	1.62%
North Dakota	0.87%	1.54%	0.11%	2.07%	0.67%	-0.76%	1.20%
Ohio	2.84%	1.48%	0.34%	1.89%	-1.36%	-2.51%	-0.96%
Oklahoma	-0.36%	1.62%	0.00%	2.24%	1.98%	0.37%	2.60%
Oregon	0.85%	1.36%	-0.26%	1.66%	0.51%	-1.11%	0.81%
Pennsylvania	**4.52%**	**1.68%**	**0.49%**	**1.51%**	**-2.83%**	**-4.03%**	**-3.00%**
Rhode Island	-0.78%	6.86%	3.06%	0.84%	7.64%	3.84%	1.63%
South Carolina	1.43%	2.56%	1.90%	3.63%	1.13%	0.47%	2.20%
South Dakota	2.34%	5.19%	1.40%	2.92%	2.85%	-0.95%	0.58%
Tennessee	-2.76%	4.78%	0.41%	2.30%	7.54%	3.16%	5.06%
Texas	4.05%	2.58%	1.17%	3.31%	-1.47%	-2.88%	-0.74%
Utah	2.24%	1.61%	0.75%	4.54%	-0.63%	-1.49%	2.29%
Vermont	2.55%	0.38%	-0.60%	2.10%	-2.17%	-3.15%	-0.45%
Virginia	2.01%	3.84%	1.96%	2.97%	1.83%	-0.05%	0.96%
Washington	1.27%	2.73%	0.70%	0.17%	1.46%	-0.57%	-1.10%
West Virginia	1.48%	1.17%	-0.13%	1.98%	-0.31%	-1.61%	0.51%
Wisconsin	3.17%	1.87%	1.53%	3.13%	-1.29%	-1.64%	-0.04%
Wyoming	3.06%	1.17%	0.59%	0.30%	-1.89%	-2.47%	-2.76%

Table 4. Construction indicator of transmission demand and siting difficulty. Positive slopes indicate that transmission growth has not kept pace with generation or demand.

State	Rank	Survey Stakeholder Groups					
		All Survey Respondents	Consulting Company	Gov't. Regulatory Agency	Public Electric Utility	Investor-Owned Utility	Other
Alabama	44	5.66	6.79	3.63	7.20	5.64	4.50
Arizona	31	6.18	9.00	8.00	6.00	5.67	3.80
Arkansas	42	5.75	6.58	5.00	6.60	5.20	5.00
California	4	7.72	9.56	8.17	6.00	7.65	5.63
Colorado	9	7.32	8.62	8.00	8.00	5.45	6.80
Connecticut	5	7.64	8.40	8.00	7.60	6.94	8.00
Delaware	23	6.55	6.18	8.00	8.00	6.13	5.67
Florida	1	8.15	9.18	8.00	8.50	7.48	7.63
Georgia	20	6.62	7.69	4.00	7.20	6.91	4.56
Idaho	34	6.13	8.22	7.00	6.00	5.25	4.75
Illinois	25	6.36	6.85	5.00	8.00	5.68	5.56
Indiana	15	7.07	8.43	5.00	7.33	7.08	4.67
Iowa	28	6.28	7.27	5.43	7.83	5.71	5.80
Kansas	35	6.11	7.75	5.40	6.60	4.80	5.00
Kentucky	30	6.19	6.47	5.50	7.20	5.93	6.14
Louisiana	33	6.13	8.25	7.00	7.20	4.69	5.83
Maine	24	6.48	7.23	7.00	7.00	6.00	5.67
Maryland	3	7.80	8.29	9.00	8.00	7.63	6.29
Massachusetts	8	7.34	9.00	7.60	8.00	6.39	6.22
Michigan	21	6.59	6.75	4.00	7.67	6.73	6.30
Minnesota	11	7.22	8.33	7.10	7.88	6.70	6.20
Mississippi	39	5.92	8.00	8.00	7.20	4.39	6.00
Missouri	32	6.17	8.30	5.80	7.64	4.73	5.40
Montana	27	6.28	8.00	5.86	7.50	5.38	6.60
Nebraska	38	5.95	7.15	3.00	7.17	4.75	6.20
Nevada	40	5.82	7.89	5.33	6.00	5.27	5.60
New Hampshire	16	7.05	7.63	7.20	7.25	6.94	6.00
New Jersey	7	7.41	7.75	8.75	7.67	6.62	7.30
New Mexico	18	6.81	8.60	7.38	8.00	5.67	6.00
New York	2	7.87	8.71	8.25	8.33	7.30	8.23
North Carolina	36	6.04	6.43	5.00	7.20	5.77	5.11
North Dakota	48	4.92	5.85	2.54	6.88	4.92	5.60
Ohio	43	5.73	6.21	3.00	7.50	5.29	5.17
Oklahoma	37	6.03	8.11	4.00	6.20	4.89	5.40
Oregon	17	6.82	8.40	6.50	6.00	6.80	6.00
Pennsylvania	**22**	**6.58**	**7.20**	**8.89**	**7.17**	**5.63**	**6.20**
Rhode Island	14	7.12	8.67	8.25	7.75	5.93	7.40
South Carolina	26	6.29	7.71	5.00	7.20	6.36	4.80
South Dakota	47	5.24	6.75	3.69	6.43	4.50	5.20
Tennessee	29	6.28	7.43	3.00	7.20	5.79	5.71
Texas	45	5.65	7.18	2.20	7.00	5.28	4.25
Utah	19	6.75	8.30	8.00	8.00	5.27	6.60
Vermont	10	7.27	7.64	8.75	7.25	6.33	7.00
Virginia	12	7.14	8.31	5.25	8.00	6.76	7.33
Washington	13	7.14	8.80	8.00	6.00	6.75	6.00
West Virginia	46	5.45	5.23	4.00	7.00	4.87	6.50
Wisconsin	6	7.59	8.52	7.44	7.88	7.26	6.11
Wyoming	41	5.78	7.78	5.80	6.67	4.53	6.40

Table 5. Perception indicator of transmission siting difficulty.

PART 2: Distributed Generation and Micro-Grids

2.1 The Basic Technologies

Thomas Edison's pioneering 1883 electric generation station on Pearl Street in New York City was the first of what he imagined to be a network of local generation stations wherever electric light was needed. The direct current (DC) Edison generated was not suitable for transmitting over distances of more than a few city blocks using the technology of the day, so the generators needed to be near load.

When users of electric motors proved to be more willing to pay the huge cost of electricity ($4.50 per kWh) than users of lights, alternating current (or AC, which is much more efficient than DC for motors) replaced Edison's direct current. AC also allowed efficient transmission over long distances, and Edison's model gave way to large generators located far from loads. Even modern long-distance transmission does have losses. The US Department of Energy estimates that 9.5% of power is lost in transmission and distribution, while the losses are 13% in France.

While generation of power in large central units is the norm today, generation close to the point of use (called distributed generation) is in use for applications ranging from industries which produce their own power on-site to small internal combustion engines and natural gas turbines for commercial and residential use. Distributed generation can offer greater efficiency, lower costs, greater reliability, greater security, and reduced need for transmission.

Locating generators near load reduces loss, but losses are not the only, or even the major, driver for distributed generation (DG). In certain installations, DG can improve both reliability of electric supply and overall efficiency. Only 31.6% of the energy used in electric power generation winds up in electricity; the remainder is given off as waste heat.[43] Plants generating power and using the waste heat for manufacturing process heat and/or space heat generate 7% of the total electric power in the US[44], and the Department of Energy estimates that fraction can triple[45]. Such units generate 10% of the European Union's power. These installations, called combined heat and power (CHP), are often 70% efficient.

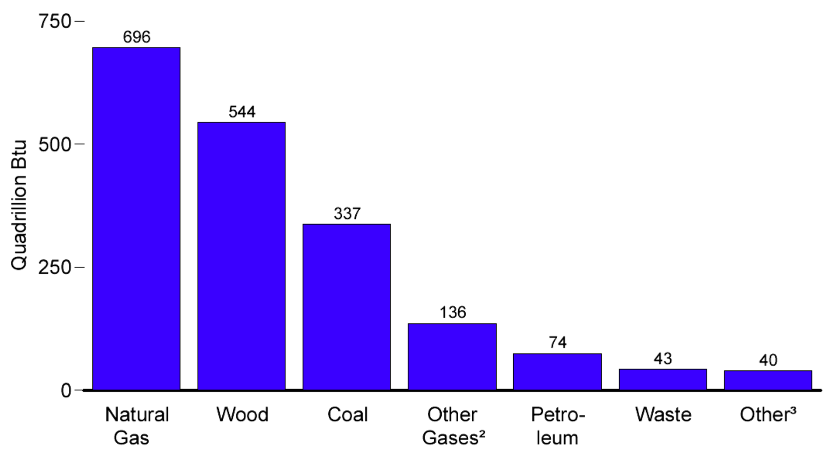


Figure 11. Fuels used at US combined heat and power plants.[46] *Notes: ²Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels. ³Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.*

Distributed Generation Technologies

- Diesel reciprocating engines. These power generators (familiar as emergency power supplies) range in size from 5 kW to 15 MW, and are used in some areas to supply peak power needs when dispatched by a central utility. Certain units can be run on methane (produced from land fill or animal waste). For reliable operation, backup units should be run on full load monthly. After-market installations to reduce particulate and NOx emissions are available, but are generally not practical for small units or economical for units used as backups.

- Natural gas reciprocating engines (some of these can also be run using propane or methane). Sized from 10 kW to 6 MW, these have efficiencies of 30 to 40%, and a Department of Energy development program is active to significantly increase efficiency. NOx emission reduction is possible, and required in control areas.

- Coal, wood, natural gas, or oil-fired steam turbines. These installations use fuel to heat boiler water to steam, which drives a turbine-generator set. Common in combined heat and power (CHP) installations, they are used for on-site power generation at many industrial sites.

- Natural gas-fired turbines. Large units derived from jet engine technology can be hundreds of megawatts in size. Small "microturbines" are derived from vehicle turbochargers, and appeared in the late 1990s at sizes from 30 kW to 100 kW, and can be used in CHP applications. Some can be fired with propane or methane. Both NOx emission and noise can be issues in sensitive areas.

- Fuel cells. Natural gas or methane is combined with oxygen from air in the presence of a catalyst to produce electricity, water, and CO_2. Commercial CHP units are presently available up to 200 kW. Operating temperatures in the 500-degree F range allow good CHP efficiencies, but cost per kW is ten times that of a microturbine at present. The US Department of Defense Fuel Cell Test and Evaluation Center (FC*Tec*), operated by Concurrent Technologies Corporation (CTC), is located in Johnstown, and is characterizing fuel cells for potential DoD and commercial applications.

- Solar photovoltaic systems convert sunlight directly to electricity. Cost per kW is 20-100 times that of a microturbine, but is justifiable in limited off-grid applications. Panel output degrades significantly over time. The intermittent nature of solar power requires significant expense in electrical storage.

- Wind turbines can be operated at 1.5 times the cost of a thermal generator. Intermittency of wind imposes significant storage costs. These installations are not suitable for CHP applications as they produce little heat.

- Small-impact hydroelectric facilities. Both low earthen dams and run-of-river hydroelectric generation can supply locally-significant amounts of electricity.

Micro-Grids

A micro-grid is a small-scale power generation and distribution network serving multiple customers, with generators near or on the same site as demand. Most micro-grids are interconnected with the grid, but can be operated independently when the grid fails.[47] A shopping center, hospital complex, or industrial park may choose to implement a micro-grid to serve their loads at lower cost or higher reliability than is available through the grid. Micro-grids may serve part or all of the local load, and generally incorporate energy storage for brief interruptions during switching of power sources. Some micro-grids may produce more power at times than is required by their load, and may sell surplus power to the grid.

Micro-grids can incorporate cogeneration, either by using the generation waste heat in the local heating, ventilation, and air-conditioning (HVAC) system, or by integrating the micro-grid with a district heating system.

The micro-grid is seen by the larger utility grid as a single entity, not as a collection of loads and generators. Designed properly, such micro-grids could provide the benefits that distributed resources have the potential to supply while alleviating many of the voltage, frequency, and control problems that may be associated with installing large number of independent distributed generators without overall control (as discussed below). The Consortium for Electric Reliability Solutions, managed by Lawrence Berkeley Laboratories, has studied control aspects of micro-grids,[48] including protective relaying and relation between the micro-grid and the utility grid.

2.2 Distributed Generation and Supply Reliability

The conventional grid of remote generators, transmission, and loads is sensitive to disruptions, and users with critical dependence on electricity frequently install local generators for emergencies. In the past, the majority of these installations have been diesel-fired generators. Within the past decade, small gas turbines have been developed to supply loads of 30 kW and above at reasonable capital costs. (Fuel cells are technically feasible, but have very high capital costs at present). Natural gas internal combustion engines also power backup generators of 25 kW and larger size.

The concept of grid-connected distributed generation units used as the primary electricity provider (rather than as a backup) has long been considered a possibility.[49] During the 2003 northeast blackout, 446 CHP systems representing 9,280 MW of capacity were in the affected area. Many of these continued to operate during the outage, although others (using induction generators which require grid power to energize rather than more expensive synchronous generators) did not.[50]

There are a number of potential reliability benefits that distributed generation can provide, including increasing generation capacity, reducing transmission and distribution losses, reducing loading and use of lines, and increasing the number of generators and reducing the size of generators to minimize the impact of losing any single generator.[51] [52]

Such arguments rely on a large number of assumptions regarding the nature of the DG system, the nature of the electrical system in which it is embedded, as well as other factors (for example, the institutional setting and choices about how the DG system is operated).[53]

Definitions

Both residential and business customers want their electricity to come on when they flip the switch – to be reliable. Reliability of electricity is composed of two separate components: **adequacy** and **security**.

The term reliability is used in the literature and in regulation to mean either concept (and sometimes an agglomeration of both).

Adequacy is primarily a function of long term planning and refers to a system's ability to meet its power needs (Is access to generation sufficient to meet demand? Is there sufficient transmission capability to handle required power flows?).

In contrast, the term **security** is used in the electricity industry to mean short-term operational and management choices and decisions. A key issue is the stability of the system in the face of disturbances and maintaining voltages and frequencies within pre-specified limits. Note that this long-standing use of the term has recently caused confusion with the ability of the system to withstand human attack.

Adequacy

DG together with storage, control of voltage and other ancillary services are termed distributed energy resources (DER), and can increase adequacy in two ways. First, by changing the mix of generating technologies, potentially displacing large generators far from the load with a larger number of small generators close to the load. Second, by providing power close to demand, distributed resources can potentially reduce the loadings on distribution lines or possibly transmission lines, as well as mitigate against failures at the transmission and distribution level. Another potential impact of installing distributed resources is reduction of the required reserve margin to meet a certain level of reliability (or alternatively, to have improved reliability for a given level of installed capacity).

At the simplest level, installing distributed resources can change the adequacy of supply for an individual facility. Whether the local generator is run in backup mode, as a stand-alone primary generator, or in parallel to the grid, the duration and magnitude of failures will be affected. A facility that installs a single distributed unit with no backup from another unit or the grid will experience significantly lower reliability than the norm in the United States for grid power[54].

An example of how distributed generation can contribute to system reliability in a cost effective manner is provided by Chowdhury and co-authors.[55] They consider a distribution system supplied by two feeders from the grid. Installation of distributed generation (ranging from 1-6 MW each with up to two units being installed) is compared to the addition of a third distribution feeder from the grid. Their model showed that adding either one 6 MW unit or two 3 MW units would result in the same reliability improvement as installing the third feeder for the particular system studied. Other examples of the potential for DG to improve adequacy at the distribution system level are given by Brown and Freeman[56] and by Hegazy et al.[57]

In addition to changing the adequacy of the system at the individual facility or distribution system level, it is possible that widespread use of grid-connected DG could affect the adequacy of the overall power system. Models comparing centralized with completely distributed system architectures show a dramatic improvement in adequacy for the distributed systems, particularly under stress conditions. In suitable installations, the use of co-generated heat and the reduction in customer outage costs can compensate for the somewhat higher costs of DG technologies.

Zerriffi and co-authors at the Carnegie Mellon Electricity Industry Center compared the results of transmission system failures on two 2,850 MW peak load systems. The first was a central generation system with 32 generators with capacities from 12 to 400 MW. The second met the load with 500 kW natural gas fired distributed generators. In reliability models run with failure rates appropriate to current generation and transmission components, the distributed generation system had roughly 25 times the reliability of the central generation system. When failure rates of the transmission system were increased, as would be the case for deliberate attacks on the electric power system, the DG system exhibits even greater advantage. When failure rates were increased by a factor of 300, the DG system was found to be roughly 600 times more reliable than the centralized system[58].

An examination of systems with mixed centralized and distributed generation shows that the potential reliability benefits depend on a mix of factors, particularly the reliability characteristics of the centralized generating technologies being replaced versus those being kept, the reliability characteristics of the distributed technology, and the degree of DG penetration.[59]

Security

The impact of distributed resources on the security of the system and, more generally, on system operations is more complicated than for adequacy. Conventional utility practices have assumed that power flows from the high-voltage transmission system through substations and then on predominantly radial distribution lines to end-users. Control and operation of the distribution system is generally for one-way power flows. Distributed resources may result in power flows that are different than the system was designed for. This can result in the need for new equipment, new operating procedures, or both.[60] Distributed resources can either improve or degrade system reliability and evaluations must be made beforehand, considering specific technologies deployed.

Distributed resources can provide improved power quality to end-users under a variety of circumstances, particularly when installed at a particular customer site.[61] Beyond the improved power delivery discussed above, these benefits include avoiding temporary interruptions and avoiding voltage sags. In addition to aiding individual customers, distributed resources have the potential to provide voltage support for the entire distribution subs-system to which they are connected. With the proper equipment, distributed resources can also provide other ancillary services, such as harmonic cancellation and reactive power compensation.[62] [63]

Distributed units can provide voltage support on distribution feeders. However, this can complicate service restoration after a fault. If the load becomes dependent upon the distributed unit for voltage but the DG unit must disconnect due to a fault, the utility may not be able to maintain voltage at acceptable levels as the fault is cleared, necessitating changes in procedures and possible delays in restoring power.[64]

Cardell and Tabors found that installing generation at the distribution level can decrease the stability of the system.[65] This is the result of changes in designed power flow direction as well as in the electrical characteristics of the lines themselves (low resistance lines at the high transmission level versus higher resistance lines at the distribution level), which can affect the degree to which connected generators and loads can interact with one another. Under certain combinations of distributed generation technologies, the system can become unstable when a disturbance (such as a line or generator outage) is introduced. One cause of these instabilities is that the relatively small mechanical inertias of the distributed units cannot compensate for the oscillations resulting from the disturbance as well as centralized generators that have large inertias in their huge rotors. The authors argue that these results show the need for new methods to control and stabilize systems that have numerous distributed generators.

Distributed resources can also create issues when there is a fault on the system, due to the fact that power is no longer flowing radially. It is no longer possible to simply open one breaker on the radial line and it may be necessary to disconnect the distributed unit. The DG infeed also reduces the "reach" of the breakers and reclosers, the distance down the line that the devices can detect a fault, used to protect the system. This can potentially result in larger faults and damage. Another potential issue has to do with the time it takes for the protection device to reclose on a temporary fault. Short reclose times are beneficial from a power quality point of view as they can avoid some issues (e.g. blinking clocks). However, the reclose time must be long enough that the DG system is able to disconnect before the reclose occurs or it may become damaged and/or the failure may not clear.[66] Many of these issues can be resolved with careful engineering (though there may be some tradeoffs regarding either cost or operations of the system).

Distributed generation can increase power adequacy (the ability to meet power needs), potentially decreasing the magnitude of outages by more than a factor of 10 over central generation. However, significant system-wide operations issues can be introduced by DG. It appears that grouping distributed generators into units such as micro-grids with advanced controls and equipment can mitigate certain categories of these problems.

2.3 Micro-grids: Opportunities and Barriers

Applicable Rules

The majority of DER customers[67] require connection to the area grid for the purchase of standby and supplementary electricity and the sale of surplus electricity back to the grid. Utilities are obligated to allow certain types of DER customers to interconnect and buy or sell power through the utility lines. In response to relatively slow growth of DER customers, federal, regional, and state authorities have begun clarifying and simplifying the process by which DER customers interconnect and interact with the area grid.

The current and pending applicable rules are described in this section.

Public Utility Regulatory Policy Act of 1978 (PURPA)

The Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate energy transactions such as interstate electricity transmission and wholesale market activity.[68] PURPA gives FERC regulatory authority over arrangements between electric utilities and "qualifying facilities" (QFs), specifically mandating that utilities allow QFs to interconnect and specifying the terms for electricity sales to and purchases from QFs.[69] [70] PURPA qualifying facilities fall into two major categories: small power production facilities and cogeneration facilities. Facilities must meet various criteria to qualify, including ownership criteria to ensure that they are not owned by a utility (to avoid conflicts of interest).

Qualifying small power production (SPP) facilities must utilize 75% or more biomass, renewable resources, geothermal resources, waste, or hydropower.[71] There is no size limit for SPP facilities that utilize solar, wind, or waste resources, but other qualified SPP facilities are limited to 80 MW. Hydropower plants are also subject to additional rules that require special permitting, limit their location, and mandate compliance with various other state and federal laws.[72] Qualifying cogeneration facilities may include generators fueled by fossil fuels (e.g., natural gas, diesel). There is no capacity limit for these facilities, but they must meet requirements for how much useful thermal energy is utilized (at least 5% of total energy output) and how efficient the overall system facility is (useful power output plus half of the useful thermal output must equal or exceed 42.5% of the total energy input).[73]

PURPA mandates that utilities have an obligation to purchase any energy and capacity which is made available from a qualifying facility, an obligation to sell any energy and capacity requested by the QF, and an obligation to interconnect. A utility is required to allow interconnection even if the QF plans to sell its power to or buy its power from another utility.

PURPA requires that utilities provide four different rates for QFs: supplementary, standby, maintenance, and interruptible power. Interruptible power contracts give the utility the right to disconnect the QF, generally in exchange for lower rates. Maintenance power is sold to the QF for use during scheduled outages, and the QF is generally required to provide a schedule well ahead of time. Standby power is sold to the QF for use during unscheduled "forced" generator outages. Supplementary power is any other power required by the QF, including any electricity needs beyond the generation capacity limits of the QF. PURPA does not lay out specific rates, but it does state that standby and maintenance power rates "shall not be based upon the assumption that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak," and "shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities."

PURPA gives state regulatory agencies the authority to determine how interconnection costs should be covered. PURPA also gives state regulatory agencies the responsibility to establish reasonable safety and reliability standards.

PURPA does not explicitly refer to micro-grids, and the definitions for qualifying facilities suggest that there is nothing exceptional about a micro-grid design as long as it meets the QF criteria. A micro-grid using conventional sources (natural gas engines, turbines, or micro-turbines) must meet the cogeneration requirements in order to qualify under PURPA.

Pennsylvania Code

Under PURPA, all issues related to interconnection (e.g., costs, technical requirements) are the purview of state regulatory authorities.

In February 1996, the Pennsylvania Code was altered to require electric utilities to provide rates, rules and regulations in their tariffs relating to the sale of power to qualifying cogeneration and small power production facilities.[74] This section of the Code borrows its definition for qualifying facilities directly from PURPA, and there is no special distinction for micro-grids or other DER system architectures.

