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The Role of Coal in a Smart Grid Environment

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Exhibits

Acronyms and Abbreviations

AC	Alternating current
ASU	Air separation unit
AWEA	American Wind Energy Association
Btu	British thermal unit
BUGS	Backup Generators
CAISO	California Independent System Operator
CCPP	Cell controller pilot project
CCS	Carbon capture and storage
CFB	Circulating fluid bed
CHP	Combined heat and power
CO_2	Carbon dioxide
C&I	Commercial and industrial
DG	Distributed generation
DEA	Danish Energy Agency
DER	Distributed energy resources
DHS	District heating system
DOE	Department of Energy
DR	Demand response
EBITA	Earnings before Interest, Taxes, Depreciation and Amortization
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FACTS	Flexible AC transmission system
FBC	Fluidized bed combustion
FERC	Federal Energy Regulatory Commission
HVDC	High voltage direct current
GE	General Electric
GT	Gas turbine
GW	Gigawatt
H_2S	Hydrogen sulfide
HRSG	Heat recovery steam generator

IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
kV	Kilovolt
kWh	Kilowatt-hour
LCOE	Levelized cost of electricity
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
MMT	Million metric tonnes
MW, MWe	Megawatts electric
MWh	Megawatt-hour
NG	Natural gas
NGCC	Natural gas combined-cycle
NOx	Oxides of nitrogen
O&M	Operating and maintenance
PC	Pulverized coal
PHEV	Plug-in hybrid electric vehicle
PJM	PJM Interconnection, LLC
PURPA	Public Utilities Regulatory Policy Act
PV	Photovoltaic
RPS	Renewable portfolio standard
psig	Pounds per square inch gage
RTO	Regional Transmission Organization
R&D	Research and development
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	System Control and Data Acquisition
SG	Smart grid
SO_2	Sulfur dioxide
SOx	Oxides of sulfur
TJ	Terajoule

TSO	Transmission system operator
T&D	Transmission and distribution

Executive Summary

In this report, we analyze how the traditional role of coal might be changed by the adoption of "Smart Grid" technologies, which use information flow to manage supply and demand requirements. We examine new roles that might leverage the advantages and mitigate the challenges for coal generation. Specifically, we analyze:

- How much the baseload might change as Smart Grid technologies are adopted
- Ways that coal might service this changing baseload, including centralized generation, distributed generation (DG), and combined heat and power (CHP)
- Coal's potential to provide Federal Energy Regulatory Commission (FERC) recommended ancillary services and North American Electric Reliability Corporation recommended (NERC) reserves in a Smart Grid, including the mitigation of problems due to higher renewable generation capacity

We integrate these analyses into a "Smart Grid City of the Future" model and analyze the City's operational and economic characteristics. We find that, under a set of explicit assumptions, the payback period for investment to develop a Smart Grid enabled infrastructure is on the order of six years.

Insights from Stakeholders

Executive, planning, and operations representatives from several utilities provided suggestions to refine the goals for the study. Their recommendations fell into four analytic categories:

1. Baseload changes and their impacts on centralized generation
2. Coal in distributed generation (DG) applications
3. Coal in combined heat and power (CHP) applications
4. Coal's role in integrating renewables

A cross-cutting issue noted in all categories was coal's possible role in providing the myriad of ancillary service applications, such as reserves and grid stability.

Future Baseload Demand Changes

Smart Grid technologies can be used to shift load from peak demand times to periods of lower demand, which allows expensive and inefficient peak generation to be replaced by less expensive, more efficient baseload generation.

Sample data for the PJM Interconnection was analyzed to understand the potential impact of load leveling on baseload generation. As an upper bound, peak demand might be reduced by as much as 18 percent, resulting in an increase in baseload of up to 39 percent. However, in the PJM case studied, there is only enough existing and planned baseload generation capacity to accommodate a 12-percent reduction in peak load. Smart Grid technologies could thus create a need for additional baseload generation capacity, above that already built, in construction, or planned.

Our analysis for the entire U.S. suggests that there is on average only enough baseload generating capacity to accommodate a 9-percent reduction in peak load through load shifting.

Moreover, if planned capacity is adjusted for cancellation probabilities, only a 7-percent reduction in peak load can be accommodated, on average. This figure declines over time; we estimate that approximately 30 GW to 40 GW of additional baseload generation capacity will be needed to sustain the current fractional level of peak load-shifting capability.

Baseload Generation Options: Centralized, DG, CHP

Construction of large, centralized generation facilities, usually coal or nuclear, is a traditional approach by which baseload can be serviced. However, Smart Grid technologies enable new smaller, distributed generation (DG) plants to meet increases in baseload demand.

Small coal-based technologies are more cost-effective with respect to fuel than natural gas and diesel, and provide lower fuel-cost volatility, but they are not currently in common use due to technology and capital-cost challenges. No clear winner among the coal-based technologies exists for all applications, but opportunities exist for additional R&D to increase competitiveness with existing alternatives.

Coal-based DG is most efficient and cost-effective in CHP settings, in which the waste heat can be partially re-used directly for space or process heat. Because both power and heat are extracted, the plants can be built larger than those supplying power alone, leading to increased efficiency. CHP economics are improved if the power generator is also used to provide local grid-stabilizing services.

To better understand the practical advantages and challenges to using coal as a distributed generation fuel in CHP applications, we considered the success that Denmark has had between 1985 and the present in transforming its electricity supply to one with a broad base of distributed CHP. Six key factors for this success include:

- Shared national vision
- Existing infrastructure conducive to transformation
- Geographic location
- Consistent energy policy
- Pricing mechanism
- Cellular network structure

Significant differences between Denmark and the U.S. exist in most of the factors, presenting challenges to implementation that would need to be addressed. However, Denmark's energy position in 1985 was similar to the U.S.'s current position, so some parallels are applicable.

Ancillary Services

Coal based DG faces similar challenges as other DG types as a source of reserves and ancillary services, such as regulation, load following, and voltage support. Ramping rates are the most common issues with power plants used for spinning reserves. We find that small coal based DG units can respond within standard limits of approximately 10 minutes. Depending on DG location, sub-transmission or distribution network, there can be additional issues with using it for reserves, ancillary services, or dispatching it in general. For example, scheduling its reactive power capacity for transmission-level voltage regulation can be more complex due to unpredictable voltage changes on radial lines.

Smart Grid City of the Future

We developed a model characterized as a “Smart Grid City of the Future”. It consists of a highly integrated set of renewable and DG resources, with consumers fully engaged in an efficient market. We used the HOMER[1] energy portfolio optimization tool, with modification to consider coal alternatives, to estimate the optimal fuel mix for the city, given its characteristics and goals.

The analysis of the Smart Grid City of the Future shows coal generation supplying approximately 30 percent of the City’s needs through distributed baseload generation—an emerging role not common today. An additional 45 percent of the City’s power needs are met by traditional grid bulk supply, much of which is likely to be generated from coal.

A municipal-merchant financial model, using the results from the mix optimization, shows a favorable return on investment for the transformation and operation of the City under certain assumptions made about load-leveling, infrastructure, and various smart grid technologies including electric vehicles. Under these assumptions, the municipality receives a reasonable profit, the merchant has reasonable return on its initial investment, annual emissions are reduced, and the customer has reduced electricity rates and improved reliability. This analysis demonstrates that distributed coal generation coupled with Smart Grid and renewables has the potential to be economically beneficial for all parties.

[1] HOMER was developed by NREL for Hybrid Energy Systems modeling and optimization [26].

1 Introduction

Frequently, the electrical power systems in the developed countries are described as the most complex engineering achievements of humankind. Lately, they can be described as the most complex engineering achievements of humankind, with some looming challenges. A large portion of the resources used for electrical power generation are fossil based and as such are becoming scarce. Since the introduction of alternating current (AC) power systems more than 100 years ago, most power-generating facilities have been built at locations remote from the loads. Aging transmission systems are approaching their limits without sufficient investment in new transmission lines. Fossil energy sources are also related to environmental problems and are becoming increasingly controversial. Our nation, along with other nations, is at a crossroads. Do we opt for continued central generation and an improved transmission system? Is the solution smaller distributed generation? Do we emphasize use of generation based on environmental attributes or do we emphasize economics? These and other related questions are not simple issues with yes or no answers, but rather complex dilemmas with solutions somewhere in between. Renewable energy resources versus fossil fuels, specifically coal, are central to these questions. This study focuses on coal in trying to answer some of the questions.

Coal-based generating plants have long been a reliable and inexpensive source of energy for the United States. But, as concerns increase about the potential effects of carbon dioxide and other fossil-plant emissions on the environment, policy makers are interested in finding ways to increase the use of renewable sources to meet future energy needs. Historically, this has involved a tradeoff between the high reliability of fossil-fuel plants and the low environmental impact of renewable fuels. This is not the only tradeoff involving coal. Coal power plants have historically been central, remote units that depend on the transmission system to deliver their power. In this case, the question is: Should the generation should be large and centralized or small and distributed, or a combination of the two? Both approaches have advantages and disadvantages. Centralized generation is more efficient but incurs higher transmission losses and is dependent on the reliability and capacity of long transmission lines. Decentralized generation is less efficient but does not need long transmission lines, and it can be used for cogeneration. The best solution is probably dependent on a combination of environmental, economic, geographical, and technical conditions.

One of the major developments in the electrical energy industry in the last 20 years is the emergence of the “Smart Grid” concept. Smart Grid refers to technology that can enable various technical and market advancements that were not possible before. The Smart Grid will provide monitoring and control capabilities and two-way information flow between energy producers and consumers at all levels. At the transmission level, bidirectional information flow and monitoring and control capabilities have been present, to some extent, for a long time. Moving these features to the distribution level, all the way to the residential level, brings up many possibilities.

The most important feature for this study is the possibility of micromanaging power generation and demand. In this case, there are two aspects of micromanaging: energy management and power generation synchronization. Low-level energy management can be used in combination with energy storage solutions for peak shaving and increasing the demand for baseload generation. Power generation synchronization can be the key feature needed for higher penetration of variable renewable energy sources. The Smart Grid has a potential to revive coal generation as a distributed generation or cogeneration option. The Smart Grid can also provide a means for supplementing variable renewable resources with electricity from coal generation. All of these possibilities might have clean coal as a prerequisite in the future.

This research is primarily concerned with the future of coal in the modern, Smart Grid-supported power system environment. To fully understand the possibilities introduced by the Smart Grid, a short review of Smart Grid features and how they relate to coal power generation is presented first. Next, since the coal power plants are usually considered as providing baseload generation, the future need for baseload generation is estimated with and without Smart Grid support. After the future baseload is estimated, a detailed analysis of different ways of supplying baseload in the future is performed. Special attention is paid to distributed generation, cogeneration, microgrids, and renewable solutions as potential sources of non-traditional baseload generation. After several potential energy sources are analyzed, a system-level solution is evaluated from the technical and economic points of view. A generation portfolio of a hypothetical Smart Grid City of the future is analyzed based on the components discussed previously. More detailed discussion of technical, economics, and environmental characteristics of different generation options can be found in the appendices.

1.2 Insights from Stakeholders

The research team interviewed electric power industry executives, operators, and other stakeholders to obtain insights into the issues, challenges, and opportunities for coal generation in a Smart Grid environment. Members from four utilities and one regional transmission operator provided opinions and ideas. To ensure openness and to avoid competitive issues, the team agreed not to identify contributors or their organizations by name.

These stakeholders' insights fell into four general categories:

- Baseload changes and their impacts on centralized generation
- Coal in distributed generation (DG)
- Coal in combined heat and power (CHP) applications
- Coal's role in integrating renewables

A cross-cutting issue noted in all categories was coal's role in providing ancillary services, such as reserves and grid stability, under different Smart-Grid enabled futures.

1.2.2 Baseload Changes and Centralized Generation

Stakeholders fell into two categories of opinion on how baseload changes might affect centralized generation in general, and coal centralized generation in particular. One group thought that there would be an increased demand for centralized generation due to flattening of load profiles enabled by the Smart Grid. The other group felt that increases in distributed generation capacity (DG) enabled by the Smart Grid were likely to meet or exceed increases in baseload from load shifting, so that the net demand change for centralized generation, including coal, would be neutral to negative. Both groups felt that additional research and analysis would be valuable to better understand this issue.

Stakeholders in the first group felt that an increase in average load capacity enabled by the Smart Grid represents an opportunity for centralized coal-fired generation to compete with nuclear and natural gas, depending on the size of carbon costs, taxes, and penalties. Several expressed a need to develop better estimates of the potential costs of carbon capture and storage (CCS) to better understanding coal's competitive position relative to other baseload generation fuels under carbon regulation.

Those in the second group felt that centralized coal generation was not likely to experience an increase in demand due to load shifting. Representatives from utilities participating in a regional transmission organization (RTO)-driven market noted that they already dispatch coal generation based on price signals in the RTO market, so they did not perceive significant changes as more Smart Grid technologies became available. Some of the stakeholders noted a decrease in coal-based construction plans already: for example, one recently removed IGCC from their long-term plans because of the cost to build, and another decided to convert a coal plant to 100 percent biomass within four years as part of a strategy to meet renewable portfolio standards (RPS).

Some in the second group thought decreases in centralized coal demand might be buffered by coal's potential role in providing ancillary services, such as generation reserve and frequency/voltage regulation. One respondent predicted that existing coal plants will continue to be retired due to age and cost of retrofits, and that the trend will continue until RTOs object that incremental plant retirements will impact reliability. This scenario would then result in an increase the value of the remaining coal plants, as they become "must run" plants to ensure reliability and stability standards can be met.

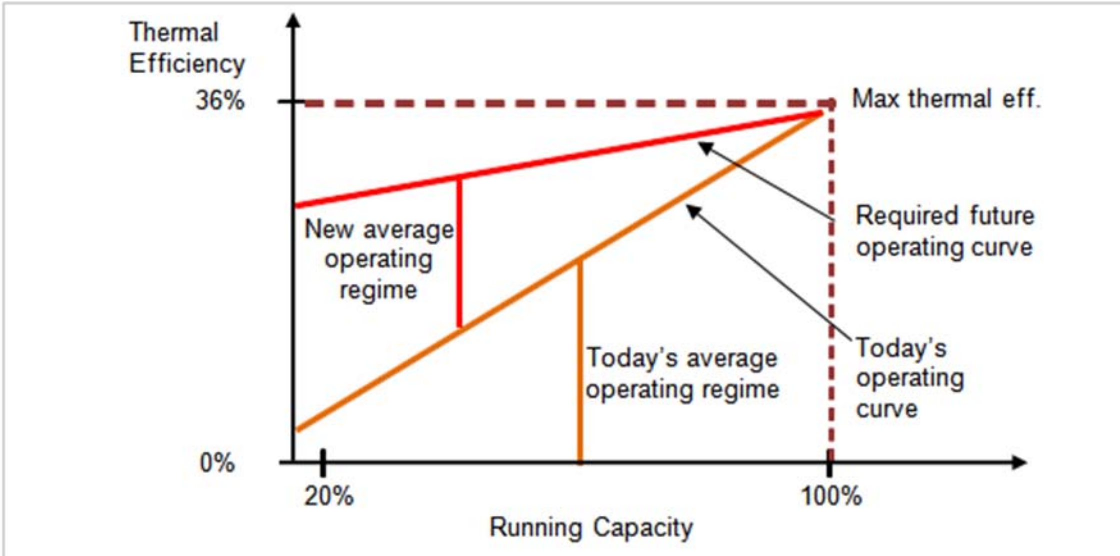
Stakeholder discussions on centralized coal generation generally assumed that the plants would be run at a constant level to service the baseload. The possibility of running coal plants at partial and variable load factors was discussed primarily in the context of increased DG.

1.2.3 Coal in Distributed Generation (DG)

While stakeholders thought that Smart Grid technologies were very likely to increase the availability of distributed generation (DG), they were generally pessimistic about the current economics and applications of small DG coal plants where there is no use of combined heat and power (CHP). Small DG coal is defined as CHP or multi-product coal generation sized 50MW to 90MW. Those expressing an opinion generally felt that other fuels, such as natural gas, were likely to provide the majority of the new DG capacity. They felt that, to be competitive, coal-fueled technologies would have to be developed that provide better thermal efficiencies at lower load factors, that respond quickly and efficiently to variable loads.

Exhibit 1-1 illustrates this graphically. The lower diagonal curve represents the current operating curve for a conceptual pulverized coal (PC) operating plant. Maximum thermal efficiency is reached when operating the plant at full capacity. Efficiency falls off rapidly as the plant is run at lower capacities. Coal plants are currently operated in a regime in which the majority of the time is spent at greater than 50 percent power. Several stakeholders believe that new DG capacity and renewables integration (discussed in Section 1.2.5 below) will result in a requirement for plants that operate in regimes at or below 30 or 40 percent of maximum capacity. For coal to be competitive with other energy sources in this regime, technologies will have to be developed with operating curves more like the upper diagonal curve in Exhibit 1-1, which shows higher thermal efficiency as the operating level decreases below 50 percent capacity.

Exhibit 1-1 Need for Higher Thermal Efficiency for Coal Generation at Partial Capacity



Source: (1)

Other challenges that stakeholders felt needed to be addressed for coal generation in a DG environment include:

- Siting
- Fuel delivery
- Waste removal
- Sizing plants for limited cycling to gain full efficiencies

One possible area in which some stakeholders thought coal generation might have an advantage as DG increases is in providing ancillary services, particularly reserves and grid stability. For example, one executive suggested that the choice of fuels in a new decentralized operating model will focus on a tradeoff between costs and reliability. Currently, the bulk supply system is very reliable, and RTOs have kept costs down. As demand increases, the executive believes there will be a challenge to keep costs down while keeping system reliability at acceptable levels

Based on the cost-reliability tradeoff, this stakeholder believes the majority of near-term new distributed generation will be fueled by natural gas, despite current volatility in gas prices. The low operating costs for coal plants would be counterbalanced by uncertainties related to the costs for carbon mitigation, taxes, or other climate-change emissions compliance requirements. Research into the effects of these uncertainties on investment decisions and resulting costs might prove valuable, particularly if it includes analysis of the sensitivities to other incentives and the market price of electricity.

As mentioned in the previous section, some utilities expect to continue getting their reserves and frequency regulations from the central resource, even with a movement to more decentralized resources. They are also interested in studies on how storage could support coal in a Smart Grid future, both on utility and DG levels.

1.2.4 Coal in Combined Heat and Power (CHP) Applications

Several stakeholders felt that coal could be competitive as a distributed generation source in combined heat and power (CHP) applications enabled by the Smart Grid. Some cited recent successful examples, such as a 99 MW CHP using lignite as a fuel. Another said that his firm's net CO_2/MW ratio was lower for coal CHP plants when compared with other coal DG applications, with the ratio for CHP approaching that of natural gas.

The research team presented stakeholders with information about Denmark's program of incentives to grow small fossil CHP over the last 20 years, which resulted in a growth of a factor of over 1,600 percent. Stakeholders recommended analyzing the program and Denmark's cell structure in particular, to gain potential lessons for coal CHP in the United States.

Stakeholders had differing opinions on the best technologies for distributed coal CHP. One recommended examining and comparing all three current technologies: pulverized coal (PC), fluidized bed combustion (FBC), and integrated gasification combined cycle (IGCC) generation. Another stated that his firm was not considering IGCC and CHP coal-fired plants due to high operational costs and infrastructure associated with CHP. Others cited possible innovative dispersed technologies to investigate, including direct coal/carbon fuel cells and micro-CHP. Yet another thought that micro-CHP plants for residential and small business may have potential for load shape flattening, but natural gas would be the likely fuel.

1.2.5 Coal's Role in Renewable Generation

Many of the opportunities and challenges for coal generation in a DG environment map to an environment with increasing renewable generation. For example, one stakeholder estimates that typical coal generation operations in his region would go from a 60 percent capacity factor to as low as 30 percent as more renewables become prevalent. As discussed in the DG section above, this would require new coal generation technology that is highly efficient at partial load, as shown in Exhibit 1-1.

Operationally focused stakeholders were interested in impact on maintenance and replacement impacts on capital equipment (e.g., turbines, transformers, and switches) if coal plants are cycled to supplement generation from variable renewables as needed.

Renewables are not dispatchable, or "firm," sources of power. Stakeholders noted that, as more renewables come on-line, dispatchable sources and reserves need to be available on short notice so that the overall generation portfolio continues to function as a “firm” system from the perspective of the grid operators and end-use customers.

Storage technologies were generally high on the stakeholders’ lists of enabling technologies for coal to contribute to a grid with increasing renewable generation. For example, one participant cited a compressed air energy storage project under development that may promote more efficient coal plant use. This plant will have a capacity of 280–2,700 MW, and is still under development. Another stakeholder was much less confident that distributed storage will occur in the near future, due primarily to its costs. He believes that electric vehicles could make widespread storage possible, if the manufacturer’s warranty issues can be resolved.

As in the DG case, some stakeholders thought that coal generation, either centralized or distributed, might have competitive strengths in providing low-cost ancillary services, and that this role should be investigated in more detail from an operational and financial perspective. For example, one firm has about 1,500 MW offered on a RPS requirement of 2,000 MW renewables, and is beginning to have great concern about grid stability as more non-dispatchable renewables come on-line.

1.2.6 Synthesis of Feedback

The high-level, research-relevant insights derived from the stakeholder interviews include:

Baseload changes/centralized generation

- There is a need to better understand how centralized baseload generation could be affected by the introduction of Smart Grid technologies, as stakeholders are divided about whether more or less centralized baseload generation will be the net result to meet the demand profile altered by Smart Grid

Coal in distributed generation (DG)

- The economics and applications of small coal generation plants need to be better analyzed and characterized; current small-scale coal generating technologies do not appear to be competitive with other sources in non-CHP settings.
- With the significant growth of DG and renewables, it will be important to develop coal technologies that are more efficient at lower capacity factors than current technologies.
- Coal generation, both centralized and distributed, may be able to provide ancillary services such as reserves and grid stability in certain situations; the economics and technologies need to be characterized more thoroughly.

Coal in combined heat and power (CHP) applications

- Coal economics and environmental impacts (such as CO_2/MW ratio) may be competitive with other distributed energy sources in specific CHP applications.
- Denmark’s experience may yield practical insights for the U.S. in creating incentives for the growth of small fossil-powered CHP generation.

- The best technologies for coal CHP applications are not clear; analysis on potential engineering and financial performance could be useful.

Coal's role in integrating renewables

- With the significant growth of renewables, it will be important to develop an operating model where the combination of "as-available" resources (renewables) and "firm" resources can be made to look firm to the grid.
- There is interest in how energy storage could support coal generation in enabling better integration of renewables in a Smart Grid future.
- There is interest in micro-CHP with residential and small business consumers based on fuel cells with either coal/carbon or natural gas as a fuel.
- There is interest in the impact on equipment if coal-fired generation is cycled more to support the variability of renewables.

2 Coal in the Smart Grid Environment

The Smart Grid involves relatively new technology that supports power systems operations at transmission and distribution levels. Some industry experts argue that at the transmission level, the grid has been smart for a long time. The level of deployment of measuring and control devices in today's transmission and distribution system varies. The ability to acquire data and act on it using System Control and Data Acquisition (SCADA) at the transmission level is fairly comprehensive. At the distribution level, the deployment of SCADA and the number of points instrumented is very limited and what is available often employs only one-way communication. At the consumer level, essentially zero information is exchanged with the grid operator. The ubiquitous deployment of measuring and control devices, along with an integrated two-way communication system, will enable the Smart Grid to process vastly more information and exert more sophisticated control. At the distribution level, the Smart Grid idea brings new possibilities that might affect coal in profound ways.

The Smart Grid is enabling technology based on bidirectional flow of information between energy producers and energy consumers, and sophisticated measurement and control hardware at all system levels. The Smart Grid transition will create opportunities for and impacts on the national generation portfolio as today's grid is transformed in two fundamental ways.

Decentralized Supply and Hierarchical Control—Unlike today's grid, which is dominated by large central power stations providing electricity to consumers via a delivery system and dispatched via centralized command and control centers, the Smart Grid vision is to move to a more decentralized operating model. This model will increase the number of generating and storage resources dramatically—from thousands of centralized plants today to tens of millions of decentralized resources, including wind, solar, electric vehicles, combined heat and power units, and distributed energy storage devices. These decentralized resources will be owned by both utilities and non-utilities, including consumers. In addition, electrical loads will become subject to a control strategy that seeks to better match supply and demand in near-real time. In such an environment, all participants are taking part in generation and demand control in a hierarchically structured framework, and both generation and demand become controlled variables.

Two-way Power Flow at the Distribution Level—Today's transmission system is a network that supports power flow in two directions. The distribution system, which is primarily a radial design, does not. As decentralized sources are deployed at consumer premises and by utilities on their distribution circuits, power will begin to flow in both directions (e.g., from the consumer into the grid). Two-way power flow is a fundamental change to distribution system design and operation and will require a large investment in new relaying and control systems. New Smart Grid technologies and applications are needed to support this change.

The Smart Grid can enable a wide array of applications within a power grid. Not all of the Smart Grid's features must be present in every implementation.

The Smart Grid Vision is defined by its seven principal characteristics (2). The Smart Grid could:

- Enable active participation by consumers

- Accommodate all generation and storage options
- Enable new products, services, and markets
- Provide power quality for the digital economy
- Optimize asset utilization and operate efficiently
- Anticipate and respond to system disturbances (self-heal)
- Operate resiliently against attack and natural disaster

The achievement of these principal characteristics will create opportunities for and impacts to the national generation portfolio in general and the coal-based generation fleet in particular. The following examples provide some details.

Enable active participation by consumers—Active participation of consumers in electricity markets has the potential to bring tangible benefits to both consumers and grid operators.