A qualifying facility in the Commonwealth is required to submit interconnection plans and specifications to the local public electric utility that controls the service territory in which it is located. The utility must accept or reject the plans within 60 days and if it rejects the plans, it must explain why and how the QF can remedy the problems. Once a QF has completed its installation of interconnection equipment, the utility may have an inspection conducted (within 20 days) at its own expense, and must provide the results of the inspection within 5 working days. If the inspection demonstrates that the interconnection is unsatisfactory, the utility will explain the problems and how the QF can remedy them.

Utilities are required to establish "reasonable standards to insure system safety and reliability of interconnected operations", and these standards must be submitted to the Pennsylvania Public Utility Commission (PUC) for approval. Utilities are required to provide these standards to prospective QFs upon request. The QF is required to pay for any interconnection equipment that is necessary in order to meet the safety standards of the utility, as well as any "reasonable" additional costs for interconnection beyond the costs that the utility would usually pay to allow a customer to purchase power.

Pennsylvania's Code states that qualifying facilities of less than 50 kilowatts may opt for net metering, or net energy billing.[75] Each utility is required to file its policy for net billing with the PUC, but it is not required to provide net metering service to any and all qualifying facilities of 50 kW or less. For example, Allegheny Energy's Net Energy Metering Rider applies to systems that do not exceed 10 kW[76] while PECO Energy Company offers net metering for systems up to 40 kW.[77]

Pennsylvania Code requires utilities to have supplementary, backup (standby), and maintenance power rates for generating customers that are not eligible for net metering.[78] The Commonwealth Code augments PURPA by providing guidelines for setting rates:

- "A utility's rate for sales of **supplementary power** to qualifying facilities shall recover the same costs that the utility is permitted to recover from another utility customer of the same customer class and with the same usage characteristics."
- "The utility's rate for **backup power** shall recover energy costs incurred by the utility plus an appropriate portion of fixed costs. Fixed costs shall be prorated over the actual days in a billing period during which backup power is consumed by the qualifying facility." There is a fundamental difference of opinion on pricing of backup power. Many utilities calculate the cost of backup power under the assumption that all DG units on their system will require backup power at the same time. DG proponents feel this is an unrealistic and costly assumption.
- "A utility's rate for sales of firm **maintenance power** to qualifying facilities shall include energy costs and a demand or capacity charge required to recover the appropriate transmission plant and full distribution plant costs. When the scheduled outages of a qualifying facility cannot be scheduled during other than utility peak periods, the demand or capacity charge shall be the full charge stated in the utility's filed tariff under which the qualifying facility receives this service."

Pennsylvania Code also defines terms for utility purchases from qualifying facilities. It states that "energy payments will be equal to a utility's highest cost source of energy to supply the energy requirements of its domestic load customers at all times." If a utility uses its own generation, "energy payments shall include the costs of fuel, variable operation and maintenance expenses, and other costs associated with that generation. The energy payments shall incorporate the costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility." Pennsylvania Code does allow that the QF and the utility can enter into a contractual agreement that provides the QF with a higher price for its power, for example if the utility is willing to act as a broker for the QF's power. Pennsylvania Code does not dictate the fees or rates that utilities may charge. Each utility sets fees and rates (including demand charges ($/kW), energy charges ($/kWh), and monthly fees) in tariffs, which are subject to the approval of the Pennsylvania PUC. Each utility tariff also defines terms for supplementary, standby, and maintenance power, usually in the form of contracts.

IEEE Standard 1547-2003

Since March 1999 the Institute of Electrical and Electronics Engineers (IEEE) has been coordinating the development of a family of standards for interconnection of distributed energy resources (DER) to the electric power system (Figure 12). After multiple iterations and refinements, the basic standard was approved by the IEEE Standards Board in June 2003. In the words of two of its developers, the standard is designed to provide "…technical requirements for electric power systems…interconnecting with distributed generators such as fuel cells, photovoltaics, microturbines, reciprocating engines, wind generators, large turbines, and other local generators[79]." The standard's abstract, available on the web, notes that the standard's "…criteria and requirements are applicable to all DER technologies, with aggregate capacity of 10 MW or less at the point of common coupling, interconnected to electric power systems at typical primary and/or secondary distribution voltages. Installation of DER on radial primary and secondary distribution systems is the main emphasis of this document, although installation of DER on primary and secondary network distribution systems is considered." [80]

The standard lays out detailed technical specifications for the performance and operation of grid-connected distributed generators and the design and performance characteristics which such interconnections should display. It specifies that in the event that problems develop on the electric distribution system which result in the loss of connectivity to central system power, all distributed resources should detect the problem and disconnect from the distribution system within two seconds. One of the primary motivations for this requirement is to protect line crews who are dispatched to repair failed distribution systems by ensuring that disrupted systems are not energized by distributed sources.

Early drafts of the standard did not consider the issue of micro-grids, or the possibility that by coordinating with an intelligent distribution system, distributed energy resources might continue to keep portions of the system energized, thus assuring the continued availability of critical services to customers. The final version of the standard does contain sections on “distributed secondary grid networks” (i.e. micro-grids) and on “intentional islanding” (i.e. keeping portions of the distribution system energized when the main supply has been disrupted). However, in both cases the text for these sections simply reads “This topic is under consideration for future revisions of this standard.” While no indication has been given of the time scale on which such revisions might be forthcoming, it is our understanding that they are under development in P1547.4. The objective of that effort is to “…provide alternative approaches and good practices for the design, operation and integration of distributed resource island systems” (i.e. systems operated without power supplied by the central grid). “This includes the ability to separate from and reconnect to part of the area [electric power system]…while providing power to the island local [electric power system]…” The committee indicates that “…implementation of this guide will expand the benefits of using [distributed resources]…by targeting improved electric power system reliability…”[81]

Many of the participants in the standard’s development process are from traditional utilities, and are not used to thinking in terms of new strategies such as micro-grids operated by competitive firms. Thus, development of text for these standards could take some time.
The Commonwealth might consider urging the IEEE committee to make sure that when such text is developed it is structured in a form that does not unduly favor the interests of traditional utilities.

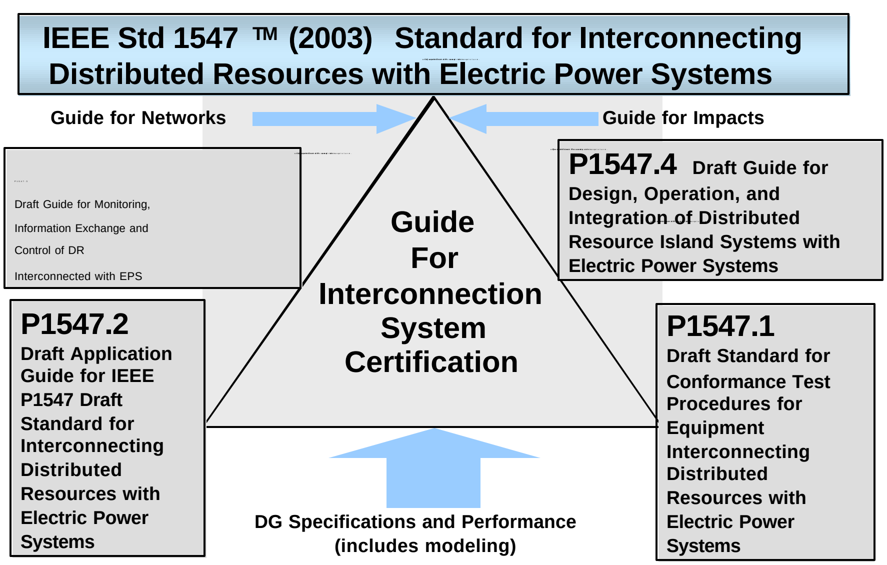


Figure 12. Illustration of the various standards now under development by the IEEE. To date, only the basic standard, 1547 has been approved.[82]

FERC Standardization of Small Generator Interconnection Agreements and Procedures

On July 24, 2003, FERC issued a Notice of Proposed Rulemaking (NOPR) that public utilities under FERC jurisdiction must provide interconnection service to "Small Generating Facilities," which are defined as facilities with a rated capacity of 20 megawatts or less. The proposed Standard Small Generator Interconnection Procedures (Proposed SGIP) are designed to improve upon PURPA by reducing interconnection time and costs for customers by standardizing many of the administrative requirements imposed upon DER customers. As with PURPA, the Proposed SGIP is applicable only to customers who want to interconnect with transmission or distribution systems that are used for interstate commerce. Unlike PURPA, the Proposed SGIP applies to all facilities, not only to facilities utilizing cogeneration or renewable energy resources.

The Proposed SGIP makes further distinctions between different small generation facilities on the basis of size and interconnection voltage. Generating facilities that are less than 2 MW and interconnect with a low-voltage transmission system (less than 69 kV) may be subject to "super-expedited" procedures. Small generating facilities that are larger than 2 MW but no larger than 10 MW and interconnect with a low-voltage transmission system may be subject to "expedited" procedures. All other small generating facilities (e.g. those facilities that are between 10 MW and 20 MW, and any facilities interconnecting at voltages of 69 kV or more) are subject to the default standard procedures.[83]

The super-expedited process requires fewer reviews than the expedited or default interconnection process. Customers that qualify for the super-expedited process and pass an initial review conducted by the local utility may be interconnected within roughly one month.[84] Customers that qualify for the expedited process are subject to a similar review, but may face additional steps if the utility has any reason to believe that the QF will "undermine the safety and reliability of its transmission system".[85] If the utility does not have this concern, a QF going through the expedited process may also be interconnected within a month. However, if the utility does have concern, the QF and utility conduct a joint Scoping Meeting and the default interconnection process begins. The default interconnection process may include an Interconnection Feasibility Study, an Interconnection System Impact Study, and an Interconnection Facilities Study; this process can take 3 to 6 months. Despite these various barriers and potential time delays, the Proposed SGIP does clearly provide specific timelines (e.g., the Interconnection Feasibility Study must be completed within 30 days) and procedural rules (see Figures 13 and 14). It also puts the burden of proof on the utility; if a utility calls for additional studies but these studies show that the proposed small generation facility posed no risk to the system safety and reliability, the *utility* is responsible for the costs of the study.

Comments on the Standard Interconnection Agreements and Procedures for Small Generators are being reviewed at the time of this writing and the final Rule is expected to be issued by the end of 2004. If the rule is promulgated as it stands now it will allow more facilities to interconnect and greatly simplify the process, reducing risks and costs for proposed small generation facilities.

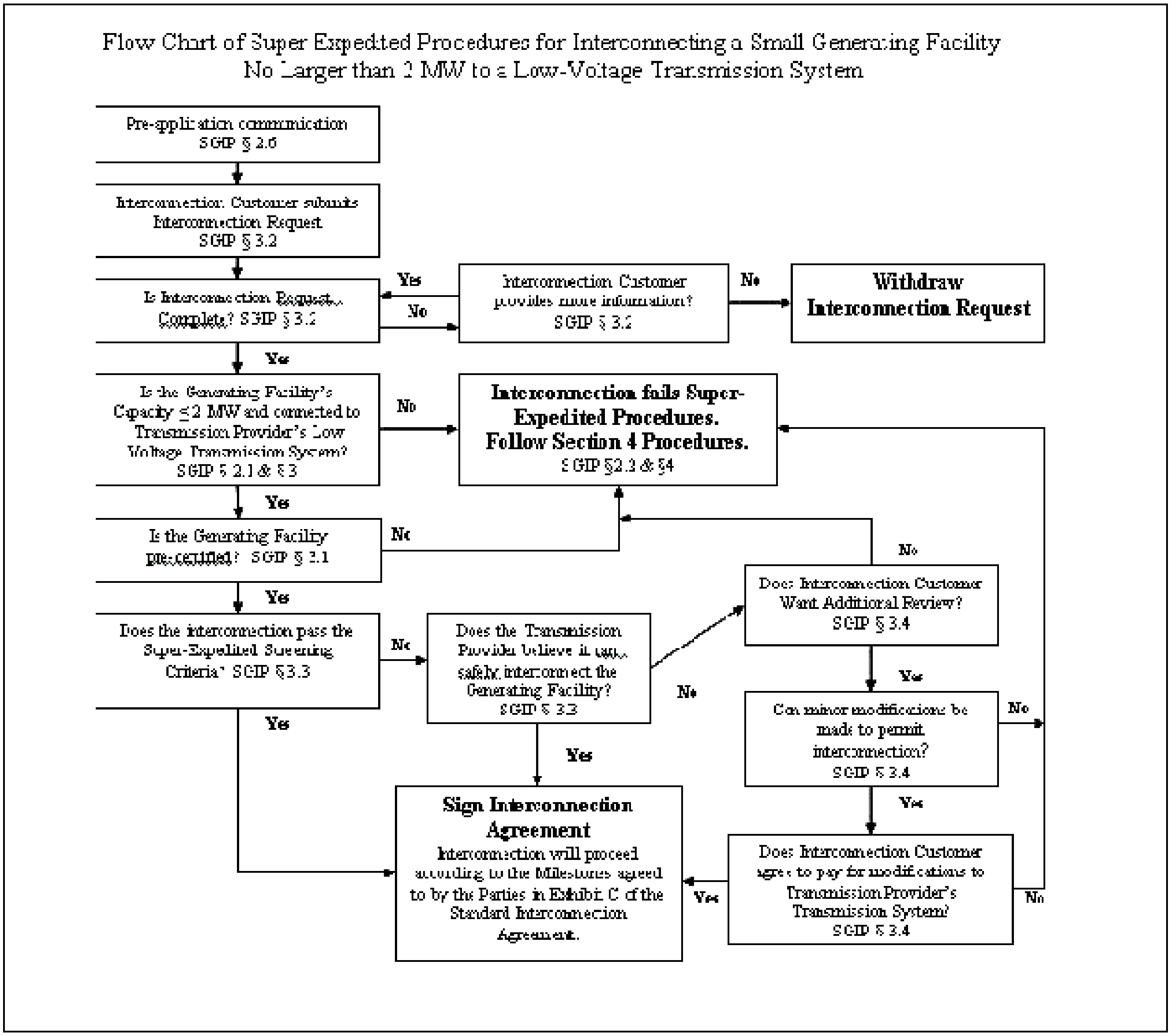


Figure 13: Flow chart of super-expedited process under the Proposed SGIP.

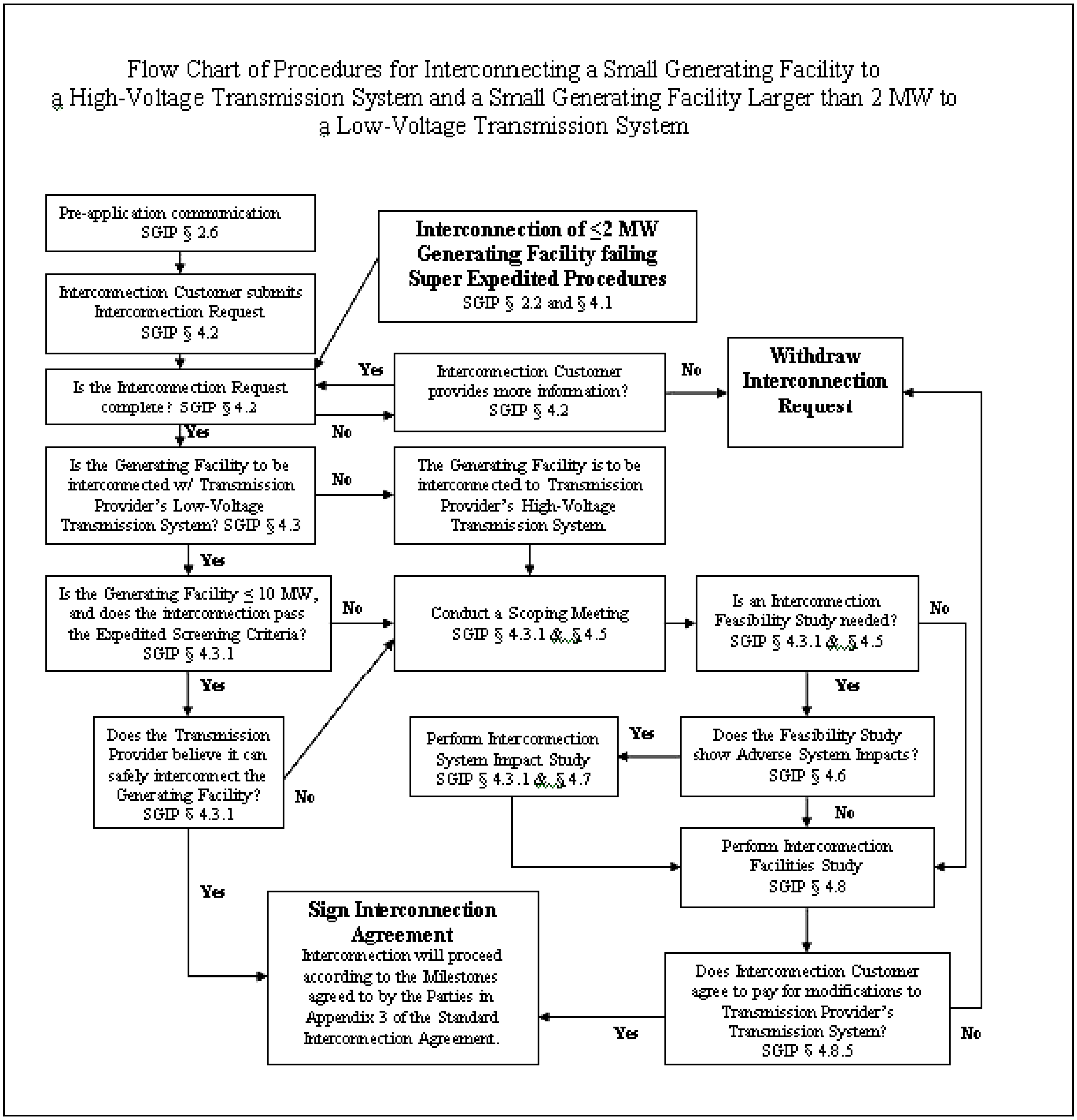


Figure 14: Flow chart of expedited and default process under the Proposed SGIP.

Pennsylvania-New Jersey-Maryland (PJM) Interconnect

The PJM Interconnect has a connection process for small generation resources that is very similar to the Proposed SGIP, but it includes more detail about technical requirements and it does not require member utilities to allow interconnection. It describes the process for member utilities that elect to use it. DER customers are to follow interconnection procedures as laid out in Section 36.12 of the PJM Tariff, but eligible "small resource" interconnections can follow the expedited procedures described in PJM's Small Resource Interconnection Procedure Manual.[86] The PJM Small Resources Interconnection Procedure is applicable to DER customers with facilities under 10 MW, regardless of fuel type.

The default standard interconnection process includes a Feasibility Study, an Impact Study (if necessary), and a Facilities Study, followed by an Interconnection Service Agreement. The expedited process allows customers to skip or shorten each of the studies under the right conditions, and removes expensive deposits (currently $10,000 to $50,000 for large customers). The various feasibility and reliability studies require less technical rigor in the expedited process, reflecting an awareness by PJM that small systems pose less of a threat to the stability of the transmission system.[87] For example, under the expedited process the Feasibility Study allows the use of linear analysis tools, and does not require a stability analysis to be conducted.

Micro-grid laws

Micro-grids have not yet been specifically identified in Commonwealth law, making laws or rules that might relate to micro-grids subject to interpretation. A study conducted by the Carnegie Mellon Electricity Industry Center[88] found that commercial micro-grids operated by a third-party firm would probably not be legal in many states because electric utilities are granted exclusive service territories. In some cases, however, the exclusivity of the service territories extends only to other utilities. Since state laws are generally not clear as to whether micro-grids would be treated as utilities, the applicability of these service territories are questionable. Likewise, many states have different laws for electric cooperatives, so a micro-grid that is owned and operated by its customers might face different legal issues than a micro-grid that is owned by a third party.

Pennsylvania law, like that of most states, is sometimes vague on the matter of service territories. Service territories exist, but they are not strictly exclusive. According to the Pennsylvania Electricity Generation Customer Choice & Competition Act, "No electric utility regulated by the commission and no affiliate of such electric utility may use the distribution system of another electric utility regulated by the commission or make sales to end-use customers in another electric utility's service territory," except under special circumstances.[89] According to one PUC official, even this law allows that under certain circumstances utilities may extend their own distribution systems into the service territory of another utility, but only with permission from the PUC.

This Act may not apply to micro-grids, depending on whether a micro-grid in Pennsylvania would be considered a public utility. This opinion was given by a PUC official, and is supported, albeit on narrow grounds, by at least one PUC decision. In fall of 1998 the PEI Power Corporation proposed the construction of a cogeneration "power park" that would provide 25 MW of power to various customers. The local utility (PPL) challenged, asserting that the facility should be considered a public utility, but the Pennsylvania PUC issued a tentative declaratory order in September 1998[90] that PEI was a private utility that could operate inside the utility's service territory. One of the most important facts on which this exemption was based was that PEI owned the land, and therefore had control over successor tenants. The Commission ruled that PPL was as a consequence not at risk that future tenants would leave the facility and present a large, unforeseen, and unplanned demand. The PUC stated that if PEI did not have restrictive covenants its service would have constituted a public utility service.

This case may not set a precedent, and a PUC official made the point that any proposed micro-grid could and likely would be challenged by the local utility and the case would have to be settled by the Pennsylvania PUC. The official stated that cases such as the 1998 PEI Power Corporation would be relevant and a micro-grid would likely be allowed to operate, but until laws were changed or precedents were clearly set, there is uncertainty about how the Pennsylvania PUC would rule.[91]

Utility practice in the Commonwealth

Many of the details of how DER customers interconnect and interact with the area grid are in the jurisdiction of local utilities under existing regulation. Each electric utility in the Commonwealth treats DER customers somewhat differently. The Commonwealth has five utilities that accounted for 99% of the electricity sales in the state in 2002: PECO Energy Company (26.7%), PPL Electric Utilities Corporation (26.2%), FirstEnergy Corporation (22.0%), Allegheny Energy, Inc. (14.2%), and Duquesne Light Company (10.1%).[92] [93] The contents of this section are based on documents (e.g., PUC approved tariffs and published policies) provided by these utilities.

We describe below issues for DER customers, and how the utilities in the Commonwealth handle them: 1) facility applicability and eligibility; 2) procedural transparency; 3) rates for the sale and purchase of energy; 4) minimum standby charges; and 5) net metering.

1. Facility applicability and eligibility

Not every DER generating facility is able or allowed to interconnect with the area grid. A customer that wishes to interconnect with the area grid and buy or sell power on the wholesale market has rights under PURPA (and soon under the FERC Small Generation Interconnection Procedures and Agreements), as discussed above. However, the Commonwealth does not grant DER customers similar rights if they want to interconnect and buy/sell power from/to a utility. Consequently, utilities are given latitude to determine what kind of systems they will allow to interconnect and buy/sell power within their service territory.

All of the public electric utilities include tariff arrangements for QFs as defined by PURPA. Allegheny, Duquesne Light, PECO, and PPL also either extend tariff arrangements to non-qualifying facilities, or include separate tariff riders for such facilities. FirstEnergy does not. None of these utilities explicitly defines what an 'eligible' facility is, and they all include stipulations that interconnection is available subject to the utility's needs and capabilities, and only under contractual arrangement between the utility and the DER customer. This lack of transparency makes it difficult for a non-qualifying facility owner to predict whether his facility will be allowed to interconnect. It also leaves DER customers with little leverage in contractual negotiations.