The Smart Grid will have the potential to provide consumers with new information and control, and options that allow them to engage in new electricity markets. Well-informed consumers will have the ability to modify consumption based on balancing their demands and resources with the electric system's capability to meet those demands and to potentially choose their preferred source(s) of generation. New rate designs will provide the incentives for participation.

Demand-response programs will likely be more widespread and provide greater choice in energy purchases. The ability to reduce or shift peak demand allows utilities to minimize capital expenditures and operating expenses while also providing substantial environmental benefits by reducing line losses and minimizing the construction and operation of inefficient peaking power plants. In addition, emerging products such as plug-in hybrid electric vehicles that have smart-charging capabilities could result in improved load factors.

The potential net effect could be a flatter load profile and an overall reduction in energy consumption as compared to business as usual. Additionally, consumers will be more aware of the sources of their energy supply, giving them the opportunity to choose between power quality and price, and choose the type of generation source (i.e. renewable power, coal, nuclear, gas, etc.). This gives coal-based generation, both central and distributed, an opportunity to compete.

Accommodate all generation and storage options—The Smart Grid will enable the integration of many types and sizes of electrical generation and storage systems using simplified interconnection processes and universal interoperability standards to support a 'plug-and-play' level of convenience. Large central power plants will likely continue to play a major role even as large numbers of smaller distributed resources, including PHEVs, are deployed.

Another feature of a smart grid is to interconnect small and large generation at essentially any voltage level. This includes distributed energy resources such as photovoltaic, wind, advanced batteries, PHEVs, and fuel cells. Commercial users will have the option to install their own generation, such as highly efficient combined heat and power installations and electric storage facilities, depending upon profitability. Through these technologies and linkages, community microgrids may become more common as economics and alternative energy supplies (i.e. DG) become more integrated with local control capabilities.

An increase in the deployment of distributed generation and storage could lead to further flattening of the load profile (when viewed from the transmission system level). This would increase the need for baseload generation and reduce the need for peaking generation. Thus, a smart grid can create the opportunity to deploy distributed coal-based generation units particularly in a combined heat and power configuration.

Enable new products, services, and markets—The Smart Grid will link buyers and sellers together—from the consumer to the Regional Transmission Organization (RTO)—and all those in between. It will support the creation of new electricity markets ranging from the home energy management system at the consumers' premises to the technologies that allow consumers and third parties to bid their energy resources into the electricity market(3), including distributed generation and storage and community microgrids.

Market forces such as demand, supply, environmental impacts, prices, and reliability, will determine whether central or distributed baseload resources will compete and operate in conjunction with other resources.

Provide power quality for the digital economy – The Smart Grid will enable monitoring, diagnostics, and responsiveness to power quality deficiencies, leading to potential reductions in business losses currently experienced by consumers due to insufficient power quality. As new power quality standards emerge, load sensitivity can be balanced against delivered power quality, which could lead to varying grades of power quality at different pricing levels.

The movement to a decentralized operating model will likely include more variable and less reliable renewable sources such as wind and solar. Therefore, coal-based generation and CHP could help address the intermittency of renewables by supporting a high power quality that supplements a distributed generation portfolio.

Optimize asset utilization and operate efficiently—Operationally, a Smart Grid will help improve load factors, lower system losses, and dramatically improve outage management performance. The availability of additional grid intelligence will provide planners and engineers with information that may enable more effective design and timely construction of distribution systems, or to help extend the life of assets, or repair equipment before it fails unexpectedly. In addition, smart grids can enable a more effective work force by reducing redundancies or guesswork in maintaining the grid prior to and during outages. Operational, maintenance, and capital costs could be reduced, thereby keeping downward pressure on electricity prices.

Coal generation technologies are discussed in the next section in terms of how they can function in a smart grid configuration at high utilization and efficiency levels.

Anticipate and respond to system disturbances (self-heal)—The Smart Grid will consist of "self-healing" mechanisms that involve performing continuous self-assessments to detect and analyze issues, take corrective action to mitigate them, and, if needed, help to rapidly restore grid components or network sections. It will also help address problems that in the past have been too fast-moving for human intervention. This "self-healing" capability will help maintain grid reliability, security, affordability, power quality, and efficiency. This aspect of smart grid may involve multiple features such as DG, automatic switching to redundancies, microgrid operations, demand response, and possibly other devices. Generation portfolio diversity is therefore important to supporting the "self-healing" aspect of a smart grid.

Operate resiliently against attack and natural disaster—The Smart Grid will incorporate a system-wide solution that reduces physical and cyber vulnerabilities and enables a rapid recovery from disruptions. This expected resilience will help deter would-be attackers, partially because of its decentralized operating model and self-healing features. These will also help make it less vulnerable to natural disasters than today's grid.

As mentioned above, the deployment of coal-based DG will increase the diversity of the entire portfolio by providing baseload operating behavior, and ability to complement the shortcomings of variable renewables.

In summary, the Smart Grid creates the following opportunities and impacts for coal-based generation:

- Use of coal-based generation in distributed applications, particularly in a CHP configuration
- Increased value of baseload generation (coal and nuclear)
- Creation of a consumer market for energy, giving coal-based generation the opportunity to compete with other options across multiple dimensions (price, economic impact, reliability, etc.)

3 Future Baseload Demand

The two main load types recognized at the systems level are baseload and peaking load. Coal is typically used for supplying the baseload from large centralized power plants. Smaller, natural gas power plants are usually used for peak demand.

Baseload[1] is the minimum power demand over a period of time, usually a year. It can be supplied by generators continuously dispatched over the time period, thus yielding a 100 percent capacity factor.[2] Generators that supply all or a part of the minimum load of the system are called baseload generators.[3] Although baseload generators can be utilized 100 percent of the time, they have to go off-line for scheduled or unscheduled maintenance. Generators that operate most reliably and efficiently at capacity factors higher than 70 percent are usually considered baseload generators. Because of technical and economic reasons, nuclear and coal power plants usually operate at high capacity factors and considered baseload generators. Hydropower plants in the past have been considered baseload generators, but their utilization over the last 20 years (now at 38 percent capacity factor) demonstrates that they should no longer be considered baseload generators. Natural-gas fired combined cycle generators are also considered baseload generation; although, as a group their 38 percent capacity factor does not fit the baseload definition. Although small in total generation, biomass power plants do meet the criteria for being considered baseload generation since they can operate efficiently at 70 percent capacity factors and higher.

Baseload generation fuel costs are almost always lower than any other non-renewable[4] generation and are usually dispatched first unless must-take or must-run generators with higher costs take priority in dispatch. Industry economics favor baseload generation at high utilization levels due to their lower costs per kWh over the plant life.

One of the visions for the Smart Grid future is shifting part of peak demand to off-peak and shoulder periods to increase the baseload, thus increasing the demand for baseload generation.

Large coal power plants have potential to play an enhanced role in a smart grid because better management of the electricity transfer and distribution system could shift the different types of load to the baseload generation. However, smaller coal plants with multiple products (electricity,

[1] U.S. Energy Information Administration (EIA) defines based load as “the minimum amount of electric power delivered or required over a given period of time at a steady rate” (7).

[2] EIA defines capacity factor as “the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period” (7).

[3] EIA defines a baseload plant as “a plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs” (7).

[4] Intermittent or variable resources such as wind and solar are not considered baseload plants because they cannot be forced to run at a steady state.

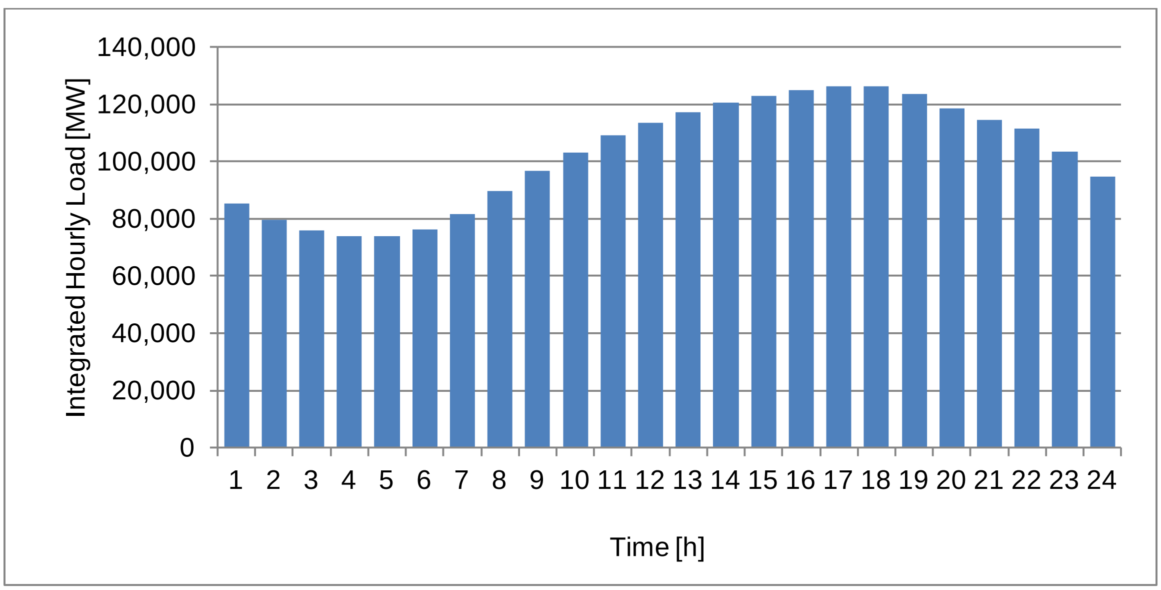
heat, fertilizer, etc.) located closer to the loads may also prove to be economical and have high-efficiency.

Evaluation of coal in a smart grid environment focuses on two major roles: the continued development of large baseload central-station generating technology, and the potential deployment of smaller baseload DG technology. The next section discusses the extent that baseload demand could increase and thus increase the need for baseload coal DG and central plant generation.

3.2 Baseload Leveling in Smart Grid Environment

Government agencies periodically forecast the nation's future energy demand. However, estimating the increase in baseload demand, due to load leveling, is a complex problem to solve. It depends on transmission and distribution network capacity, network congestion, and electricity price. It should be estimated for each substation in the system because the loads at different locations have different profiles. Due to lack of data, aggregated demand at an independent system operator (ISO) level is used in the following scenario. PJM Interconnection, LLC (PJM) ISO is used to illustrate maximum baseload demand achievable through load leveling. June 23 2010, when PJM ISO load reached the maximum level in the first six months of 2010, is chosen as the representative day (Exhibit 3-1).

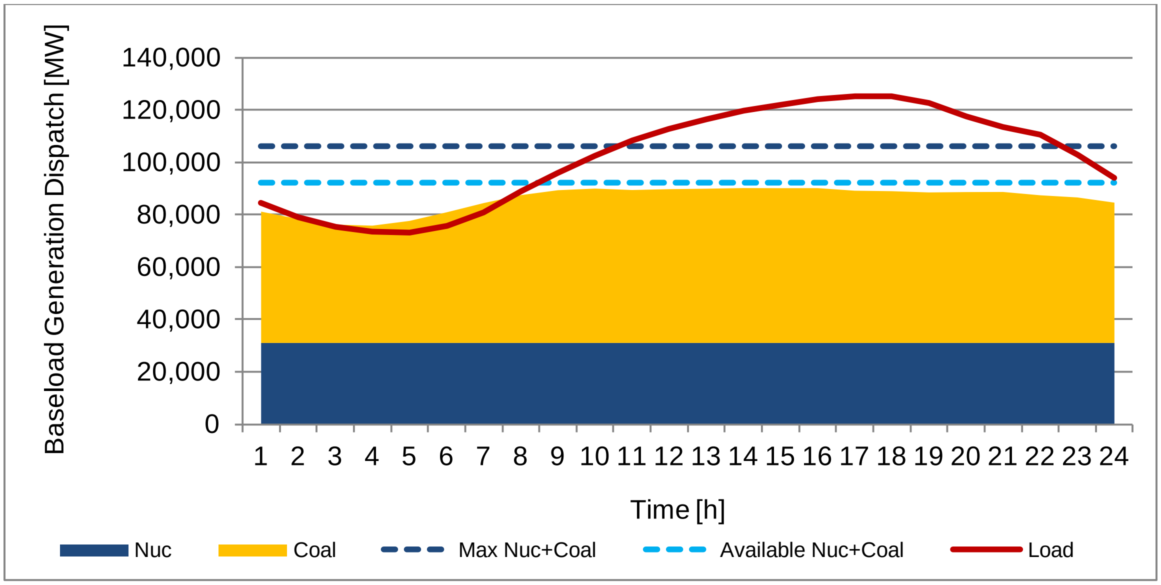
Exhibit 3-1 PJM ISO Integrated Hourly Load (June 23, 2010)



Data source: (4)

The integrated hourly load has a characteristic load profile with an off-peak load period during the night and a peak load period during the day. The given load was supplied by baseload generation (nuclear and coal), hydro generation, natural gas generation, and renewable generation. Exhibit 3-2 shows the total aggregated demand supplied by baseload generation. The dark blue dotted line represents the maximum available baseload generation plus 15 percent spinning reserve for June 23, 2010. The maximum baseload generation (106,165 MW) includes maximum coal and nuclear capacity on that day. Since this value includes 15 percent as required reserves, the available baseload generation capacity that can be used during the day to supply the baseload is 92,318 MW (dotted light blue line in Exhibit 3-2).

Exhibit 3-2 Baseload Generation Dispatch on June 23, 2010



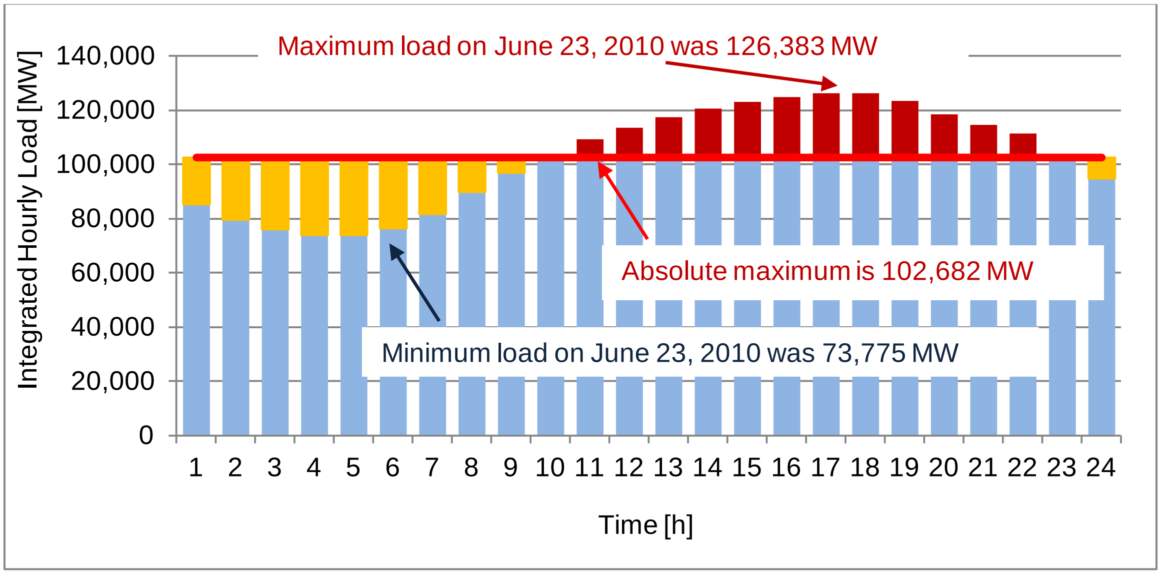
Data source: (4), (5)

Baseload generation should supply all or a part of the minimum demand and should run constantly. However, PJM baseload generation is higher than the minimum load and coal generation is cycled.[1] Coal generation can be better utilized if Smart Grid technologies such as energy storage, demand response, or demand dispatch are used for load leveling. In this report, we do not analyze different Smart Grid technologies, but we assume that the appropriate technologies will be in place when needed.

A scenario in which Smart Grid technologies would completely level the integrated load is shown in Exhibit 3-3. The load from peak hours (red bars) are transferred to baseload hours (orange bars) such that the total energy consumed during the day remains the same. This energy transfer determines an absolute daily maximum of 102,682 MW, representing a completely leveled aggregated load. The peak load is reduced by 19 percent, the baseload demand is increased by 39 percent and there is not enough baseload generation to fully supply the leveled demand. Complete load leveling is not a realistic case, but it provides an upper limit (19 percent) of possible load transfer from the peak to the baseload period. If more than 19 percent of the peak load is transferred to the baseload period, the peak and baseload periods would switch hours — the baseload period would become the peak period.

[1] A study (80) has documented the negative effects of frequent cycling these types of plants.

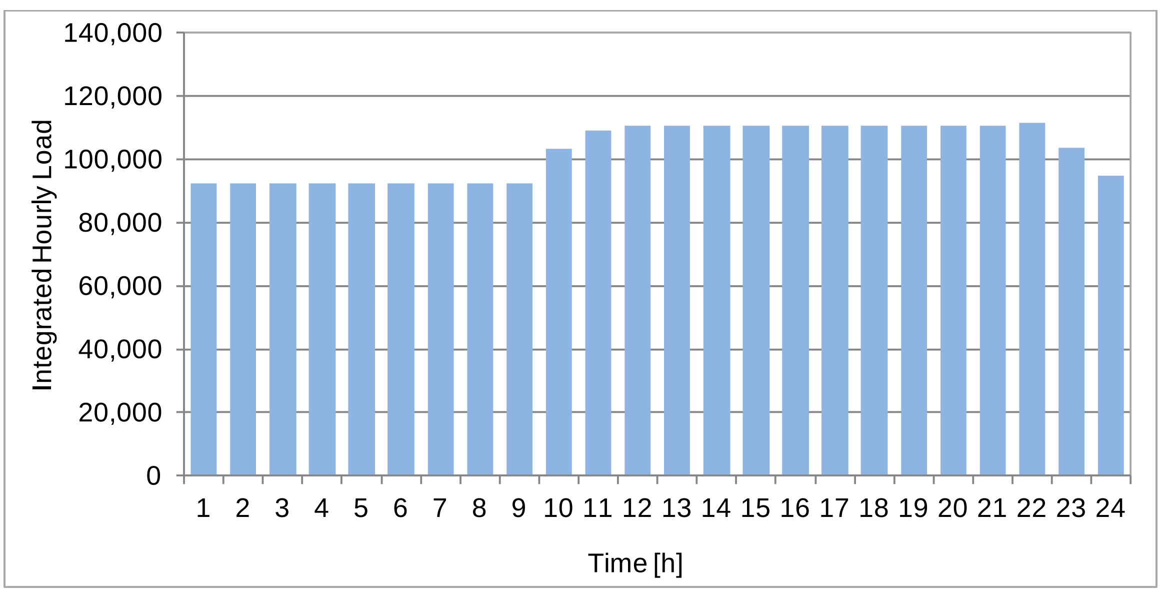
Exhibit 3-3 Integrated, Completely Leveled Load



Data source: (4)

On the other hand, the available baseload generation capacity that can be used during the day is 92,318 MW. The total energy that can be transferred from peak to baseload period is 102,103 MWh. This energy corresponds to 12 percent of peak load reduction (from 126,383 MW to 110,700 MW) and a baseload increase of 25 percent (from 73,775 MW to 92,318 MW). The new load profile is illustrated in Exhibit 3-4.

Exhibit 3-4 Aggregated Load Leveling



Data source: (4)

Clearly, the conclusion is that even today, PJM would not have enough baseload generation capacity if the load is completely leveled by the Smart Grid technologies. Even if the Smart Grid and baseload generation are available to completely flatten the load, it might not be the best decision. The Smart Grid can enable use of appropriate resources, but it does not mean that the resources are available at any given time or economically justifiable. The next section discusses a more general case and estimates the forecasted baseload generation and its ability to meet the forecasted demand at the aggregated U.S. load level.

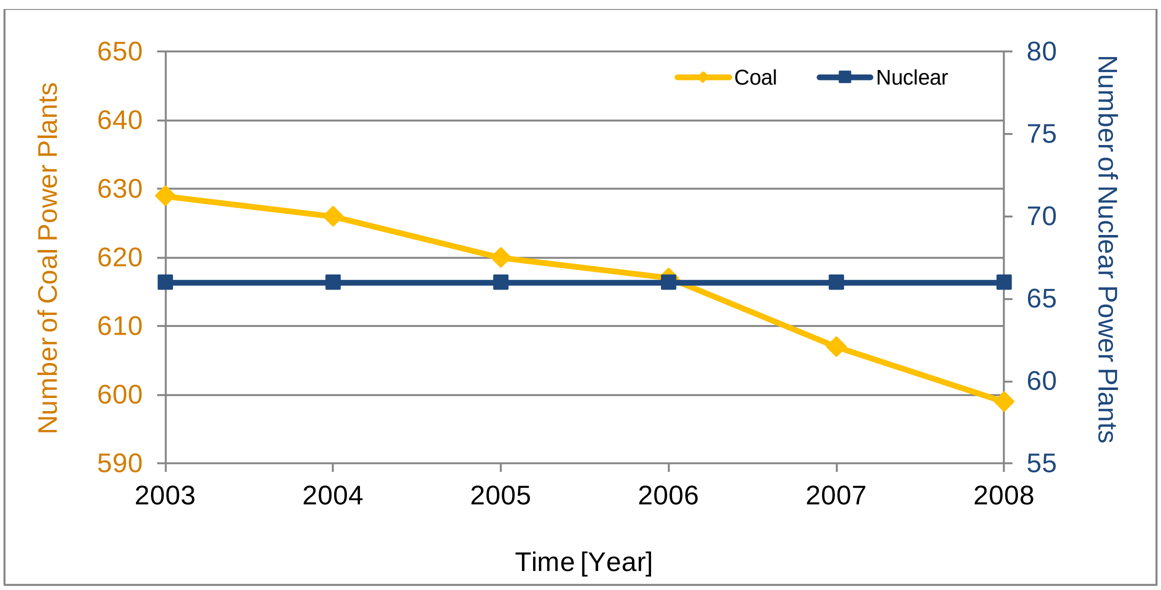
3.3 US Ability to Meet Forecasted Baseload

The current status of U.S. baseload generation is estimated using the Ventyx Velocity Suite Database (6). From this database, the upper limit of a baseload generation shortage or excess is determined and then used as the baseline case. The analysis determines whether baseload generation for load leveling is needed based on what is in place today and on the forecasted future resources and demand.

Considering that baseload generation is cheaper than peaking generation, ideally, the most economical situation would be to use baseload generation for generation reserves, supplement variable renewable generation, and level peak-load. The available baseload generation for load leveling is calculated as the forecasted baseload generation minus the forecasted baseload demand, minus the generation reserve, and minus reserves for variable renewable generation.

The number of coal baseload power plants has decreased (Exhibit 3-5) while the coal baseload generation output has increased.

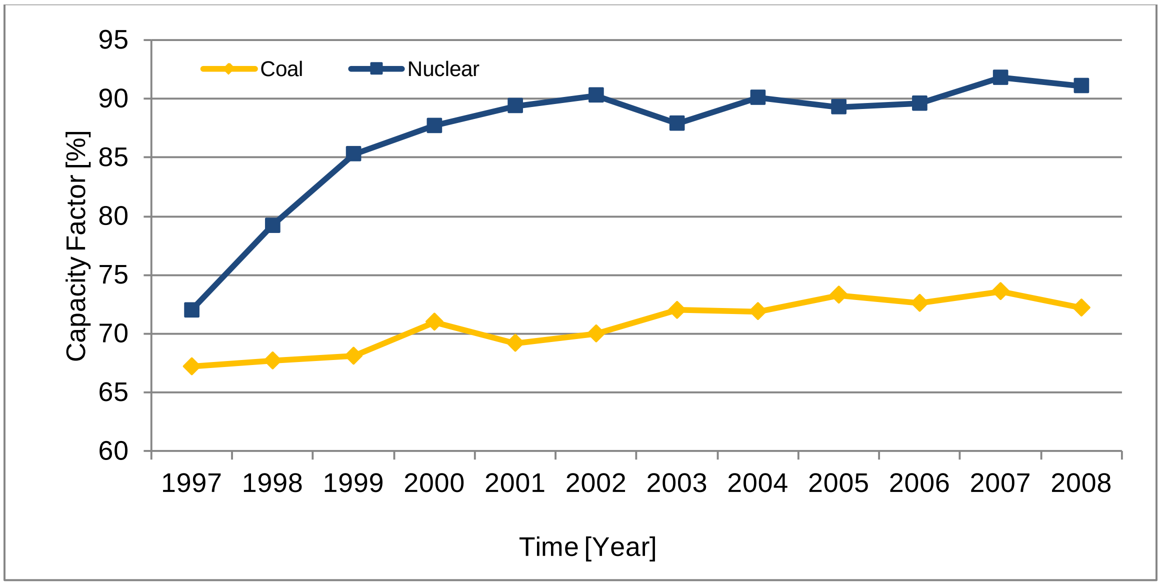
Exhibit 3-5 Number of Baseload Power Plants



Source: (7)

The logical conclusion is that the baseload generators are operating at increasingly higher capacity factors,[1] and/or the number of generating units increases, and/or the units are larger. Higher capacity factor means that baseload generators are dispatched with higher output. Exhibit 3-6 shows that the coal generation units' capacity factor has increased since 1997. In 1997, the capacity factor was 67 percent while in 2008 this value increased to 72 percent.