2. Procedural Transparency

If interconnection procedures are confusing, overly laborious, or open-ended, customers are less likely to invest in a DER project. Without a clear process, a customer risks expensive and time-consuming delays and the possibility that the project will never be completed. Each utility is required to follow the basic procedural steps described in Pennsylvania Code, but some provide more detail about customer and utility responsibilities, timelines, and costs. All the utilities require DER customers to pay for the cost of necessary protective equipment, advanced meters, and any unexpected changes to the distribution system that arise as a consequence of interconnection. These latter costs may not be determined until impact studies are performed. Without any laws or mandates dictating specific procedural requirements, most of the details of the process are designed by the individual utility and subject to change.

The PECO process is organized and transparent. In addition to the procedures and rates outlined in its tariff,[94] PECO publishes two easy-to-read interconnection guides – one for small customers (= 40 kW of generation capacity), and one for all other customers (> 40 kW of generation capacity). The 58-page guide for customers with over 40 kW of capacity includes definitions, customer responsibilities, and information for customers interested in selling or buying through PJM. Interconnecting with PECO is not simple or inexpensive for large customers (customers with more than 5 MW of generation must pay $5,000 in initial fees), but customers under 300 kW may apply for a simplified approval process and PECO sets reasonable time limits for its reviews and feedback.

Both the Allegheny[95] and FirstEnergy[96] tariffs provide prospective DER customers with a relatively clear process for interconnecting and operating in parallel with the area grid. Both tariffs include standby, maintenance, and supplementary power rates and conditions, although the FirstEnergy and Allegheny rates differ considerably. Allegheny provides safety and reliability standards for DER interconnection in the company's Engineering Manual, Section 35, entitled "Nonutility Generators, Interconnection Policy and Guidelines." FirstEnergy's tariff requires the QF to "provide the equipment necessary for it to interconnect… in a manner which is compatible with and meets the safety standards of [FirstEnergy]," and later it states that the QF "must comply with the General Conditions for Interconnection of Customer-Owned Generation with Ohio Edison/Penn Power System." No interconnection standards or guidelines could be attained from FirstEnergy's website or through verbal and e-mail requests within the timeframe of this study.

The Duquesne Light tariff[97] includes detailed rate-setting information for non-utility generating facilities. Rider #16, Section E of the tariff indicates that DER customers must install any necessary interconnection equipment; this equipment must be reviewed and approved by Duquesne. Customers are responsible for any additional costs to the company for new line extensions, relocation of facilities, etc. Duquesne provides a copy of interconnection standards, "Standards for the Connection of Qualifying Generating Facilities and Non Utility Generating Facilities Which are Operated in Parallel with Duquesne Light Co." to any interested customers. These standards include fairly detailed safety and operating requirements.

The PPL tariff[98] does provide prospective DER customers with information about rates and service conditions for interconnected facilities. It includes very little information on interconnection and parallel operation requirements. These requirements are included in power purchase agreements and interconnection agreements between PPL and DER customers.

3. Rates and fees

All of the utility tariffs include rates and terms for selling electricity to eligible customer-generator facilities. These rates include energy charges ($/kWh) and demand charges ($/kW) for standby, maintenance, and supplementary power, as well as minimum standby or reservation charges. The contractual terms generally limit the number of hours that standby and maintenance power are available to the customers and when it can be used.

Supplementary rates are equal to the rates that the customer would otherwise be billed if it weren't generating electricity but was consuming the same amount of power; these are referred to as "otherwise applicable rates." Standby rates in Pennsylvania are oftentimes equal to or lower than the customer's otherwise applicable rate and maintenance rates are lower than standby rates.

Table 6 is a comparison of standby and maintenance rates for utilities in Pennsylvania. Rates for maintenance power are consistently lower than rates for standby power. These lower rates reflect the value to utilities of scheduling maintenance power well ahead of time.

Each utility requires DER customers to contract for supplementary, standby, and maintenance power. They also require customers to schedule maintenance power 30 or more days in advance so the utility can prepare. Customers can only contract for a limited number of hours of standby or maintenance power service, and these hours are only allowed to be used when outages occur, which is why the standby and maintenance rates are fairly low. If a customer's demand exceeds its generation capacity, power is purchased at the supplementary rate.

Table 6. Standby and Maintenance Rates for Pennsylvania Utilities.

Utility Service/ customer type	**Firm Standby Rates** ***demand charge $/ peak kW*** ***energy charge $/ kWh***	**Maintenance Rate** ***demand charge $/ peak kW*** ***energy charge $/ kWh***
Duquesne Light		
HPVS (high voltage)	$ 3.56 $ 0.028	$ 2.26 $ 0.029
L (> 5,000 kW)	$ 3.54 $ 0.026	$ 2.05 $ 0.023
GL (300 – 4,999 kW)	$ 3.30 $ 0.017	$ 2.41 $ 0.015
GS (< 300 kW)	$4.27 $ 0.024	$ 3.39 $ 0.022
Allegheny Power		
All	First 100 kW: $5.36 Additional kW: $4.50 $ 0.024	$ 4.31 $ 0.024
PPL		
High voltage (> 69,000 volts)	$ 1.21 $ 0.036	None $ 0.036
Medium voltage (12,470 volts)	$ 1.67 $ 0.040	None $ 0.040
Low voltage (480 volts or less)	$ 1.72 $ 0.042	None $ 0.042
FirstEnergy		
All	30% of OARs (1) cheapest block of OARs (1)	None cheapest block of OARs (1) minus $0.002
PECO		
High tension voltage	$ 2.88 $ 0.075	Summer: same as OARs (1) (2) Winter: none Summer: same as OARs (1) (2) Winter: $ 0.027
Primary voltage	$ 2.88 $ 0.095	Summer: same as OARs (1) (2) Winter: none Summer: same as OARs (1) (2) Winter: $ 0.031
Low voltage	$ 2.88 $ 0.127	Summer: same as OARs (1) (2) Winter: none Summer: same as OARs (1) (2) Winter: $ 0.061

(1) 'otherwise applicable rates' that customers would pay if they were not generating customers.
(2) PECO defines summer as June – September and winter as October – May.

4. Minimum standby charges

Standby charges, sometimes called reservation charges, are a controversial issue for DERs. Utilities argue that it is costly to have reserve capacity available for DER customers, and that if customers switch to DERs the utility incurs stranded infrastructure costs. DER customers argue that DERs can be installed and managed in a way that minimizes the probability of a forced outage, particularly an outage that disables multiple generators at one time, and that in many areas DERs can save the utility money by providing ancillary services and reducing the need for utility improvements.

PECO charges DER customers $2.88 per kW per month of contracted standby power, regardless of whether the customers make use of this standby power or not. PECO does not require customers to contract for the entire amount of their generation capacity, and since contractual agreements can be as short as one month DER customers are able to adjust their contracted standby power needs based on projected needs and generator performance.

PPL requires DER customers to pay a minimum monthly charge equal to the contracted kW of standby power multiplied by the standby power capacity charge (approximately $1, depending on the voltage). Allegheny requires interconnected customers to pay minimum demand charges on 70% of its contracted standby power capacity, regardless of how much of the standby power capacity is used.[99] In both cases if a customer's actual demand and energy charges exceed this minimum, there are no redundant fees. PPL and Allegheny impose minimum charges also on their non-generating customers, so the charges to DER customers are not necessarily discriminatory. Neither the Duquesne Light nor the FirstEnergy tariffs indicate any minimum standby charges.

Standby charges are debated among policy-makers and regulators; there is a wide variation in standby rates across the country. For example, Florida Power & Light imposes a minimum charge of roughly $3 per kW of contracted standby demand, regardless of use.[100] Central Illinois Light Company (owned by parent company Ameren Corporation) imposes a minimum charge of roughly $4 per kW of contracted standby service in summer months and $3 in winter months, regardless of use.[101] Union Electric Company in Missouri (also owned by Ameren) imposes a minimum charge of $14 per kW of contracted standby service in summer months and $6 per kW in winter months, regardless of actual use.[102] Connecticut Light and Power's tariff [103] includes a minimum charge that is equal to the sum of three parts – a basic customer service charge, a distribution demand charge, and a production/transmission demand charge. Each of these components depends on the contracted standby service rather than actual use, and the production/transmission demand charge is determined by a complicated and confusing equation.

5. Net metering

Utilities charge their customers for electric energy (in units of kWh). If the customer generates power themselves, they can use less energy from the grid, or might produce more than they need, selling it back to the grid. Making the meter "run backwards" is termed "net metering". Net metering has long been seen as a way to provide customers with the opportunity to produce small amounts of energy, typically from "clean" resources such as solar or wind power, or biomass fuels. The environmental community has championed net metering laws in every state, and in federal legislation. This effort has resulted in net metering laws in 38 states. Table 7 shows the various state net metering provisions, including the applicability, statewide limit on total net metered capacity, how net excess generation is handled (if the customer sells more electricity to the utility than it purchases), and the legal authority and scope of the net metering program. This table was created and published by the US Department of Energy's Energy Efficiency and Renewable Energy Program and updated using information provided by the North Carolina Solar Center's Database of State Incentives for Renewable Energy (DSIRE).[104]

Pennsylvania Code states that qualifying facilities of less than 50 kilowatts may opt for net metering, or net energy billing.[105] Each public electric utility is required to file its policy for net billing with the Pennsylvania PUC, but it is not required to provide net metering service to qualifying facilities of 50 kW or less. Allegheny Energy, PPL Electric, and Duquesne Light offer net metering to customers with renewable energy systems with a rated capacity of up to 10 kW; PECO Energy Company offers net metering for renewable energy systems with a rated capacity of up to 40 kW, and FirstEnergy offers net metering for renewable energy and cogeneration systems (qualifying facilities, as defined by PURPA) with a rated capacity of up to 50 kW.

Each Pennsylvania utility has arrangements for net metering customers, and they are generally similar to one another and in line with net metering provisions in other states:

- All Pennsylvania utilities charge customers if a net metering interconnection requires any changes to the utility distribution system. PPL and PECO will pay the first $1,000 of these costs, but other utilities offer no cost-sharing.

- Most Pennsylvania utilities charge a one-time processing and inspection fee; PPL and PECO charge $100 for photovoltaic installations and $300 for other installations, Allegheny charges $35 for photovoltaic installations and $250 for other installations, and FirstEnergy only states that customers will be charged "reasonable charges." Duquesne Light does not list any application fee.

- Most of the Pennsylvania utilities provide bi-directional meters for little or no charge; Duquesne Light charges less than $10, while PPL, Allegheny, and PECO have no charge for standard bi-directional meters. FirstEnergy does not have any information about metering costs in its tariff.

- None of the Pennsylvania utilities pay or credit customers for net excess generation (if the customer sells more electricity to the utility than it purchases).

Table 7: Summary of State Net Metering Programs

State	Allowable Technology and Size	Allowable Customer	Statewide Limit	Treatment of Net Excess Generation (NEG)	Authority	Enacted	Scope of Program	Citation/Reference
Arizona	Renewables and cogeneration ≤100 kW	All customer classes	None	NEG purchased at avoided cost	Arizona Corporation Commission	1981	All IOUs and RECs	PUC Order Decision 52345, Docket 81-045
Arkansas	Renewables, fuel cells and microturbines ≤25 kW residential ≤100 kW commercial	All customer classes	None	Monthly NEG granted to utilities	Legislature	2001	All utilities	HB 2325, effective Oct. 2001; PSC Order No. 3 July 3, 2002
California	Solar and wind ≤1000 kW	All customer classes	0.5% of utilities peak demand	Annual NEG granted to utilities	Legislature	2002; 2001; 1995	All utilities	Public Utilities Codes Sec. 2827 (amended 09/02; 04/01; effective 9/98)
Colorado	Wind and PV 3 kW, 10 kW	Varies	NA	Varies	Utility tariffs	1997	Four Colorado utilities	PSCO Advice Letter 1265; PUC Decision C96-901 [1]
Connecticut	Renewables and fuel cells ≤100 kW	Residential	None	Not specified	Legislature	1990, updated 1998	All IOUs, No REC in state.	CGS 16-243H; Public Act 98-28
Delaware	Renewables ≤25 kW	All customer classes	None	Not specified	Legislature	1999	All utilities	Senate Amendment No. 1 to HB 10
Florida	Solar or wind, ≤10 kW	Residential	N/A	NEG carried over to following months	Utility (JEA) tariff	2003	JEA	JEA tariff
Georgia	Solar, wind, fuel cells ≤10 kW residential ≤100 kW commercial	Residential and commercial	0.2% of annual peak demand	Monthly NEG or total generation purchased at avoided cost or higher rate if green priced	Legislature	2001	All utilities	SB93
Hawaii	Solar, wind, biomass, hydro ≤10 kW	Residential and small commercial	0.5% of annual peak demand	Monthly NEG granted to utilities	Legislature	2001	All utilities	HB 173
Idaho	All technologies ≤100 kW	Residential and small commercial (Idaho Power only)	None	Monthly NEG purchased at avoided cost	Public Utility Commission	1980	IOUs only, RECs are not rate-regulated	Idaho PUC Order #16025 and #26750 (1997) Tariff sheets 86-1 thru 86-7
Illinois	Solar and wind ≤40 kW	All customer classes; ComEd only	0.1% of annual peak demand	NEG purchased at avoided cost	ComEd tariff	2000	Commonwealth Edison	Special billing experiment [1]
Indiana	Renewables and cogeneration ≤1,000 kWh/month	All customer classes	None	Monthly NEG granted to utilities	Public Utility Commission	1985	IOUs only, RECs are not rate-regulated	Indiana Administrative Code 4-4.1-7

State	Allowable Technology and Size	Allowable Customer	Statewide Limit	Treatment of Net Excess Generation (NEG)	Authority	Enacted	Scope of Program	Citation/Reference
Iowa	Renewables and cogeneration (No limit per system)	All customer classes	105 MW	Monthly NEG purchased at avoided cost	Iowa Utility Board	1993	IOUs only, RECs are not rate-regulated[2]	Iowa Administrative Code [199] Chapter 15.11(5)
Kentucky	PV ≤15 kW	All customers except industrial	0.1% of supplier's single-hour peak load	NEG credited to following month	Legislature	2004	All utilities	SB 247
Louisiana	Renewables ≤25 kW residential ≤100 kW commercial and agricultural	Residential, commercial, and agricultural	None	Not specified	Legislature	2003	All utilities	HB 789
Maine	Renewables and fuel cells ≤100 kW	All customer classes	None	Annual NEG granted to utilities	Public Utility Commission	1998	All utilities	Order # 98-621 RC of ME Chapter 36
Maryland	Solar only ≤80 kW	Residential and schools only	0.2% of 1998 peak	Monthly NEG granted to utilities	Legislature	1997	All utilities	Article 78, Section 54M
Massachusetts	Qualifying facilities ≤60 kW	All customer classes	None	Monthly NEG purchased at avoided cost	Legislature	1997	All utilities	Mass. Gen. L. ch. 164, §1G(g); Dept. of Tel. and Energy 97-111
Minnesota	Qualifying facilities ≤40 kW	All customer classes	None	NEG purchased at utility average retail energy rate	Legislature	1983	All utilities	Minn. Stat. §216B.164
Montana	Solar, wind and hydro ≤50 kW	All customer classes	None	Annual NEG granted to utilities at the end of each calendar year.	Legislature	1999	IOUs only	SB 409
Nevada	Solar and Wind ≤10 kW	All customer classes	None	Monthly or annual NEG granted to utilities	Legislature	2001; 1997	All utilities	Nevada Revised Statute Ch. 704; amended AB661 (2001)
New Hampshire	Solar, wind and hydro ≤25 kW	All customers classes	0.05% of utility's annual peak	NEG credited to next month	Legislature	1998	All utilities	RSA 362-A:2 (HB 485)
New Jersey	PV and wind ≤100 kW	Residential and small commercial	0.1% of peak or $2M annual financial impact	Annualized NEG purchased at avoided cost	Legislature	1999	All utilities	AB 16. Electric Discount and Energy Competition Act
New Mexico	Renewables and cogeneration ≤10 kW	All customer classes	None	NEG credited to next month, or monthly NEG purchased at avoided cost (utility choice)	Public Utility Commission	1999	All utilities	NMPUC Rule 571, 17 NMAC 10.571
New York	Solar only residential ≤10 kW; Farm biogas systems <400 kW	Residential; farm systems	0.1% 1996 peak demand	Annualized NEG purchased at avoided cost	Legislature	2002; 1997	All utilities	Laws of New York, 1997, Chapter 399; amended SB 6592 (2002)

State	Allowable Technology and Size	Allowable Customer	Statewide Limit	Treatment of Net Excess Generation (NEG)	Authority	Enacted	Scope of Program	Citation/Reference
North Dakota	Renewables and cogeneration ≤100 kW	All customer classes	None	Monthly NEG purchased at avoided cost	Public Utility Commission	1991	IOUs only, RECs are not rate-regulated	North Dakota Admin. Code §69-09-07-09
Ohio	Renewables, microturbines, and fuel cells (no limit per system)	All customer classes	1.0% of aggregate customer demand	NEG credited to next month	Legislature	1999	All utilities	S.B. 3 (effective 01/01/01)
Oklahoma	Renewables and cogeneration ≤100 kW and ≤25,000 kWh/year	All customer classes	None	Monthly NEG granted to utility	Oklahoma Corporation Commission	1988	All utilities	OCC Order 326195
Oregon	Solar, wind, fuel cell and hydro ≤25 kW	All customer classes	0.5% of peak demand	Annual NEG granted to low-income programs, credited to customer, or other use determined by Commission	Legislature	1999	All utilities	H.B. 3219 (effective 9/1/99)
Pennsylvania	**Renewables and fuel cells, £50 kW allowable**	**All customer classes**	**None**	**Monthly NEG granted to utility**	**Legislature**	**1998**	**All utilities**	**52 PA Code 57.34**
Rhode Island	Renewables and fuel cells ≤25 kW	All customer classes	1 MW for Narragansett Electric Company	Annual NEG granted to utilities	Public Utility Commission	1998	Narragansett Electric Company	PUC Order Docket No. 2710
Texas	Renewables only ≤50 kW	All customer classes	None	Monthly NEG purchased at avoided cost	Public Utility Commission	1986	All IOUs and RECs	PUC of Texas, Substantive Rules, §23.66(f)(4)
Utah	Solar thermal, PV, wind, hydro, fuel cells ≤25 kW	All customer classes	0.1% of 2001 peak demand	Customers are given credit for the avoided cost of NEG, carried into following month	Legislature	2002	All utilities	House bill 7
Vermont	PV, wind, fuel cells ≤15 kW Farm biogas ≤150 kW	Residential, commercial and agricultural	1% of 1996 peak	Annual NEG granted to utilities	Legislature	1998	All utilities	Sec. 2. 30 V.S.A. §219a; amended Senate Bill 138, 2002
Virginia	Solar, wind and hydro Residential ≤10 kW Non-residential ≤25 kW	All customer classes	0.1% of peak of previous year	Annual NEG granted to utilities (power purchase agreement is allowed)	Legislature	1999	All utilities	Virginia Assembly S1269 Approved by both Assembly and Senate 3/15/99

State	Allowable Technology and Size	Allowable Customer	Statewide Limit	Treatment of Net Excess Generation (NEG)	Authority	Enacted	Scope of Program	Citation/Reference
Washington	Solar, wind, fuel cells and hydro ≤25 kW	All customer classes	0.1% of 1996 peak demand	Annual NEG granted to utility	Legislature	1998	All utilities	Title 80 RCW House Bill B2773
Wisconsin	All technologies ≤20 kW	All retail customers	None	Monthly NEG purchased at retail rate for renewables, avoided cost for non-renewables	Public Service Commission	1993	IOUs only, RECs are not rate-regulated	PSCW Order 6690-UR-107
Wyoming	Solar, wind and hydro ≤ 25 kW	All customer classes	None	Annual NEG purchased at avoided cost	Legislature	2001	All IOUs and RECs	HB 195, Feb. 2001

Notes:

IOU — Investor-owned utility
GandT — Generation and transmission cooperatives
REC — Rural electric cooperative
Alabama, Alaska, Mississippi, Nebraska, North Carolina, South Carolina, South Dakota, Tennessee, and West Virginia do not offer any net metering provisions.
Kansas allows interconnection for renewable energy systems under 25 kW (residential) or 100 kW (commercial), but not net metering. Net metering laws are being developed.
Michigan has no net metering laws, but the Michigan Public Service Commission issued an order in May 2004 calling for the development of a statewide net metering program.
Missouri allows for interconnection for renewable energy systems smaller than 100 kW, but the customer is refunded the avoided cost of power, not the retail price.

[1] For information, see the Database of State Incentive for Renewable Energy, http://www.dsireusa.org.
[2] Except for the Linn County Electric Cooperative, which is rate-regulated by Iowa PUC.

Current Micro-grid Projects in Pennsylvania

Two micro-grids have recently been proposed in Pennsylvania: one began development in 1998 but was successfully opposed by the local distribution utility; the other is currently being developed.

In 1997, Pennsylvania Enterprises, Inc. (PEI) purchased a 25 MW coal-fired cogeneration facility from the Archbald Power Corporation. PEI converted the plant to a natural gas cogeneration plant, and planned to construct a micro-grid, or 'power park', that would supply electricity and heat to customers at a 600-acre industrial park in Archbald, Pennsylvania. The local utility, PPL, argued before the Pennsylvania PUC that the PEI Power Park constituted a public utility and should not be allowed to provide services to customers in the PPL service territory. In September, 1998, the Pennsylvania PUC issued a declaratory order that the PEI Power Park was not a public utility, and could progress with the project.[106] Ground was broken on the project in November of 1998 and PEI obtained customer commitments. PPL sued PEI in civil court. Deciding that litigation would decrease its customer base and delay revenue, PEI abandoned its plans to directly supply electricity to its customers. Instead, PEI reached an agreement with PPL and was designated an 'exempt wholesale generator' that continues to produce power (and steam) but sells its electricity on the wholesale market through PJM. PPL services the PEI Power Park, customers continued to move to the industrial park, and PEI expanded by adding 45 MW of generation in 2001. However, the Power Park is not able to isolate from the distribution system during outages, is not guaranteed power quality beyond normal utility provisions, and its customers pay utility rates that are higher than they would have paid had the Power Park been operated as a micro-grid.[107]

A current example of a micro-grid project in Pennsylvania is the proposed EnergyWorks commercial micro-grid in Lancaster, Pennsylvania. The electric power micro-grid is still in the development stage, but EnergyWorks is already the energy service provider for the 170-tenant shopping mall on the site. The following description of the project was provided by EnergyWorks:[108]

> EnergyWorks plans to incorporate on-site generation and technology improvements that will enhance the characteristics of the facilities as an efficient commercial micro-grid. Operational "optionality" will be achieved through the ability to create and aggregate demand response, store energy and conduct buy/sell transactions in the wholesale energy market. The facility currently purchases power from the local utility, but once on-site generation is installed the facility will purchase energy in the wholesale spot market. The on-site generation capacity will be less than the peak demand, but demand response and load shifting (via thermal storage) will mitigate the need to buy power during wholesale price spikes.
>
> Energy services are contracted individually for the mall common areas and each of the mall's commercial tenants. The aggregated central plant and end-use customer peak electrical load is over 7.5 MW. The facilities include a central boiler and chiller plant; a high voltage substation with two independent 69kV feeders connected to the public grid; over 13 km of medium voltage primary electrical distribution to 14 substations, providing secondary distribution to more than 220 electrical sub-metering points; and hot and chilled water distribution to over 160 air handling units.
>
> The electrical and thermal distribution systems are installed and fully operational. Design requirements and proof of concept testing were completed for an Energy Services Hub (ESH) in January 2004. The ESH provides the capability to automatically execute make vs.

buy decisions (on-site generation vs. electricity purchase from the grid) based on real-time market price signals. EnergyWorks is currently working with a technology partner to develop software for managing a central operations database and integrating automated meter reading and customer billing. The following system modifications and upgrades are planned for completion by the end of 2005: integrated controls and other central heating and cooling efficiency improvements; electric metering upgrades for the larger tenants, enabling implementation of a pilot program for inducing and aggregating demand response within the mall complex; on-site generation with automatic make vs. buy capabilities; and ice-thermal storage, incorporating automatic storage and consumption operations.

Benefits will accrue to both end-use customers, who will obtain savings in energy costs, and the public transmission and distribution grid, which will obtain cost effective congestion relief and various ancillary services. EnergyWorks will benefit from lower risk and higher investment returns from more diversified utilization of its energy infrastructure assets.

District Heating

A district heating plant provides heat in the form of steam or hot water through a network of pipes to customers within a small proximity of the plant. Some systems also provide chilled water to customers as a way of balancing seasonal business to make use of their human and physical resources. Pennsylvania has at least eight large commercial district heating plants,[109] in addition to small systems accommodating individual institutions. Pittsburgh has three district heating plants, Philadelphia two.

District heating systems commonly serve a diverse group of customers that collectively have a fairly consistent demand for heat (and probably electricity). Commercial customers might have high demand during typical business hours; residential and/or industrial customer demand might peak during night and weekend hours. This synergy allows the district heating plant to make efficient use of its resources and offer low rates to customers. The same principles would apply to electricity supply from a micro-grid, and the ability to make use of waste heat from electric generators to improve system economics.

Micro-grid recommendations for the Commonwealth

Although distributed generation presents system stability and safety issues which require careful engineering evaluation, it appears as if aggregating generation, control, storage, and load in micro-grids presents opportunities to overcome these issues. The 1968 FCC decision in the Carterfone case which permitted connection of non-Bell equipment to telephone lines led to decades of innovation in telecommunications. There are good indications that micro-grids may foster similar innovation in electric power delivery.

The Commonwealth can facilitate DER and micro-grid market growth through three basic actions: 1) adopt standardized and transparent interconnection procedures and applications for all DER customers, including non-qualifying facilities; 2) formalize the definition and legal status of micro-grids and adopt standardized operating rules; and 3) allow or require appropriate natural gas tariffs for DER customers.

Standardize interconnection procedures, agreements, and model designs for all DER customers

Standardized interconnection procedures and agreements exist for customers interested in selling power on the wholesale market. Pennsylvania should follow the lead taken by Texas, New York, California and other states by requiring that utilities grant interconnection and standby service to DER customers in addition to qualifying facilities as defined by PURPA. Texas laws apply to customers with 10 MW of capacity or less, and the proposed federal rules will apply to systems with 20 MW of capacity or less. Pennsylvania may want to start by allowing facilities under 10 MW in size to interconnect as a trial, and then perhaps increasing the limit to 20 MW or larger after the Commonwealth and its regulatory community has gained experience with these systems.

The Texas Distributed Generation Interconnection Manual[110], most recently revised and published by the PUC of Texas in May 2002, is one model for Pennsylvania to standardize and clarify the interconnection procedure. This document includes a discussion of pertinent state laws and rules, as well as applicable national codes and standards (National Fire Protection Association, Underwriters Laboratory, Institute of Electrical and Electronics Engineers). The Manual includes minimum technical requirements for DER customers, and a clear outline of the procedural steps for interconnection, including guidelines for how any studies or reviews should be conducted. It also lays out the rights and responsibilities of both the distribution utility and the DER customer, and contains information (contacts, procedures, etc.) related to dispute resolution and general inquiries.

By creating standardized and transparent procedures and agreements and communicating them in a clear, easily accessible format, Pennsylvania can remove many of the real and perceived barriers facing interested DER customers.

Formalize the definition and legal status of micro-grids and adopt standardized operating rules

Micro-grids lack a formal legal definition in the Commonwealth. In addition to the barriers faced by DERs, micro-grid projects are likely to face barriers from distribution utilities and uncertainty from potential customers and creditors.

Pennsylvania should define micro-grids as legal entities that are allowed to conditionally serve customers within the public service territories of distribution utilities. There should be differentiation between micro-grids owned by the customers and operated as a cooperative, and those owned and operated by a third-party. Competition would be enhanced if private micro-grid companies are independent, not utility-owned. Micro-grid companies should have multi-year contracts with their customers, subject to advance renewal so that utilities are given adequate notice of customers returning to their service as provider of last resort. Micro-grid companies should not be required to own land or maintain landlord-tenant agreements with their customers.

It is important that these distinctions be made in legislation because without clarity, lengthy court challenges may inhibit the growth of micro-grids in Pennsylvania. A potential micro-grid company may opt instead for being a merchant producer or qualifying facility. Section 2.4 presents our guidance for states considering legislation which enables micro-grids.

If and when micro-grids are defined by the Commonwealth, micro-grid companies should be required to demonstrate some level of financial and managerial capability. For example, Michigan's law requires any alternative electric suppliers to submit 'licensing procedures' to the Michigan PSC. These procedures require suppliers to submit to the Michigan PSC for approval

the products and services it provides, methods for billing and customer disputes, a line of credit, methods for paying state fees and taxes, methods for meeting minimum electric quality standards, and its plans for collecting and providing data to customers and the state.[111]

Many states and some localities impose small public benefits charges on electric power sales in order to provide funding for a variety of programs such as financial support for low-income customers, research and development, and renewable energy and energy-efficiency initiatives. This fee is usually collected by electricity distribution companies and deposited into a public benefits trust. We recommend that Pennsylvania legislation require that micro-grid firms be required to pay public benefit fees to public benefits trusts at the same rate per kWh for energy supplied to their customers as applies to other power companies operating in the state. This will require that micro-grid companies submit consumption data to the PUC, and set up a payment method with the public trust holder. Micro-grid systems and their customers should be eligible to receive benefits from public benefit funds on an equitable basis.

Micro-grid customers should be required to contribute to any public trust funds on the same basis as do utilities, and they should also be eligible to receive services or benefits from such funds.

Allow or require natural gas tariffs for DER customers

In July 2001, New Jersey Natural Gas Company (NJNG) filed a petition with the NJ Board of Public Utilities seeking approval of a Distributed Generation Service Tariff. In the proposal NJNG stated that DER service typically peaks in the summer period while traditional natural gas service peaks in the winter periods. New DER load is expected to enable NJNG to improve its load factor and better utilize existing assets to service summer DG peaking requirements, thereby offsetting potential price increases to existing customers. NJNG had performed a cost analysis and presented the findings to the NJ Board of Public Utilities in order to support their proposed rates for DER customers. The NJ Board of Public Utilities found that NJNG's petition was reasonable and approved the new rates.[112]
The only component of the natural gas rate that was reduced was the distribution charge; actual fuel rates were not reduced. The new rates[113] result in an overall savings of roughly 11% and 16% for residential DER customers in winter and summer, respectively.[114] Commercial DER customers save approximately 22% and 25% overall in winter and summer, respectively.

In April 2003, the New York Public Service Commission ordered natural gas companies to develop unique tariffs for DER customers with rates based on the impact of such customers.[115] These tariffs will also take into account the benefits (and costs) that DER customers provide to natural gas utilities.

Pennsylvania should follow the lead of both New York and New Jersey by requiring natural gas companies to analyze the impact of DER customers on their distribution costs, and provide distribution rates to DER customers based on the load leveling benefits (if any) these customers bring to the natural gas business. Such a move would improve the economics of DER projects without adversely affecting other customers on the system.

Equipment Certification

California and New York have begun keeping lists of pre-approved equipment that can be used by DER customers for expedited interconnection procedures. These states either conduct testing or follow testing by nationally recognized laboratories and use this information to determine which off-the-shelf systems or models are low-risk and reliable. Pennsylvania could simplify the interconnection process by adopting similar procedures.

2.4 Guidance for Drafting State Legislation to Facilitate the Growth of Independent Electric Power Micro-Grids

In 2003, the Carnegie Mellon Electricity Industry Center developed guidance for states considering micro-grid enabling legislation. After review by stakeholders, the following document was sent to the chairs of the relevant energy committees in the fifty states' legislatures.

Motivation

A variety of small-scale electric generation technologies are now available. Many of these can operate as combined heat and electric power (CHP) systems that achieve much higher overall end-use energy efficiencies than conventional systems. In addition, solid state power electronics and advanced computer control technology make it possible to condition and control the local use of electric power, and interconnections to the distribution system, in ways that had previously not been possible.

Today it is technically possible, and sometimes economically attractive, for small "micro-grid" companies to establish local distribution systems underneath the traditional (or "legacy") electric power distribution system. These micro-grids would serve small groups of customers and could provide special services and needs, such as increased reliability and power quality.[116] Some micro-grids might still purchase a portion of their power from the traditional power system. Most would rely on the traditional system for backup power. Some might occasionally make modest amounts of power available for sale via the distribution system.

As Morgan and Zerriffi recently reported,[117] laws that grant traditional utilities exclusive service territories prohibit, or seriously inhibit, the growth of micro-grid markets in many states. We believe that new legislation that would permit the development of independent micro-grids should be passed in states where such systems are not now allowed, or where present laws and regulation discourage their development. It is our belief that such enabling legislation could unleash a wave of technological and business innovations similar to what occurred in telecommunications after the 1968 Carterphone Decision allowed customers to attach non-Bell devices such as phones, answering machines, fax machines, and modems to the public telephone system.

A micro-grid system may provide a variety of benefits, both to its customers and to the legacy distribution utility,[118] its customers, and society more generally. These benefits include:

- reducing the need for new generation capacity;
- relieving stressed distribution feeders;
- obviating the need for some transmission and distribution system expansion;
- providing distribution system support and backup power when the legacy distribution system is stressed or experiences failures;
- competing with the legacy utility, and other distributed power options, consequently driving innovation and lowering costs;
- providing special services such as DC power, and clean or highly reliable power; and
- stimulating an equipment and services market for small-scale generation, technologies for power conditioning and control, local power architectures, and demand-side management equipment and services.

At the same time, micro-grids may impose costs upon a legacy distribution utility and its customers. Possible costs include:

- reducing the customer base over which current distribution system capital investments, and various regional transmission system charges, can be spread;
- contributing to planning ambiguity for transmission and distribution capacity expansion (in much the same way as independent power producers [IPPs] and other non-utility competitive players contribute to such ambiguity);
- requiring distribution system upgrades;
- providing standby power (although this will be limited by the magnitude of the micro-grids interconnection to the legacy utility, and the fact that micro-grids with multiple generators are unlikely to lose all of their generating capacity at once);
- adversely impacting the system's load profile;
- complicating distribution system fault protection and emergency repairs; and
- adding strain on the natural gas distribution system.

Not every micro-grid will impose these costs or provide these benefits. Many costs, such as those associated with standby or peak loads, can be readily dealt with through appropriate demand charges and peak load tariffs as they are for other customers. Some of the benefits may require that the distribution utility adopt modern flexible control systems and distribution automation. In the discussion that follows, we suggest policies designed to minimize these costs while realizing the benefits.

Definition of an Electric Power Micro-grid

State law should specify the minimum characteristics that a system must have in order to be classified as an electric power micro-grid. These should include:

- more than one legally distinct entity served with electric power, and
- one or more independent sources of electric power generation and/or storage.

In addition, states may wish to limit the size of micro-grid systems by specifying:

- the maximum installed generating capacity that a micro-grid can have, and/or,
- the maximum number of customers that a micro-grid system can serve.

The first two characteristics are important to distinguish micro-grids from small-distributed generation (DG) installations that serve a single customer. While interconnection to the distribution system continues to present barriers, such small DG installations are now possible in most jurisdictions. Micro-grids should also not be confused with small-scale independent power producers (IPPs). Small IPPs are in the business of making electricity to sell to others over the distribution and transmission systems. In contrast, micro-grids are in the business of serving a small number of local customers with electricity, probably heat, and possibly cooling. They may also purchase power from the distribution utility, or sell a fraction of the power they make over the distribution system, but such transactions are not the primary focus of their business.

Some limit should be set on installed generating capacity, and/or the number of customers served, since otherwise micro-grids could grow into conventional distribution companies. Most states will probably want to preserve the natural monopoly of distribution companies and avoid multiple wires serving the same geographic region.

One way to think about setting a capacity limit is to think in terms of typical loads that a micro-grid may serve. The peak load of a residential home is typically between 10 and 30 kW_e. Peak loads for typical shopping centers range from 2 to 8 MW_e. Typical mid-sized office buildings have peak loads that range from 6 to 20 MW_e.[119] [120] We recommend that the maximum capacity level for a micro-grid be set somewhere between 20 and 40 MW_e.

States that wish to develop their micro-grid markets slowly might start with a lower threshold, and then later consider increasing the capacity limit once they have gained some experience.[121] Note, however, that placing a capacity limit that is too low may make micro-grid operations less economically attractive and prevent the development of any micro-grid market. Strachan[122] shows that engine cogeneration units installed in the UK and the Netherlands during the 1990's experienced significant economies of scale.

Figure 15. Eight 800-kW Caterpillar engines supply power to a plastics plant in Illinois. Design and photo by LaSalle Associates.

In the early stages of micro-grid development, a customer limit could be set to provide legacy utilities with some measure of stability. Likewise, a limit would ensure that any technical difficulties would affect only a small customer base. However, if a capacity limit is established, it may not be necessary to add a customer limit. States that wish to specify both a capacity and customer limit could think in terms of the maximum size of a residential subdivision that they believe a micro-grid should be allowed to serve. An upper limit of between 100 and 200 customers would be reasonable. If these were all residential customers, their peak load would be well under our recommended capacity limit.

State law should not specify the number or type of generators that a micro-grid system can contain because such a restriction would constrain technical innovation and might prevent the micro-grid market from developing.

Legal Authorization of Micro-Grids

New enabling legislation should allow micro-grid firms to be structured either as:

- co-ops serving their members, or
- for-profit firms.

In many states, such authorization will require a modification of existing state laws that grant exclusive service rights to legacy utilities.

Micro-grid firms should be free to contract fee and service arrangements with their customers without approval by the state Public Utility Commission (PUC/PSC).

Some states might also wish to impose certain consumer protection requirements on micro-grid firms. This possibility is discussed in a later section.

Tariffs Arrangements between Micro-Grids and the Legacy Utility

Virtually all U.S. distribution systems continue to be operated as regulated utilities. In some states, electricity supply has been deregulated and is now provided through a competitive market. In many states, supply remains regulated and operates along with transmission and distribution in a vertically integrated regulated utility. Thus, in considering tariff arrangements between micro-grids and legacy utilities, we must differentiate between states in which supply has, and has not, been restructured.

Guidance for states that have not restructured generation

In these states, state law should require that the PUC/PSC develop a tariff that governs the sales of power[123] and other services between micro-grids and the legacy distribution utility. We recommend that different tariffs be developed for small and large micro-grid systems.

Micro-grids smaller than some *de minimus* size (we suggest between 0.5 and 1 MW) should be served under a standard commercial tariff. Such tariffs typically include both time-of-day and capacity charges. Power sales to the utility from such small micro-grids should be covered under the standard tariff for sales by small independent generators.

A special symmetric tariff governing bilateral transactions between large micro-grid systems and the legacy distribution utility should be developed by the PUC/PSC. The enabling legislation should direct the PUC/PSC to consider both the benefits that could be provided to the state's electric power system by micro-grids and the costs that such systems may impose on legacy distribution systems and their customers. Many of these benefits and costs, such as increased distribution system reliability and the possible need to supply standby power, are listed in the introduction to this document.

As previously noted, one potential benefit that micro-grids could provide to traditional distribution system customers is much higher levels of electric power reliability. However, to achieve such increased reliability, legacy utilities must install more advanced distribution system automation and control than many now use. In developing tariffs, micro-grid firms should not be penalized if the legacy distribution utility chooses not to install such systems, and thus forego these benefits.

One important issue that will arise in the development of a special symmetric tariff governing bilateral transactions between large micro-grid systems and the legacy distribution utility is that of location specificity. Micro-grids located in some places could prove highly beneficial to the operation of the legacy distribution system by relieving congestion and providing needed system support. Location in other places could impose costs on the distribution system.

We believe that the basic tariff should *not* be made location-specific because over time the result of a series of location-specific tariffs could grow into a path-dependent tangle of different rates. Instead, we recommend a fixed set of basic rates to which both parties must adhere in the absence of any other agreements.[124]

We recommend that there be flexibility to allow micro-grid operators and the legacy utility to reach contractual agreements that supercede the basic rates set by the PUC/PSC. In this way, the legacy utility could provide incentives for private micro-grid firms to locate in places that would provide maximum benefit to the operation of the distribution system. Such special contractual agreements should be filed publicly with the PUC/PSC. In order to minimize red tape, distribution utilities should be authorized to reach such agreements with micro-grid firms without PUC/PSC review so long as the size of the tariff reduction does not exceed some maximum (e.g., a 20% reduction). However, to reduce the risk of abuse, larger proposed reductions should be subject to PUC/PSC review and approval. To avoid long-term "path-dependent" inequities all special tariff agreements should be set for a specified fixed term, not to exceed 20 years, although subsequent renegotiation and extension of special tariffs should be allowed.

In states that have not restructured, legacy utilities should not be allowed to enter the competitive micro-grid market. However, there is no reason they should be precluded from installing and using distributed resources on their own system, including on customers' premises.

Guidance for states that have restructured generation

In states that have restructured, a micro-grid firm should be able to buy additional power it may need from power suppliers in the wholesale market. If there is an operating spot market, a micro-grid firm should be able to buy and sell power in that market. If the nature of its interconnection makes it relevant, it should also be allowed to participate in ancillary services markets.

Micro-grid firms should be able to enter into longer-term contracts to buy or sell power if those markets exist. In such circumstances, no PUC/PSC energy tariff arrangements would be required. There would be a need for PUC/PSC approved tariffs to cover distribution system use, including exchanges between several different micro-grids on the same distribution feeder. Tariffs imposed upon micro-grids smaller than the *de minimus* size should be exactly the same as for any small commercial customer. For larger micro-grids, a special symmetric distribution system tariff may be needed depending upon the state's existing distribution system tariff schedules. If such a special symmetric tariff is created, it should be based on considerations similar to those outlined in the previous section.

States that have restructured generation markets may wish to consider allowing legacy distribution utilities to enter the market for customer-side distributed resources, including micro-grids. In the Netherlands, when distribution entities that had divested their large generation were allowed to install and operate distributed resources, the result was a substantial increase in the market penetration of these systems.[125] If a state decides to allow its legacy distribution companies to enter such markets, they should do so through an appropriately separate unregulated subsidiary.

Guidance that applies to all states

In order to allow the legacy distribution utility to perform adequate system planning, state law should require that micro-grid firms give advance notice to the legacy utility and the PUC/PSC of their intent to make an installation. We recommend a notification time of between 6 and 9 months. If the warning time were shorter, utilities would not have enough time to adjust operational plans. If it were longer, the notification requirement could significantly inhibit the growth of micro-grid markets. Notice should include the capacity, location, number of customers expected on the micro-grid, and an estimate of the power sale and purchase transactions anticipated with, or through, the legacy distribution system. This should include a discussion of the demands on the distribution system associate with scheduled micro-grid maintenance and plausible unscheduled micro-grid outages.[126]

Many states impose small public benefits charges on electric power sales in order to provide funding for a variety of programs such as financial support for low-income customers, research and development, and renewable energy and energy-efficiency initiatives. This fee is usually collected by electricity distribution companies and deposited into a statewide public benefits trust. We recommend that state legislation require that micro-grid firms be required to pay public benefit fees to the state public benefits trust at the same rate per kWh for energy supplied to their customers as applies to other power companies operating in the state. This will require that micro-grid companies submit consumption data to the PUC/PSC, and set up a payment method with the public trust holder. Micro-grid systems and their customers should be eligible to receive benefits from public benefit funds on an equitable basis.

Interconnection and Power Quality Standards

One of the primary obstacles to the development of small independent power producers has been regulatory and bureaucratic impediments that have prevented or slowed interconnection with legacy distribution companies, or made such interconnection so expensive as to be infeasible. Many examples of such problems have been documented by Alderfer et al.[127] Micro-grids face the same set of impediments.

Clearly there must be standards governing interconnection in order to assure safe and reliable operation. At the same time, innovative technology and flexible engineering solutions can drastically reduce the cost and difficulty of such interconnection. The Institute of Electrical and Electronics Engineers (IEEE), Underwriters Laboratory (UL), and the National Fire Protection Association (NFPA) all have published or are drafting standards that pertain to grid interconnection safety issues.[128]

The recently promulgated IEEE standard for interconnection (IEEE P1547) includes a provision that distributed resources must disconnect from the distribution system within two seconds after a distribution system power outage occurs, so as to avoid the formation of unintentional isolated energized "islands." One of the principal motivations for imposing this requirement is to ensure that linemen performing repair work on distribution feeders are not exposed to energized systems during outages. The ability of the micro-grid to disconnect from the utility is also important to protect against large fault currents.

Unfortunately, in its present form, this specification is not compatible with some of the key benefits that micro-grids can bring to provide improved security and reliability to distribution systems.[129] The IEEE plans to update the standard at some time in the future. If legislators or regulators choose to adopt the IEEE standard in its current form as the default standard governing interconnection, they should augment the emergency disconnection portion of the standard for cases in which the legacy utility has installed intelligent distributed control. In such cases, the standard should specify that when a fault occurs in the distribution system, and distributed resources such as micro-grids are not threatened by large fault currents, they should electronically query the distribution system to ask whether they should stay connected, in order to supply limited service to nearby customers or disconnect for safety or other reasons. The default option should be disconnection, especially if there is a risk of large fault currents.

Historically, many legacy utilities have sought to discourage the development of distributed generation technologies by "gold plating" interconnection standards, thus unnecessarily raising the costs of distributed resources. One approach that a legislature might use to mitigate this market barrier is to require that PUC/PSCs establish approved specifications and rates for interconnection under which the utility would be required to cover half the cost of the interconnection. This would provide both parties with an incentive to minimize costs, subject to the necessary constraints of safe and secure operation. Such an approach is reasonable because the micro-grid can provide benefits to the utility, and utilities routinely support the entire cost of transformers and other devices necessary to serve conventional customers.

Tariffs or interconnection standards for micro-grid systems should specify minimum power quality supplied by and to the micro-grid. IEEE P1547 requires that the interconnection system be both designed and tested to meet the power quality requirements. This standard only imposes requirements on the distributed supplier (e.g., micro-grid). In keeping with the arguments advanced above, we believe that any power quality requirements (and any associated penalties) in tariffs or interconnection standards should apply equally to both legacy utilities and micro-grid firms.

Consumer Protection Issues

While state contract and consumer protection laws should be adequate to cover competitive micro-grid firms, some states may wish to impose a set of additional requirements on such firms.