Exhibit 3-6 Baseload Generation Capacity Factors by Fuel Type



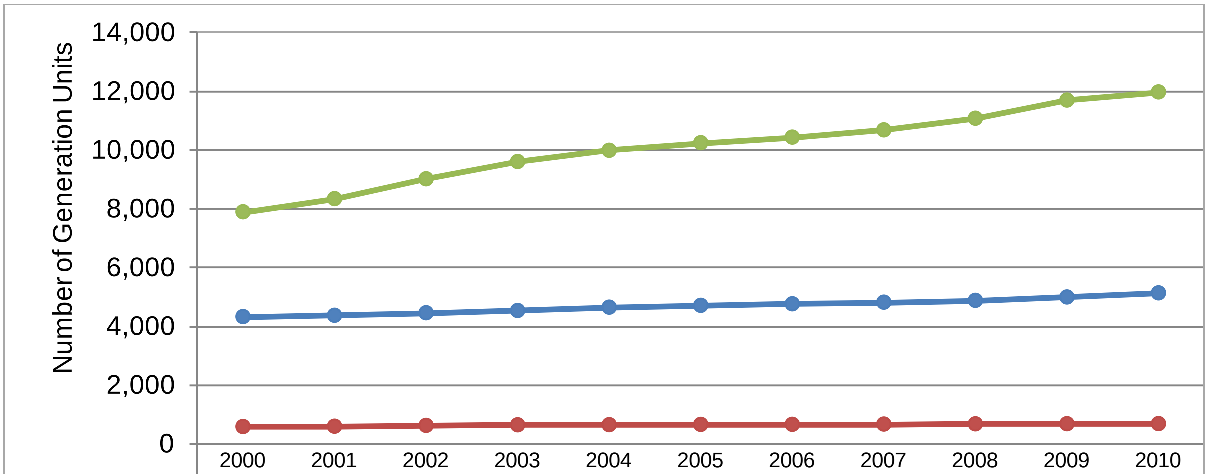
Source: (7)

The number of baseload generation units also increased (Exhibit 3-7). In 2000, the number of baseload generation units was 4,324 while in 2010 this number increased to 5,131, an increase of 18 percent.

Exhibit 3-8 illustrates a 22 percent increase in size of baseload generation units. In 2000, the baseload generation unit size was 103 MW while in 2010 the average size is 126 MW.

[1] The EIA definition of capacity factor is "the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period" (7).

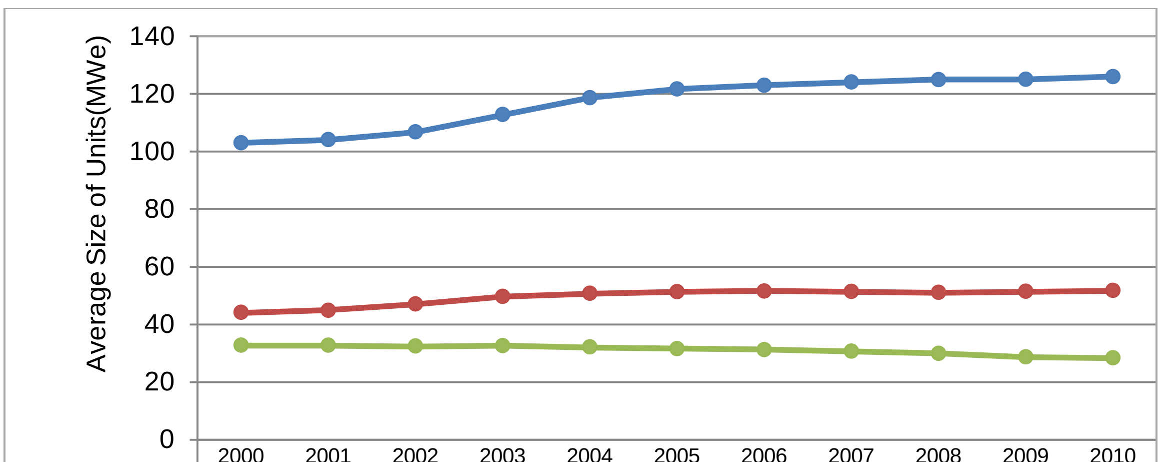
Exhibit 3-7 L48[1] Historical Dispatch by Number of Generation Units, 2000-2010



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Baseload	4,324	4,368	4,454	4,531	4,644	4,706	4,759	4,814	4,876	4,991	5,131
Cycling	582	593	621	641	645	655	657	666	674	678	681
Peaking	7,890	8,337	9,013	9,601	9,983	10,241	10,431	10,678	11,074	11,692	11,969

Data source: (6)

Exhibit 3-8 U.S. L48 Historical Dispatch Size of Units 2000-2010



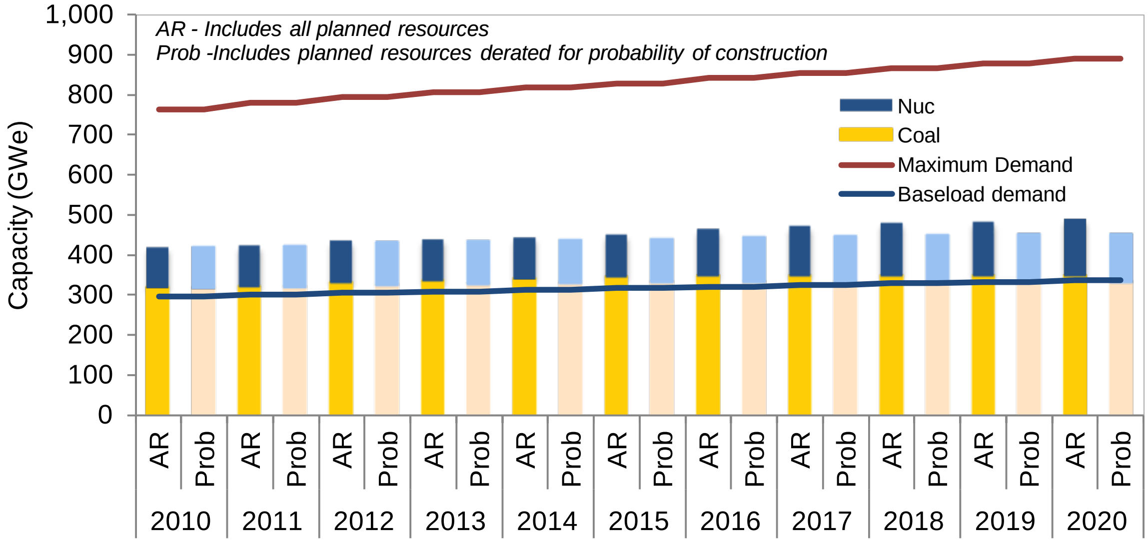
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Baseload	103.0	104.1	106.8	112.8	118.7	121.7	123.0	124.1	124.9	125.1	126.0
Cycling	44.1	44.8	47.0	49.6	50.7	51.3	51.5	51.4	51.0	51.4	51.7
Peaking	32.7	32.7	32.4	32.5	32.1	31.5	31.1	30.6	29.8	28.6	28.3

Data source: (6)

The estimated baseload,[1] maximum load, and baseload generation profile over the 2010-2020 period is shown in Exhibit 3-9.

[1] Lower 48 states – the United States without Hawaii and Alaska.

Exhibit 3-9 Operating Baseload Generation Resources in U.S L48, 2010-2020

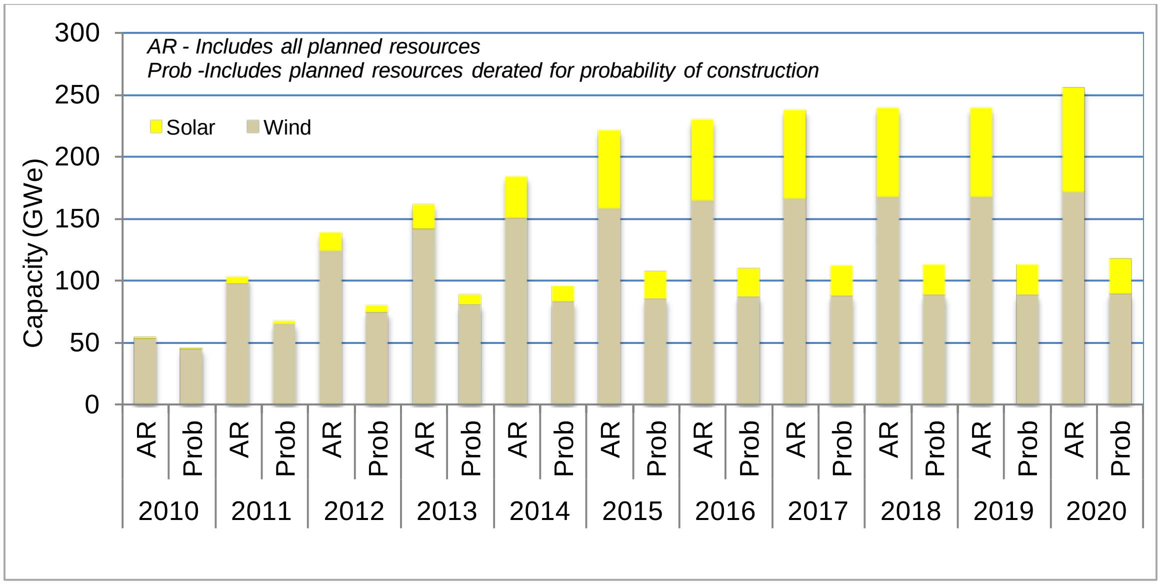


Data source: (6)

Generation reserve is generally 15 percent of demand. Renewable resources such as wind and photovoltaic are variable and need to be backed up by firm generation, including baseload generation if possible. Backup generation for variable renewables could be constructed based on wind and solar penetration each year (Exhibit 3-10) where wind capacity is multiplied by 10 percent and solar capacity by 30 percent (numbers currently being used in planning for using firm generation to accommodate variable renewables).

[1] The baseload for 2010-2020 is estimated based on fitting a linear curve through baseload data from 1997-2009. The data are obtained from the Ventyx Velocity Database.

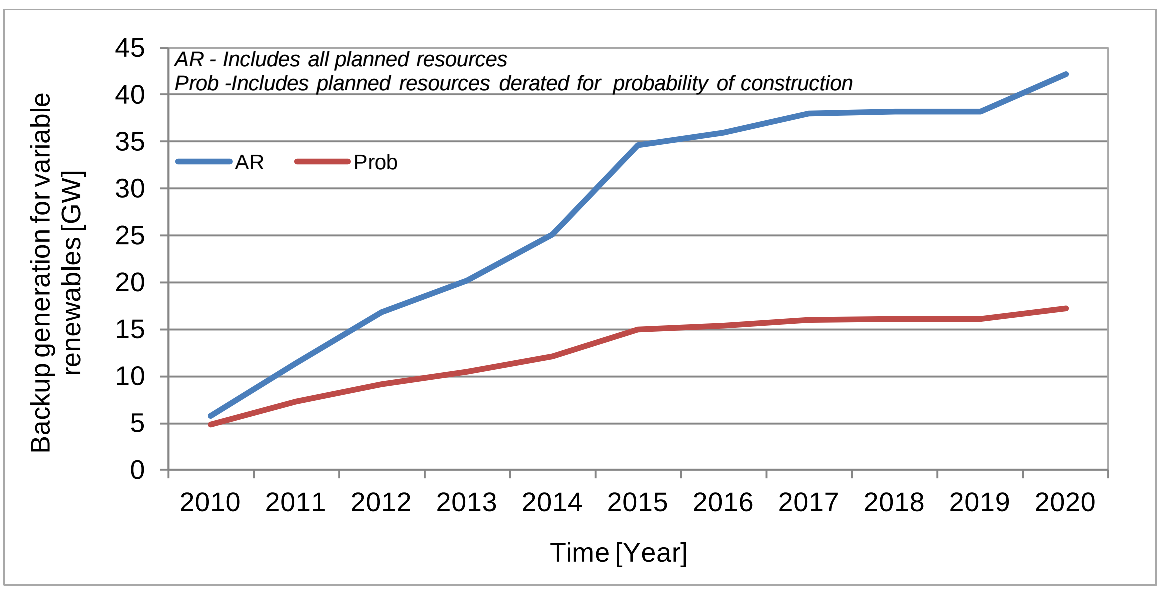
Exhibit 3-10 Solar and Wind Capacity Estimation in U.S. L48, 2010-2020



Data source: (6)

Exhibit 3-11 shows different projected generation operating reserves for projected wind and solar generation penetrations for the scenario when all planned resources are included (AR) and when the probability of construction is included in the forecast (i.e., "Prob").

Exhibit 3-11 Backup Generation for Variable Renewables



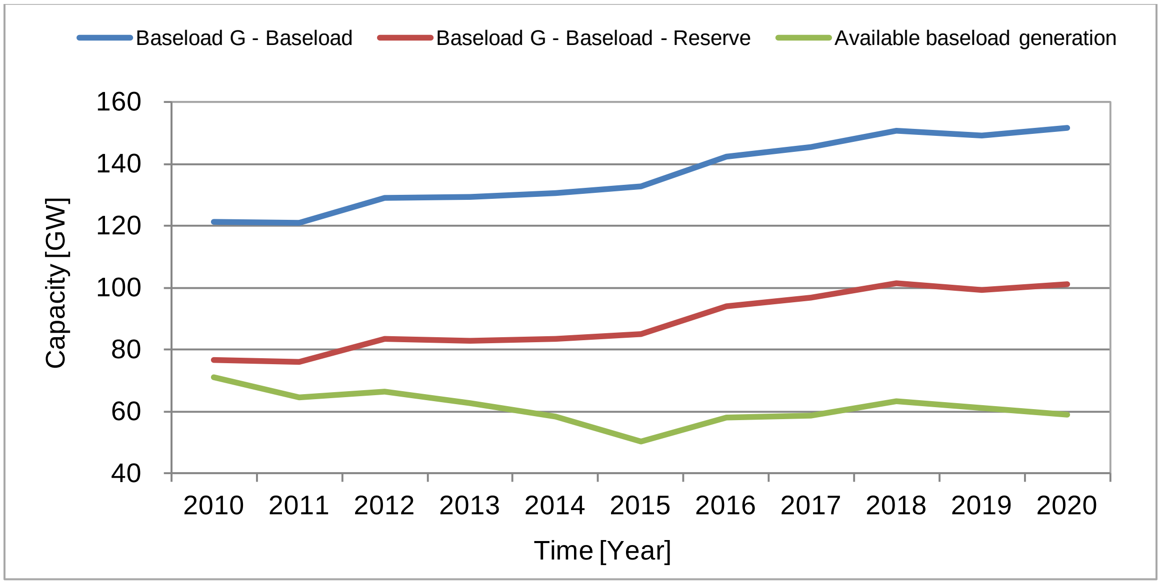
Data source: (6)

The baseload generation available for load leveling is calculated as:

$$P_{available\ base\,load\ gen} = P_{base\ \mathrm{load}\ gen} - P_{base\,load} - P_{reserve} - P_{renew\ reserve}$$

Exhibit 3-12 shows the baseload generation available for peak load leveling for the planning case when all planned resources are included.

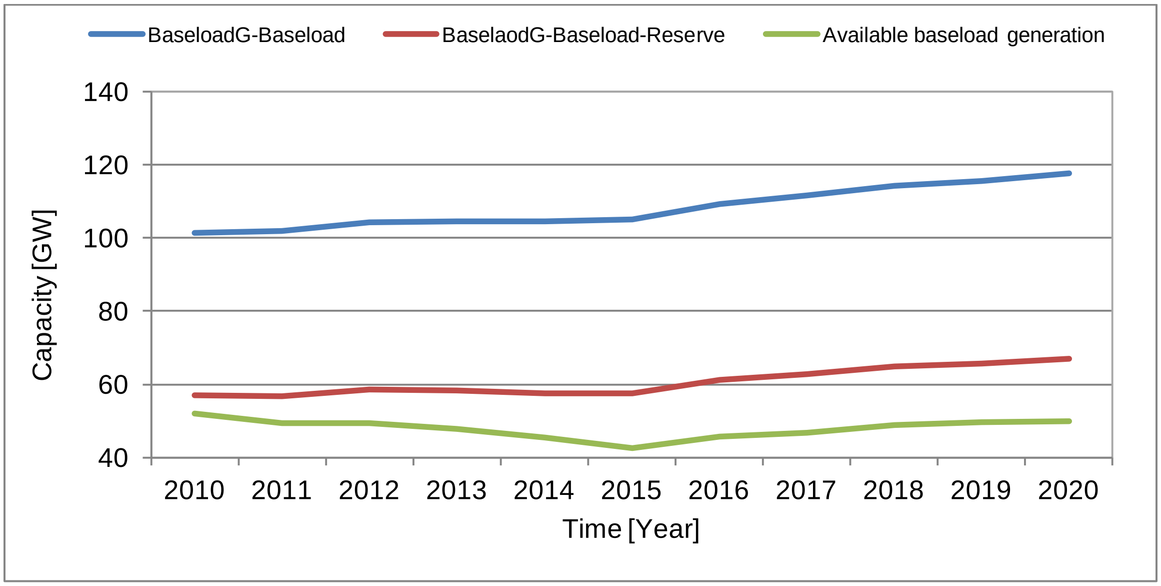
Exhibit 3-12 Available Base Load Generation for Load Leveling (AR)



Data source: (6)

Exhibit 3-13 shows the baseload generation available for peak load leveling for the planning case when the probability of construction is included.

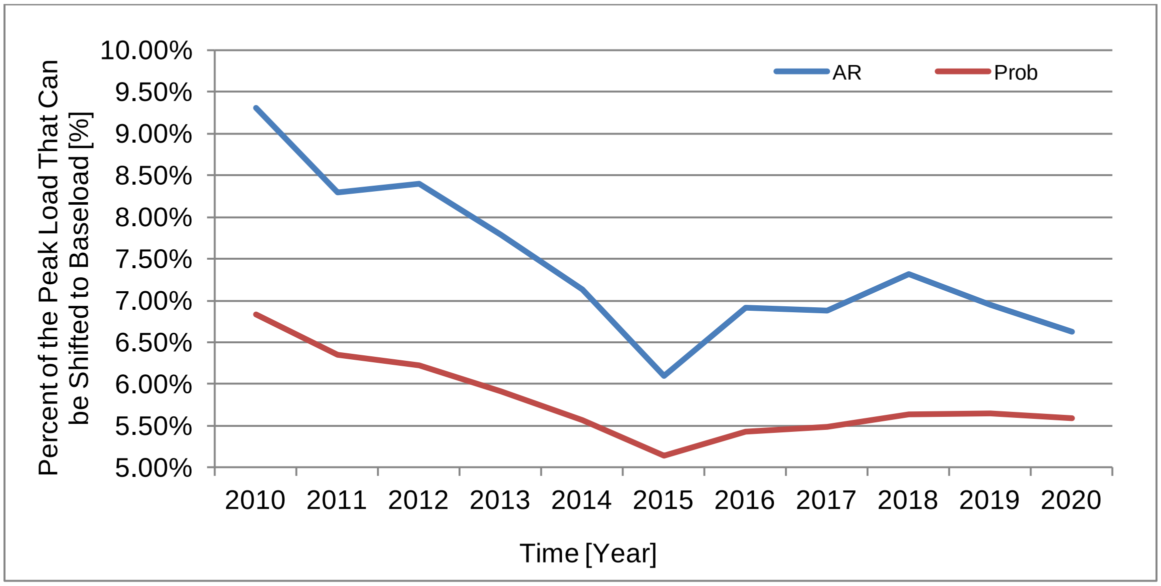
Exhibit 3-13 Available Baseload Generation for Load Leveling (Prob)



Data source: (6)

The forecasts show that baseload generation available for load leveling decreases over the years, and the percent of the peak load that can be shifted to baseload decreases as well (Exhibit 3-14). In 2010, the peak load percent is 9 percent for the AR case and 7 percent for the Prob case. In 2020, the peak load percent decreases to 6 percent for the AR case 5 percent for the Prob case.

Exhibit 3-14 Percent of the Peak Load That Can be Shifted to Baseload



If the peak load is kept at the values that we have today, there will be a need for new baseload generation. Today, the baseload generation available for load leveling is between 7 and 9 percent, but it decreases over the coming years (Exhibit 3-14). The baseload generation capacity should be increased by 30 to 40 GW to maintain current load leveling capabilities. This capacity increase can be achieved by building large centralized power plants, small distributed power plants, or mix of the two.

3.4 Summary

The above analysis performed at the aggregated US level shows that there will be shortages of baseload generation if the Smart Grid enables load leveling and use of variable renewables. In the past, baseload generation was mostly supplied by large coal power plants. The Smart Grid also has potential for enabling distributed generation and higher penetration of renewable resources. In the following sections, the possibility of baseload supplied by coal-based DG, cogeneration, and microgrids will be explored further. Effects of these resources acting as baseload generation on the reliability and stability of a power system will also be discussed.

4 Baseload Coal Generation Technologies

Coal power plants are typically dispatched to supply the baseload part of the total demand, with recent plants sized at 500-600 MW per unit. In the Smart Grid environment envisioned in this study, coal power plants can be different sizes based on location and multi-purpose designs for supplying both baseload and peak demand.

Small distributed power plants are always less efficient and more expensive than large power plants using the same technology. In the past, a common justification for using distributed generation was to resolve transmission congestion and to supply power locally to remote communities that are difficult to reach with transmission lines. With the Smart Grid introduction, DG provides additional benefits. A well-designed Smart Grid can make a mix of traditional coal power plants and variable renewable resources appear as providing firm power to the local community without interfering with grid operations. Coal DG can also reduce transmission losses while improving system security and reliability. DG can be located on either a sub-transmission or a distribution system. DG operations can be significantly affected by their location within the power network. Operations of the power plants located on the sub-transmission system are very similar to large centralized power plants. DG located within the distribution system might require additional monitoring and control and energy resources if coupled with variable renewable energy sources or if it causes bidirectional power flow on the radial power lines. Regardless of the location, DG can be coal and/or cogeneration based. Combined heat and power (CHP), is usually not an option for centralized power plants. All these options for baseload generation will be discussed in more detail in this section.

Coal power plants of any size are usually considered as baseload plants. Small coal DG can function as baseload generators if properly dispatched and if they provide mandatory reserves as discussed in Section 5. The following sections evaluate different baseload generation options in terms of efficiency, capital and operational cost, and environmental impact. More detailed review of particular power plant technologies can be found in the appendices.

4.2 Centralized Coal Generation

Large centralized coal power plants have dominated baseload generation for almost a hundred years. Their efficiency and capital and operational costs usually compare favorably against smaller plants. The transmission loss and capital and maintenance costs are sometimes a major obstacle to utilizing large, remote power plants in general.

Efficiency is usually used as one of the benchmarks for electricity generation. Large thermal generators are always more efficient than smaller ones of the same technology. Exhibit A- 2 and Exhibit A- 16 show that the difference in efficiency between 600 MW and 10 MW power plants can be 14 percent.

Although large centralized power plants appear to be considerably more efficient, it is important to properly account for reduced transmission losses and other benefits that might be significant in the case of small DG plants.

Several mechanisms can increase the efficiency and utilization of baseload coal generation. In a Smart Grid environment, this could be derived from a lower and more stable hour-by-hour on-peak load requirement and a higher minimum load at night (off-peak) resulting in less load follow and higher "full-time" asset utilization.

The PC and CFB capital cost per kWe are around 20 percent lower than IGCC capital cost per kWe. However, the capital cost of PC and CFB are three times larger than NGCC for the same size unit. At approximately $4.50/MM Btu, coal and natural gas are competitive fuels. Natural gas combined cycle (NGCC) is forcing older pulverized coal plants off-line. Natural gas prices have historically been volatile, so this situation may not be relevant to planning for 2020 and 2030. The following table (Exhibit 4-1) supports this claim.

Exhibit 4-1 Fuel Cost for Different Technologies

	Gas	Coal new, best in class	Coal, average	Coal, older unit
Price (per MMBtu)	$4.00	$2.00	$2.00	$2.00
Heat Rate	6,600	8,500	10,000	11,500
Lower and Higher Heating Value	57 % LHV	40.1 HHV	34.1 HHV	29.7 HHV
$/MWh	24	17	20	23

Data Source: (8), (5)

A baseload coal power plant is competitive with a natural gas baseload power plant if the price of natural gas is high. Both baseload coal and baseload gas CC power plants are less expensive than the same size IGCC power plant. However, IGCC belongs to coal technology and it lends itself to carbon capture more readily and at lower incremental cost compared to coal combustion technologies. IGCC will be competitive in levelized cost of electricity (LCOE) terms with coal combustion if a penalty of $300/ton of CO_2 is adopted.

From a technical point of view, both PC and IGCC have slow and long start-up and shut-down times, and they both are suitable for baseload generation. PC operation is more flexible in terms of changing the output in comparison with IGCC and it can be cycled as a function of demand. In addition, PC has higher efficiency than IGCC. However, PC lends itself to carbon capture less readily and at higher incremental cost compared to IGCC.

4.3 Distributed Coal Generation

Under a distributed baseload generation scenario, the baseload is different for every community, industrial park, neighborhood, and campus. Baseload becomes a small, distributed quantity and varies during the year, in a neighborhood or industrial park, or when aggregated across a utility's service territory.

There would be an advantage to placing a small DG for baseload generation in the same community where large penetration of PV, or other variable renewables, exists. This would allow the small DG to "firm up" the renewables. Now, considering energy storage, the effective firm power represented by the small DG, storage, and renewables would exceed the firm capacity of just the small DG.

Currently, the U.S. distributed generation technology portfolio is not conducive to economically supporting baseload. Today, only natural gas and diesel fuels can be used as firm distributed power for baseload. The cost of gas or diesel makes this form of firm distributed power uneconomical. Exhibit 4-2 presents a look at these types of plants, their typical efficiencies, and the resulting cost of electricity.