An example of such requirements is provided by Michigan's Customer Choice and Electricity Reliability Act of 2000 (Public Act 141).[130] Section 10a (2) of the Act requires:

> "The Public Service Commission of Michigan establish licensing procedures for all alternative electric suppliers. To ensure adequate service to customers in this state, the commission shall require that an alternative electric supplier maintain an office within Michigan, shall assure that an alternative electric supplier has the necessary financial, managerial, and technical capabilities, shall require that an alternative electric supplier maintain records which the commission considers necessary and shall ensure an alternative electric supplier's accessibility to the commission, to consumers and to electric utilities in this state."

In June 2000, the Michigan PSC specified in detail what such "licensing procedures" should entail.[131] Among the requirements, electric suppliers must demonstrate: the products and services it will provide, billing and customers dispute methods, a line of credit; a mechanism for collecting State fees and taxes, a method for meeting minimum electric quality standards, and a method for providing data (consumption, reliability, etc.) to customers and the State.

Some states might wish to impose specific insurance and liability standards on micro-grids. Some may also wish to impose requirements that micro-grid firms provide "escape clauses" in their contracts that would allow customers to return to service provided by the legacy distribution utility. However, some states may not view such a requirement as necessary, relying upon normal state commercial and contract law to handle such issues.

Environmental Considerations

Figure 16. A 30-kW microturbine provides heat and power for a municipal building in Durham, England. Photo courtesy of Capstone

Electricity generation by micro-grids may[132] impose environmental loading as a result of the burning of fossil fuels.[133] In a few cases, micro-grids may also impose externalities such as noise or objectionable aesthetics (wires, smoke, etc.).

In most cases, local zoning ordinances and state air pollution laws should be sufficient to address these issues. Since micro-grids will often displace boilers and other conventional heating equipment (particularly when used in CHP applications), it is reasonable to expect micro-grid generators to meet the same emissions requirements as conventional heating systems. For example, environmental permits are typically only required for natural gas combustion units with a heat output of more than 10 MBTU.[134] Using typical efficiencies of 30-40%, this translates into roughly 1 MW_e of power output. That means that small, clean-burning micro-grids would not require special permitting and would be treated like boilers or furnaces. Larger plants would be subject to standard state and federal air pollution requirements and permitting procedures.

Micro-grids that include CHP capabilities can provide considerable environmental benefits, because they result in greatly increased overall energy use efficiencies (through the use of "waste" heat and reduced transmission and distribution losses). In many cases, they will also burn cleaner fuel than central station plants. If a state decides to consider imposing additional environmental regulations on micro-grid generators, these possible benefits should be carefully considered, since in some cases, micro-grids that replace conventional systems may be able to improve air quality and public health.

PART 3: A Service-Centric Approach

Electric power outages affect customers several times annually, for periods of several hours. Longer outages affecting large areas are not uncommon. In the winter of 1998, Montreal was without power for two weeks and some of its suburbs were blacked out for six weeks. Examples of recent large and long blackouts and statistics of blackouts are given in the Introduction.

Continuing essential services in the face of a power failure is both possible and practical for certain public and private services. Ensuring the fulfillment of these "critical missions" is very different from either a traditional vulnerability assessment approach, or the approach of making the electric delivery system 100% reliable. Invulnerability is not only very expensive, it is also impossible to test and probably impossible to achieve for a complicated system.

The steps in defining and verifying solutions to the survivability of critical missions are as follows.

> The first step is to determine a set of design reference events, such as the geographical extent and duration of an outage. The system is evaluated on the basis of whether it is able to fulfill the critical missions during these design events.
>
> The second step is to define the missions which must be fulfilled (in power systems parlance, "ride through" the event). This step results in enumeration of life-critical and economically important missions that are provided by electric power, together with a list of missions which, if unfulfilled, have important socio-economic consequences (such as inducing terror).
>
> The third step is to prioritize the missions. The priority list will be different for different design reference events (a 12-hour outage from a cascading grid event will have different priorities than a month-long blackout from a severe ice storm or terrorist attack on system components).
>
> The fourth step is to determine which missions are already protected, e.g., hospitals and navigation aids for air traffic. Weak links in the chain are identified at this step. For example, while Newark and Kennedy airports quickly restored power for passenger screening and other boarding functions the day after the August 2003 blackout struck, LaGuardia could not; as a consequence, East Coast air traffic was snarled.
>
> The fifth step is to determine which missions require new hardware (such as light-emitting diode traffic signals with trickle-charge batteries or onboard energy storage systems which return elevators to the ground floor) or procedure changes.
>
> The sixth step focuses on the missions in step five that require new hardware. This step seeks cost-effective technologies which can fulfill the critical missions during the design reference events. Some missions will be attractive for private investment (for example, high-rise tenants may choose to locate in a building with higher rents if the building has its own micro-grid with backup power). For public goods, the costs of fulfilling the missions are compared at this stage with the value of the missions, and alternate methods of fulfilling the missions can be evaluated. Effects of the candidate solutions on the nominal and recovering grid are assessed and verified during this step, by building and testing prototypes where necessary. For example, loads must have smooth transfers from distributed power systems to and from the grid, without affecting grid stability (this may require hardware and operations changes, and will certainly require tariff changes[135]).

The seventh step is to build a system for allocating competing resources required for these missions during an extended blackout. This is often the first step considered by managers trained in emergency response, but will be much more effective if preceded by the above steps.

These steps provide an up to date assessment of the readiness of the system to respond to challenges. Knowing the available hardware and procedures, the governing authority can estimate which missions could be accomplished and where the greatest trouble spots are likely to be.

Some effects of power loss effect national capabilities, such as air travel or military readiness. Others are local or can be addressed with state incentives and preparedness.

3.1 Effects of Power Disruptions

The determination of whether a given service is critical depends upon the broader environmental context of a disruption. Specific reference events can be determined in the manner described in Section 3.3 below for Pittsburgh (Table 9 and discussion preceding it). Environmental context includes time of day and year, duration, and geographic scope of an outage. Consider the following examples:

Example 1: A supply disruption of an hour's duration in a city or neighborhood.

If such an outage occurs during the work day in a dense downtown area, the failure of traffic signals will slow traffic, increase the risk of traffic accidents, and decrease the ability of emergency services to respond to calls in that area. Traffic may be further disrupted by the failure of trains or other public transportation, bridge opening mechanisms, or tunnel ventilation systems. A disruption would have much less effect if it occurred at night or on a weekend when fewer people work or drive.

Depending on the performance of their backup systems, hospitals may see some disruption in power which could put critical patients at risk and decrease the level of care provided to other patients.

Businesses may close for the day, not knowing how long the outage will last. Large buildings without backup power may be evacuated, risking injuries to people descending dimly lit stairways, and putting large numbers of people on the sidewalks. People in the street and motorists stranded in traffic may be exposed to extreme hot or cold weather.

Telephone and cell phone use will spike as people call to check on friends and family, which may overwhelm those systems and make it difficult for people to call for emergency services. Since the supply disruption lasts only an hour these effects should dissipate quickly.

A power outage in an industrial area could be costly to businesses and present an increased risk of fire or accidental release of pollutants. For example, the largest single particulate release in modern Houston history was due to a power interruption of both feeder lines at the Exxon Bayport refinery causing all process equipment to transition to emergency vent modes.

In a residential or suburban area only the continued provision of emergency services, and some access to communication for emergency calls, would likely be considered critical. Traffic lights outages will not affect traffic as badly as in dense urban areas, but lack of street lights on rural roads may lead to accidents. Since the land-line telephone system is independently powered it will continue to operate (although newer handsets and cordless phones which require local power would not work). Cell phones will also continue to work, although the system may not be able to service the high call volume.

Example 2: A supply disruption of four day's duration in a city or neighborhood.

The initial disruptions to traffic, telephones, businesses, hospitals, and emergency services will occur in the same way for a long power outage as for a short power outage, and also depend on the time of day during which the outage began. If the power outage begins during a work day these initial disruptions, particularly traffic congestion, will persist. If the power outage occurs in the evening or at night the initial effects will be minimal, but there may be some risks posed by the undetected failure of services as people sleep. Heating or cooling systems in a house may fail, endangering the sick or elderly or risking damage to the building. In-home medical devices may also stop functioning.

On the first morning of the supply disruption the public will seek information on the extent and expected duration of the outage, school and business closings, and other emergency information, probably by listening to commercial radio stations on a battery operated or car radios. Use of land-line telephones will eventually return to a normal level after the initial surge. Cellular phones transmitters will have failed by dawn due to lack of power at the towers. There will be some loss of frozen and refrigerated foods, and greater inconvenience. A few people may begin to be at risk from improperly ventilated use of ad-hoc cooking arrangements and motor-generator sets.

As the outage persists vehicle traffic will be reduced as many businesses remain closed, but grocery stores, banks and other stores will see a surge in demand as people come to buy non-perishable food, batteries, and other supplies. The level of stockpiling or hoarding will depend on how long the public expects the outage to last and the severity of the weather.

It is possible that panic, lack of information or scarcity of supplies could lead to acts of crime or looting, or that criminals could try to take advantage of the power outage to rob or vandalize.

Over the four-day outage the city will see declining supplies of food, water and fuel. Enough food is normally stored in homes that a widespread food shortage is unlikely to occur in four days. However, disruptions in traffic, extreme weather, or the closing of grocery stores may leave some people or families hungry and cut off from their normal means of support.

Scattered loss of water service is possible over four days, depending on the city’s water system. A water shortage may force other businesses or services to shut down and may hinder fire fighting. In extremely hot weather a shortage of water may pose health risks. In suburban areas with groundwater wells, water will have to be trucked in and rationed.

A city’s sewage system may also fail over four days without electricity, depending on storage capacity and weather. This could lead to flooding, pollution, or contamination of the drinking water supply. Performance of the sewage system is highly dependent on rainfall.

Fuel, particularly gasoline and diesel, are needed to operate private and city owned vehicles and to power generators. Gasoline may not be available, since electricity is normally used to pump fuel out of storage facilities at both the wholesale and retail level. If fuel is available (either in or outside the region affected) people may try to stock up. There will be an increase in demand for delivered fuel as initial supplies of fuel stored at generator sites are depleted.

If this type of outage happens in very cold weather, many heating systems will not operate, even if natural gas supply is unaffected, because most furnaces also require electricity to operate igniters, fans or pumps. Home owners who are not aware of the problem, or do not know how to shut off and drain pipes, could experience serious water damage after frozen pipes burst.

If this same outage occurs in very hot weather people may be at risk of heat stroke and related medical complications unless arrangements existed for them to move to air conditioned shelter spaces. Loss of refrigerated and frozen food would be large.

Example 3: A supply disruption of four day's duration in an entire region.

Regional-scale disruptions will decrease cross-support of emergency assets, and will black out rural areas where service providers are geographically dispersed.

Many people and communities in rural areas receive water from pumped wells, and will lose water supply immediately. Propane deliveries may be interrupted if trucks do not have access to priority fuel, leading to heating and cooking issues for some homes.

Transportation between cities may depend on electricity at bridges, train crossings and junctions, but disruptions at these points will only force delays or detours. Communications between cities may depend on electricity, although landline telephones are expected to survive a four day disruption. Radio, microwave, optical, data, and satellite communications are vulnerable at transmitting, receiving, and relay points, although facilities at those points probably have some backup. Emergency Operations Centers are required to have backups for a number of hours, and have satellite communications.

Example 4: A supply disruption of two week's duration in an entire city.

During a two-week supply disruption a city will face the same problems as a four-day outage with added demand for food, water, and fuel. Widespread water shortages are likely, and emergency water distribution may be necessary even though stocks of clean water are sufficient at reduced levels of consumption. Fuel may need to be transported to the city by truck, as is often done under normal conditions to meet local demand. Normal shipments of food into the city will also be necessary. Residents with access to vehicle gasoline will attempt to travel out of the city after a few days to seek temporary shelter with relatives or elsewhere.

Example 5: A supply disruption of two week's duration in an entire region.

Emergency services in the affected area will see increased demand, and will be hampered by operations with incomplete electrical backups. Mutual assistance between local emergency services will be more difficult than under normal conditions and it may be necessary to bring equipment and personnel from outside of the region to help areas in particular distress or whose emergency services are insufficient. Communication is vital to this effort and supplying dispatch centers should be a top priority.

Hospitals can be expected to maintain emergency services for a number of days or longer, but some non-emergency services may not be as well provided. People in need of out-patient care, such as kidney dialysis or in home nursing may find it necessary or preferable to evacuate out of the affected region.

Normal water supply in the region will be disrupted if there are not sufficient backups at pumping stations. Conservation and rationing may allow some areas to rely only on stored water distributed normally or by truck, but other areas will require deliveries of water or fuel to run treatment and pumping facilities. Pipe interconnections may exist that allow neighboring regions to pump water between systems. Sewer systems may also fail without electricity, risking widespread contamination of surface water with health and environmental damage.

Broadcast media will exhaust their initial supply of fuel and require additional delivers in order to maintain communication with the public. Telephone services may also deplete their initial supply of fuel for backup generators.

Many people will decide to leave the region when they learn the outage will last a long time, when instructed to evacuate, or when they grow impatient, uncomfortable, or run out of supplies. This decision will depend on the information they receive and on the availability of vital services in the region. Refugees will travel by car to nearby cities or islands of service in the blackout region. This may cause traffic problems on major roads out of the region. Rail and barge transportation into the region may also be hindered by failure of crossings, switches, bridges, or locks. Transportation into the region is necessary to maintain supplies of food and fuel.

After finding some equilibrium of supply and demand for the most vital services the region will try to return to everyday life. Businesses and non-emergency government services that can find backup power or operate without it will reopen. Grocery stores will continue selling non-perishable food.

The example power outages outlined in this section provide a framework for determining which services are most critical during different outage scenarios. Figures 15 and 16 illustrate the integrated effects of outages, using data from the Pittsburgh study described in Section 3.3.

3.2 A Taxonomy of Critical Services

Which of the services provided by electric power fall in the category of critical social services? As illustrated in the previous section, the answer is sensitive to:

- the nature of the service
- who the service is provided to
- how many others depend upon the service
- how long the provision of service will be interrupted
- the broader social and environmental context when service is disrupted.

Table 8 lists the characteristics of emergency services, medical services, public utilities other than electricity, communications, non-emergency government services, transportation, lighting, food, financial services, and the fuel infrastructure.

Table 8. Taxonomy of Critical Services.

SERVICE CATEGORY	SPECIFIC SERVICE	TIME, DURATION AND SCOPE OF OUTAGE DURING WHICH SERVICE IS CRITICAL	TYPICAL EXISTING BACKUP	HEALTH & SAFETY RISKS	ECONOMIC RISKS
Emergency Services	911 and related dispatch centers	All outages	Most systems have comprehensive backup power systems.	Increased risk of injury and fatality. Inability to report and prioritize emergencies leading to potentially chaotic situation.	Indirect costs associated with increased chaos after an outage. Businesses and stores may delay re-opening.
	Police headquarters and station houses	All outages	Varies. Some stations do not have backup. AC power is often required for recharging hand-held radios.	Increased risk of injury and fatality. Inability to report and prioritize emergencies leading to potentially chaotic situation.	Indirect costs associated with increased chaos after an outage. Businesses and stores may delay re-opening.
	Fire protection services	All outages	Varies by location.	High risk of injury and fatality.	High risks to businesses and residences.
Medical Services	Ambulance and other medical transport services	All outages	Limited. Many require AC power for radio charging, rely on cell phones, and buy fuel at commercial gas stations.	Increased risk of injury and fatality.	Loss of life, loss of workforce.
	Life-critical in-hospital care (life support systems, operating rooms, etc.)	All outages	Full, but some failed on 8-14-03. Some systems have inadequate testing procedures.	High risk of fatality.	Loss of life, loss of workforce.
	Less-critical in-hospital services (refrigeration, heating and cooling, sanitation, etc.)	Medium and extended duration	Varies.	Increased risk of infection.	Indirect

SERVICE CATEGORY	SPECIFIC SERVICE	TIME, DURATION AND SCOPE OF OUTAGE DURING WHICH SERVICE IS CRITICAL	TYPICAL EXISTING BACKUP	HEALTH & SAFETY RISKS	ECONOMIC RISKS
Non-electric public utilities	Water treatment	Extended duration	Typically very limited.	Risk of illness if system pumps untreated water.	Incapacitation and workforce productivity.
	Drinking water	Extended duration; immediately in areas with wells	Limited gravity-fed areas. Some pumps have backup power.	Risk of dehydration and/or disease, especially during hot weather.	Incapacitation and workforce productivity.
	Sewer treatment	Medium and extended duration	None in most areas.	Risk of disease from untreated sewage in water supply.	Incapacitation and workforce productivity.
	Sewer pumping	Short duration, high use periods (morning, evening); Long duration	Very limited.	Risk of disease from sewage buildup in low elevation areas.	Incapacitation and workforce productivity. Damage to buildings in low-lying areas.
	Natural gas	All outages (some critical backup generation is fueled with natural gas)	Most pipelines use product for pumps. In-home furnaces require power for pilot lights and fans.	Significant health risks for customers using gas heat during cold weather.	Pipes may burst in cold weather if homes/buildings are left without heat.
Commun-ications	Radio broadcast media	Medium and extended duration	Most stations have backup systems with several days of fuel on hand.	Radio is important for distributing emergency information. Risk of chaos if stations fail to disseminate information.	Increased chaos costs from decreased communications.
	Television broadcast media	Medium and extended duration	Many stations have backup power systems with several days of fuel.	Less vital than radio communications as most TV sets require electricity.	Most risk is born by broadcasters and advertisers.
	Cable television and broadband services	Medium and extended duration	Not determined for this study.	Less vital than radio communications as most TV sets require electricity.	Risk for businesses that rely on cable broadband services.
	Wired telephone systems	All outages	Most systems have good backup power systems.	High risk as many vital services rely on the wired telephone system.	Very high economic costs. Communications are vital to every sector in an emergency.

SERVICE CATEGORY	SPECIFIC SERVICE	TIME, DURATION AND SCOPE OF OUTAGE DURING WHICH SERVICE IS CRITICAL	TYPICAL EXISTING BACKUP	HEALTH & SAFETY RISKS	ECONOMIC RISKS
	Wired data service	All outages	Not determined for this study.	Minimal.	Significant as many business functions require broadband connectivity.
	Wireless (cellular) telephone and data systems	All outages	Minimal. Battery backup provides only 2-8 hours of service.	Possible risk to those unable to make emergency calls	Significant risks to customers who rely on cellular phones.
	Computer services (on and off premise)	All outages	Data centers typically have good backups with several days of fuel on hand and priority fuel contracts. On-site typically limited to several minutes.	Loss of data.	Minimal if computers use commercially available automatic shutdown software based on state of discharge of uninterruptible power supply. Significant for unprotected businesses.
Non-emergency government services	Information service offices	Medium and extended duration	Varies with location and type of building.	Important for distributing emergency information. Risk of chaos if information not available.	Increased chaos costs from decreased accurate information.
	Prisons and other detention facilities	All outages	Not determined for this study.	Potential risks to prisoners, guards, and public if security systems fail.	Indirect risks from increased chaos.

SERVICE CATEGORY	SPECIFIC SERVICE	TIME, DURATION AND SCOPE OF OUTAGE DURING WHICH SERVICE IS CRITICAL	TYPICAL EXISTING BACKUP	HEALTH & SAFETY RISKS	ECONOMIC RISKS
Transport and mobility	Building elevators	All outages.	Varies with local building codes, height and age of building.	Decreased mobility for elderly and disabled.	Indirect, from lost time.
	Traffic signals	All outages, particularly in urban areas	Traffic police.	Risk of injury and fatality. Increased fatality risk due to emergency vehicle delays	Large social costs associated with traffic delays.
	Tunnels	All outages	Generally none for ventilation. Lighting has limited backup.	Accident risk if lighting fails.	High social cost resulting from traffic delays.
	Light rail systems and subways	All outages, evacuation immediately after event	None aside from emergency lighting.	Some risk to elderly or disabled if adequate evacuation plans are not in place. High heath risks if ventilation is inadequate.	High social costs from workforce delays in urban areas.
	Conventional rail systems including railroad crossings	Extended duration	Crossings have backup batteries	Some additional accident risk at busy intersections.	Loss of life at rail crossings.
	Air traffic control, navigation, and landing aids	All outages, immediately after event	FAA requires that backup power systems be in place.	Some risk of airplane accidents that would result in a large number of fatalities.	High social costs resulting from air traffic delays, and in airport delays.
	Airport operations including security and on-airport transportation and food	All outages, immediately after event	Partial backup power is typical.	Some heath risks during extreme weather conditions.	High social costs resulting from air traffic delays, and in airport delays.
	River lock and dam operations	Extended duration	Not determined for this study.	Minimal unless there is a diesel fuel shortage, and river transport is required.	Significant costs if there is a diesel shortage. Lost trade.
	Buses	Medium and extended duration	Not determined for this study.	Minimal	Significant social costs because most people will not have access to gasoline for personal vehicles.
	Drawbridge operations		Not determined for this study.	Minimal unless there is a diesel fuel shortage, and river transport is required in affected areas.	Significant costs if there is a diesel shortage. Lost trade.

SERVICE CATEGORY	SPECIFIC SERVICE	TIME, DURATION AND SCOPE OF OUTAGE DURING WHICH SERVICE IS CRITICAL	TYPICAL EXISTING BACKUP	HEALTH & SAFETY RISKS	ECONOMIC RISKS
Lighting	Building evacuation and stairwell lighting	All outages	Required by building codes	High risk of injury and fatality without emergency lighting, especially in densely populated locations.	Injury and workforce incapacitation.
	Residential lighting	All outages	Flashlights and lanterns	Some risk of injury in stairwells. Risks due to makeshift lighting.	Loss of life from fires due to candles.
	Indoor commercial and industrial lighting	All outages	Varies	Varies	Varies. Risks are primarily concentrated.
	Security lighting	All outages	Varies	Varies by location.	Potential for high economic losses. Risks are primarily concentrated.
	Street lighting	All outages	None typically	Increased accident risk when roads are unlit.	Indirect
Retail grocery	Cash registers, lighting, refrigeration, security	Medium and extended duration	Varies with location and firm preferences.	Risk of food and emergency supply shortage during an extended outage.	Large social costs resulting from insufficient access to food and supplies.
	Wholesale grocery distribution networks	Medium and extended duration	Not determined for this study.	Risk of food and emergency supply shortage during an extended outage.	Large social costs resulting from insufficient access to food and supplies.
Financial	Cash machines	Medium and extended duration	None typically	Minimal	Significant social costs resulting from inadequate access to cash.
	Bank branches	Medium and extended duration	Only for security systems.	Minimal	Minimal if some other access to cash exists.