Exhibit 4-2 Some Technologies for Supporting Distributed Baseload Generation

Fuel	$/MMBtu	Avg Heat rate (Btu/kWh)	$/kWh
Coal (avg)	$2.07	10,378	$0.0215
Petroleum Products	$10.87	11,015	$0.1197
Natural Gas	$9.02	8,305	$0.0749

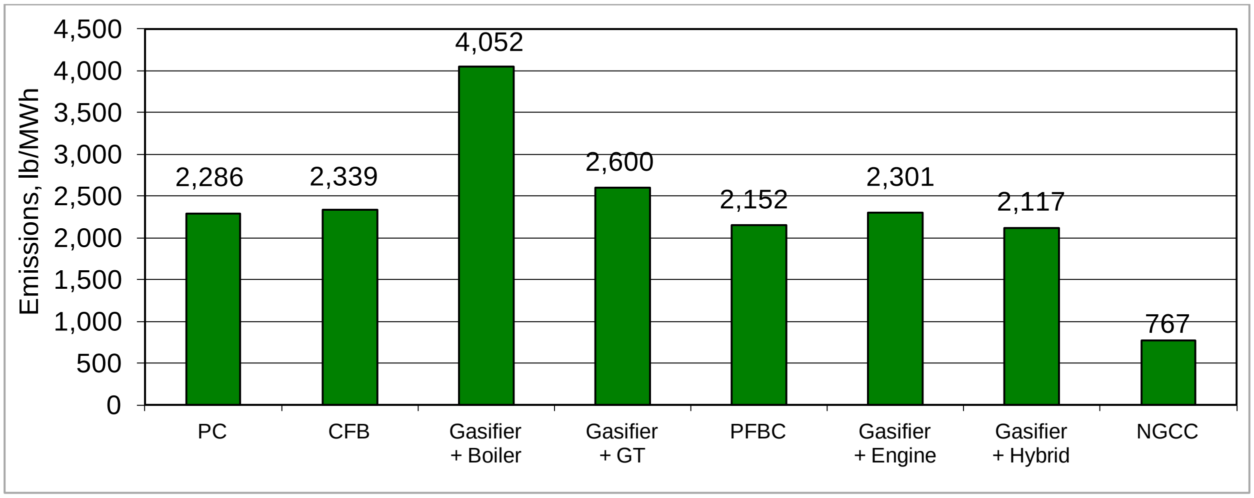
Data Source: (8)

Note that the fuel cost for natural gas is attractive now, but natural gas prices have a history of being very volatile. Should prices rise to previously seen levels, natural gas-generated power will also become uneconomical. Note that the difference in natural gas prices between Exhibit 4-1 and 4-2 is that larger plants would likely pay wholesale prices for natural gas and smaller plants would likely pay a higher price for natural gas that is closer to retail prices. The configurations of coal-fired technology that can approach the economy levels of large central stations are discussed in Appendix A. All evaluated small coal-fired CHP-capable power plants have emissions within the competitive range for pollutants of interest (Exhibit 4-3).

As smaller units are distributed close to the baseload, the need for transmission and distribution infrastructure is greatly reduced, thus providing additional savings. In addition, with this distributed fleet, the typical 10 percent transmission and distribution power losses to the load from a large central-station generator are nearly eliminated. To deliver 1,000 MW to the baseload, the single large unit would need to be at least 1,100 MW, costing $6.6 billion. This additional $600 million would not be required for the 100 10 MW DG units. However, at a typical value of $210/kW, 1000 MW of additional new generation would cost $210 million, which would be considerably less than the cost of 100 10 MW DG units.

Integrated gasification combined cycle power plants are primarily suited for baseload generation and have low feasibility as a load following or peak load generation application. The IGCC gasifier and its refractory need hours to warm up to the required gasification temperature and pressure. During the startup, natural gas (NG) for the gas turbine and/or electric power for the air separation unit (ASU) are supplied externally. Because of the additional load on the power grid during start-up, IGCCs are not suitable for peak load. They are especially suitable, however, for baseload operation (9). Using small air-blown IGCC plants has been suggested as a potential solution for startup problems.

Exhibit 4-3 CO_2 Emission



Source: (10)

Other solutions have also been suggested to help IGCC operate as a load-following unit (11). One possibility is converting the syngas to synthetic natural gas, followed by transportation via pipelines (11). However, the economic implications are thought to be significant. Our conservative estimates reveal a more than 100 percent potential increase in the cost of energy for a 620-MW plant. This is consistent with the values reported in the literature (12).

Another suggested solution includes storing the syngas when it is not needed and using it when it is. The syngas is stored under pressure because the pressurized gas occupies a smaller space and, therefore, needs less storage space. Depending on the size of the plant and other factors, this approach is believed to impose a COE increase of at least 20–40 percent to store enough syngas needed to run a 620-MW plant for 24 hours. This is probably a very optimistic estimate because it assumes that the material of construction for the storage is available at the price of commercial steel. Storing hydrogen-containing gasses for prolonged periods is believed to be problematic and impractical due to the hydrogen embrittlement (13). To successfully store syngas, the storage must be built out of special material, such as carbon-fibers or "reversible crystalline metal hydrides" (13), which could be several times more expensive than the assumptions here.

Certain underground reservoirs could also be used to store large volumes of gas. These reservoirs are generally categorized in four groups (14):

- Depleted oil or gas fields
- Aquifers
- Excavated rock caverns
- Salt caverns

There is extensive experience in storing syngas in underground reservoirs (14). For large quantities of gas, underground storage is considered the least costly method ((15), (16)). Economic and technical aspects of storing the syngas are discussed in the literature, and it is shown to be more economically viable when compared to methanation (11).

4.4 Coal Combined Heat and Power

Interest in combined heat and power (CHP) technologies has increased over the past decade because there is a need for more efficient use of energy; in some cases, CHP could also enhance energy reliability. CHP is a form of distributed generation involving electric generation sited near a heat demand requirement in order to take advantage of the waste heat typically emitted in electricity generation. Today, 9 percent of the global power generation is provided by CHP (17).

The diversity in fuels and prime movers offered by CHP may provide an important integration platform for distributed renewable sources in the future. Since the early 1980s, Denmark has been redirecting their energy production efforts towards renewables and CHP. Denmark has succeeded in supplying most of its energy needs from wind and small, distributed, CHP-based power plants. It is not clear if CHP/wind combination was chosen by design and how well they are integrated. A detailed review of Denmark's CHP/wind evolution with respect to policies, economics, and technological solutions can be found in Appendix B as well as a comprehensive comparison with the U.S. experience. The conclusion of that review is that Denmark is much better suitable for small, community-based CHP power plants than the U.S. Denmark had significant thermal heating infrastructure in place when the country decided to invest in CHP and renewable resources. U.S. policymakers made similar attempts to encourage CHP energy production, but it was mostly adopted by industrial and commercial installations that did not require significant investment in thermal energy distribution infrastructure.

4.4.2 CHP Technologies in Use

CHP can have different prime movers, such as steam turbines, reciprocating engines, gas turbines, microturbines, and fuel cells. Depending on the prime mover, CHPs differ in capacity, efficiency, and costs. Exhibit 4-4 shows summary of typical CHP performance and cost for the five different technologies.

The capacity of a CHP plant capacity can vary from 5 kW (fuel cell) up to 250 MW (steam and gas turbines). The steam turbine and reciprocating engine have the highest overall efficiency (~80 percent); the fuel cell may have an overall efficiency as low as 55 percent and as high as 80 percent while the microturbine efficiency ranges between 65 percent and 75 percent. Depending on the technology and start-up time, CHP can be used as a base power plant, or as an intermittent or peaking power plant. As shown in Exhibit 4-4, start-up times can be between 10 seconds and 2 days. The most expensive technology, both in original investment and operating costs, is the fuel cell while the steam turbine is the cheapest.

According to the International Energy Agency's (IEA) Clean Coal Centre, the most used fuel worldwide for CHP is natural gas. Because the price of this fuel is relatively high, the natural gas power plant operators are motivated to maximize efficiency by converting their plants into

CHP. However, due to gas price volatility and supply constraints, coal is the more preferred fuel for some applications (18). The IEA also reports that the most used coal-based technology is FBC. The most used natural gas-based technologies compared with FBC are shown in the Exhibit 4-5 (17):

- Gas turbine with heat-recovery steam generator (GT-HRSG)
- Combined cycle gas turbines (CCGT)
- Internal combustion engines (ICE) with electrical generators and heat extraction systems

Exhibit 4-4 Summary of Typical CHP Performance and Costs

Technology	Steam Turbine	Reciprocating Engine	Gas Turbine	Microturbine	Fuel Cell
Capacity [MWe]	0.5 – 250	0.01 – 5	0.5 – 250	0.03 – 0.25	0.005-2
Power efficiency (HHV)	15-38%	22-40%	22-36%	18-27%	30-63%
Overall efficiency (HHV)	80%	70-80%	70-75%	65-75%	55-80%
Availability	Near 100%	92-97%	90-98%	90-98%	>95%
Start-up time	1 h – 1 day	10 sec	10 min – 1 h	60 sec	3 h – 2 days
Fuels	All	Natural gas, biogas, propane, landfill gas	Natural gas, biogas, propane, oil	Natural gas, biogas, propane, oil	Hydrogen, natural gas, propane, methanol
Installed cost [$/kWe]	430 – 1,100	1,100 – 2,200	970 – 1,300	2,400 -3,000	5,000-6,500
O&M cost [$/kWhe]	<0.005	0.009-0.022	0.004-0.011	0.012-0.025	0.032-0.038
Note:	Data are illustrative values for typical available systems; higher heating value (HHV) All costs are in 2007$				

Data source: (19)

Pulverized coal combustion (PCC) may also be used as a CHP technology, but the large boilers and associated equipment required by PCC are unsuitable for small CHP units. Capital, operating, and maintenance (O&M) costs for different technologies are summarized in Exhibit 4-5. FBC is the most expensive technology, but it has lower O&M costs than internal combustion engines. Gas turbines with heat recovery steam generators can be the preferable technology because both the installation and O&M costs are lower.

Exhibit 4-5 Installed and O&M Costs for Different CHP Technologies

Technology	GT-HRSG	CCGT	ICE	FBC
Installed cost[$/kWe]	900-1500	1,100-1,800	850-1,950	3,000-4,000
Typical cost [$/kWe]	1,000	1,300	1,150	3,250
O&M [$/kWe/annual]	40	50	250	100

Data source: (17)

4.4.3 US Hybrid CHP/Renewables Economics

Any energy-intense application requiring heat and electricity presents a strong business case for CHP. DG is naturally size-limited by the constraints of the distribution system (approximately 15 MW of power rating per line). As noted in Appendix B, the capital costs of coal based generators increase as the size decreases, from $2000/kW for a 600 MW plant to $4000/kW for an 80 MW plant to $5000/kW for a 40 MW plant. CHP allows a larger generator inside the distribution system while delivering all the benefits of CHP. One of these benefits is residential heat, and residential CHP is already widely used in Europe. For example, an 80 MW generator can provide 65 MW of steam to residential users while delivering 15 MW of electricity to these same customers. An 80 MW plant is 20 percent less expensive in capital costs than a 40 MW plant on a per kW basis.

The frequency stability provided by the hypothetical 80 MW power plant can also stabilize the local grid in the face of variable renewables, and perhaps even allow islanded (microgrid) operations. The two-way power and information flow that Smart Grid provides allows smarter coordination of the coal-fired and renewable resources. What is different between this DG vision and previous distributed generation is the number of installations inside the distribution system and the potential for power to be exported beyond the substation.

Because of the natural size limitations due to the nature of the distribution system, it may be feasible to build coal-fired power plants of a standard size, and reasonably standard configuration. Henderson's law can have some applicability here—with standardized pipes, fittings, valves, and so on allowing modular assembly.

4.4.4 US Hybrid CHP/Renewables Environmental Impact

As described in the previous section, CHP enables capital cost-efficient DG to reside on the grid at the distribution level. However, being locally available also means that emissions will be local as well, in the absence of a tall smoke stack. Coal fired plants are also less efficient the smaller they are, which implies an increase in emissions both locally and regionally. CHP allows DG to operate in a more efficient fashion, due to the efficient use of waste heat, and because the generator is larger. This mitigates the effect of increased emissions due to decreased efficiency. There is also some benefit from reduced transmission losses due to the local nature of the generation.

Due to high efficiency and the ability to enhance distributed resources, CHPs have significant societal and environmental benefit. Studies (20; 21) have indicated that CHP, as a means of distributed resources, brings the following advantages to a local community:

Autonomy to the local community where it is installed:

- CHP can be used as a main power and heat supply while the grid performs a power backup role.
- If CHP is supplied with local fuel, the local community is shielded from fuel price volatility and rate increases.

- In case of a natural catastrophe, CHP can provide an independent supply to critical facilities.
- An integration platform for distributed renewable sources because it uses different fuels such as biogas, solar, wind, biomass;
- Scalability and easy operation (a single CHP can be installed at apartment buildings, supermarkets, hospitals, schools, etc; 10 kWe CHP can provide power and heat to a single household).

Additional CHP benefits include the following:

- High efficiency in comparison with a conventional power plant because CHP requires less fuel than separate heat and power sources to produce the same amount of power;
- Reduced transmission and distribution losses because it is located close to users;
- The possibility to be located at existing facilities so there is no need for a new green space;
- Use of less water than thermoelectric systems because CHP captures and uses the heat, and does not require condensers or cooling towers.

Depending on the fuel and the type of prime mover, CHP brings different environmental benefits. For example, natural gas CHP versus a typical coal power plant would reduce greenhouse gas emissions: ten times less SO_x, two times less NO_x, and three times less CO_2 for the same power produced.

One study estimates (21) that if in 2030 CHP capacity is 20 percent of U.S. capacity, it would reduce annual energy consumption by 5.3 Quads. Moreover, the total annual CO_2 reduction would be 848 million metric tonnes (MMT) and the total annual carbon reduction would be 231 MMT. This amount of annual CO_2 emission reduction is equivalent to 154 million cars being taken off the road.

To take advantage of a CHP power plant, the local air quality and the local air permitting environment must be able to tolerate the additional emissions that will ensue with coal gasification and subsequent firing of the syngas in lieu of NG. This raises the important point of permitting many local small coal-fired CHP plants as opposed to putting business and legal resources into a permit for a larger plant. Although the CHP has less environmental impact per MW over a large area, its impact is concentrated, and especially so in a highly populated area.

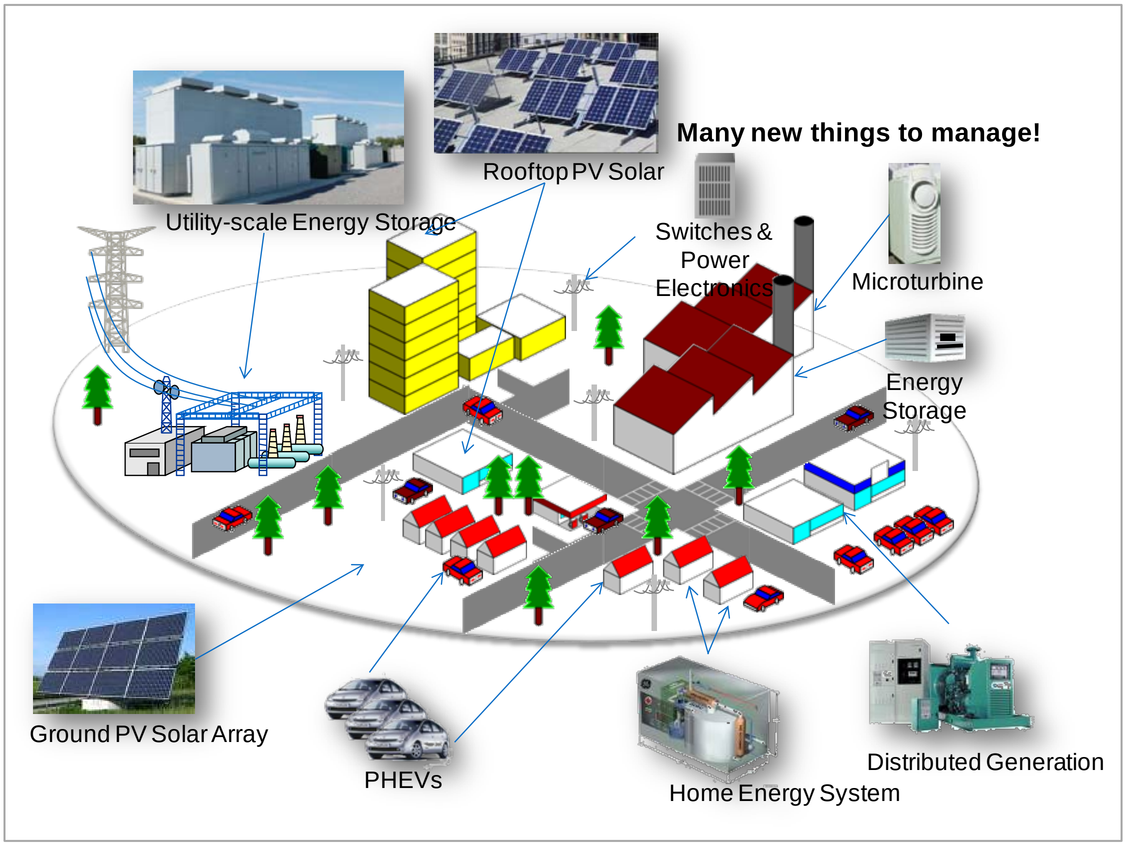
4.5 Coal Generation in a Microgrid Environment

Microgrids are clusters of energy sources, storage, loads, local networks, and controls organized to deliver a common set of community- or campus-based economic, reliability, and environmental objectives while connected to the main grid, or operated as an electrical island, as the community objectives determine.

To understand the eventual role of coal DG in a microgrid, it is important to realize that a microgrid will operate grid-connected more than 90 percent of the time and only shift to island mode when the overall operating objectives dictate it. The economic and reliability drivers will primarily dictate when the microgrid will be grid-connected or islanded. Microgrid resources are expected to play a supporting role in the grid, but always be ready to intentionally island if the economic, reliability, and environmental objectives of the community are challenged. This should be a forecasted transition—not a surprise transition. Either way, increased reliability is one of the expected benefits and there must be an automatic seamless transition from or to the grid. When the condition that caused the transition is resolved, the microgrid should return to its original grid-connected configuration.

The inherent design of the microgrid incorporates the various distributed energy resources such as renewables, energy storage, and backup generators, as well as demand response and energy market programs; see Exhibit 4-6.

Exhibit 4-6 Community Microgrid



Source: (22)

Pike Research predicts that the US will see 2,000 microgrids by 2015 mainly driven by commercial and industrial businesses, and utilities with substantial renewables obligations.

Microgrid Economics

One of the key needs for microgrid economics is an affordable, firm power resource to place in the portfolio with variable renewables and energy storage. Today, the firm power resources are based on natural gas and diesel fuels, with high costs to operate.

If coal DG can be developed as a firm power resource with a levelized cost of energy less than that of natural gas or diesel, the microgrid, utilities, and consumers will benefit. From this perspective, the generation objectives for a microgrid are the same as the main grid.

Microgrids are conducive to generation applications that could share a purpose with other needs such as district heating or commercial process heating. In addition, the proximity and close coupling with the load being served give the microgrid a particular advantage over large enterprise-wide electric systems. Microgrids offer utilities an alternative to upgrading plants and network assets or building new plants and assets by providing power to meet demand locally, avoiding the expansion of large-scale infrastructure.

The microgrid real-time monitoring and controls system readily supports the baseload generation profile (firm generation) that would be required by a coal DG application.

Microgrid Reliability

If the loss of main grid supply to the microgrid “community” is anticipated because of voltage drops, faults, blackouts, etc., a microgrid should smoothly transition to island operations to maintain reliability for consumers.

Islanding in response to either main grid or microgrid faults adds reliability. For a fault on the main grid, the desired response may be to island the entire microgrid from the grid as rapidly as necessary to protect critical loads and consumer processes. If a fault occurs within a portion of a microgrid, the desired protection is to isolate the smallest possible section of the microgrid to eliminate the fault. This will be possible through the intelligence (sensing, controls, and predictive algorithms) in the microgrid which will likely exceed that typically applied to the distribution network.

This high reliability is not without challenge. UL-1741 and IEEE 1547 standards provide a challenge to microgrids because today they do not allow for seamless transition to and from an island on a main grid fault. It is not necessary to dwell on this here, but it is clear that these standards will require change should the nation use coal DG as baseload generation in a microgrid or main grid application.

Microgrid Environmental Objectives

One of the emerging objectives of the microgrid is to support the management of the emissions footprint in the community served by a microgrid. For example, in the San Diego microgrid project, the objective functions of the microgrid controller include near-real-time prediction of the combined emissions footprint in main grid-connected mode or island mode, so that the controller can decide which configuration is best balanced against the economic and reliability objectives.

In conclusion, the microgrid economic, reliability, and environmental objectives are better served if there exists a cost-effective, coal DG application for baseload generation.

4.6 Coal Generation's Role in Renewable Resource Integration

Although no national policy exists as in the European Union, the integration of renewables is becoming a national energy priority driven by many state mandates and goals for renewables penetration into the electric system. The primary technologies for meeting these targets are wind and solar, both of which represent a variable resource issue that limits the ability of the grid operators to consider these sources "firm" power. As the targets are approached, the penetration of variable renewables will increase to levels (renewables currently have < 3 percent penetration) requiring these resources to be integrated to meet firm power requirements.

The following graphs illustrate what effects, if any, variable renewable energy source participation will have on baseload coal for the year 2020. The North American Electric Reliability Council (NERC) models were developed by combining the Renewables Portfolio Standards goals for each state into values that could then be compared to NERC regional estimates for year 2020. The NERC Electric Supply and Demand (ES&D) database (used for the Long Term Reliability Assessment (LTRA)) and Ventyx databases were used to obtain the required information for each NERC sub-region. EIA data were not explicitly used due to an anticipated changeover in the boundaries of certain regions. Rather, NERC sub-regions are used and are consistent with the NERC ES&D database for demand. Once the data were assembled and placed into a supply matrix, typical generation stacking curves were generated for CAISO to show the "with and without" variable renewable values for the selected NERC regions. This also illustrates the effects of islanding, i.e., being separated from the grid baseload component.

Also shown on the dispatch curves are the effects that storage recharge will have on baseload generation to increase its off-peak participation. Both a descriptive and economic narrative follows each selected graph.

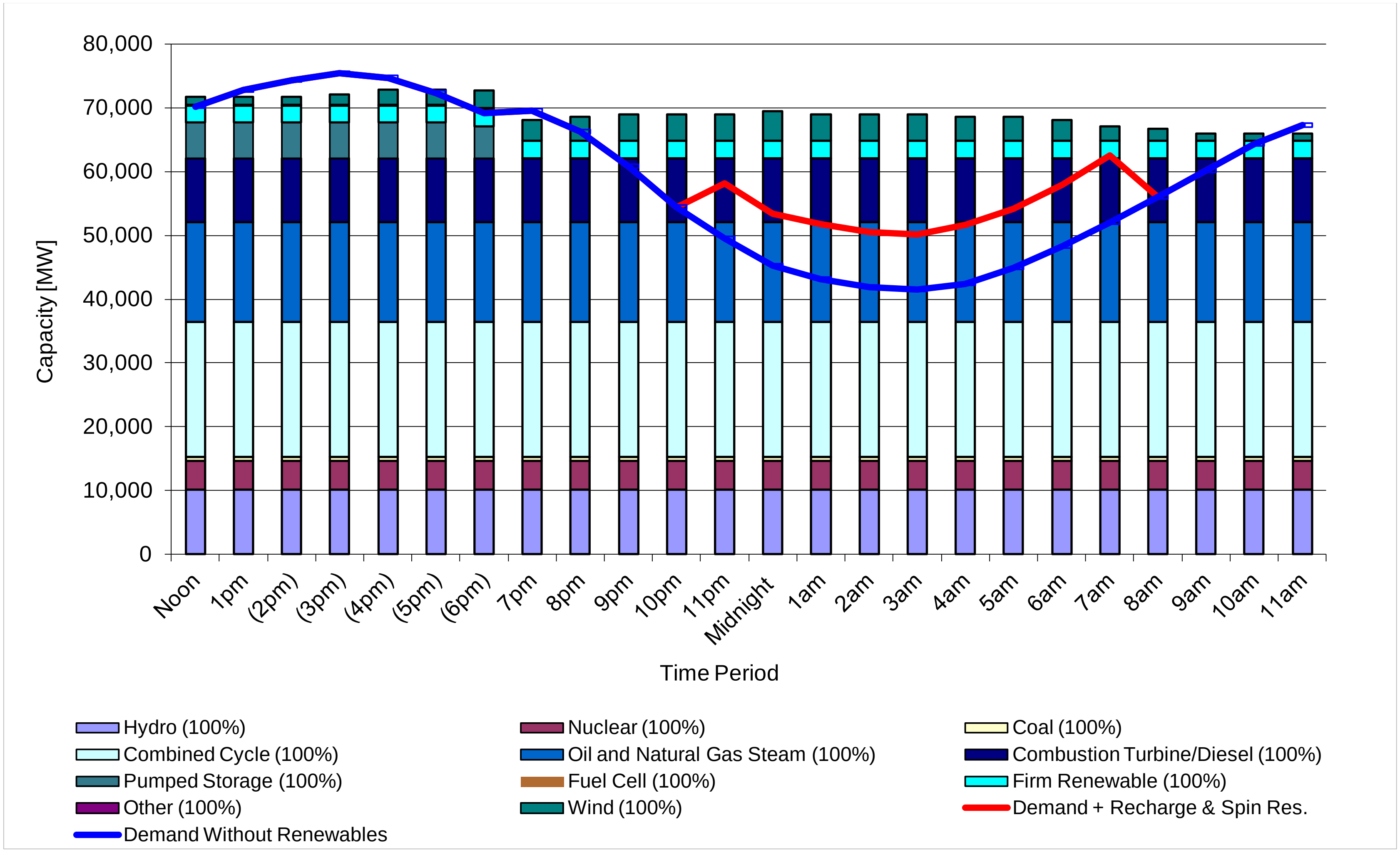
The following graphs represent several 24-hour available generation capacities. The vertical bars depict the capacity available for each hour over the 24-hour period. Each bar is derived by stacking the committed block of energy for each energy source by relative cost; note that this applies to traditional energy sources only. The solid line in the following graphs represents the load demand that must be met by the stacking of the available blocks of energy. It consists of the hourly load demand, plus the published NERC regional reserve margin, plus any off-peak energy storage recharge load.