SERVICE CATEGORY	SPECIFIC SERVICE	TIME, DURATION AND SCOPE OF OUTAGE DURING WHICH SERVICE IS CRITICAL	TYPICAL EXISTING BACKUP	HEALTH & SAFETY RISKS	ECONOMIC RISKS
Financial	Credit card systems	Extended duration	Some backup power typically	Minimal	High during an extended outage where there may be a shortage of cash.
Fuel infrastructure	Pipeline and pumping systems	Medium and extended duration	Full for natural gas, typically none for other products.	Indirect risks for vital services if fuel pumps fail to supply required fuel.	High risks to services that rely on diesel fuel to backup important systems.
	Local storage infrastructure	All outages	Varies. Many locations must switch from pump to gravity feed.	Indirect risks for vital services if fuel cannot be distributed.	High risks to services that rely on diesel fuel to backup important systems.
	Non-pipeline transport and distribution systems	All outages	Backup not required as long as truck fuel is available	Indirect risks for vital services if fuel cannot be distributed.	High risks to services that rely on diesel fuel to backup important systems or propane for heating and cooking.
	Retail gasoline sales	Medium and extended duration	None	Significant risk if emergency services cannot obtain gasoline for vehicles.	High social costs associated with lack of mobility if gasoline is unavailable.

3.3 Case Study: Sustaining Pittsburgh's Vital Services when the Power Goes Out

In order to develop specific data on sustaining services when the electric grid fails, the Carnegie Mellon Electricity Industry Center assigned the students in an engineering project course[136] run jointly by the Carnegie Mellon University Department of Engineering and Public Policy, The H. John Heinz III School of Public Policy and Management, and the Department of Social and Decision Sciences during the spring 2004 semester the task of assessing options for sustaining Pittsburgh's vital services when grid power is not available.

The team of twenty undergraduates, two Ph.D. students, and four course faculty[137] was assisted by a review panel with members from Duquesne Light Company, Allegheny Energy, the Pittsburgh Emergency Management Agency, Pittsburgh Department of City Planning, Pittsburgh Police, Dominion Peoples Gas, Pittsburgh Water and Sewer Authority, Pittsburgh International Airport, and the University of Pittsburgh Medical Center. Additional information was provided by PNC, Citizens Bank, Chevron, Guttman Oil, the Allegheny County Airport Authority, and the Allegheny County Sanitary Authority.

Since some of the data when compiled could potentially be misused, the following summary has been approved for public distribution.

Summary: Pittsburgh Study

Potentially critical services were classified into the following categories: Emergency Services, Private Services, Utilities, and Ground and Air Transportation. Three reference blackout events were determined for which the robustness of each service was evaluated. The reference events were designed to vary in duration and size of the affected area. The diesel fuel supply available in Pittsburgh and the interactions between the services under different blackout scenarios was assessed.

While some important services, such as hospitals and 911 emergency response, have taken measures to ensure that service will continue during a blackout, there are several vital services, such as police zone stations and traffic control, that are highly sensitive to electricity outages.

Overview of Project Findings

1. Three of the five Pittsburgh police zone stations houses do not have backup generation installed on site.
2. Important private services such as grocery stores, gas stations and cellular phone service are vulnerable. Although the social benefits from keeping these services running during an outage are large, these benefits are dispersed among individuals, whereas the capital costs are concentrated in the hands of the service provider. There is little incentive for the private service providers to change.
3. Traffic networks are vulnerable, as all traffic lights fail during a blackout. Tunnel ventilation fans also become inoperable. Installing LED lights with backup batteries would reduce congestion in the event of a blackout, and save the city in terms of annual electricity and maintenance costs. Backups for fans in heavily-used tunnels have a good benefit/cost ratio.
4. Liquid fuel pipelines and storage tanks rely on electricity to pump fuel and generally have no backup. Some fuel can be released from storage tanks via gravity flow, but the switchover from pump to gravity flow can be time consuming.

5. An outage during extreme hot or cold weather could have significant health and economic impacts. If the outage occurs during very cold weather, forced air heaters and auto-pilot boilers will fail; during hot weather, air conditioners will fail. In either event, some people may be at risk and it is important to ensure that emergency shelters are available and that information regarding such emergency services is disseminated through an effective information campaign. In addition to these health effects, an extended outage during the winter could cause pipes in homes to freeze, putting even more stress on emergency management personnel. While some plans do exist for handling such emergencies, it is important that such plans be regularly reviewed and updated to ensure that the region is well prepared for an extended power outage.
6. The natural gas system is highly reliable; possibly more so than the diesel supply chain. Although natural gas generators are typically more expensive than diesel, natural gas powered backup might be an option worth considering for high value services, especially if the generators are used to produce electricity and heat during normal operating conditions.

Reference Events

The study defined three reference events based on the spatial extent, temporal duration, and likely causes of a blackout scenario in order to accurately study the benefits of the policy options proposed in this report. The project used data on outage frequency and duration from Allegheny Power Company to determine the likelihood and the extent of a relatively low-impact outage, the first reference event.

The extent and duration of the second reference event, as well its frequency in Pittsburgh, was estimated using the data on "major disturbances and unusual occurrences" collected by the US Department of Energy's Energy Information Agency (EIA).

For completeness in analysis, the third reference event was chosen such that it would affect all of southwestern Pennsylvania (about 4 million people) for two weeks. This would be appropriate to a severe weather event or planned attack, affecting a large area with delays in power restoration. It is extremely difficult to estimate the future likelihood of such a large-area, long-duration event. One can roughly estimate this frequency to be of the order once in 50 years based on the historic frequency of major events in the North East such as the 1965 blackout that affected New York and parts of Canada and New England, the 1977 New York blackout, the Quebec Ice storm in 1998, and the 2003 blackout that affected New York, parts of eastern US and Canada. Since the frequency of such events is hard to determine, this probability will be treated as a parameter for several of the analyses in this report. For a given policy, a calculation can be made of a "probability threshold for cost-effectiveness" that represents the probability required to make the benefits of the policy exceed its costs.

Table 9. Design Reference Event Definitions.

	Temporal Duration	**Spatial Extent**	**Reference frequency**	**Likely causes**
Ref. Event 1	4 hours	1 circuit (about 1,000 people)	1 in 22 months	Load shedding, weather
Ref. Event 2	2.5 days	400,000 people	1 in 6 years	Weather, disruption of transmission or generation
Ref. Event 3	2 weeks	All of south-western PA	1 in 50-100 years	Weather, terrorism

Assumptions and methodology of the cost benefit analyses of services

Benefit-cost analysis was used to evaluate policy options. Most costs were for backup power for a particular service.

The majority of the benefit from installing backup power comes from the avoided social costs incurred during a reference event. These costs are function of expected time losses, fatalities, and healthcare service delays resulting from a particular reference event. The Pittsburgh average hourly wage of $16 per hour was used to determine the social cost of time lost. The Value of a Statistical Life used in this analysis was $2 million. In order to find the net benefit of a policy, capital, operation and maintenance costs are subtracted from the social benefit. For calculations related to reference event 3, the annualized cost and annualized net benefit are used to calculate the break even probability at which the expected benefit from avoiding the social cost in case of a blackout outweighs the cost of the backup:

Break Even Probability = Annualized cost of generator / benefit for specific reference event.

If the Break Even Probability is significantly less than the estimated probability of the corresponding reference event the backup option is a good investment.

Emergency Services

Emergency Services for the City of Pittsburgh are comprised of hospital systems, police and fire, and 911 emergency call centers. These operations are critical to the health and safety of the people of Pittsburgh. Most of these facilities have carefully considered operations during a power outage, and have plans and equipment in place to sustain service during a blackout.

Hospitals

UPMC is the largest health care system in Western Pennsylvania. The main UPMC facilities currently have enough backup power generation capacity to remain operational indefinitely during a power outage. UPMC has a secure fuel contract to ensure that its generators can run when needed. Generators are tested monthly, on loads, to ensure proper functionality, and the entire system is tested every six months. The backup systems at UPMC consist of diesel generators with battery ride through. This configuration can operate for several days before refueling. There are separate backup systems associated with each critical center at UPMC.

During the Northeast blackout of August 2003, a hospital in Cleveland, Ohio lost power, even though it had backup generators installed. As a result of this incident, UPMC officials are developing a plan of action for updating UPMC's backup power subsystem.

Police

The police department separates Pittsburgh into five zone areas, each of which has a station house. Currently, only two of the five zone stations have backup power systems in place. One is backed up by a 12.5 kW natural gas generator; the other by a 20 kW natural gas generator.

All necessary functions within these two stations, including lighting, radio chargers, computer systems, and telephony, can be operated on backup power. Batteries for police radios can be charged by the generators. Handheld radios in service with the Pittsburgh police department do not charge in vehicles. They must be plugged into an AC outlet.

In the event of a blackout, only the two stations that currently have backup systems in place can remain fully operational. Access to the National Crime Information Center (NCIC) is possible through radio, and as such this service is not affected by power outages if radios are operational. The police department is confident of their ability to remain functional, but a full test with only two of the five stations operational has not been performed.

Based on our analysis of the generator system, we recommend that the city install backup generation at the three remaining zone stations. The region covered by the Pittsburgh police department is large. It is essential that police functions remain fully operational during an emergency situation such as a wide-spread blackout.

Emergency Operations Center (911)

The Emergency Operations Center provides the means by which the police and fire fighters are alerted to potential risks. The Emergency Operations Center has a backup diesel generator and an Uninterruptible Power Supply (UPS) System. The UPS supplies the center with power immediately after a power disruption while the generator starts. This system is operated once a month on full load. In the event of an outage, the Emergency Operations Center will be able to function 24 hours a day for seven days before requiring additional diesel fuel.

Public Utilities

The survivability and electrical dependence of public utilities in the city of Pittsburgh was studied, specifically focusing on drinking water systems, sewage systems, landline telecommunications, natural gas services, and garbage collection.

Water

Most of the electricity required at the Pittsburgh Water and Sewer Authority's Aspinwall Water Treatment Plant is consumed pumping water from the river. From the treatment plant, water is pumped to the three primary reservoirs. About half of the water from the primary reservoirs is delivered directly to homes and businesses. The other half is pumped to a series of smaller reservoirs, tanks, towers, and standpipes around the city. The main reservoirs are referred to here as "primary storage" and the smaller storage facilities as "secondary storage."

Secondary storage facilities are normally kept full, but may drop to 80% capacity in the evenings. Electricity is needed only to pump water into storage facilities when they fall below a set level. Once water is stored at a high point in a reservoir or a tower it can flow by gravity to any customer located below it.

Immediately following a blackout water supplies will be unaffected. In the absence of any backup generation, after one day of power outage, 15% of customers can expect to lose water as secondary storage is depleted. All secondary storage is likely to be depleted after three days, leaving 50% of the Pittsburgh population without water, increasing the load on primary storage and depleting the first of the primary storage reservoirs within about nine days. The remaining water storage will be depleted after two weeks.

It may be desirable to backup only secondary pumping, which can ensure full water supply for 7 days everywhere in the city assuming conservation measures can cut consumption by 75%. Secondary pumping would require 7.2 MW, 12,800 gallons per day of diesel and $2.57 million in generator and installation costs.

Current emergency plans include distribution of water by tanker trucks (called water buffalos). Emergency response plans at the city and county level include steps to acquire these trucks from local governments and agencies. With a typical capacity of 2,500 gallons, these trucks would be practical for providing only minimal supplies of water. To provide all 370,000 people in Pittsburgh with an emergency one gallon ration of water per day would require 15 trucks working 18 hour days. To provide 10% of normal drinking water supply would require 240 trucks.

Based on standard fuel consumption and price assumptions for this project, running the treatment plant and Ross Pumping station at normal levels on diesel generator backup would cost about $7,200 per day, with estimated installed generator capital costs of about $1 million.

Sewage Systems

ALCOSAN is the sewage treatment plant for the City of Pittsburgh and 82 surrounding municipalities, serving 896,500 people in Allegheny County and parts of communities in Washington and Westmoreland Counties. Sewage from residential and commercial buildings flows by gravity through municipal owned pipes to larger pipes owned by the Pittsburgh Sewage and Water Authority, and thence into interceptors. The interceptor sewers carry sewage and storm water to the treatment plant where it is pumped into treatment facilities. The treated water is discharged into the Ohio River. The bio-solids resulting from treatment are combusted in an energy recovery facility.

ALCOSAN's average electrical load is 10 MW. There are four on-site generating systems with total energy output of 2.7 MW servicing a portion of overall plant electricity requirements.

There are five main pump stations to assist in the delivery of wastewater to the treatment plant. Four are on the Allegheny River and one is on the Ohio River. The stations along the Allegheny River are backed up by diesel generator units, while the pump on the Ohio River is not backed up, so it will not operate during an outage, and sewage will be discharged into the river.

Options studied included expanding the backup of the sewer treatment plant and of the Corliss pump station on the Ohio River. The backup at ALCOSAN would enable the utilization of the sludge cake incinerator, reducing sewage discharge during a power outage. The capital costs of such expansion are high. One of the benefits from such backup is expected to be improved human health from reduced sewage discharge. National studies show medical cost associated with the exposure to the sewage-contaminated environment are $4.1 billion per year. It is possible that the benefits of reduced discharge would outweigh the cost of the proposed backup; detailed analysis is required.

Telecommunications

Communication is a key service that needs to be provided during an emergency situation. It is important to keep land-line communications up and running during a blackout, because many emergency services, including 911 and the hospitals, rely largely on fixed-line telephones for communications.

Normal land-line telephones are powered at 48 volts, via multiple-redundant backup power systems at the Central Office. Most phones will continue to operate in a power-failure, although hand sets with newer features that require local power will not operate. The Oakland Verizon Central Office is connected to at least two electricity substations. All equipment in the office is powered by DC batteries located in the Central Office. These batteries are continually charged with utility power, so there is no switch-over time or interruptions when the power goes out. The batteries are powered simultaneously by both substations so if one link goes out, the other takes over.

The Central Office has at least 8 hours of battery power. A Central Office is required by Verizon to have at least one backup generator on site. The Oakland Verizon office has two 2.5 MW generators. On a weekly basis, the Central Office tests the backup system by cutting the utility power and running the generators.

Due to the backup systems in place, the land-line phone system in affected areas survived the 29-hour large-scale Northeast blackout during August 2003. Land-line telecommunications are generally sufficiently prepared for a power outage of moderate duration.

Natural Gas

Natural gas comprises over 90% of the fuel source used in industrial, commercial, and residential heating in the Pittsburgh metropolitan area. Its survivability during a power outage is critical, especially during the colder winter months. The city of Pittsburgh relies on three major natural gas suppliers for its fuel needs: Equitable, Dominion Peoples, and Columbia. The natural gas is shipped through the pipeline system primarily by fluid flow, with pumps powered by natural gas.

The gas infrastructure relies on electricity to power a few pumps and the monitoring equipment at stations. These monitoring stations have natural gas generators on-site. Preliminary analysis indicates that the natural gas system is well-prepared to deal with any of the reference outages.

Garbage Collection

The City of Pittsburgh uses private contractors to collect garbage from its municipalities, and delivers this refuse to four landfill locations. These landfills are situated to the east, west, and south of the city limits, and are located in the cities of Library, Imperial, Monroeville, and Elizabeth, Pennsylvania. The garbage itself is collected via truck, powered by diesel fuel, and shipped directly to one of these locations. This service may be indirectly affected by a power loss due to the potential shortage of diesel fuel over the course of a long term blackout; however lack of garbage collection for 2 weeks is unlikely to have large social consequences.

Ground Transportation

The ground transportation system in Pittsburgh depends on traffic lights, public transportation, gas stations, tunnels, river barge travel, and rail transport.

Traffic Lights

Traffic lights facilitate the (relatively) efficient movement of vehicles throughout the city. In the event of a power outage, all of the traffic lights in Pittsburgh would go dark, causing significant delays for motorists and emergency vehicles. In addition, police officers would have to direct traffic at some intersections, diverting a much-needed resource in a time of need.

Intersection delay times would be maximal during a late afternoon outage, and lowest during a late evening blackout.

Benefit-cost analysis was performed for backing up traffic lights on the Forbes and Fifth Avenues corridor from Squirrel Hill to the hospital district and thence to the Downtown area assuming that the outage occurs during a high-traffic period. This analysis accounted for replacement of incandescent traffic lights with LEDs, and installation of Uninterruptible Power Sources (UPS) to power the lights during an outage. Standard UPS backup systems can power traffic lights for approximately eight hours at a cost of approximately $5000 per intersection. More expensive photovoltaic systems can extend this time.

Considering the cost of delay to emergency vehicles and commuters, and the electricity and maintenance savings with LED lights, the benefits of installing LED traffic signals with battery backup systems significantly outweigh the costs. The very large costs associated with first responders becoming snarled in traffic when attempting to reach the scene of an attack were not quantified, but will make adoption of backups in critical corridors even more attractive.

Public Transportation

Since many will not have access to gasoline to fuel private vehicles during a blackout, buses are critical infrastructure in the city of Pittsburgh. The main electricity dependence of this service is on diesel pumping. To operate at full capacity, the buses require approximately 9,400 gallons of diesel every day. In the event of an outage, demand for bus service will initially drop, as people stay home from work or school. As outage persists, the demand will rise again as people begin to need supplies (groceries, pharmaceuticals, etc.).

Citing security reasons, the Port Authority of Allegheny County declined to share information on the extent to which their fuel supply is dependent on electricity, and the amount of electric backup or fuel storage at Port Authority depots. They also declined to provide information on whether they have diesel fuel contracts guaranteeing supply in the event of emergencies. From other sources, it appears as if such contracts are not in place. A number of buses operate on natural gas, and should be less dependent on electricity; the Port Authority chose not to share information on the number of routes they could maintain in this manner.

Tunnels

When the electricity fails, lights in the tunnel go out, as do traffic signals just outside the tunnels. Large ventilation fans that prevent carbon monoxide build-up do not function. The movement of cars through the tunnel normally provides limited ventilation for the tunnel, but if traffic slows, and the fans are not working, traffic personnel prevent traffic from traveling through the tunnel. The loss of lights (outside and inside tunnels) will cause traffic to slow within the tunnel, decreasing traffic-assisted ventilation. Hand held carbon monoxide detectors are used to monitor CO buildup; power for these detectors may be vulnerable in a long power outage.

Considering the value of lost time sitting in traffic, and assuming that the loss of tunnel lights would cause delays of approximately 30 minutes/commuter, the benefits of backup generation for the tunnel ventilation systems generally outweigh the costs. This analysis does not include the value of cost of a delay to emergency vehicles traveling into or out of the city. There are alternate routes emergency vehicles can follow, although these routes are considerably longer than traveling through the tunnels, and they may become trapped in tunnel traffic.

Gas Stations

Gas stations become more important to emergency vehicles and residents as a blackout endures. Initially, most vehicles can rely on the gas already in the tank. But over time, demand for gas will grow, as people will want to leave their homes to procure needed items, or to just "get out."

There is little incentive for gas station operators to install generators. The probability of a long outage in Pittsburgh is sufficiently low that the owner will likely not recover the cost of a backup generator over its lifetime. It may be feasible to designate a few fueling stations around Pittsburgh as "emergency" gas stations and provide incentives to install backup generators. Alternatively, some stations may be able to recoup the cost of a generator through customer loyalty programs which guarantee priority service during blackouts.

Pittsburgh International Airport

Pittsburgh International Airport serves nearly 12 million travelers per year. The major services that do not receive power in the case of a major power outage are:

- People Mover (Tram)
- Jet-ways
- Automated Baggage Equipment
- The Air Mall
- Car Rental Areas
- Baggage X-Ray machines (in some circumstances).

All other services will receive power from two 1.1 MW diesel generators. The airport can function without the services listed above, but delays will occur, estimated at two hours per flight. These delays result from the increased turnaround time for each flight, due to reduced mobility. Passengers would have to take a bus instead of the tram between the air-side terminal and the land-side building, and would have to walk to the tarmac to board planes via stairs (since the jet-ways would not function). Also, bags which normally travel on automatic conveyors would be put on trucks or carts, and check-in time may be greatly increased due to the baggage X-Ray machines being down.

Analysis indicates that it would be cost-effective for the airport to install a third back-up generator, especially since there is already a space for one on an existing pad which was planned and provisioned at the time the airport was constructed.

Private Services

Many socially important services are provided by the private sector. Normally, decisions regarding electricity outage survivability are made using profit/loss as the decision criterion, rather than overall social benefit. Intervention from public institutions may be required if a private service is socially valuable during a blackout, but is not backed up by private service providers. This section will discuss several important private services, and discuss measures to make these missions more survivable.

Grocery Stores

Giant Eagle is the dominant firm in the Pittsburgh grocery market, with 12 stores within the city limits. Most have generators to power critical equipment such as emergency lights, but do not have backup capacity for refrigeration equipment. Pittsburgh has relatively reliable power, and Giant Eagle has decided that large backup is not economically attractive or necessary. On the other hand, Giant Eagle stores in the Cleveland area typically have complete backup capacity, since power there is less reliable.

During an extended blackout (reference event 2 or 3), the benefit to consumers of keeping grocery stores open is estimated to be of the order of $1.4 million per day. This estimate is based on the valuation of consumers' willingness to pay for food they otherwise may not be able to purchase during the blackout. This implies that a blackout of two weeks duration would have to occur at least as frequently as once in 80 years in order for the public benefit to outweigh the cost.

Banking

For security reasons, banks do not provide backup to keep individual branches operating during a blackout. The rationale is such that, for example, if the outage occurred in the winter, the bank would be at risk if people started using the bank as a shelter from the cold. Both PNC and Citizens report extensive backup capacity at their data and operations centers.

During the two shorter reference events, people can travel to other parts of the city to bank. During the third reference event, their access to cash may be limited. All Giant Eagle stores have ATMs in-store. Thus, if the grocery stores were kept running, people would have access to cash via ATMs.

Elevators

Elevators may be considered a critical service, depending on whom or what they are transporting. In hospitals elevators are necessary. In retirement homes, where residents may have limited ability to climb stairs, elevators perform a vital service. The building codes in Pittsburgh stipulate that such buildings must have backup for elevators. Buildings over seven stories high constructed in the past few years must provide standby power for elevators. For buildings fewer than seven stories, the decision about whether or not to provide backup is left to the owner of the building. The cost of installing a small generator to power an elevator is approximately $160 per month. For a five floor apartment building with six apartments per floor, a monthly rent increase of $5 would be required to pay for the backup.

Wireless Telecommunications

Unlike land-based phone lines, wireless communications are susceptible to failure in the event of a power outage. During the August 14, 2003 blackout, many people were unable to use their cell phones immediately after the blackout, due to the over-congestion of the wireless network. About 6 hours after the blackout began, the battery backups for the cell phone tower-mounted stations became depleted and the wireless network started breaking down. Of special concern are those calls made by emergency personnel such as police officers, fire-fighters and medical professionals. Since an increasing number of people rely on cell phones as their primary means of communications, wireless communications is a service whose criticality is increasing.

A survey of 30 students at Carnegie Mellon University found that they would be willing to pay, on average $6.00 per minute of calling if the city had been blacked out for four days. If cell stations are to survive an outage longer than six hours, backup generators are required. In a city, many generators would be required to back up cell phone service. This would involve both high capital and maintenance costs. However, the willingness to pay six dollars for a minute of emergency service suggests that cell operators might be able to recover cost through charges levied when a cell station is being powered by the generator. This small survey was meant to act only as a preliminary indicator, and the conclusion should be verified with a large sample size.

There is a possible synergy between elevator backup and cellular station backup. Cell stations are often installed on tall buildings; these buildings often have elevators. If building owners installed generators with a small amount of excess capacity – enough to power a cell station – they may be able to lease part of the generator to a cell phone operator.

Many users' cell phones will discharge after about two days (although solar charges are available and methane fuel cells will be available to power cell phones by the end of the decade). The issue of cell phone survivability can benefit from more in-depth study. How much benefit would consumers get from having the network function for two days instead of four hours after an outage? Perhaps even more importantly, what is the value of calls made by emergency personnel (who may have the means to recharge cell phones) during power outages?