CAISO with Renewables

The first graph (Exhibit 4-7) represents the CAISO NERC sub-region for all predicted energy resources for the year 2020. Predictions were derived from the 'scrubbed' Ventyx database as opposed to EIA data, which lack reliable renewable predictions. The value of adding variable renewables and associated storage is derived by taking the marginal costs of the energy sources that variable renewables displace, less the costs associated with the storage recharge cycle.

For the CAISO sub-region, the total fuel cost realized from the addition of variable renewables and its associated storage is approximately $2.3M per day. This value was derived by summing the total megawatt recharge hours (including recharge efficiency of 75%) for both battery (106.9k) and PHEV (10.4k) storage, deducting the nighttime wind contribution (34.5K), which could be used to recharge the batteries and then multiplying by the estimated cost of replacement energy of coal ($27.99).

Exhibit 4-7 CAISO Available Generation Capacity with Renewables



Data Source: (5)

CAISO without Renewables

Exhibit 4-8 is similar to Exhibit 4-7 except that the renewable contribution has been removed. As illustrated, the contribution of renewable does not affect baseload, especially the coal commitment during on-peak hours. In addition, it can be seen that additional coal capacity could be added to support the energy recharge cycle during off-peak hours. This increase of baseload generation should be considered an improvement in existing asset utilization rather than a call to build more central-station generation. The reality is that the central-station generation fleet design capacity is already well above the nighttime baseload generation of 40,000 MW but currently operating well below its design capacity. Today, high-cost combustion turbines would have to be brought on-line to support the energy storage recharge cycle.

In Exhibit 4-8, the nighttime baseload generation for California is about 41,000 MW, while the afternoon firm generation is about 50,000 MW. Thus, in reality the baseload generation (steady and unchanging) is 41,000 MW. Through the use of storage technologies to address variable renewables and a PHEV fleet, the nighttime baseload generation could increase 10,000 MW or more. Thus, a higher baseload generation (50,000 MW) could be realized on the electric system in California.

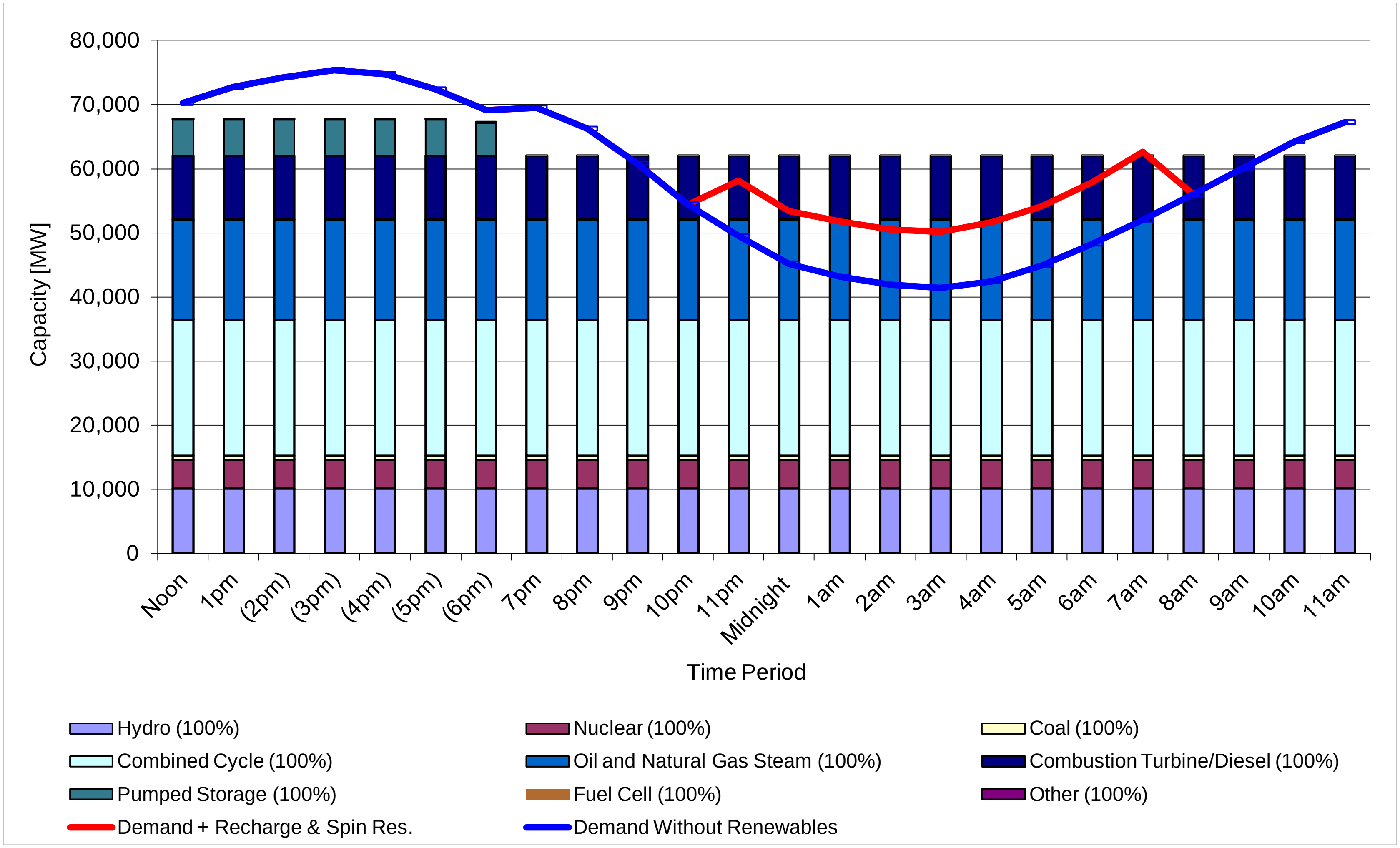
Over time, the generation fleet could see improved efficiencies and higher capacity factors for baseload generation and renewables generation.

In meeting the consumer objectives discussed above, a key weakness in the generation resources portfolio is the potential lack of affordable, local baseload generation. There are sufficient local resources to address peak demand and add to the reserve margins. As distributed renewable resources are added to the electric system, however, the need for affordable, local baseload generation must grow to support reactive power management and meet inertia needs for system stability.

There is an important lesson for the U.S. from Denmark's experience with wind turbines distributed geographically and electrically across their country. To accommodate deep penetration of variable renewables, distributed baseload generation is important to local system stability.

In addition, Sandia National Laboratory recently reported on the benefits and market potential for firming renewables with energy storage (23). The objective is to use energy storage matched with variable renewables to provide a constant output. With energy storage, the need to schedule dispatchable capacity is reduced. Sandia also recognized that firmed, distributed renewable energy may also offset the need for new transmission and distribution infrastructure, and that this becomes even more important when considering peak demand. They suggest that the best opportunity for firming renewables is where the renewables are coincident with the peak demand.

Exhibit 4-8 CAISO available Generation Capacity without Renewables



Data Source: (5)

It is important to note that the need for firming distributed and variable renewables exists and that system stability is related to the total amount of inertia present locally on the network that is inherent with coal power plants.

Thus, if there is significant penetration of variable renewables in a local area of the network, system stability is enhanced if there is a local baseload generation component present providing inertia.

Consider a local distribution network with significant variable renewables, variable load, local baseload generation (such as a small coal power plant), and energy storage. Such a configuration would provide inertia from the small coal power plant, transient ride-through from the energy storage, and a reduced emissions footprint from the renewables. In addition, an option emerges for the local baseload generation to routinely charge the energy storage for serving the peak demand, and other on-demand uses.

The AWEA suggests that where a variable renewable (wind) is generating up to ~10 percent of the delivered electricity, the variability is not a significant issue for the grid (24). The system has sufficient flexibility to accommodate reserves, wind variability, and load variability.

If between 10 percent and 20 percent of delivered electricity comes from variable renewables, stability needs to be addressed through improved wind forecasting, software modifications, etc., that can address the added risk associated with the forecast delta, and likely other actions.

Above 20 percent, the system either must accommodate the variability with significant spinning resources, energy storage, significant load curtailments, and/or system design changes.

4.7 Summary

Ultimately, the mix of coal, renewables, and other sources of energy will be dictated by an optimal integration of economic, reliability, and environmental objectives. In addition, the mix of central-station firm resources (coal, nuclear, natural gas) and variable renewables (large wind and solar plants) will also be balanced with distributed firm resources (small coal, fuel cells, microturbines, BUGS, etc) and distributed variable renewables (residential solar, building-integrated PV, architectural wind, etc.).

The key point of view is that of the residential, commercial, and industrial consumer. The optimal integration of economic, reliability, and environmental objectives is the goal of the consumer. For the electric industry to support the consumer's objectives, tradeoffs will emerge and must be considered. For example, the following must be balanced within key objectives:

- Economics of central-station resources versus distributed resources
- Reliability of a distributed firm resource base versus a central-station resource base
- Environmental footprint of a local renewables resource versus a central-station resource base, etc.
- In addition, issues such as the following must be balanced across key objectives:

- Economics of a distributed firm resource versus the environmental advantages of a central-station renewables resource
- Reliability of a distributed firm resource base versus the economics of a central-station resource base, etc.

This is a complex vision of the future electric system. Energy-informed consumers, primarily industrial and commercial consumers, are asking themselves whether or not they should invest in local or self-generation to offset rising costs and slipping reliability from utilities. The consumer's question is not a strict comparison of $/kWh between self-generation and utility-provided electricity. The consumer must balance the $/kWh of delivered energy, utility demand charges, utility surcharges from a wide variety of regulatory-driven programs, how their business is affected by its environmental footprint, the importance of mitigating reliability challenges, the return on investment, and how well the choices stabilize future costs of their products.

In this section, we applied the findings from our review of the Smart Grid (Section 2) and coal-based generation alternatives (Section 3) by analyzing the roles that coal-fueled technologies might serve in a future enabled by Smart Grid technologies.

Smart Grid technologies will give grid operators the means to modify demand and achieve more efficient utilization of existing generation and transmission assets. Shifting load from peak demand times to periods of lower demand will allow some peak generation to be replaced by less expensive, more efficient baseload generation. An analysis using sample data from the PJM Interconnection shows the potential of load leveling to increase baseload demand beyond the total existing baseload generation capacity. These analyses suggest that Smart Grid technologies will likely create a need for additional baseload capacity, above that already built, under construction, or planned.

The current transmission system is stressed at some key locations in the Eastern and Western Interconnections and could be even more so if the future demand increase is met with centralized generation only. Smart Grid technologies can enable smaller, distributed generation to meet the increase in baseload demand. Savings with distributed over centralized generation include a reduction in transmission and distribution (T&D) losses and T&D capital requirements. Natural gas and diesel are currently the fuels used for firm power in a distributed environment, but their fuel costs make them unattractive for baseload applications. Small coal-based technologies might be more cost-effective, but they are not currently in common use.

Coal-based DG is most efficient and cost-effective in CHP settings, in which the waste heat can be used directly for space or process heat. To better understand the practical advantages and challenges to using coal as a distributed generation fuel in CHP applications, we review the success that Denmark has had between 1985 and the present in transforming its electricity supply. It previously had a centralized, fossil-intensive system, which it has transformed to one with a broad base of distributed CHP and a renewable generation fraction of almost 30 percent. Six key factors for this success include:

- Shared national vision
- Existing infrastructure conducive to transformation

- Geographic location
- Consistent energy policy
- Pricing mechanism
- Cellular network structure

The U.S. differs in important ways from Denmark in many of these factors. The size and geophysical diversity of the U.S. makes it difficult to formulate a single vision for energy policy; therefore, energy policies are not uniform across states and regions. In addition, the infrastructure is not designed for district heating systems; economical wind resources are not as broadly distributed; renewable and CHP pricing mechanisms are primarily tax dependent; and transmission and distribution networks are not currently designed for easy transformation into a network of small cells or microgrids. However, Denmark's energy position in 1985 was similar to the U.S.'s current position, so some lessons may be learned.

Key similarities include the low average capacity factors in each nation, similar portfolio mixes (less nuclear), relatively low demand growth, coal's share of total capacity, high growth in natural gas capacity, little international trade in electricity, and similarly privatized electricity markets. Key differences include size (and hence total capacity and consumption); Denmark's higher importation of coal, a higher fraction of renewable and CHP capacity, a higher amount of coal-based CHP, and lower share of fossil capacity. Denmark also makes significant use of feed-in tariffs, and has fewer agencies regulating the electric power industry. We conclude that, whereas both countries have energy policies and pricing mechanisms that support developing CHP, the United States' geographic size, state-level regulatory structure, state policies, and short-term tax credits have slowed the development of CHP relative to its growth in Denmark.

We briefly analyze the technology, economic, and environmental impacts of coal-based CHP. Technologies include PC, FBC, and modular gasifiers powering a gas turbine or a reciprocating engine. The heat portion of CHP can be used for cooling and dehumidification as well as heating. Efficiencies that are lost due to the small size of the plants are more than compensated for through the use of the waste heat to provide process or space heat. Because both power and heat are extracted, the plants can be built larger than those supplying power alone, leading to increased efficiency. The cost of piping for CHP is a major cost factor, so energy-intensive industrial applications are the most common seen. CHP economics are improved if the power generator is also used to provide local grid-stabilizing services. CHP brings a range of local economic and environmental benefits, such as semi-independence from the grid and reduced T&D losses. However, it produces local emissions of pollutants, so the local air permitting environment must be able to sustain the increased emissions.

Based on the success in Denmark with cellular microgrids, we examine the potential role for coal generation in microgrids within the U.S. Natural gas and diesel generators currently are considered the primary sources of dispatchable power for microgrids, supported by utility-scale energy storage systems. Small coal-fired systems based on steam turbines, reciprocating engines, gas turbines, microturbines, or fuel cells have the potential to replace natural gas and diesel at a cost savings in various microgrid scenarios, although no demonstration plants have been built to date.

5 Use of Coal Power Plants for Reserves and Regulations

In an electrical power system, power demand and power generation must be balanced at all times and at all nodes of the system. To maintain power system stability and reliability, the generation must be controlled to match the demand and the power flows throughout the system so that the generated power is actually delivered where the demand exists. The demand is continuously estimated in advance, and generation and its location are planned appropriately so that the power amount and delivery requirements are satisfied. The efficiency of the planning process is not perfect, and occasionally there might be shortages (or excesses) of generation or difficulties with delivering it. In addition to imperfect demand forecasting, generating units can fail, resulting in abrupt demand-to-generation mismatches. For this and other similar reasons, the North American Electric Reliability Council (NERC) and system operators require that generating utilities provide ancillary services to address potential generation problems.

Ancillary services are directly related to and dependent on available reserves. Power reserves and ancillary services can be grouped into:

- Spinning reserves
- Non-spinning reserves
- Replacement reserves
- Regulation
- Load following
- Voltage support

The characteristics of the above services and the ability of baseload coal technologies to provide them, in conjunction with DG and a smart grid environment, is discussed in the following sections.

5.2 Reserve Requirements

All services depend on the reserves upon which they can call quickly. Reserves can be spinning and non-spinning reserves. Spinning reserve is a running generator capacity set aside for emergency situations. For example, a generator might be providing 80 percent of its power to the energy market and 20 percent to the ancillary market as spinning reserve. Spinning reserve must respond in less than 10 minutes. Non-spinning reserve is, as the name says, reserve supplied by a non-spinning generator. A non-spinning reserve generator must be able to respond within 10 minutes but it does not have to respond in less than 10 minutes. Replacement reserves are used to restore spinning and non-spinning reserves after a contingency.

Distributed coal generation does not need any special reserves for operations. Larger DG plants operating as baseload generators do not have an effect on normal load variations and do not trigger primary frequency control during normal operations. Statistically, smaller DGs should not have a significant effect on usual load fluctuations either. As reserves providers, large transmission- and sub-transmission level DGs are very similar to centralized generation regardless of their prime mover fuel. Small generators dispersed throughout distributions systems are rarely used as reserve and ancillary services providers. This is especially true if they are not under direct utility control. Small DGs within distribution systems are too small to be coordinated by a central authority. The Smart Grid will provide communication and control means for hierarchical energy and capacity management, thereby enabling DG plants to serve as reserve and ancillary services providers.

5.3 Regulation Services

Regulation service includes automatic generation control (AGC), which acts after the primary control and within minutes after a contingency occurs. AGC is a centralized type of control under a Balancing Authority's coordination. As the generation-to-demand is synchronized by AGC, the primary control is automatically returned to its original setting

Power system regulation refers to controlling real power generation to match continuously varying demand and to mitigate contingencies. Frequency deviation from the nominal 60 Hz is the main indicator of a mismatch between generation and demand. When there is a frequency deviation, primary control provides an almost instantaneous response to arrest frequency excursions. A generator's primary control is independent of any other actions in the system, and controlled at the plant.

The ancillary services do not include primary (governor) control. Primary control provides the first and fastest control action when a contingency occurs. All generators larger than 10 MW are required by NERC to maintain primary control reserves but the fraction of the generator's nominal output power set aside for this type of control is not specified. Because it is included in the 10 MW and larger requirement, there is no market for this type of reserves.

Secondary generation control reacts after the primary control to restore the frequency to its nominal value. Frequency, and indirectly generation, control is a well-understood process that functions well in a centralized generation environment.

In an environment with lots of distributed generation, the control scheme must be implemented carefully. Distributed generation within a distributed system is usually of intermittent nature and as such cannot provide the continuous spinning reserve (25) needed for both primary and secondary frequency control. This is especially problematic for primary control since there is no central control center that can coordinate primary control from different sources. If a distribution system is to participate in primary control, a generation capacity aggregator must exist to ensure sufficient capacity for pre-agreed spinning reserve. Smart Grid is expected to provide communication channels for such coordination.

Since frequency control is based on spinning reserves, there is not much significance in the fuel used for the prime mover as long as it is controllable and with ramping rates less than 15 minutes. Small coal power plant ramping rates are within these limits as are large baseload coal plants.

Load following acts similarly to regulation but slower. Load following is a connection between the regulation services and the regulated energy market. In summary, regulation and load following are achieved by adjusting real power injections, and differs from other services as described below.

5.4 Reactive Power Requirements and Voltage Support

Voltage support belongs to very fast-acting services such as load tap-changing (LTC) transformer actions, reactive power supply, and use of various Flexible AC Transmission System (FACTS) devices. Voltage support (control) depends on reactive power supplies and impedance adjustments, and is performed by adjusting synchronous generator field current, by supplying reactive power, or use of LTC transformers.

Voltage magnitude and reactive power are two related aspects of power system networks. Real power delivery over T&D lines is mostly determined by voltage angles. Reactive power is used for voltage angle adjustments and therefore for controlling voltage and power flows in a network. The same effect can be achieved using transformer phase shifters and FACTS devices.

Real power delivery to a single load depends on the power factor at the load location and can be controlled with controllable reactive power sources, either shunts or FACTS devices. Clearly, voltage is a local phenomenon that can be controlled locally. How it is done depends on the location at which the voltage needs to be controlled. Such a location can be on either a transmission or sub-transmission network, or on a distribution system. This study is concerned with distributed coal-fired generation plants and their use for voltage and reactive power support on both of these network types.

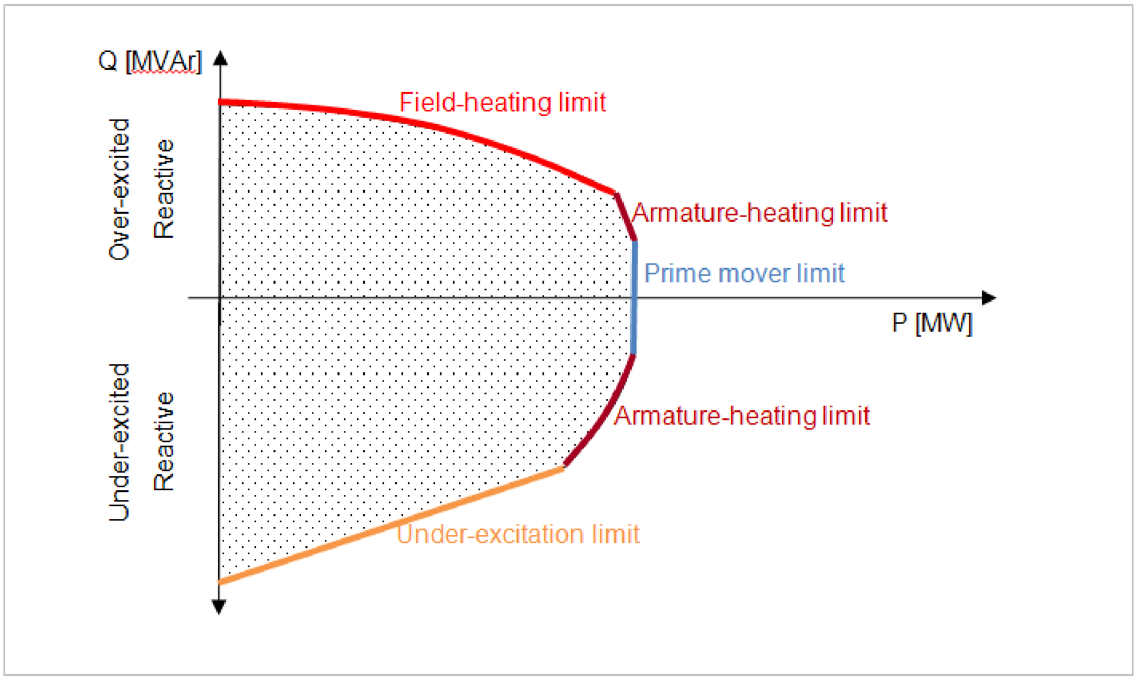
If coal DG is located on the transmission or sub-transmission part of the network, voltage or reactive power control is no different from control of any other power plant in that environment. Voltage control is achieved by adjusting a synchronous generator’s field current and is not dependent on the prime mover (fuel). Reactive power generation is completely dependent on an electrical generator’s capability curve and not on the prime mover, which can use coal, natural gas, or another fuel. Exhibit 5-1 shows a typical generator capability curve. Scheduling reactive power generation located on the transmission or sub-transmission network is done in the same manner as centralized generation.

In mostly radial distribution systems, the main purpose of voltage control is to provide acceptable voltage levels along the entire feeder. Customers expect the supply voltage to be between predefined limits, even at the end of a radial line, and to be able to use equipment with such specifications. In standard distribution systems design, the network is assumed to be radial and without distributed generation. The substation LTC transformer has its primary side connected to the transmission system and the secondary side to the distribution system. The secondary side voltage is controlled to provide the desired voltage level for the feeders.

In distribution systems without distributed generation, it is relatively straightforward to control the voltage at the substation so that the customers along radial lines are supplied with acceptable voltage levels. When there is distributed generation in the network, however, voltage regulation can be quite complex and very likely impossible without a good, two-way communication network. A distributed generator on a radial line makes the load seen by the substation LTC appear lower resulting in wrong tap setting and under-voltage. If the LTC is set to its maximum value, over-voltage can easily result. For this reason, there must be control coordination between the LTC and distributed generators in a distribution system (26).

DG is very desirable for voltage and reactive power control. Voltage and reactive power control are a local problem and therefore baseload coal technologies capable of providing these services are desirable and beneficial to the electric system. Supplying reactive power from local sources is much more effective than from remote, centralized power plants. However, if distributed generation is to be used for transmission-level voltage control, some kind of hierarchical control scheme will be necessary (27). The market for reactive power is location-dependent, based on the local need for voltage and reactive power support (25).

Exhibit 5-1 Loading Capability Curve of a Synchronous Generator



Source: (28)

If the DG is located on the transmission or sub-transmission network, usual voltage control methods can be utilized. If DG is located within a distribution system, scheduling its reactive power capacity for transmission-level voltage regulation can be more complex. Generation of reactive power must be coordinated with the substation LTC control. If a large number of very small DGs are dispersed throughout the distribution system, there must be some kind of aggregation entity that can represent their aggregated availability for both technical and market purposes (25). These issues require reliable, bidirectional, and high bandwidth communications that will be provided by the Smart Grid.

5.5 Summary

Coal-based DG faces the same obstacles as any other DG type to be used for reserves and ancillary services. Ramping rates are the most common issues with power plants used for spinning reserves. Small coal-based DG units can respond within standard limits of approximately 10 minutes. Depending on the DG location, sub-transmission, or distribution network, there might be some additional issues with using it for reserves, ancillary services, or dispatching it in general. Potentially, there might be a very large number of very small DG and renewable sources within a distribution system making it almost impossible to be controlled from a central location. For such situations, there should be an aggregator and some kind of hierarchical control in place to dispatch these resources in a predictable fashion. It is almost certain that the Smart Grid will be a prerequisite for successful control and synchronization of these resources with the rest of the grid.

6 Smart Grid City of the Future

Previous sections discussed in some detail, coal generation options that can be used as either central or distributed generation. The coal baseload generation options must also be evaluated as a generation portfolio at the system level. To properly evaluate the economics, reliability, and environmental aspects of a future role of coal in a smart grid environment, it is important to extend what is known today to what could reasonably be expected about the future, say 2020. One potential future scenario, the Smart Grid 2020 City described below, takes into account trends in consumer objectives, technologies and applications, regulatory change, and costs. Using these trends, an optimal generation mix is calculated and applied to a typical size city in 2020. Technical and financial analysis is performed to support feasibility of such a scenario.