Fuel Supply

Survivability of many critical missions in Pittsburgh depends on a reliable source of diesel fuel.

Many services have enough fuel on-site to endure an outage of a few hours' duration. Demand for diesel will increase during the second and third reference events. Most services have less than a two day supply of fuel on-hand. Only the land-line telephone service could survive a two week outage without refueling.

Pittsburgh is a fuel hub; large amounts of fuel are stored in and near the city and distributed by truck and barge. The diesel and gasoline pipeline system feeding the area is dependant on electricity, but barges can supply fuel when the rivers are free of ice. There are enough trucks to supply fuel to all the critical services outlined in this report. However, the pumps that pump fuel from the large storage tanks are vulnerable to electricity outages.

Interactions

In order to understand the impact to an individual service of a localized power outage, it is sufficient to study that service in isolation. During a sustained blackout, interactions between services become important. A coordinated communication system will be essential to the survivability of Pittsburgh services. For example, since weather-related blackouts are more likely during extreme weather and most heating and all cooling requires electricity to operate, there will likely be a high demand for climate controlled emergency shelters during a blackout. Both coordinating and communicating such emergency services will require an intensive effort by public sector employees such as police officers and emergency personnel during a blackout.

The effect of system interactions is critically dependent on the time of day the power outage begins. Figure 17 shows a top-level analysis of interactions for a widespread long-duration outage (design reference event 3) for Pittsburgh beginning during a work day, while Figure 18 is for a similar outage beginning late at night.

Figure 17. Widespread power outage beginning during a work day.

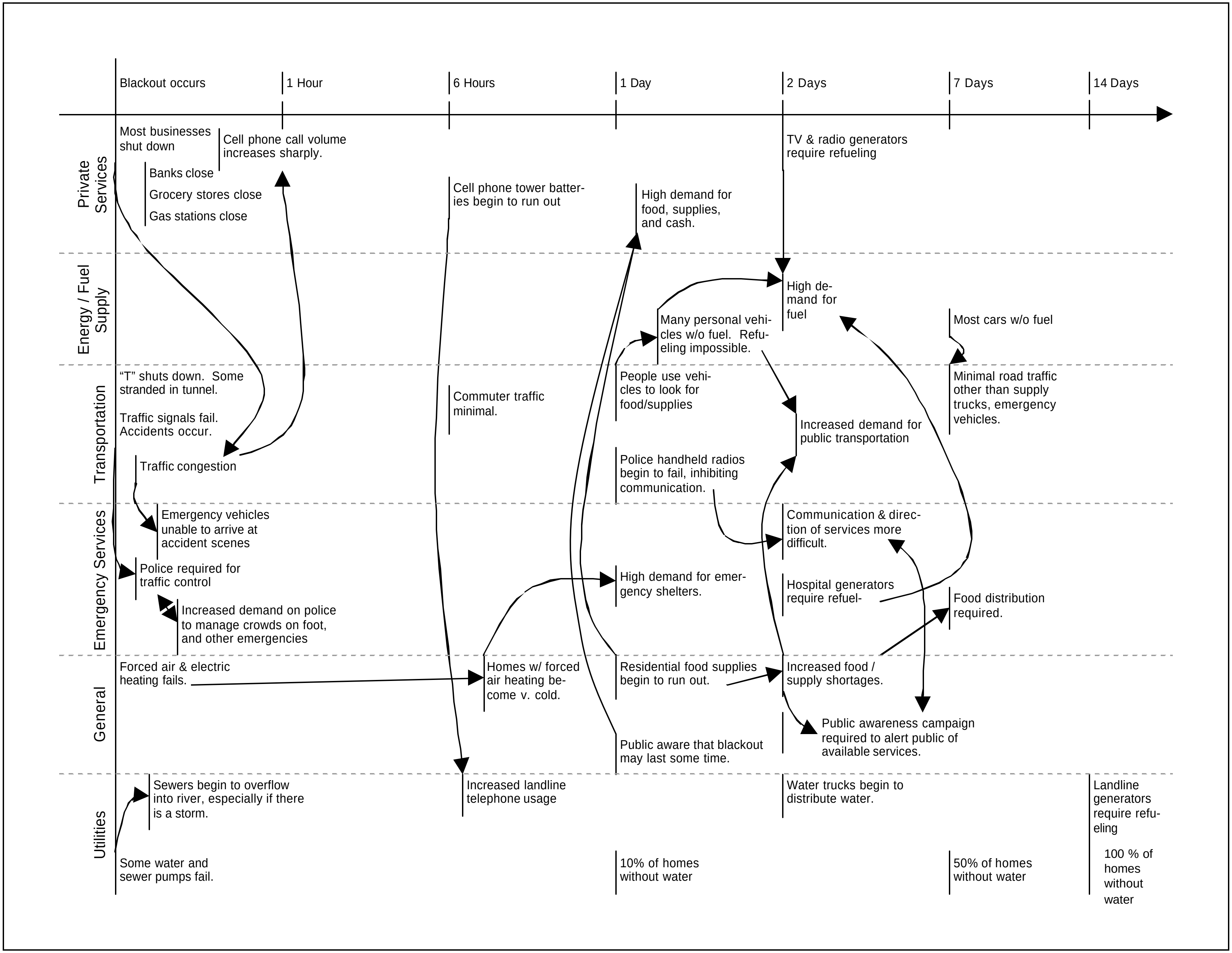
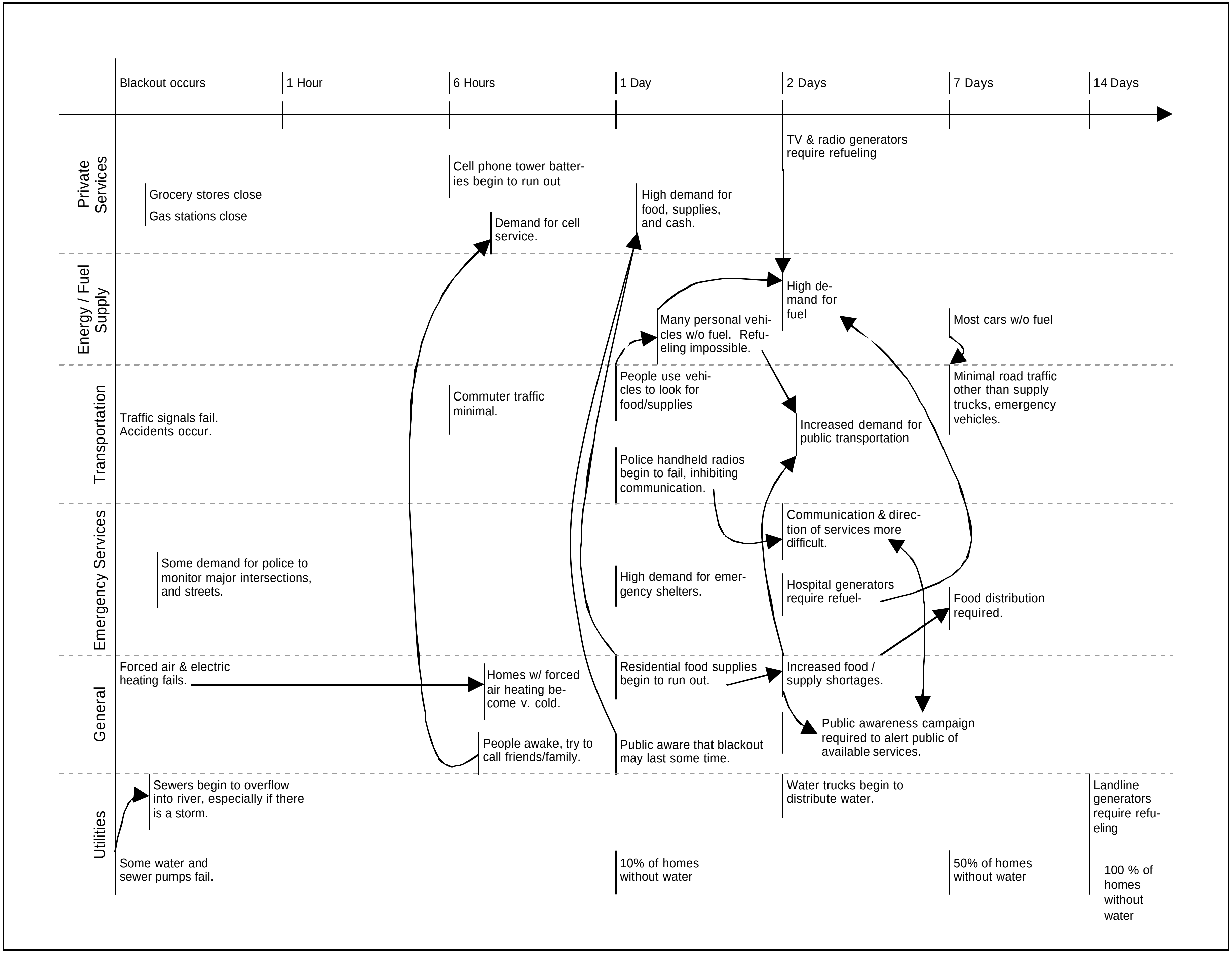


Figure 18. Widespread power outage beginning late at night.



3.4 Initial Surveys of Critical Services in Pennsylvania

In order to get a preliminary idea of whether the Pittsburgh results on the survivability of services extend to other regions in Pennsylvania, we sampled two groups: county Emergency Management Agency (EMA) coordinators, and hospitals. Neither survey was extensive, and we do not mean to imply that the results are definitive; formal extensive surveys are required. A survey was sent to EMA coordinators for counties containing the 12 largest cities in the Commonwealth. EMA coordinators were asked about the electrical backups for 911 service, police and fire dispatch centers, drinking water supply, and sewage system in the city in their region. They were asked to list the fuel supply and testing frequency of these backups.

Responses indicate that the county EMAs do not have the depth of information required to assess survivability of critical services in the Commonwealth. Several county EMAs indicated that some of the information resided with city personnel. A survey of city emergency personnel was beyond the scope of this study.

This initial survey has allowed us to make observations in two areas which indicate differences from the Pittsburgh study.

<u>Drinking Water Supply</u>

Public water systems in Pennsylvania have been required to file vulnerability assessments and emergency response plans with the US EPA. These reports are checked by the Pennsylvania Emergency Management Agency (PEMA) for compliance with state law, but are not regularly retained by the state. Individual public water systems and the federal EPA have copies of the reports, but this information is closely held. Details of backup electrical systems and general emergency preparations at water treatment plants and drinking water pumping stations are said to be contained in those reports, which were not made available to us in the course of this study.

From data which is publicly available, we estimate that during power outages in most areas of the state (including the Philadelphia area) at normal levels of consumption and without backup pumping or sharing between water systems, half the population will be without water 36 hours after electricity is lost in the affected area.

<u>Hospitals</u>

A survey of hospital electrical backup systems was conducted with help from the Hospital Council of Western Pennsylvania. Based on 15 responses, a typical hospital, normally treating 130 patients at a time, has four backup generators and fuel to provide 85% of normal power for 72 hours. Three of the hospitals have fuel stored to provide power for more than a week. Some hospitals have backup generator power for more than 140% of normal power use, while others have capability less than 90%. Most hospitals use diesel fuel for their generators, one used only natural gas, two used a combination of diesel and piped natural gas, one used fuel oil, and one used a combination of fuel oil and natural gas. All but one had a contract to obtain additional fuel in an emergency.

All hospitals reported testing their electrical backups on a monthly basis. All but two of the hospitals received power from two electrical substations. One issue affecting backups at hospitals suggested by this survey is the age of the generators: the newest generator at the surveyed hospitals is 12 years old.

On August 14, 2003 a number of hospitals in Pennsylvania were affected by the blackout. According to records kept by the Pennsylvania Department of Health, eleven hospitals reported loss of grid power. Of these, two reported disruptions of hospital services. In one of these, the backup generator came on line but motor control units failed, interrupting certain hospital functions. In the other, radiology systems were not on the backup units, and were interrupted. Others reported air handling system interruptions (the loads exceeded what the generators were designed to supply). The importance of practicing is indicated by reports such as "Two generators started automatically. Within minutes generator #2 failed, due to the breaker being tripped, which affected portions of the hospital. A backup was manually started but all procedures not followed."

3.5 Decision-Making for Survivable Services

Most backup systems required to provide services independent of grid power have associated capital and maintenance costs. If a 100 kW generator costs $76,000 and is financed over its 12-year life, the annual cost of capital to purchase the generator at an interest rate of 7% is $9,400. Operations and maintenance costs for this size generator if properly maintained and operated at full load once per month are approximately $1,900 annually, for a total yearly backup cost of $11,300.

If the example generator is used to back up a service which incurs losses of $25,000 when the power goes out (perhaps in lost product during a furnace heat treating cycle), then the generator would be a sensible purchase if the power is expected to fail more frequently than once every two years.

Figure 17 illustrates the decision process. When a purchase of a given capital expense is contemplated, the decision maker estimates the frequency of power outages at the location being considered, and the cost of the power outage. That defines a point on the graph, marked with an "X" on Figure 17 for a $25,000 cost of an outage expected to occur once every two years. If the capital cost of the system is less than roughly $100,000 the backup system would avoid more cost than its annual cost for capital, operations, and maintenance.

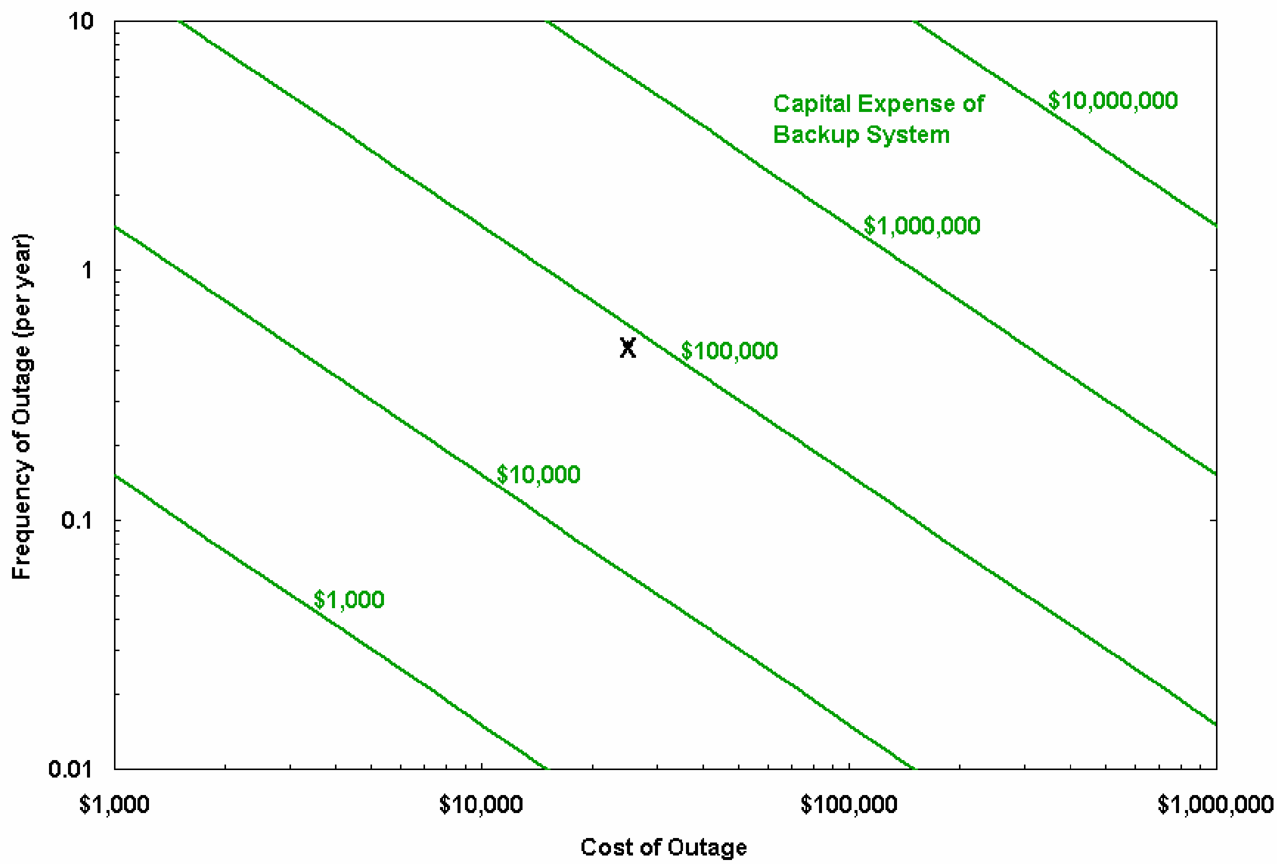


Figure 17. Example analysis for backup systems with 12-year depreciation at 7% discount rate and annual operations and maintenance costs equal to 2.5% of capital cost. If the capital cost of the backup system is lower than the point at the intersection of the assumed cost and frequency of a power outage, the purchase of a backup provides more benefit than cost.

As an example of a product differentiation backup decision, consider a typical small traction elevator backed up by a 12 kW generator, with capital cost of $13,200 and annual maintenance cost of $240. Using a discount rate of 7% and a 12-year equipment lifetime, the amortized monthly cost of the backup is $160. For a five-floor apartment building with six apartments per floor, a monthly rent increase of $5 would be required to pay for the backup. While some tenants would not value this service, others may seek out such a building.

3.6 Barriers to Implementation of Survivable Services

Information is required to convince decision makers to invest in survivability. Organizations which hold important information about survivability and the power network are highly protective of this information. Critical information barriers were identified in the course of this study.

<u>Information is required at the State level for the decision process</u>

To pursue the decision-making process described above requires significant in-depth information. While we have attempted to make some general conclusions about the importance and requirements of different kinds of services and present guidelines for decision making, any survivability improvement project must be decided on its own merits. Projects that are not obviously beneficial may make sense with closer study, and vice versa. A significant barrier for many projects will be the cost of analyzing their effects.

The following tools are needed to assist Pennsylvania in the decision-making process:

- Models of the storage, transportation, and consumption of fuel and other goods during a blackout.
- Catalogs of the electrical needs and generating ability of facilities, agencies, businesses, and communities in Pennsylvania.
- Quantification of the criticality of different services during design reference power interruptions.

<u>Information security</u>

Obtaining the information necessary to assess the vulnerability of important services in the face of power outages and propose solutions is to some extent at odds with the natural desire of many organizations, especially those involved with homeland security, to keep information about vulnerabilities out of the public domain so that pernicious persons or groups can not exploit those vulnerabilities. Of course the problem is that if groups like ours performing system-level analysis for state or local governments can not access important information, it is extremely difficult for policy makers to develop rational policies to reduce future vulnerabilities.

Public utilities are particularly protective of information about their emergency preparedness. For example, community water systems have prepared vulnerability assessments and emergency response plans. Questions about any aspect of emergency operations at water system facilities, including the number and size of generators, the amount of fuel stored at pumping stations, or the parts of the water system that will first lose service are all answered by saying that the information is contained in the emergency response plans. These documents are reviewed but not retained by the DEP and PEMA before being sent to the US EPA. They are not available to the public.

This is a problem even for responsible government agencies: the emergency management coordinator of one Pennsylvania county described hitting an information "roadblock" when requesting information from local utility companies in order to develop a critical infrastructure plan. The purpose of protecting information about emergency preparedness is to assure the public that emergency plans will not be compromised. This must be balanced by releasing enough information to assure the public that emergency plans are effective.

At the moment the pendulum appears to have swung too far in the direction of compartmentalized information. For example, certain actions by the Department of Homeland Security to centralize and compartmentalize information about vulnerabilities are not conducive to developing corrective action. A recent example is contained in an Associated Press report from July 11, 2004, excerpted below.[138]

> "When a landline phone network suffers a serious outage, the company involved has to tell federal regulators what happened and how it can be avoided next time.
>
> The Federal Communications Commission believes the public outage reports, required since the early 1990s, have helped to dramatically improve network quality. But the rule applies only to landline companies, an anachronistic loophole in this age of wireless phones and voice service from the cable company.
>
> So it would make sense to expand the rule to other communications companies, right? Not so fast.
>
> The FCC's proposal to make that change has met with strong opposition, not only from phone companies but also from the Department of Homeland Security, which contends that the outage reports could serve as blueprints for terrorists bent on wrecking U.S. communications systems.
>
> Homeland Security wants future reports to be filed with one of its own infrastructure-monitoring bodies, the Information Sharing and Analysis Center in the National Coordinating Center for Telecommunications, and kept from public analysis."

The problem of course is that Homeland Security and other similar organizations have neither the resources nor the authority to develop and implement most of the changes that will be needed to make important social services less vulnerable. Those resources and responsibilities are widely distributed among state and local government and in the private sector. It would help if Homeland Security and other similar organizations could develop:

- a greater ability to engage in system-level analysis which considers and balances a range of legitimate but perhaps conflicting social objectives;
- a greater ability to think about problems in terms of preserving social services as opposed to a unitary focus on protecting "critical network services";
- a greater ability to develop and promote a range of alternative polices which states and private entities might adopt to promote viable solutions that will reduce vulnerabilities.

In the mean time the Commonwealth would be well advised to develop an interagency arrangement, perhaps in the form of a standing interagency committee, which is charged with better balancing the conflict between the short-term need to protect information about vulnerabilities with the long-term need to encourage responsible parties to use such information to develop and implement solutions. Such a group should also have responsibility for exercising oversight to assure that solutions and systems developed by others will actually provide the protection they promise. Too often, entities provide assurances that everything is under control, only to find that back-up systems fail to operate when an actual outage occurs.[139]

3.7 Developing Policies to Assure that Critical Services in Pennsylvania are Survivable

Most of the organizations in the best position to assure that important social services continue during a power outage are private companies. While it might be to the collective benefit of society for these organizations to make investments that will make services more robust, it is often not in their private interest to do so. In other cases it may be in their private interest, but they may not have identified the opportunity, or it might be possible to provide incentives to make these investments more attractive.

A few of the policies to encourage survivable services are win-win situations. Some large utilities in Pennsylvania report that industrial and commercial customers ask them to use the utility's expertise to integrate backup power components as a turn-key system. Current tariffs do not permit utilities to charge for this service; both public and private interests would be served by a tariff change.

The following are options which the State and local governments might pursue to encourage or require *private parties* to improve the reliability of important social services:

- Modify electricity tariffs to permit load serving entities to recover costs associated with designing, installing, testing, and maintaining backup on-site power systems for individual customers.

- Provide information and suggestions to private parties to help them see how they might benefit from strategies that would make the services they provide more robust in the face of power outages. For example, once they think about it, a multi-story retirement home that installs backup power for its elevator might find that advertising this fact provides it with a comparative advantage.

- Encourage firms to offer "preferred customer" services which assure continued availability of services such as access to gasoline and ATM machines to those customers who have paid a fee which allows the companies to make the necessary additional investments. Customers of some fuel companies now are offered preferential delivery positions during emergencies in exchange for a fee. The Commonwealth may be able to create a supportive environment for preferential service agreements in other industries by increasing the awareness of potential blackouts. Entities such as gas stations have no incentive to install emergency power systems unless they are permitted to recover their cost through surcharges during emergencies. Such surcharges would be in the public interest, and the Commonwealth should study whether barriers exist to fostering backup power installations funded through peak charges.

- Require organizations to post public information on the presence or absence of back-up or other solutions to keep specific services such as elevators or gasoline pumps running in the event of a power disruption. In much the same way that the publication of EPA's toxic release inventory has induced many companies to cut emissions, such postings might induce companies to take steps to make their critical services more robust.

- Make changes in building codes and other legal requirements for business practice. For example, a decade ago Pittsburgh adopted a building code which requires elevators in newly constructed buildings of more than seven stories to have backup power. Similarly a community could require, as a condition of doing business, that firms operating gasoline pumps, ATM machines, or similar devices must work together to arrange that some percentage of these services will remain operational in the event of a power outage.

- Provide tax incentives, subsidies or grant programs to support the development of needed facilities. Given limited resources, this option should be used sparingly, but there might be some circumstances, such as certain upgrades in the emergency rooms of private hospitals, which warrant modest assistance.

- Facilitate the construction, interconnection and operation of distributed generation (DG) systems, and the operation of competitive micro-grid systems through actions outlined in Part 2 of this report.

Pennsylvania may wish to study whether promoting survivable mission activities or funding would be justified as an attraction for businesses to thrive in the global economy.

The following are options which the State and local governments might pursue to encourage or require *public and non-profit parties* to improve the reliability of important social services.

- Provide information and suggestions to local governments, and non-profit organizations such as hospitals, to help them see how they might benefit from strategies that would make the services they provide more robust in the face of power outages. For example, LED traffic lights require far less power than conventional traffic lights. Cities and towns could be encouraged to convert to LED systems and add trickle charge battery back-up. Such backup have capital expenses of several thousand dollars per intersection over the cost of an LED conversion without backup, but may be justified for critical urban corridors.

- Offer selective State subsidy programs, or lobby for the creation of selective Federal subsidy programs, to cover just the *incremental* cost of making systems more robust. To continue with the traffic light example above, such a program might cover only the trickle-charge battery back-up portion of the costs of conversion. Since this would dramatically improve the access of emergency vehicles during power blackouts, it might be a program that Homeland Security should support. Federal funding already exists for emergency power for air navigation. Restricted funds may be available from the Department of Homeland Security for increased security, the Airport Trust Fund for hub and reliever airports, and the Highway Trust Fund for tunnels. Use of state and local general tax revenue may be justified for survivable missions such as police precinct backup power. Water and sewer system backup should be studied as systems are repaired and upgraded. A formal investigation of funding sources such as these is warranted.

All of the preceding options are focused on making services more robust in the face of a supply outage from the power company. However, since most power outages arise from failures in the local distribution system, some jurisdictions have adopted regulatory requirements to foster retail competition based on reliability. This is most prevalent in New Zealand and Australia, where up-to-date reliability indices are posted on utility and government websites.[140] [141] **Transparency of this sort aids consumers, but is uncommon in the US. Pennsylvania does not currently require that utilities publish their reliability statistics;[142] we recommend that the Commonwealth do so.**

We recommend against legislation which would make utilities responsible for some portion of loss from a blackout (except selectively for customers who sign on for a high reliability service) and against a tax to penalize unreliability. Utilities may experience blackouts for which they are not responsible. Tax-based strategies may distort investment. Tying revenue from an unreliability tax or from an electricity sales tax to specific expenditure categories is generally inefficient in the long run (e.g. the Highway Trust Fund). In Pennsylvania's retail choice environment, a market approach based on required reporting and tariffs that allow utilities to offer high reliability service plans could increase local reliability through competition.

References and Notes

[1] Year 2002 figures complied by the Energy Information Administration, US Department of Energy, available at http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html, accessed July 11, 2004. Net Pennsylvania 2002 generation was 204 billion kWh and retail sales for all sectors was 141 billion kWh. Texas and Florida were first and third respectively in net electricity generation.

[2] http://www.med.govt.nz/ers/inf_disc/disclosure-statistics/2003/2003-08.html, accessed July 14, 2004.

[3] http://www.northpower.com.au/wrs/nthpower.nsf/html/regiongraphs.html , accessed July 14, 2004.

[4] 52 Pa. Code § 67 "Service Outages" requires only that "All electric, gas, water, and telephone utilities shall notify the [Public Utility] Commission when 2,500 or 5.0%, whichever is less, of their total customers have an unscheduled service interruption in a single incident for six or more projected consecutive hours."

[5] White House Fact Sheet, "Protecting America's Critical Infrastructures: PDD 63" May 22, 1998. See: http://www.fas.org/irp/offdocs/pdd-63.htm

[6] James Ellis, David Fisher, Thomas Longstaff, Linda Pesante, and Richard Pethia , "Report to the President's Commission on Critical Infrastructure Protection," CERT Coordination Center, Software Engineering Institute, Carnegie Mellon University Pittsburgh, Pennsylvania, January 1997

[7] C. Paul Robinson, Joan B. Woodard, and Samuel G. Varnado, "Critical Infrastructure: Interlinked and Vulnerable," *Issues in Science & Technology* 15(1): 61-67 (Fall 1998). Also see Sandia National Laboratories Program in Critical Infrastructure Surety http://www.sandia.gov/CIS/

[8] White House Fact Sheet, "Protecting America's Critical Infrastructures: PDD 63" May 22, 1998. See: http://www.fas.org/irp/offdocs/pdd-63.htm

[9] White House Press Release, "Executive Order on Critical Infrastructure Protection", October 16, 2001. See: http://www.whitehouse.gov/news/releases/2001/10/20011016-12.html

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[13] DHS, for details on the Department of Homeland Security's efforts in critical infrastructure protection see: http://www.dhs.gov/dhspublic/theme_home6.jsp

[14] Energy Information Administration Annual Energy Report 2002, Table 8.2a, see http://www.eia.doe.gov/emeu/aer/txt/ptb0802a.html, accessed October 28, 2003.

[15] Monthly data source: Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls , accessed June 9, 2004. Seasonal periodicities removed by Fourier transform processing (details will appear in a forthcoming journal article by Jay Apt).

[16] Susan Rodentis, "Can Your Business Survive the Unexpected?" (1999) see http://www.aicpa.org/pubs/jofa/feb1999/rodetis.htm, accessed April 10, 2004.

[17] Tom Short (2002), "Reliability Indices," presentation at T&D World Expo 2002, Indianapolis, IN, May 7-9, 2002, see http://www.epri-peac.com/td/pdfs/reliability2002.pdf

[18] Data compiled by NERC for the period 1984–2000, see http://www.nerc.com/~dawg/database.html, accessed September 6, 2003.

[19] H.F. Lipson and D. A. Fisher, *Survivability — A New Technical and Business Perspective on Security,* Proceedings of the 1999 New Security Paradigms Workshop, Caledon Hills, Ontario, Sept. 21–24, 1999, Association for Computing Machinery, New York, NY, available at http://www.cert.org/research/ .

[20] http://www.nerc.com/about/index.html, accessed July 16, 2004.

[21] "Electric Blackouts: A Systemic Problem" by Jay Apt, Lester B. Lave, Sarosh Talukdar, Granger M. Morgan and Marija Ilic, *Issues in Science & Technology* **20**(4): 55-61.

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[44] Energy Information Administration Energy Annual 2002, Figure 8.7.

[45] "Integrated Energy Systems (IES) for Buildings: A Market Assessment", Oak Ridge National Lab, September 2002.

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[53] While it is convenient to group a set of technologies under the "distributed generation" rubric, there are significant differences between technologies and in the operation and management of distributed resources. These differences can have an impact on the role that the distributed resource plays in the reliability of the system.

- Size. There is no standard definition of distributed generation, though some use the size of the units (in addition to their location) to define DG. Size of distributed resources can play a role in reliability in a variety of ways. If a distribution system becomes too dependent on a single large distributed unit to maintain reliability on the feeder, this can create a vulnerability. On the other hand, the contribution of small generators may not be sufficient to materially affect the reliability indices of the system.

- Location. The location of the DG units can have an impact on their reliability benefits. For example, a cluster of generating units at the sub-station level cannot mitigate against a line fault further down the distribution line (the site of the majority of incidences, though not the cause of widespread outages). On the other hand, placement of a distributed resource on a distribution feeder can cause stability and power flow problems for operation of the line.
- Dispatchability and Intermittency. Intermittent resources, such as photovoltaics or wind, can aid in reducing power needs, but can either create reliability issues or have a negligible impact on reliability needs due to their lack of dispatchability. Such technologies cannot be counted on to provide grid support as needed.
- Controllability. The controllability of a technology (e.g. the time necessary to connect or disconnect from the system, the time required to ramp up or down, etc.) plays a role in the operation of the system and therefore in the reliability of a system. Technologies with fast switching times can potentially provide a wider variety of reliability support. On the other hand, if a technology is installed that has a slower response time, it may be necessary to modify the operation of other components in the system, potentially degrading one measure of reliability even as another is increased.
- Fuel. For those distributed systems that rely upon a fuel, the reliability of the fuel supply must also be considered when evaluating the reliability of the distributed technology.
- Cost. Even if a distributed technology can improve the reliability of a system, the benefits of deploying the technology may not outweigh the costs. Benefits can be both in the form of other deferred investments (e.g. in distribution system upgrades) or in the form of reduced outage costs to customers. As with all other reliability investments, overall system costs (including customer outage costs) decrease until a certain point, after which additional investment to improve reliability results in increasing overall costs.
- Operating Mode. Distributed resources can be run in a variety of operational modes. The most common is as a backup to grid power. In these cases, the distributed resource only operates when there is a problem on the utility system and it is operated in isolation until grid power is restored. A second operation mode is as a peak shaving unit. In this case, it runs in parallel with the utility system at times of peak load in order to reduce requirements on the grid system. Distributed units can also be run at a high capacity factor, in some cases even as the primary source of power for a load. In these cases, the unit can be a stand-alone unit (as might be common for remote loads) or run in parallel to the grid (with the grid providing either supplemental power or acting as the backup for the distributed unit).
- Unit Reliability. The reliability characteristics of the distributed resource itself will play a role in determining its contribution to system reliability. A distribution system that is dependent upon a single DG unit with a high forced outage rate would likely provide unacceptable performance when compared to either relying upon the grid alone or deploying an alternative technology.

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[67] The term "DER customer" will be used to mean an individual or groups of electric power consumers that install DERs to meet their demand. In some cases, a third party company might install or maintain the DER system, but this company is still working on behalf of the customer.

[68] The full scope of FERC authority with regard to electrical energy sales is described in detail in 16 USC. Section 824.

[69] Utilities are exempt from this obligation if it will either "impair the electric utility's ability to render adequate service to its customers, or place an undue burden on the electric utility. Additionally, qualifying facilities are required to meet various technical and non-technical standards.

[70] US Code of Federal Regulations, Title 18, Chapter 1, Part 292, Subpart C.

[71] The term 'waste' is defined in the US Code of Federal Regulations, Title 18, Chapter 1, Part 292, Subpart B, Section 202, and includes fourteen types of fuel, including materials certified for disposal by combustion (municipal waste), used rubber tires, plastic materials, petroleum coke, and bituminous coal waste that meets various requirements.

[72] US Code of Federal Regulations, Title 18, Chapter 1, Part 292, Subpart C, Section 209.

[73] US Code of Federal Regulations, Title 18, Chapter 1, Part 292, Subpart C, Section 209.

[74] Pennsylvania Code, Title 52, Part I, Subpart C, Section 57, Subchapter C.

[75] Pennsylvania Code, Title 52, Part I, Subpart C, Section 57, Subchapter C, subsection 34: Purchases of energy and capacity.

[76] Allegheny Power (West Penn Power Company) electricity service tariff, issued December 22, 2003 and effective January 1, 2004. Available from Allegheny Energy, Inc.

[77] PECO electric service tariff, issued February 27, 2004 and effective April 30, 2004. Available from PECO.

[78] Pennsylvania Code also states that "when appropriate, a utility shall provide supplementary backup and maintenance power on both a firm and interruptible basis."

[79] T. Basso and R. DeBlasio, "IEEE 1547 Series of Standards: Interconnection Issues", National Renewable Energy Laboratory, NREL/JA-560-34882. See www.nrel.gov/docs/fy03osti/34882.pdf .

[80] Finding the standard on line at IEEE is not straightforward. Copies are available for a fee of $70 through http://shop.ieee.org/store/, specifically at http://tinyurl.com/ywsgz.

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[83] FERC docket number RM02-12-000, Notice of Proposed Rulemaking, Section II A, Subsection 5b. Appendix 1 outlines ten criteria for the super expedited process. Appendix 2 outlines five criteria for the expedited process.

[84] To qualify for the super-expedited process, facilities must be "certified by a national testing laboratory as having met applicable consensus industry and safety standards" and meet ten screening criteria. The screening criteria are listed in Appendix 1 of the Standard Small Generator Interconnection Procedures, as laid out in the NOPR.

[85] FERC docket number RM02-12-000, Notice of Proposed Rulemaking, Section II A, Subsection 5b.

[86] Available from PJM, see www.pjm.com/planning/downloads/small-resource.pdf. Accessed June 8, 2004.

[87] This point is arguable, and PJM does specify in its Small Resource Interconnection Procedure Manual that while "generally, small capacity additions will have very limited and isolated impacts on system facilities," further analysis is required in cases where expedited studies show a considerable impact.

[88] M. Granger Morgan and Hisham Zerriffi, "The Regulatory Environment for Small Independent Micro-Grid Companies" (2002), Carnegie Mellon Electricity Industry Center Working Paper CEIC-02-07, see http://wpweb2k.gsia.cmu.edu/ceic/papers/ceic-02-07.htm.

[89] Pennsylvania House Bill # 1509, Session of 1995, Section 2805.

[90] A petition for a declaratory order was filed by PG Energy, Inc., then-owners of PEI Power Corporation, at docket # P-00981405. The Pennsylvania PUC issued its order on September 3, 1998.

[91] Telephone interview with Bob Bennett, Manager of Energy Industries with the Commission of Fixed Utility Services in the Pennsylvania Public Utilities Commission, June 16, 2004.

[92] FirstEnergy is the parent company of Metropolitan Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company. Allegheny Energy, Inc. is the parent company for West Penn Power Company.

[93] Electric Power Outlook For Pennsylvania 2002-2007, published by the Pennsylvania PUC Bureau of Conservation, Economics and Energy Planning in August, 2003.

[94] Applicable parts of the PECO electricity tariff include *Rate R-S Renewable Energy Service*, and *Auxiliary Service Rider*.

[95] Applicable parts of the Allegheny (West Penn Power Company) tariff include Net Energy Metering Rider, Cogeneration Schedule 85, and Alternative Generation Rider Schedule 86.

[96] Applicable parts of the FirstEnergy (Pennsylvania Power Company) tariff include Purchase of Energy from Cogeneration and Small Power Production Facilities, and Partial Service Rider.

[97] Applicable parts of the Duquesne Light tariff include Rider No.16 Service to Non-Utility Generating Facilities, Rider No. 18 Rate for Purchase of Electric Energy from Customer-owned Renewable Resources Generating Facilities and Rider No. 22 Renewable Energy Service.

[98] Applicable parts of the PPL tariff include Auxiliary Service for Non-Qualifying Facilities, Standby Service for Qualifying Facilities, and Renewable Energy Development Rider.

[99] For example, if a customer contracts for 100 kW of standby capacity, and its peak standby needs are 40 kW, the customer must pay a demand charge on 70 kW of power. If its peak standby needs are 80 kW, the customer must pay a demand charge on 80 kW of power.

[100] Florida Power & Light Company tariff, "Standby and Supplemental Service."

[101] Central Illinois Light Company tariff, "Auxiliary or Standby Rate 27." The actual rate is $5.44 (winter) and $3.45 (summer) per kVA billing demand, but customers are only required to pay this charge on 80% of the contracted standby service as a minimum.

[102] Union Electric Company tariff, Missouri Service Area, "Miscellaneous Charges: Supplementary Service Minimum Monthly Charges."

[103] Connecticut Light & Power Company tariff, "Backup and Maintenance Power Service".

[104] Original state-by-state net metering table published at www.eere.energy.org/greenpower/markets/netmetering.shtml. North Carolina Solar Center's DSIRE website, www.dsireusa.org. Accessed June 8, 2004.

[105] Pennsylvania Code, Title 52, Part I, Subpart C, Section 57, Subchapter C, subsection 34: Purchases of energy and capacity.

[106] A petition for a declaratory order was filed by PG Energy, Inc., then-owners of PEI Power Corporation, at docket # P-00981405. The Pennsylvania PUC issued its order on September 3, 1998.

[107] Phone discussions with employees of PEI Power Corporation in June, 2004, and news releases published between 1996 and 1999 on the PRNewsWire (http://www.prnewswire.com/gh/cnoc/comp/684209.html).

[108] Telephone interview, Patrick Thompson, President and CEO, EnergyWorks North America.

[109] The International District Energy Association lists eight member district energy systems in Pennsylvania. See www.districtenergy.org.

[110] http://www.puc.state.tx.us/electric/business/dg/dgmanual.pdf

[111] These requirements were set forth generally in Michigan's Customer Choice and Electricity Reliability Act of 2000 (Public Act 141), and details for the procedures were published by the Michigan PSC in June 2000.

[112] State of New Jersey Board of Public Utilities, Docket # GT01070450. Published January 8, 2003.

[113] New Jersey Natural Gas Company tariff, BPU No. 7 Gas, as of 5/26/04.

[114] In the NJNG tariff, winter is defined as November through April, and summer is May through October.

[115] State of New York Public Service Commission, case 02-M-0515, Order Providing for Distributed Generation Gas Service Classifications, issued April 24, 2003.

[116] Other examples of such special services include ultra-high reliability, AC power with very low noise and harmonic content, or DC power for electronic systems.

[117] M. Granger Morgan and Hisham Zerriffi, "The Regulatory Environment for Small Independent Micro-grid Companies," *The Electricity Journal*, pp. 52-57, November 2002.

[118] We use the term "distribution utility" to cover investor owned, co-op and municipal systems.

[119] These estimates are based on calculations done using the 1999 HVAC ASHRAE Applications Handbook.

[120] The Public Utility Regulatory Policy Act of 1972 specified that independent electricity generators selling to the grid cannot exceed an installed capacity of 60 MW.

[121] Such a conditional option for future growth could be included in the initial legislation.

[122] Neil D. Strachan, *Adoption and Supply of Distributed Energy Technology*, Ph.D. thesis, Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, 2000.

[123] Here, and in subsequent discussions of rates, the word "power" refers to both real power, and when relevant, to reactive power.

[124] Locational marginal pricing (LMP) is implemented in certain transmission systems. Should LMP be extended to the distribution level, then these arguments would change. Micro-grid legislation today does not address distribution-level LMPs, which have not been shown to be economically effective.

[125] Neil D. Strachan, *Adoption and Supply of Distributed Energy Technology*, Ph.D. thesis, Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, 2000.

[126] Since the micro-grid will typically include several generators, it is unlikely that its entire load would ever have to be served by the distribution system, and the maximum size of the load that could be imposed on the distribution system could be regulated both physically and via tariff.

[127] R. Brent Alderfer, M. Monika Eldridge, and Thomas J. Starrs, *Making Connections: Case studies of interconnection barriers and their impact on distributed power projects*, National Renewable Energy Laboratory, NREL/SR-200-28053, May 2000 (Rev. July 2000).

[128] UL Standard 1741 is designed to ensure that the equipment used in power systems (e.g., inverters, converters) minimize the risk of fire or electric shock or injury. NFPA's National Electric Code sets national standards to minimize the risk of fire from electrical equipment not used in power systems (e.g., conductors in buildings).

[129] Hisham Zerriffi, Hadi Dowlatabadi, and Alex Farrell, "Incorporating Stress in Electric Power Systems Reliability Models," Department of Engineering and Public Policy, Carnegie Mellon University, 2003. Manuscript in review for publication.

[130] The Act is available on line at the Michigan Public Service Commission website: http://www.cis.state.mi.us/mpsc/electric/restruct/pa141.htm, accessed July 21, 2003.

[131] Details on this ruling are available on line at the Michigan Public Service Commission website: www.cis.state.mi.us/mpsc/orders/electric/2000/u-11915.pdf , accessed July 21, 2003.

[132] We say "may" because some micro-grids may rely on renewable energy sources.

[133] Neil D. Strachan and Alex Farrell, "Emissions From Distributed Generation," CEIC working paper, 2002, http://wpweb2k.gsia.cmu.edu/ceic/papers/ceic-02-04.htm.

[134] These specific numbers are those used by the Pennsylvania Department of Environmental Protection. We have confirmed that similar numbers apply in other states including Ohio, Oregon and New York.

[135] M.G. Morgan and H. Zerriffi, *The Regulatory Environment for Small Independent Micro-Grid Companies*, The Electricity Journal, 2002, 15 (9): 52-57.

[136] Projects address real world problem in technology and public policy, usually with an outside client for whom the work is being done. Typically half of the students are junior or senior engineering students in Engineering and Public Policy and half are a mixture of first-year masters students in The Heinz School and undergraduates in Social and Decision Sciences. Students start the semester with a vaguely defined problem area and various background materials which they must use to define and shape a workable problem and then undertake the necessary analysis to get the problem solved. There are typically between two and four faculty advisors, drawn from engineering and from social sciences as well as one or two student managers. Over the first couple of weeks of a project, students in the course work on developing a thorough understanding of the subject and defining the focus of the work they will do. About a third of the way into the semester, students make a first formal presentation at which they present their proposed research to an outside review panel of experts who represent different expertise and points of view in the problem field. The review panel assists the students by providing critical comments on the way in which they have structured the problem and by suggesting various resources and information sources. About two-thirds of the way through the semester, students make a second presentation to the project review committee at which they present a progress report and receive steering suggestions from the review panel. At the end of the semester, the students prepare a final written project report and make a final verbal presentation of their findings and conclusions to the review panel.

[137] The student members of the team were Benjamin Anderson, Erik Andreassen, Michell Birchak, Barbara Blackmore, Laura Cerully, Helen Davis, Jonathan Fasson, Dominic Fattore, Sandra Gani, Wenyao Ho, David Lagattuta, Emily Lauffer, Rachel Lin, Landon Lochrie, Nick McCullar, Ben Mosier, Jonathan Ng, Laura Sperduto, Marena Tiano, and Jennifer Wong. The Ph.D. candidate project managers were Kyle Meisterling and Paul Hines. Course faculty were Dmitri Perekhodtsev, Marija Ilic, Jay Apt, and M. Granger Morgan.

[138] http://www.wired.com/news/print/0,1294,64168,00.html, accessed July 15, 2004.

[139] Two notable recent examples are one large hospital in Cleveland which lost power during the northeast blackout of August 14, 2003, and the April 12, 2004 outage at the air traffic control tower at Los Angeles International airport which disrupted nearly 100 flights.

[140] http://www.med.govt.nz/ers/inf_disc/disclosure-statistics/2003/2003-08.html, accessed July 14, 2004.

[141] http://www.northpower.com.au/wrs/nthpower.nsf/html/regiongraphs.html, accessed July 14, 2004.

[142] 52 Pa. Code § 67 “Service Outages” requires only that “All electric, gas, water, and telephone utilities shall notify the [Public Utility] Commission when 2,500 or 5.0%, whichever is less, of their total customers have an unscheduled service interruption in a single incident for six or more projected consecutive hours.”

For more information,
visit DEP's website at www.dep.state.pa.us, "Keyword: OETD."

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