6.2 The Smart Grid 2020 City Model

Arguably, the nation will see the greatest implementation of Smart Grid strategies and technologies in urban and suburban areas where the concentration of load and resource needs are greatest. Therefore, the best place to understand the broad aspects of the role of coal in a Smart Grid environment will be in and around cities. In researching characteristics of cities in the United States as described below, there are many in a range of what would be considered medium-sized cities. The model described in this section helps focus the research on the role of coal in a Smart Grid environment on a potential future where, if viable, the role of coal would probably be most advantageous and repeatable.

For this study, a city of 130,000 residents is chosen as the most typical community likely to adopt Smart Grid technologies. From the US Census Bureau, there are 2.6 residents per meter. From EIA national data [65], there is one commercial business for every 7 residential consumers, and one industrial business for every 161 residential consumers. This means that a city with 130,000 residents has about 50,000 meters, about 7,000 commercial businesses, and about 300 industrial businesses. The use of a meter as a basis rather than population helps in the quantification of costs and benefits for these municipalities since most of the electricity system data is based on the number of meters served.

6.2.2 Nature of the 2020 Load Centers

Currently, the electric power grid delivers electricity primarily from centrally located power plants to the consumers, by way of a network of transmission and distribution systems. In addition, there is a variety of distributed energy resources to serve the local critical loads.

The 2020 typical city (Smart Grid 2020 City) study will apply Smart Grid integration of advanced technologies, such as smart meters, centralized generation, distributed generation, renewable energy, and energy storage. It will also require an extensive communications network to provide the means to communicate to all of the advanced technologies to better match supply and demand. The development of the typical city will allow for more efficient asset utilization, which will result in reduced fuel consumption and CO_2 emissions, and increased grid reliability. The analysis assumes that needed Smart Grid technologies are available and operational without getting into details about how this is achieved.

The 2020 load centers will therefore change from being dependent on centralized generation to a distributed system that leverages the smart grid advanced technologies to help support the aging and stressed electrical power system and improve overall electricity production efficiency.

6.2.3 Effects of Variable Renewables on Typical 2020 City Model

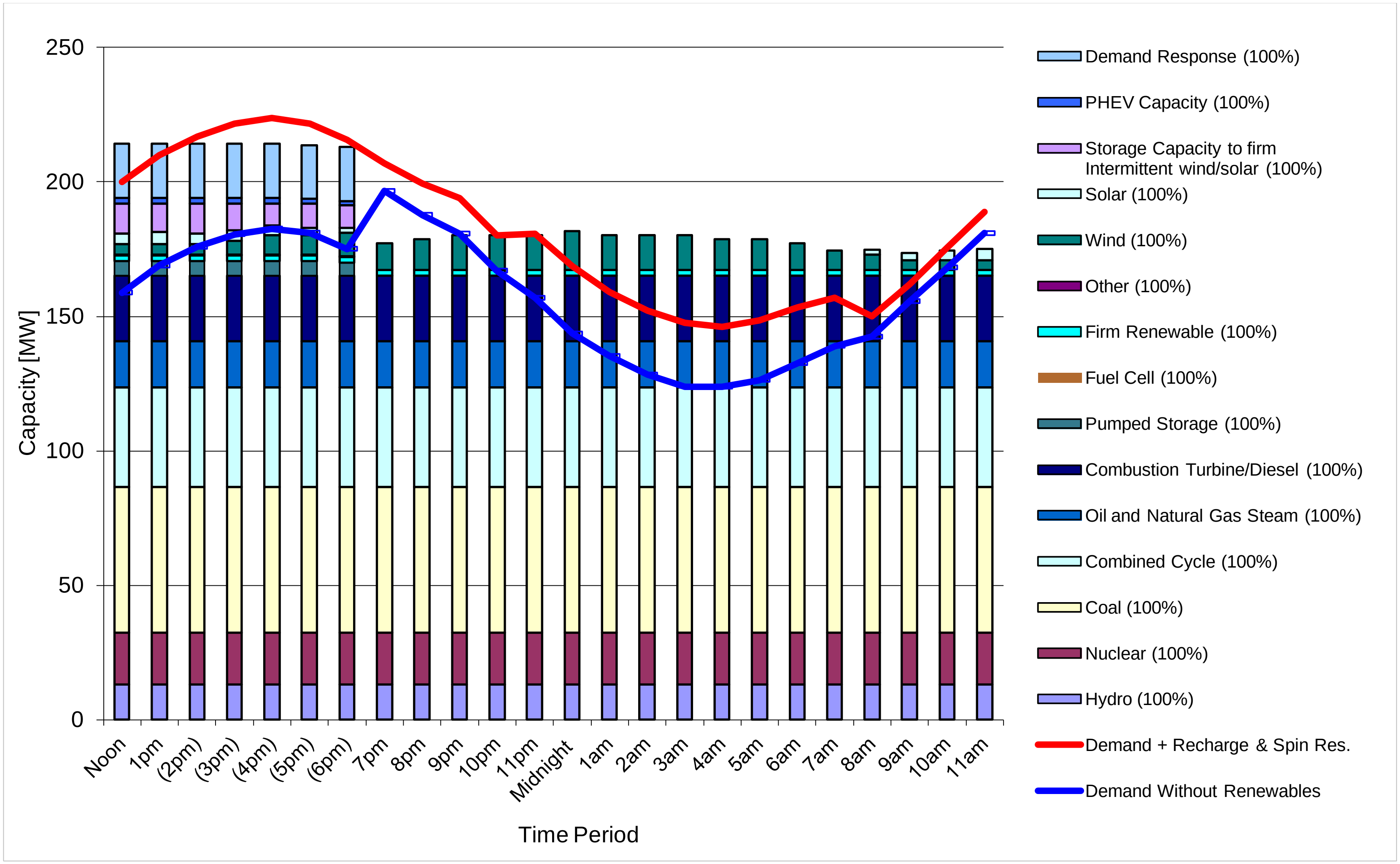
Using EIA and Ventyx databases, the national average demand of the typical city described in the previous section is 162 MW. Using the EIA published ratio for peak demand to average demand of 1.2, the peak demand of this city would be 194 MW. Using forecasts from the same databases, a possible future energy portfolio of the future city is estimated.

The energy source data was derived by averaging the energy sources in the NERC regions and determining the proportion attributed to a 194 MW peak typical city. The NERC electricity supply and demand (ES&D) database and Ventyx databases were used to obtain the data for each NERC sub-region. EIA data was not explicitly used due to an anticipated changeover in the boundaries of the EMM regions. Rather, NERC sub-regions were used and are consistent with the NERC ES&D database for demand.

Exhibit 6-1 represents the "with and without" renewable contributions for the typical city. The solid red line in the following graphs represents the load demand that must be met by the stacking of the available blocks of energy. It consists of the hourly load demand, plus the published NERC regional reserve margin, plus any off-peak energy storage recharge load. The difference between the blue and red lines represents the amount of renewable energy that is available for each hour. Note that Exhibit 6-1 represents the supply stack for all predicted energy resources for the year 2020. Predictions were derived from the "scrubbed" Ventyx database as opposed to EIA data which lacks reliable renewable predictions

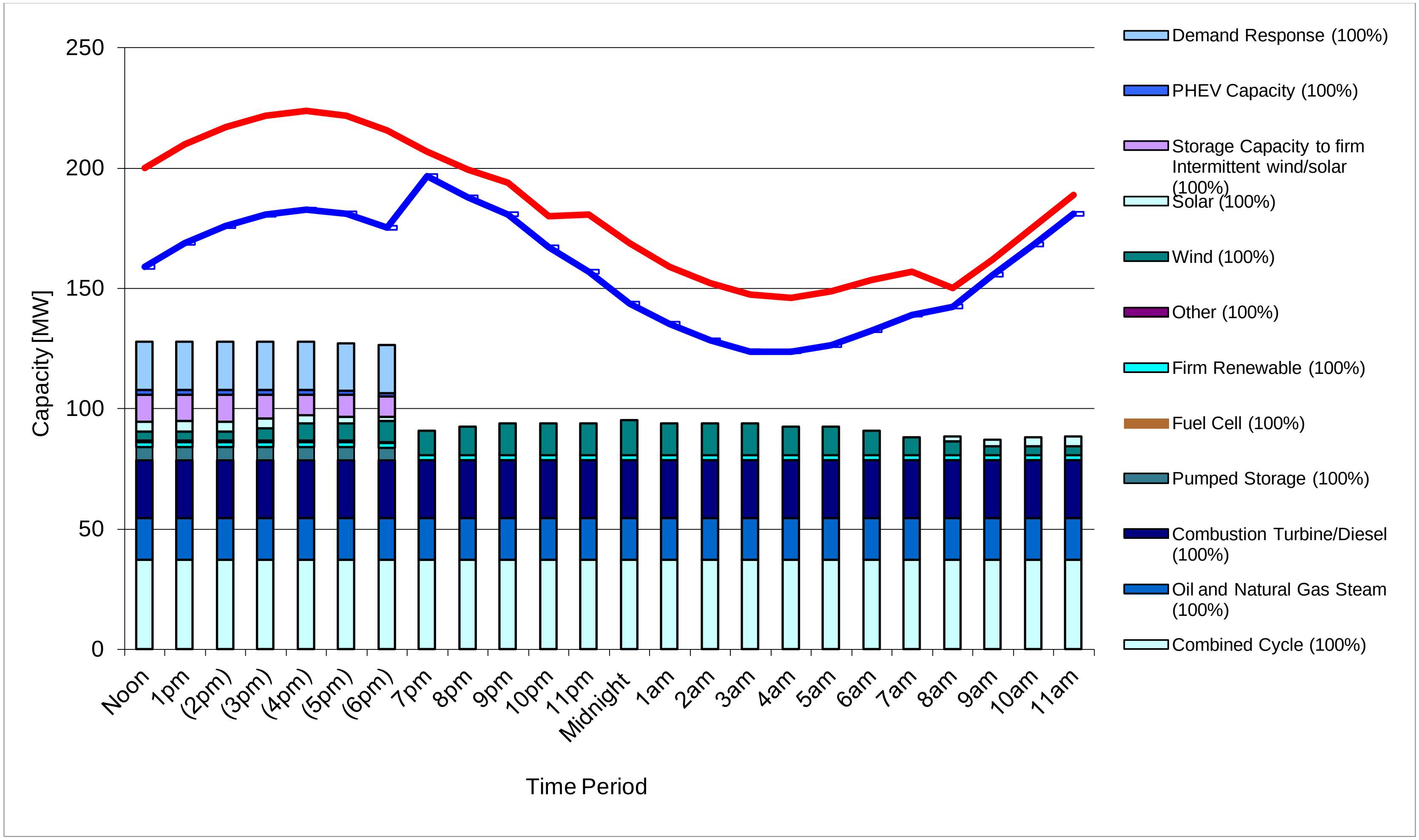
Exhibit 6-2 illustrates the effects of islanding, i.e., being separated from the grid and what effects baseload will have on the typical city. Exhibit 6-2 is similar to Exhibit 6-1, but the typical city is in island mode and has been disconnected from the electrical grid. This illustrates that in order for a Smart Grid 2020 City to be separated from the grid it will require about 70 MW during the peak and 90 MW during the off-peak of addition local (distributed) generation. Coal generation CHP applications would be a good candidate for this generation. Also shown on the curves are the effects storage recharge will have on the baseload in increasing its off-peak participation. Note that the curves are constructed by allocating firm generation first and then intermittent resources and storage. The standard dispatch procedure would dispatch generation with the lowest marginal cost first, which would be the renewable generation in this case because of wind or sunlight as the zero cost fuel sources.

Exhibit 6-1 Available Generation Capacity With and Without Renewable Contribution for 2020



Data Source: (5)

Exhibit 6-2 Available Generation Capacity – Island Mode



Data Source: (5)

The above data are used to formulate a more detailed model of a typical Smart Grid City of the future with some minor changes and model extrapolation. From the data used for the above graphs, renewables penetration is lower than projected by the DOE. To be more consistent with the DOE estimates, the renewable penetration used in the analysis is approximately 20 percent. The demand is modeled using a daily demand profile with 194 MW peak and 162 MW average.

6.3 Smart Grid City 2020 model

Technical analysis of the Smart Grid City 2020 was performed using renewable software package HOMER(29) from the National Renewable Energy Laboratory. HOMER is an optimization tool designed to analyze and optimize use of different DG renewable and non-renewable energy portfolios while connected to or disconnected from the grid. For the purpose of this analysis, distributed baseload coal was defined as the new fuel and new generator type. Fuel and generator characteristics include fuel cost, generator efficiencies, and carbon dioxide and other environmental emissions. The optimization algorithm can also include cogeneration.

In addition to the coal generator, wind and photovoltaic power sources are used. These renewable power sources are based on commercially available devices. Wind and PV profiles from Wisconsin are also used. The output of each energy source is defined over an upper and lower limit. HOMER does the optimization to determine the optimal generation portfolio for a given daily demand profile. The daily demand profile is a daily profile from MISO adjusted to have 162 MW average value and 194 MW peak value. This daily profile is replicated over a 25-year period. The optimization is performed over the lifetime of the resources and with the assumption that 45 percent of the needed energy would come from the grid's bulk power market. These features are sufficient to simulate and optimize all of the generation options previously discussed in this report.

Three different approaches were used in obtaining 45 percent of the annual energy from the grid. In the first approach, the grid supplies a constant 45 percent of the Smart Grid city's power demand. This is equivalent to a 45 percent demand reduction. The second approach limits capacity that can be from the grid to 45 percent of the annual maximum demand (194 MW). This capacity provides 45 percent of annual smart grid energy demand. This case is used to compare business as usual and Smart Grid city cases. The third approach does not limit capacity that can be bought from the grid to 45 percent of maximum annual demand. The capacity is then used to provide 45 percent of annual Smart Grid energy. These approaches give similar results; however, distributed baseload generator output differs from case to case for a given generation mix. If the distributed baseload generation is not capable of following load or wind and solar fluctuations, additional back-up power from the grid is needed to firm up renewable generation.

Generation mix for the Smart Grid city also depends on the Smart Grid city's location. One assumption is that 20 percent of demand could be supplied from renewable power plants. This constraint will be satisfied only if there is enough wind power and PV power generation.

Maximum net grid purchase and coal price affect the optimal generation mix as well. The main question is if the 55 percent of demand is more economical to supply from the grid or to use distributed resources. The answer depends on how far from the grid the Smart Grid city is. The capital cost for 1 km of transmission is $571,661/km assuming $335,540/km capital cost for 138 kV line and $236,121/km capital cost for 69 kV line (30), and assuming that the same length of 138 kV and 69 kV lines will be needed to connect the Smart Grid city to the grid. It is economical to buy the rest of the 55 percent of demand from the grid if the Smart Grid city needs less than 700 km of grid extension. The distributed resources are more economical if the Smart Grid city needs more than 700 km of grid extension.

6.4 Key Scenarios for an Economic Coal – Renewables Mix

The key scenarios for an economic solution for a typical Smart Grid 2020 City involve balancing trade-offs in the primary objectives of a community. The economic scenarios may change over time, which requires flexibility in the energy supply and energy delivery.

Smart Grid 2020 City Architecture

- Mix of resources (bulk power, local utility, consumer)
- Smart Grid infrastructure to support management of load and generation
- Ability to optimize local and bulk power supplies
- Ability to support fuel delivery to city and consumer generators

Balanced Objectives

- Economics
- Reliability
- Environment

Broad Generation Portfolio (modeled example)

- Coal DG baseload – 29.9%
- PV (city-level and consumer) – 4.9%
- Wind (city and consumer) – 15.1%
- Energy storage (city and consumer) – 2.1%
- Consumer DG (baseload & peak) – 2.9%
- Consumer fuel cell – 0.0%
- RTO/ISO wholesale market – 45.0%

Optimal Resource Applications

- Downtown district heating CHP
- Multiple industrial process CHP
- University campus CHP and cooling
- Commercial building campus CHP and cooling

From this Smart Grid 2020 City scenario, the need for a distributed baseload presence is key to the accommodation of renewables targets. The size conducive to this scenario and CHP applications in such a community would be 50 – 70 MW. The likely generators include the following:

- Air-blown coal gasifier + hybrid 6B gas turbine
- Air-blown coal gasifier + reciprocating engines
- Natural gas combined cycle
- Biomass gasifier + reciprocating engines

The coal gasifier above would likely be able to incorporate multiple fuels including coal, waste, and other biomass.

The choice between these technologies goes back to the key scenarios with tradeoffs around the objectives, architecture, and availability of optimal applications.

6.5 Optimal Resource Mix Objective

The goal of the local municipality and consumers is to optimize the integration of economic, reliability, and environmental objectives. This represents a complex vision for the future electric system.

The use of distributed coal baseload generators at a city's edge adds inertia to the system locally, which can help address grid stability issues arising from the increase in renewables penetration in and around the local grid. A distributed coal baseload generation is a prime candidate to match heating, cooling, and process needs of the municipality or local businesses. A mid-sized city will have several industrial firms, two or three industrial business parks (typically at the edge of the city), and a university as candidates for CHP applications.

In addition, the smaller size coal plant is a good match for using municipal solid waste (MSW) and other biomass as additional fuels in the coal plant. This works well with the municipal environmental objectives and would likely be incentivized by the city government.

The resulting economic model for the Smart Grid 2020 City of 50,000 residential meters outlines a coal–renewables mix (no poly-plant applications assumed in the analysis):

Exhibit 6-3 Optimal Resource Mix

Resource	% of Energy Supply
Coal baseload	30%
Renewables	20%
Other local baseload	2%
Storage / Peak DG	3%
Traditional grid bulk supply	45%

The transformation of the city to a Smart Grid 2020 City with the above optimal resource mix is expensive upfront. However, the annual savings delivers a six-year payback period for the municipality's initial equity investment; while the whole project capital (debt and equity) will be paid off in approximately 25 years.

The objectives of the city and consumers are further met by improving electricity reliability from 99.97 percent to 99.999 percent, and reducing the total combined emissions by 198,189 tons per year, which is a 12% reduction in emissions.

Finally, there are coal technology options available to support this 2020 vision.

6.5.2 Estimated System Economics

An economic analysis was conducted on the typical Smart Grid 2020 City model described in Section 6.2 of this report. The analysis uses an economic model developed for microgrids, which closely approximates the Smart Grid 2020 City model. The analysis combines several key elements:

- Inputs and assumptions derived from the Smart Grid 2020 City model or national averages or trends
- New resources
- Delivered electricity portfolio
- Other infrastructure costs necessary to perform the integration of the portfolio
- Financial assumptions

The model optimizes the portfolio and new electricity rates to deliver the results in the form of traditional financial parameters, such as internal rate of return and payback period.

The key characteristics for the Smart Grid 2020 City are shown in Exhibit 6-4. It is important to remember that this model is based on a meter population structure; that is, 50,000 residential means 50,000 residential meters where each meter represents a residence with 2.6 people on average (U.S. Census Bureau). For commercial and industrial, each meter represents one business. The assumed business and operating structure is a municipal utility that collects the electricity revenue, implements the transformation, and operates and maintains the electricity system.

For the economic analysis, the Smart Grid 2020 City was considered a municipality with a third-party developer (merchant) who builds, owns, and operates the new resources with external equity and financing. Of the more than 1,300 U.S. municipalities with a population over 10,000 today, the 430 medium-sized ones, indicated by the Smart Grid 2020 City above, represent a significant sample set for this analysis.

The Smart Grid 2020 City analysis involved adding resources and capabilities to explore the viability of coal DG baseload generation and renewables as described in Exhibit 6-5. The city was modeled with these resources interconnected on a smart grid with access to the RTO/ISO bulk power market. The installed cost of the resources were estimated from 2010 average installed costs and escalated at the inflation rate to 2018 as a start date for construction, such that the first year of operations would be 2020.

Exhibit 6-4 Smart Grid 2020 City Characteristics

Characteristic	Value	Basis
Residential	50,000 meters	Section 6.1
Commercial	7,050 meters	Section 6.1
Industrial	311 meters	Section 6.1
Average power requirement	162 MW	Historical US residential, commercial, & industrial annual consumption divided by 8760 hrs/yr
Peak power requirement	194 MW	Target 1.2 peak to average power ratio
Planned renewable energy requirement	20% of energy delivered	Assumption
Consumer PV capacity (pre-existing)	1.9 MW	Assumed 1% from national average pre-existing participation
Demand Response capacity (pre-existing)	7.8 MW	Assumed 4% from national average pre-existing participation
Smart Grid quality network management (DMS/SCADA, switches, reclosers, comm's, etc)?	No	Assumed no pre-existing Smart Grid
Price-driven load management enabled?	No	Assumed no pre-existing Smart Grid
Residential HEMS installed?	No	Assumed no pre-existing Smart Grid
Historic SAIDI	120 minutes	2009 reported national average
Historic SAIFI	1.2	2009 reported national average
Regional daytime heat	Medium	Based on territory selection
RTO/ISO	MISO	Assumption
Local utility structure	Vertically-integrated utility	Assumption
C&I demand charges in use?	Yes	Typical; applied to commercial and industrial firms above 50kW demand
Consider federal tax credits for renewables and Smart Grid technologies?	Yes	Federal Investment Tax Credit (ITC)

Exhibit 6-5 New Resources for the Smart Grid 2020 City

Resource	Operations (hours/yr)	Installed cost ($/kW)*	Capacity Needed (MW)[1]	Installed Cost ($M)
Coal DG baseload**	7008	$4,182	62.4	$260.8
City-level PV	2008	$5,317	14.6	$77.5
City-level wind	4380	$3,584	50.2	$180.0
City-level energy storage	6 hrs/day	$1,792	13.3	$23.8
Consumer DG baseload	2088	$209	15.5	$3.2
Consumer DG peak	400	$209	26.4	$5.5
Consumer fuel cell	8322	$8,364	0.0	$0.0
Consumer PV added	2008	$5,317	21.1	$112.4
Consumer wind	4380	$3,584	0.0	$0
Consumer storage	6 hrs/day	$1,792	6.3	$11.4
		Total	210	$674.7

* *Various industry sources for 2010 escalated by the inflation rate to 2018 for start of construction*
** *WorleyParsons 2010 cost (Hybrid 6B model IGCC without CCS)*

From a delivered energy perspective, Exhibit 6-6 describes the coal, renewables, consumer DG, energy storage, fuel cell, and wholesale energy portfolio. The design of the portfolio of resources enables the municipality/merchant to select times of the day (in the day-ahead market at the RTO/ISO) that are lower cost to make purchases of power. This drives the average price of electricity down for the municipality. At night, the coal baseload generation and wind turbines are the primary energy resource, supplemented by inexpensive nighttime wholesale power.

[1] A proprietary Internal Rate of Return (IRR) optimization algorithm is run combining installed cost, operating hours/year, renewables energy deliver, energy storage required, and percentage of base generation needed. A constraint was added for: coal DG baseload to be between 50 - 90MW; for sum of renewables to meet the 20% Renewable Energy Portfolio assumption; for sum of Consumer peak DG and total energy storage to meet the design peak demand of 1.2 X average load; for the maximum expected participation from existing C&I DG resources base (swing) generation and peak demand.

Exhibit 6-6 Delivered Electricity Mix

Resource	Electricity Delivered Annually (MWh)	Percent of Total Electricity Delivered
Total consumer electricity requirement	1,460,047	100%
Coal DG baseload**	437,083	29.9%
PV (city-level and consumer)	71,709	4.9%
Wind (city-level and consumer)	219,961	15.1%
Energy storage (city-level and consumer)	30,710	2.1%
Consumer DG (baseload and peak)	42,914	2.9%
Consumer fuel cell	0	0.0%
RTO/ISO wholesale market	657,670	45.0%

Additional costs were modeled to account for Smart Grid infrastructure, monitoring, and control systems, as well as other typical costs associated with a major infrastructure change. These costs are shown in Exhibit 6-7.

Exhibit 6-7 Other Infrastructure Costs beyond Primary Resources

Other Infrastructure	Installed Cost ($M)
Smart Grid network management, smart devices, integration, testing, etc	$65.1
Market access and linkage	$2.4
Site purchase and development	$1.6
Other fees and services	$18.8
Contingency reserve	$62.2
Construction period interest	$28.2
Federal investment tax credit	($121.5)

The total cost of development of the resources and infrastructure, minus the tax credits, is about $751.5M.

The financial assumptions used in the economic model are described in Exhibit 6-8. It is important to note that the financing structure is that the municipality invests equity (approximately 18%), finances the remaining debt against its preferred credit rating with a municipal bond, and receives a return on the investment by serving the consumers. In essence, this is a typical municipal utility model.

Exhibit 6-8 Financial Assumptions

Parameter	Value	Value	Comments
Equity investment	$140.0M		Assumed 19.1%
Debt interest rate	6.0%		Assumed 3rd party debt financing
Financed debt	$611.5M		Calculated
Loan period	25 yrs		The length of a typical power purchase agreement
Tax rate	10%		Assumed municipality
Inflation rate	2.3%		Posted 2010 rate
Tariff rates Residential ($/kWh) Commercial ($/kWh) Industrial ($/kWh) Demand charge($/kW/mo)	2020 US avg $0.1330 $0.1130 $0.0750 $12.26	Used in the model $0.1200 $0.1020 $0.0675 $12.26	EIA Annual Energy Outlook 2010 for 2020 rates; (Table A8 Ref Case) Assumed a 10% reduction in energy tariffs for consumer incentive
Rate escalator	0.1%		EIA Annual Energy Outlook 2010

The above tariff rate assumptions are very important. The model uses the 2020 national average rates for residential, commercial, and industrial consumers reported by DOE EIA Annual Energy Outlook 2010 (reported in April 2010) Table A8 for the Reference Case.

In consideration of the shared goals of the municipality and its consumers, the model uses a 10 percent reduction in energy tariffs to consumers as a shared benefit, as well as a reasonable internal rate of return (IRR) for the merchant's investment in the resources and infrastructure.

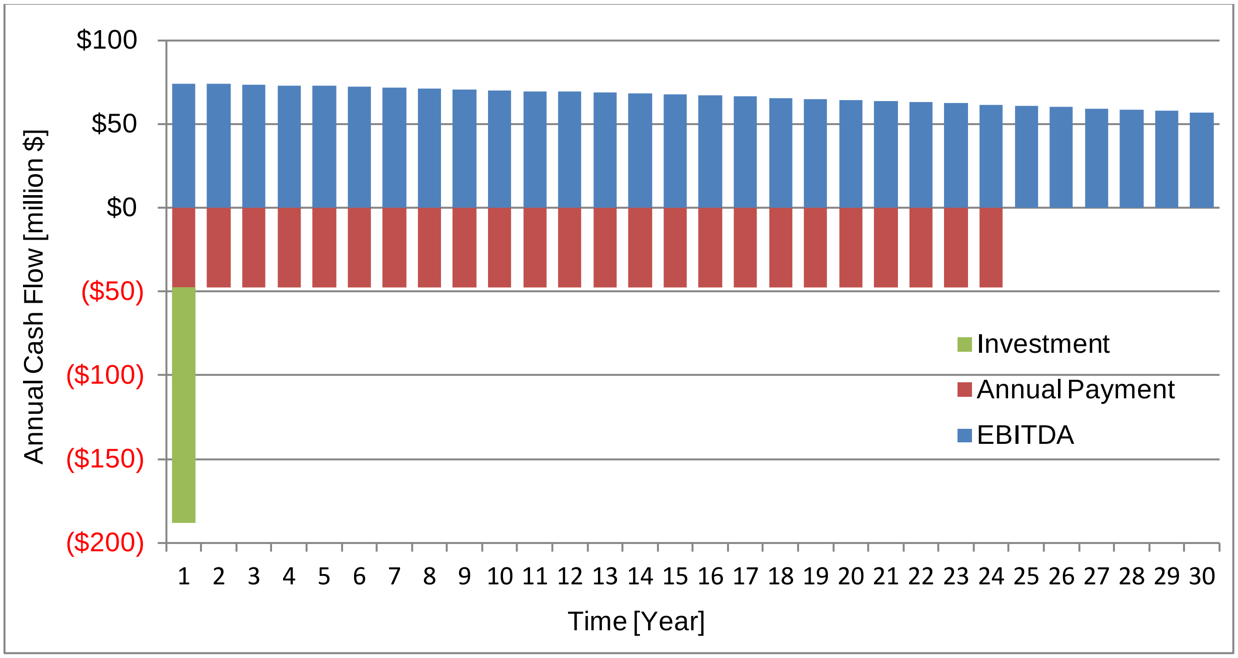
Considering the added resources, infrastructure, and financial assumptions, the system economics result in a viable future in which the Smart Grid 2020 City is well-supported by a coal–renewables mix from an economic, reliability, and environmental perspective. See Exhibit 6-9 for the results.

Exhibit 6-9 Smart Grid 2020 City Analysis Results

Parameter	Value
Total transformation cost	$873.1M
Federal investment tax credits	($121.5M)
Net transformation cost	$751.5M
Traditional annual consumer electricity spend with vertically-integrated utility	$171.5M
New annual consumer electricity spend with municipal utility (annual revenue)	$156.1M
Annual wholesale electricity cost	$32.9M
Annual fuel cost	$12.7M
Annual O&M and G&A cost	$36.3M
Annual EBITDA	$74.2M
Annual loan payment	$47.8M
Annual tax (depreciation basis > tax liability for the first 10 years)	$0.0M
After-tax profit	$26.3M
Internal rate of return (IRR)	18%
Annual emissions reduction	198,189 T/yr
Annual emissions offsets	$1.0M
New SAIDI	12
New SAIFI	0.5
Annual sales into the market	17,542 MWh
Annual net market sales profit	$0.5M
Total annual profits	$27.8M

The project equity ($140 million) will be paid off in six years; however, the whole project will be paid off in 25 years. Exhibit 6-10 shows annual cash flow. Net present value of the project is 77 million dollar.

Exhibit 6-10 Annual Cash Flow



The economic analysis shows that a coal–renewables mix in a Smart Grid environment is not only cost effective, but also meets other municipal objectives as well. For example, over the duration of the analysis, the city will realize an emissions reduction of nearly 5 million tons.

To put this Smart Grid 2020 City into the proper context, consider the business as usual (BAU) situation which is represented by tariff rates projected for 2020 from the EIA Annual Energy Outlook 2010 data and the generation and transmission infrastructure that had to be built to deliver the energy to the city.

The tariff savings (Exhibit 6-9), as the difference between the traditional annual consumer electricity spend and the new annual consumer electricity spend, is about $15.4M per year. Over the term of the loan, the total consumer electric bill savings is about $385M.

For the capital expense savings, the BAU situation must be estimated for 2020. First, use the FERC staff report [93] on new central-station generation costs for 2008 to calculate the average cost of central-station generation. Escalating the new central-station generation installed cost, adding the transmission component, and averaging across the fleet according to its contribution to the generation mix as shown in Exhibit B- 2, the average cost is $4,541/kW.

From the economic analysis perspective, there are a few additional questions to address.

<u>Issue: What is the Business As Usual (BAU) CO_2 Emissions Impact ($0/Ton CO2)?</u>

The model used for this economic analysis considers the emissions offsets delivered by renewable energy resources against the average central-station generation mix, but does not consider the emissions reduction differences from using the IGCC distributed generator in the local generation portfolio. This is a conservative approach since it is unclear whether or not the IGCC – hybrid power plant will be a reduction in CO_2 emissions.

In the results above, the CO_2 emissions offsets yield about $368,000 of CO2 trading revenue annually (based on the Regional Greenhouse Gas Initiative (RGGI) market price at $1.86/Ton CO_2).

If a zero price CO_2 scenario is used, the annual revenue under the Smart Grid 2020 City model is reduced by $368,000. Therefore, the total annual profit decreases from $27.8M to $27.4M. Under this assumption of US marketplace CO_2 pricing, the effect is minimal on the total annual profits.

However, if a 2030 projection from McKinsey & Company [94] of $50/Ton CO2 is used in the model, the CO_2 emissions offsets would represent a $9.9M (compared to the $368,000 using the September 2010 RGGI price) addition to the annual profit of the municipal/merchant. This $50/ton CO_2 projection would add significant incentive to use the Smart Grid 2020 City design.

<u>Issue: Does the natural gas price projection and volatility change the economics?</u>

With natural gas prices in 2010 hovering around $4.20/MMBTU, some suggest that increasing the natural gas power generation fleet is a good choice. However, according to the Energy Information Administration [95] and the CME Group [96], the price of natural gas will be above $6.00/mmBTU by 2015. The EIA further projects the price to be $6.60/MMBTU in 2020 and $8.00/mmBTU by 2030. Natural gas prices are volatile.

The Smart Grid 2020 City uses a coal baseload generation component versus a natural gas baseload generation component. The economic analysis did not evaluate the comparison of LCOE for coal baseload generation versus natural gas baseload generation over the 25 year term starting in 2020. However, other LCOE comparisons between coal and natural gas have been made [13] that demonstrate that coal is more cost-competitive than natural gas at much less than a $6.00/MMBTU natural gas price.

For the customer-owned distributed generation used in the Smart Grid 2020 City model, the fuel cost assumptions used is very conservative at > $10/MMBTU, therefore, the projected natural gas price and volatility should not affect the results of the analysis.

<u>Issue: Can renewable energy resources be relied upon in this situation?</u>

While variable renewables do have the occasional significant downturn or upturn in resource availability (wind, sun), the National Renewable Energy Laboratory reports that the Colorado Public Utility Commission accepted a certain percentage of wind farm capacity as the overall statistical probability in meeting demand requirements (31). This is another way of saying that a portion of the wind farm capacity should be considered firm, roughly equivalent to its capacity factor. The actual amount of capacity value depends on the wind characteristic, wind patterns, load requirements, geographic dispersion of the turbines, and how well connected the utility is with its neighbors.

6.6 Estimated System Reliability

When the electric system must address rapidly developing shortfalls in supply or drops in load, the following equipment or characteristics mitigate loss or failure:

- Baseload generation and spinning reserve inertia provides immediate ride-through support for transients.
- The voltage can be reduced slightly.
- Pumped hydro storage (if properly staged) can respond within 15 seconds and quickly accommodate changes up to its maximum capacity.
- Spinning reserve from generation kept at partial load, the output of which can be increased by about 7 percent per minute.

When there is a loss of load, some of these system or characteristics accommodate the loss as well. For example, the plant supplying spinning reserve can regulate downward at some ramp rate (may be a smaller rate than regulating upward) and the pumped hydro storage turbines can quickly pump water up to the reservoir.

There are risks in the power system that typically form the basis for designing the reliability of the system (24). These characteristics include:

- Failure of the interconnected tie lines, which may be in the 1,000 to 2,000 MW per circuit range.
- Steam turbine trips. A utility or transmission operator plans for spinning reserves for the contingency of losing the largest unit within the network, which could be over 1,000 MW. This is typically referred to as an “N-1” contingency.
- Transformer failures. This type of failure usually results in curtailment of certain loads within a short period of time to avoid significant imbalances, damage to equipment, and cascading events.
- Thunderstorms. Network circuits can trip, if struck by lightning, to protect equipment.
- Unexpected increases in demand. While the load is routinely forecasted at least a day ahead, unforeseen weather changes present a challenge to the nature of the load and supply balance on the network.

In reality, the major reason for spinning reserve requirements is to account for an imperfect match between generation and demand during a 10-minute period. With a small number of network nodes representing the large central-station generation sending electricity over long distances to large load centers (“pockets”), an individual loss of a generator or load pocket can create significant trauma on the system. This effect is often referred to as the “lumpiness” of the U.S. electric system. Ideally, a large number of smaller generators and load centers would reduce the lumpiness of the system, and thus reduce the challenges to system stability on the loss of any one generator or load. This would improve system reliability.

As the network becomes more intelligent (Smart Grid), increases its use of distributed generation, microgrids, energy storage, and sophisticated demand response programs, the lumpiness of the system should decrease.

This phenomena was analyzed for West Virginia during the West Virginia Smart Grid Implementation Plan (32) and showed that the added combination of 1,000 MW of wind, DG, and storage in a more intelligent electric system using Smart Grid strategies, yielded an order of magnitude improvement in system reliability as measured by the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI).

6.7 Summary

This section integrated the previous analyses by describing a "Smart Grid City of the Future." The City is characterized with a vision that is locally focused, with a high share of renewable generation, a broad set of DG resources, and an engaged consumer base working in an efficient market. Economic, environmental, and reliability factors are used to determine the best coal and renewables mix for the city. Coal generation is used to mitigate the stability impacts of variable renewable sources.

A municipal-utility model shows a favorable return on investment for the transformation and operation of the City under credible assumptions. Under an explicit set of assumptions, the municipality has a six-year payback period on its initial investment. The City scenario demonstrates the viability of deploying distributed coal plants in a Smart Grid coupled with renewables as evidenced by reduced electricity prices for consumers, profit for the municipality, a reasonable internal rate of return for the merchant utility, improved reliability, and reduced emissions.

One of the key objectives of the Smart Grid is to eliminate or mitigate peak load, which should increase the importance of baseload generation. The economic and portfolio analysis shows coal technology supplying baseload generation as a new, unique role not common today.

As variable renewables and PHEV increase in numbers and capacity in the local community, the need for local baseload generation will increase even more.

The analysis shows that while IGCC technology is more expensive to install, it is well suited for the smaller sizes (50 – 90 MW) that would be compatible with the baseload generation needs of the Smart Grid 2020 City. Placing a 60 MW IGCC plant on the edge of the city eliminates the need for new transmission lines and the associated transmission losses. In addition, it is well suited for poly-plant applications (e.g., CHP). Both of these factors offset some of the higher installed cost of the IGCC.

Plus, higher thermal efficiencies come with poly-plant-applications; therefore, the emissions per MW should decrease.

7 Conclusions

In this report, we analyzed how the role of coal might be affected by the adoption of Smart Grid technologies: how traditional and non-traditional generation technologies and electrical grid designs might empower consumers to take advantage of the low cost and reliability of coal while mitigating the environmental and congestion issues associated with centralized coal generation.

Several themes emerge from the analyses:

Baseload demand will increase.

Our analyses suggested that load leveling enabled by the Smart Grid will significantly increase the amount of demand that can be met with constant baseload generating technologies. All other things being equal, this increases the value of existing baseload plants, since the higher demand will correspond to a higher load factor.

Coal can serve as a cost-effective way to meet this increased demand, if transmission and carbon-control constraints are not binding.

Coal remains the fuel that provides centralized baseload generation at the lowest levelized costs. Centralized generation depends upon transmission capacity to get this low-cost supply to the load. Coal combustion generates a larger quantity of CO_2 per kWh than other common fuels, so its cost-competitiveness is sensitive to future, and uncertain, carbon control costs.

If carbon control costs are sufficiently high, coal gasification will be more cost-effective than coal combustion.

Our analysis suggested that a price of approximately $180 per ton of CO_2 is the break-even point for IGCC with CCS over PC with CCS, given current prices, regulations, and technology. NGCC with CCS is more cost-effective than either coal technologies, but natural gas prices tend to be volatile and could rise to levels that make it more expensive than these coal-based technologies.

Distributed generation is likely to increase.
Smart Grid technologies should make distributed generation easier to implement. Public resistance to new transmission construction is high, so some of the increased baseload and peak demand will have to be met by distributed assets.

Distributed generation is more efficient and economical in CHP applications.

Small distributed plants are less efficient in pure power generation than are larger plants. However, the difference can be overcome if the small plant re-uses its waste heat in process and space heating. Moreover, a CHP plant will generally be larger than a plant designed only to meet the electrical load at a given location, so that the demand for direct heat can be met simultaneously with peak electrical demand. Economies of scale will make such a plant more efficient than the smaller, power-only plant.

The Danish experience suggests that coal-based CHP can play a significant role in meeting energy demand.
There is little coal-based CHP in the U.S., but a significant amount in Denmark. We described

several coal-based CHP technologies currently in use in the paper, including PC and FBC, gasification with a combustion turbine, and gasification with a reciprocating engine.

The Danish experience suggests that public policies can significantly increase the adoption rate of CHP. Some of the factors that contributed to Denmark's success in its transformation were environmental monitoring, carbon tax implementation, feed-in tariffs, government-supported financing, guaranteed open access to the grid, taxpayer-funded R&D, streamlined permitting, and a bottom-up approach to R&D.

Modular coal-based IGCC generation is a promising technology for DG in a carbon-constrained scenario, but it is not yet cost-competitive with natural gas alternatives.
If sharp learning curves ("Henderson's Law") apply to the production of modular IGCC plants, the construction of many small plants will result in a substantial decrease in construction and operating costs. However, there are no data currently available that validate this assumption. Under current technology and fuel costs, modular IGCC is not as cost-effective as NGCC when CCS is required.

Coal-based CHP may have a role in providing firm power in microgrids.
As currently conceptualized, microgrids will have significant variable renewable generation, but will be conducive to CHP applications due to the proximity of district heating or industrial process heat demand. They also will, by necessity, have some energy storage capacity. In such a situation, CHP, such as low-cost coal-based CHP, is a potential choice for providing the firm power capacity needed to make use of renewables feasible at an acceptable level of reliability.

Under some credible scenarios, the transformation investments needed to create a "Smart Grid City of the Future" may result in good financial rates of return for municipalities. The sample scenarios given in Section 5 yield a payback period of about six years. This financial return is in addition to non-market benefits such as reduced environmental footprint and reduced grid dependence.

8 Recommendations

The conclusions above lead to recommendations for R&D decision makers, energy analysts, and policy analysts.

Perform regional technology analyses on the role of coal

Although climate impacts are global, most other potential impacts of coal in a Smart Grid are local. Energy costs, transmission congestion, criteria pollutant emissions, and grid reliability are all locally or regionally specific. Hence, the appropriateness and effectiveness of coal-based generation will be sensitive to local conditions. Knowledge of the specific regions where different applications are effective will assist regional and local decision makers, both private and public, in making investment decisions that influence the role of coal in meeting their power needs. Regional analyses might examine

- Local costs and benefits of coal technologies in different applications
- The need for DG to overcome transmission constraints
- The feasibility and desirability of migration towards a microgrid

Perform regional policy analyses

In parallel with the regional technology analyses, modeling and analysis of local, state, and regional policies that positively or negatively affect the adoption of coal-based DG or CHP would be valuable to public and private policy makers. Lessons from the Denmark experience might be mapped to U.S. regions and analyzed so potential changes to policy might be better understood and implemented.

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Appendix A - Coal Power Plant Technologies Review

Large and small coal power plants are discussed in terms of technical characteristics, economic feasibility and environmental impact. This Appendix reviews pulverized coal power plants as representatives of a time-tested and proven solution and integrated gasification combined cycle power plants as a new technology capable of addressing environmental issues.

Centralized Large Power Plants

Because of economies of scale, higher efficiency of large power plants, and usually lower cost of coal, historically, the US power industry favored large, coal-based, centralized power plants. A strict definition of a large power plant would be application and environment or any other criteria dependent. For our purposes, we consider plants larger than 90 MW as large plants.

In the United States, the size of power plants grew from a few tens of megawatts to 340 MW around 1929 and around 1965, even larger plants were developed (33). This trend is attributed to technological advancements in building power generating turbines capable of operating at higher temperatures and pressures and, therefore, higher efficiencies. Exhibit A- 1 shows a typical process schematic of a pulverized coal plant.

Exhibit A- 1 Schematic Representation of a PC Power Plant

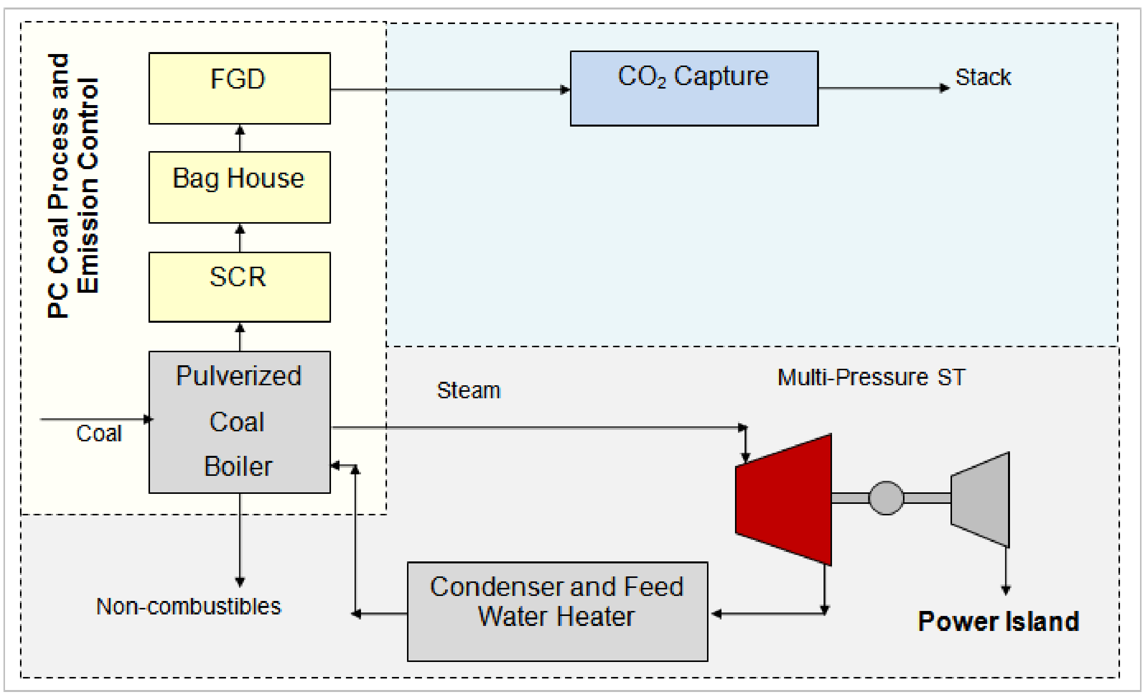


Exhibit A- 2 shows the relationship between typical PC plant sizes, design values, and efficiencies. This exhibit shows the typical values from Worley Parsons Internal Data based on firing Eastern Bituminous coal. Comparative cycle performance was calculated using GateCycle with common boundary conditions.

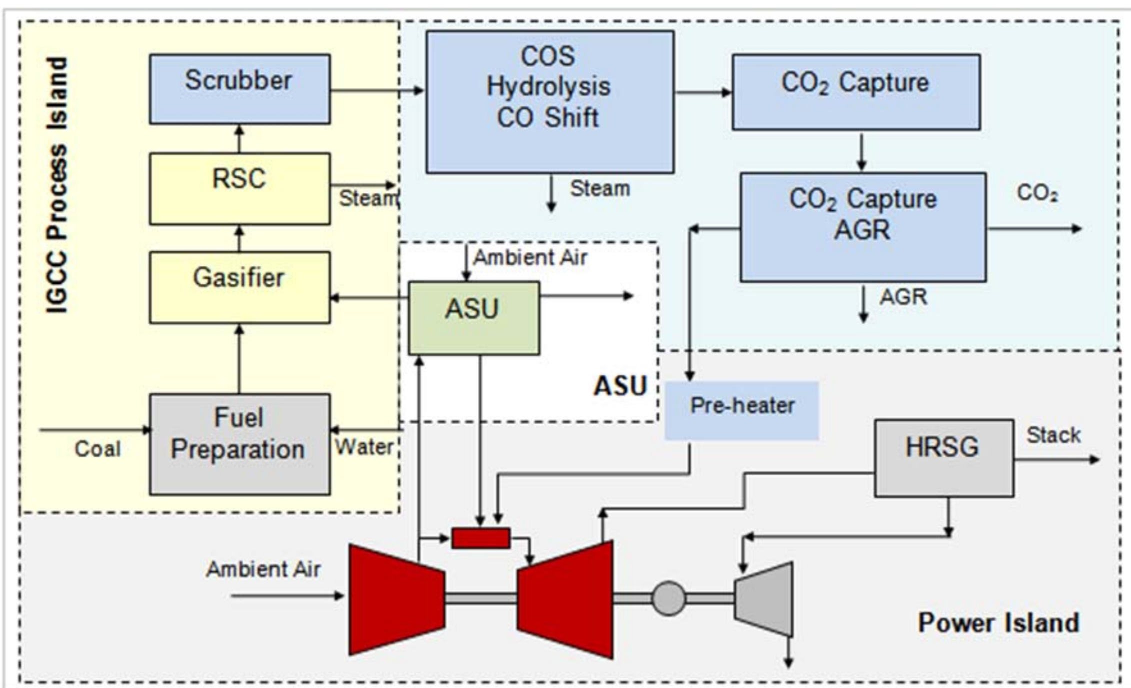
Exhibit A- 2 Large PC Plants with Reheat, Steam Conditions vs. Plant Performance

MWe	Design Values	Efficiency, HHV
600	3500 psig 1050F/1050F	40.0
400	3500 psig 1050F/1050F	39.5
200	2000 psig 1050F/1050F	38.5
100	1500 psig 1050F/1050F	38.0

Source: (10)

IGCC is a potentially clean coal technology for power generation. An IGCC plant does not burn coal completely; rather, it breaks down the coal into gaseous hydrocarbons referred to as syngas. The solids and syngas are separated and the syngas is cleaned, cooled, and then used as fuel for a combustion turbine. As shown in Exhibit A- 3, a typical IGCC includes three major sections: (1) the process island, (2) the air separation unit, and (3) the power island or the combined cycle. Detailed discussion of the IGCC processes can be found in (34).

Exhibit A- 3 Typical IGCC Process with CO_2 Capture



WorleyParsons Group recently performed a comparison study for a major utility. The study evaluated PC, CFB, IGCC, and NGCC. These coal- and natural gas-fired units were nominally 630 MWe, net, in size. A nuclear unit was briefly looked at. Some numerical comparisons are presented in the table below (Exhibit A- 4). Note that the capital costs are on a Total Plant Cost basis (as defined in EPRI TAG), and are in year-2006 dollars. They are also based on siting a plant on a generic site in the Midwestern United States, without consideration of particular site factors such as the need for piles or other special site-related design and construction measures. The pricing also does not take into account extraordinary permitting measures that a coal-fired plant may experience in today's regulatory climate. Actual values that may be experienced in today's pricing environment can vary significantly.

Exhibit A- 4 PC, FBC, IGCC and NGCC Comparison

	PC	FBC	IGCC	NGCC
Total Net MWe	630	630	630	630
Heat Rate, Btu/kWh, HHV	8530	8930	8360	6750
Cap Cost, $/kWe	1740	1780	2130	580

Source: (10)

Technical characteristics

IGCC and PC based power plants differ in a number of operational characteristics. The most important features for electrical power generation include efficiency, up- and down-ramping rates, load following capability, and cycling characteristics. These key characteristics are hard to define uniquely for both IGCC and PC. The efficiency is usually defined as the output power divided by the input power. The IGCC has two distinct parts, the gasifier and turbine and the efficiency can be defined for each part independently or for the entire plant. Similarly, up- and down-ramping rates can be defined for the entire IGCC plant or just for the turbine.

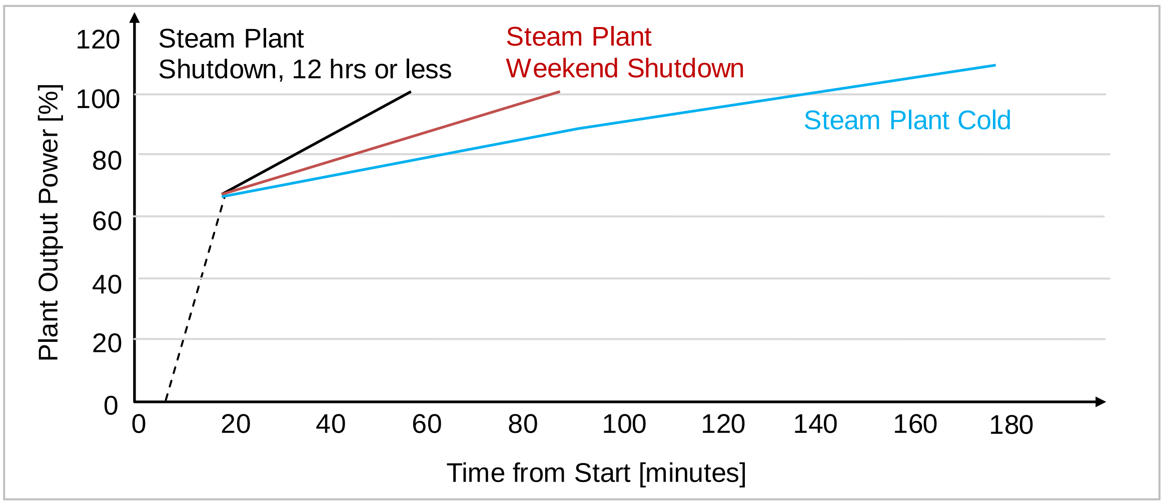
The IGCC gasifier needs hours to warm up to the required gasification temperature and pressure. For example, warm startup times for a GE oxygen-blown gasifier could be between 8 and 12 hours. Complete cycle time for the gasifier shutdown/cool-down followed by a startup is 24 hours or more. Assuming full syngas supply during a cold start up, the GT part of IGCC's CC part takes 15 to 20 minutes to reach full load. This brings the entire plant to about 65 percent of its output capability for multi-shaft plants. The plant then needs an additional 45 minutes to about 3 hours to come to full capability, depending on the startup temperature. Exhibit A- 5 shows typical startup of a large combined cycle power plant. The total time required for a single shaft system to come to full capacity is approximately the same as for a multi-shaft system but with a different ramping profile. This is because in single shaft systems the GT and ST are started as a single integrated unit and not separately. A typical ramping profile of a single shaft CC is shown in Exhibit A- 5 (b). The exact ramping rates are affected by the construction materials used for the turbines and the rate of temperature changes of machine parts. Turbine manufacturers provide guidelines for these not just through start-ups but also for the scheduled and unscheduled maintenance. These considerations remain valid for IGCC, NGCC, PC, and other types of power plants.

It is important to remember that these ramping rate estimates are just for the CC part of an IGCC plant. If the gasifier is not running, the time needed to bring it up to desired capacity should be accounted for. Also, during the startup, natural gas for the gas turbine and/or electric power for the ASU are supplied externally. During the operations, IGCC gasifier turndown is limited to only about 15 percent, that is, down to 85 percent load.

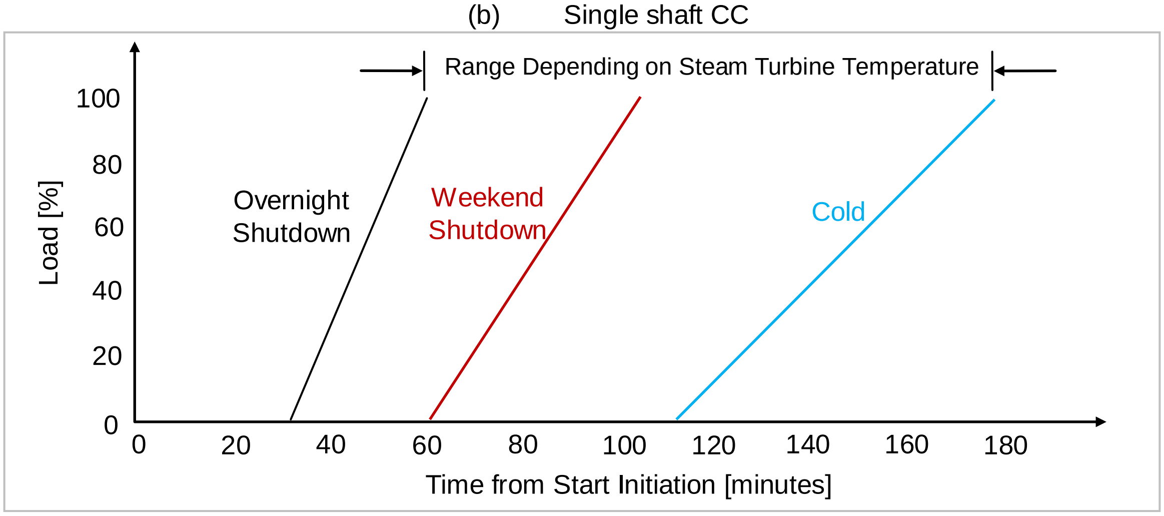
Similar concerns exist for PC plants. The boiler ramping rate could take about an hour to bring the system to full capacity depending on the boiler design, among other operating conditions. The Rankine cycle of these plants requires about the same time shown by the solid lines shown in Exhibit A- 5 (a) and (b). For these reasons, the steam in these plants is usually throttled to provide more operational flexibility; however, throttling the steam means loss of useful energy and lower efficiency. Recent literature (35) suggests changing boiler operating point instead of throttling to overcome the efficiency loss. Considering the slow boiler response this practice, it faces challenges if the plant is to be used for fast response services.

Exhibit A- 5 Typical Start-Up Time of a Large Combined Cycle

(a) Multi-shaft CC



(b) Single shaft CC



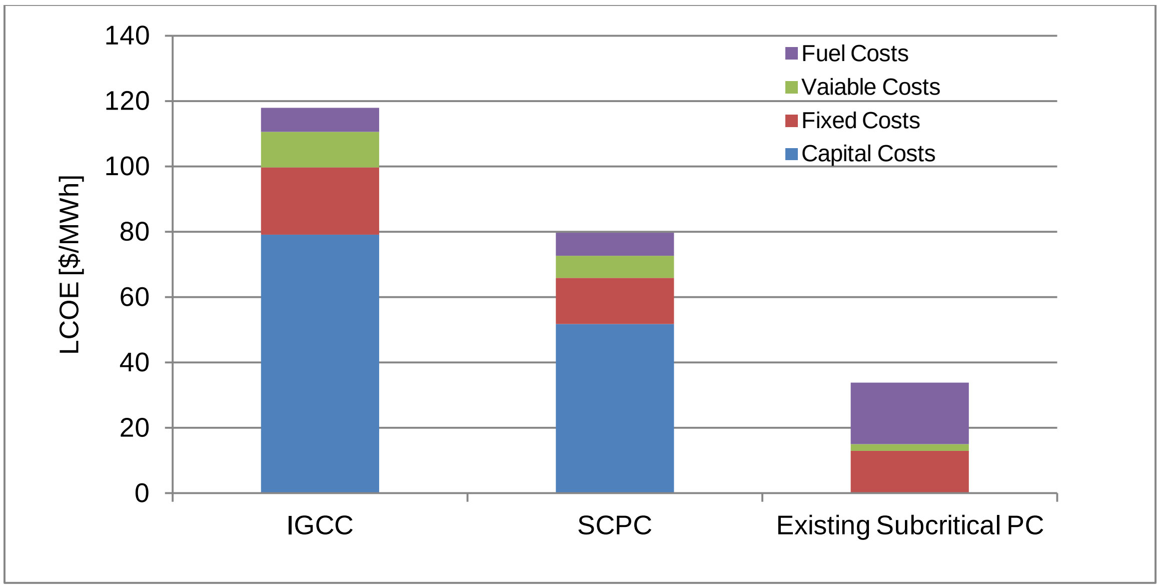
Source: (36)

Economic Feasibility

This section starts with economics of the coal-based power generation plants and then reviews other factors that affect the economics of these plants such as the modes of operation and the plant size.

IGCC is often regarded as a technology that will be economically more competitive in the future, when CO_2 emission penalties are enforced. As an example, Exhibit A- 6 compares the levelized cost of electricity (LCOE) of a Shell IGCC power plant to new supercritical (SCPC) and existing subcritical pulverized coal (PC) plants (37). The method used for calculating the LCOE is shown in the following for a plant life of 30 years (37). The LCOE is calculated based on the total overnight cost (TOC), which includes the owner's cost plus the total plant cost (TPC). The method for calculating the LCOE is shown in the following. The LCOE parameters for Exhibit A- 6 are shown in Exhibit A- 7. The reader is referred to (37) for more detailed information.

Exhibit A-6 Comparing LCOE of Various Coal Power Plants (without CO_2 Capture)



Data Source: (37)

Where

LCOEP = *levelized cost of electricity over P years, \$/MWh*

P = *levelization period (e.g., 10, 20, or 30 years)*

CCF = *capital charge factor for a levelization period of P years*

TPC = *total plant cost, \$*

LFFn = *levelization factor for category n fixed operating cost*

OCFn = *category n fixed operating cost for the initial year of operation (but expressed in "first-year-of-construction" year dollars)*

CF = *plant capacity factor, 85% for the PC and 80% for the IGCC plants. Addition of carbon capture is assumed not affect these levels (37).*

LFVn = *levelization factor for category n variable operating cost*

OCVn = *category n variable operating cost at 100 percent capacity factor for the initial year of operation (but expressed in "first-year-of-construction" year dollars)*

MWh = *annual net megawatt-hours of power generated at 100 percent capacity factor*

Exhibit A-7 Parameters for the Plants Shown in Exhibit A-6

	IGCC	SCPC	Existing PC
Capital Charge Factor	0.1773	0.1691	0.1567
General Levelization Factor	1.443	1.4299	1.4101

Source: (37)

Exhibit A-6 assumes the original capital cost for the subcritical PC plants is already paid, and fully depreciated. In other words, capital costs are not included in the LCOE. Therefore, supercritical PC plants would be the next economic choice for coal plants without CO_2 capture. The IGCC plant used to generate the results shown in Exhibit A-6 is a shell IGCC with a net output of 502 MWe. The SCPC and the existing PC plants have net outputs of 550 and 532 MWe respectively. The coal used for this example is sub-bituminous PRB from Montana. More details on these plants are provided in (37). Exhibit A-6 indicates that the LCOE generated by IGCC is higher than the LCOE for PC plants.

Future emissions regulations might make the IGCC plant more competitive (37), as illustrated in Exhibit A-8. The power plants are the same as in Exhibit A-6 with the CO_2 emission penalty added to the cost. An estimated penalty of $300/ton of CO_2 would make the IGCC plants competitive with PCs in LCOE terms (again, no capital cost is included in the existing PC plant LCOE). This estimate is generated using PRB coal from Montana, the corresponding CO2 generated, and the generated power. Under such conditions, a carbon penalty can be added to the total LCOE and adjusted to obtain the above estimate. Changing the coal type or other plant operational parameters would have an effect on the plant performances reported.

Currently, all commercial IGCC installations are carbon capture-ready only. A carbon capture and storage (CCS)-ready plant is described in (38). The IGCC and SCPC plants can be built with carbon capture and the existing PC plants can be retrofitted. This would change plant performance and costs. IGCC and PC plants are expected to have a reduced net output with carbon capture because their inability to maintain a constant output from the steam cycle given the fixed input. However, the SCPC plants can utilize a bigger boiler and steam turbine to do so.

The increased auxiliary loads (including those of the power generation plant and the carbon capture plant) and capital costs causes an increase in the LCOE compared to that shown in Exhibit A-6. This is shown in Exhibit A-9. The carbon is captured at 90 percent level. The capital cost of the existing PC plant is the cost of carbon capture retrofitting only, while the case of other plants includes the plant and carbon capture capital cost. These plants are discussed in more details in (37).

Exhibit A-8 Penalty of about \$300/ton of CO_2 Makes IGCC Competitive with Existing PC

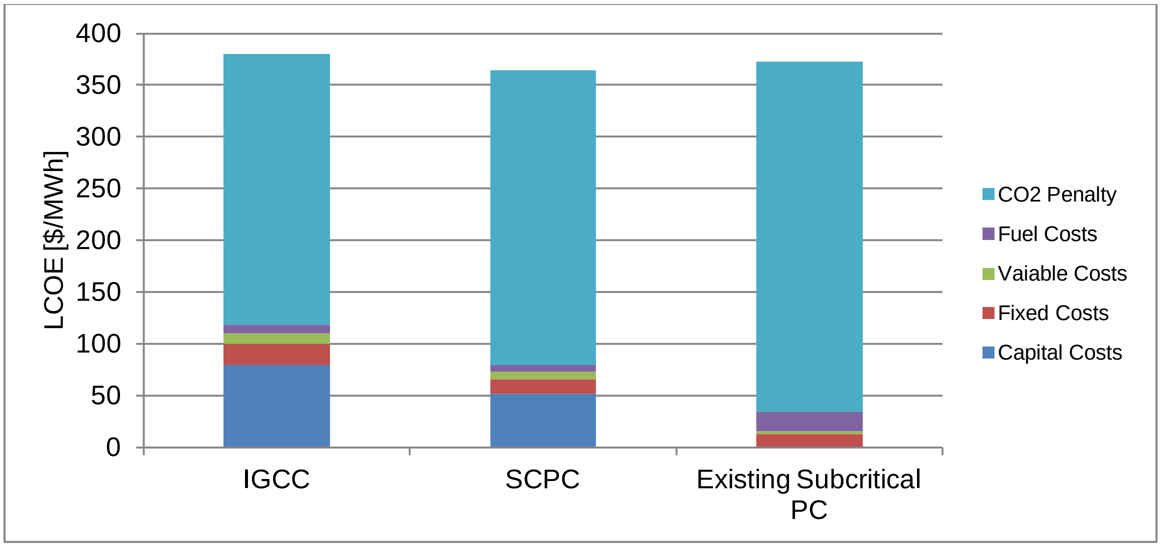
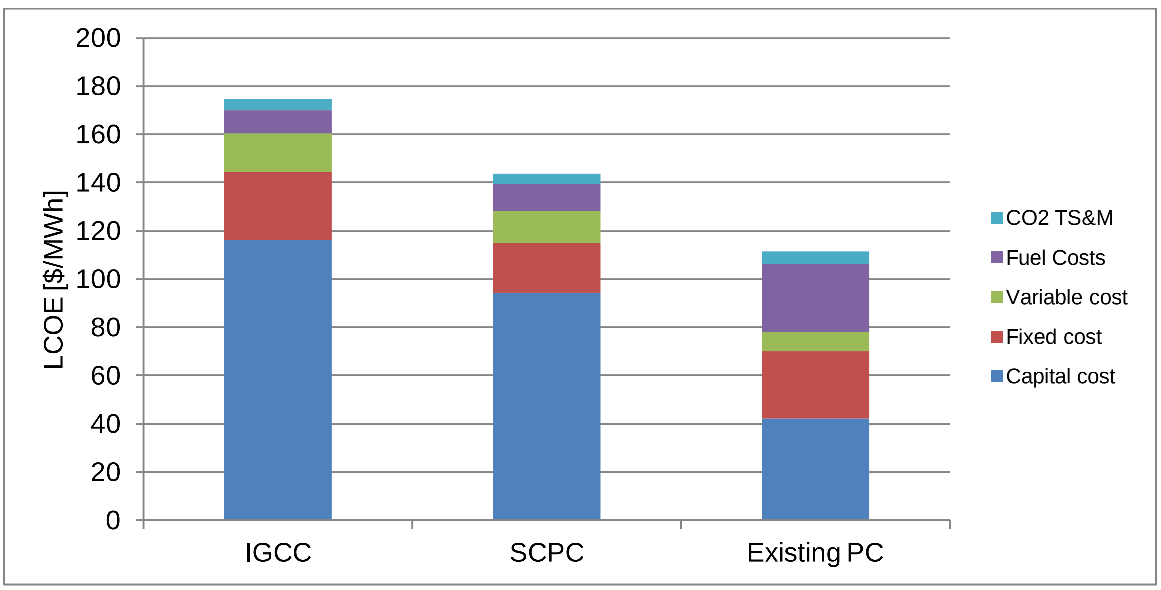


Exhibit A-9 Comparing LCOE of Various Power Plants with CCS (with CO_2 Capture)



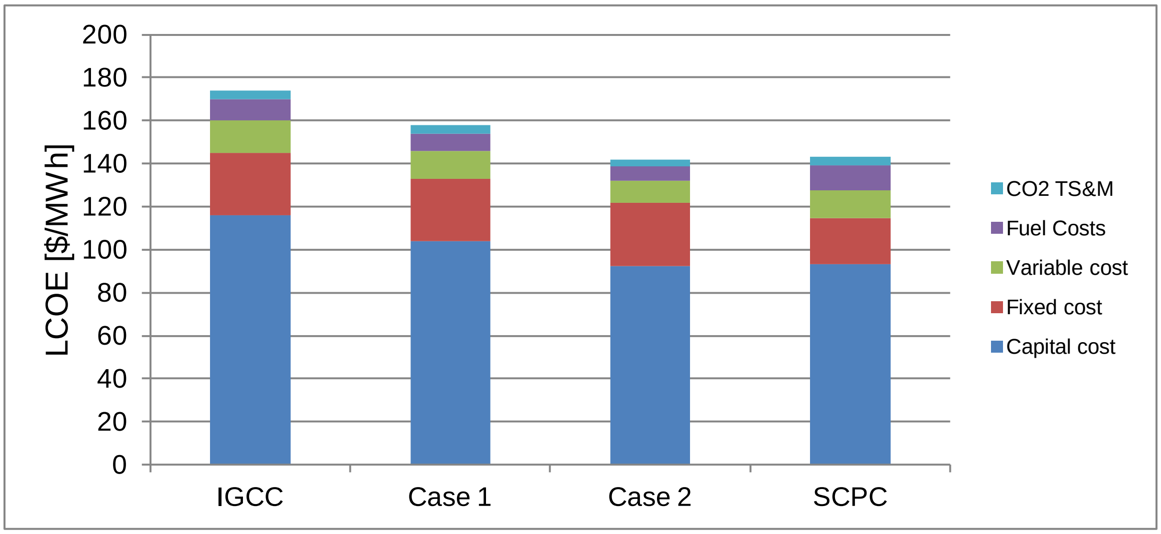
Note: TS&M: Transmission, Storage and Monitoring

Data Source: (37)

The TS&M cost shown in Exhibit A- 10 includes pressurizing and dehydrating the CO2 to 2215 psia, transporting it to the plant fence line, and monitoring the storage for 30 years (37).

Future improvements in performance of coal power plants could make them more competitive in terms of the cost of electricity. For example, an increase in the efficiency of the IGCC with carbon capture would make it competitive with SCPC. The IGCC shown in Exhibit A- 10 is the same shown in Exhibit A- 9. Cases 1 and 2 represents the same plant if the efficiency is increased from 31 percent to 37 percent and 45 percent respectively, assuming that the plant output remains constant. Higher efficiency means a lower flow rate of fuel input is needed and therefore the plant could be smaller. This would lead to smaller itemized and total LCOE costs as shown in Exhibit A- 10 shows that an improvement to 45 percent (HHV) in the efficiency of the IGCC with carbon capture shown in Exhibit A- 9 would make it quite comparable to SCPC with CC in terms of the LCOE.

Exhibit A-10 Improvements in the IGCC/CCS Compared SCPC/CC



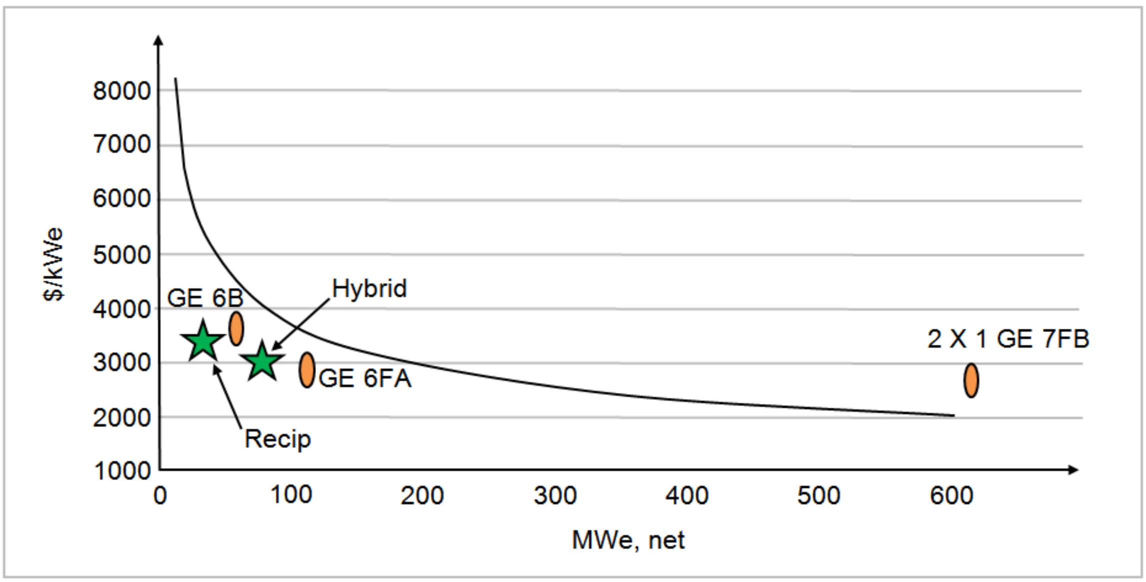
The size of the power generation plants is another factor affecting their cost directly through the capital cost and indirectly through the operating costs. The concerns associated with using the coal power plants as non-baseload sources of power generation were mentioned in the previous paragraphs. They are partially due to the long times required to change the plant generation set point. In the case of the IGCCs, the smaller plants Exhibit A-11 and Exhibit A-12 (10) for the PC plants for two different types of cost. In Exhibit A-11, the solid line represents the COE change of a single unit subcritical PC plant as the plant size changes. The change in COE is highly non-linear due to economies of scale for large plants. The same exhibit compares the PC costs to other types of plants simulated with the same output. These plants are modeled using GTPRO or Thermoflex, which are commercially available software packages for simulating power plants. On the right-hand-side of the curve, an oxygen-blown IGCC plant including a Shell gasifier and a 2×1 GE 7FB combined cycle is shown. The hybrid plant on the left hand side is a “hybrid” plant, which partially gasifies refinery residues. It uses the gas phase from gasification in a GE 6B turbine and burns the liquids in a diesel engine. The "GE 6FA" and "GE 6B" are single unit plants coupled with air blown coal gasifiers. The "Recip" point shows an air-blown coal gasification unit that uses a reciprocating engine. According to Exhibit A-11, the economies of scale lacking for small plants could shift the interest towards IGCC, which is a more expensive technology for large plants (39). Exhibit A-12 shows that the number of the required staff per kW is reduced as the plant size is increased. Exhibit A-13 shows how the plant efficiency changes for the PC plant (solid line) and other simulated plants explained above.

The points at the most right-hand side of the curves shown in Exhibit A- 14 represent the same Shell IGCC plant shown in Exhibit A-9. It is based on an advanced F class turbine without carbon capture. The detailed description of the plant is given in (37) . To produce this graph, the coal flow rate is varied from 50,000 to 478,697 lb/hr. The upper part of this range is the coal feed flow rate for the IGCC plant mentioned above. The total cost (2010 dollars) is then calculated using the "6/10th rule":

$$\frac{Cost_2}{Cost_1} = \left[\frac{Capacity_2}{Cpacity_1} \right]^n$$

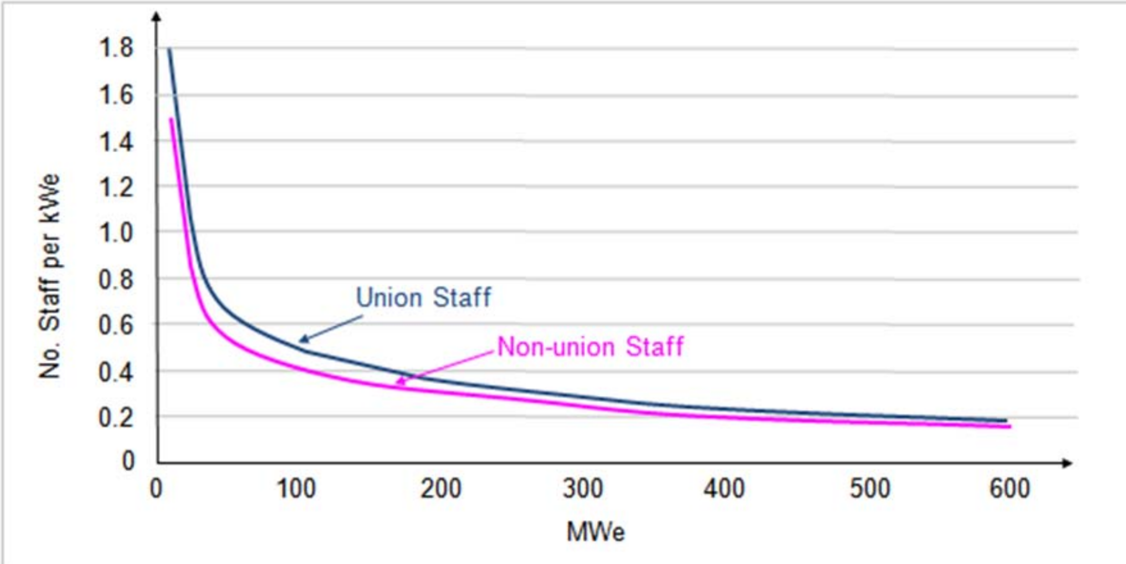
n is assumed to be 0.6 and the feed coal flow rate is used as the capacity. The output is assumed to change linearly with the coal flow rate yielding a relationship between the costs shown and the plant output. The required total capital cost is reduced as the plant size is reduced; however, the LCOE ($/kW) is increased.

Exhibit A-11 Plant Cost of Electricity vs. Size



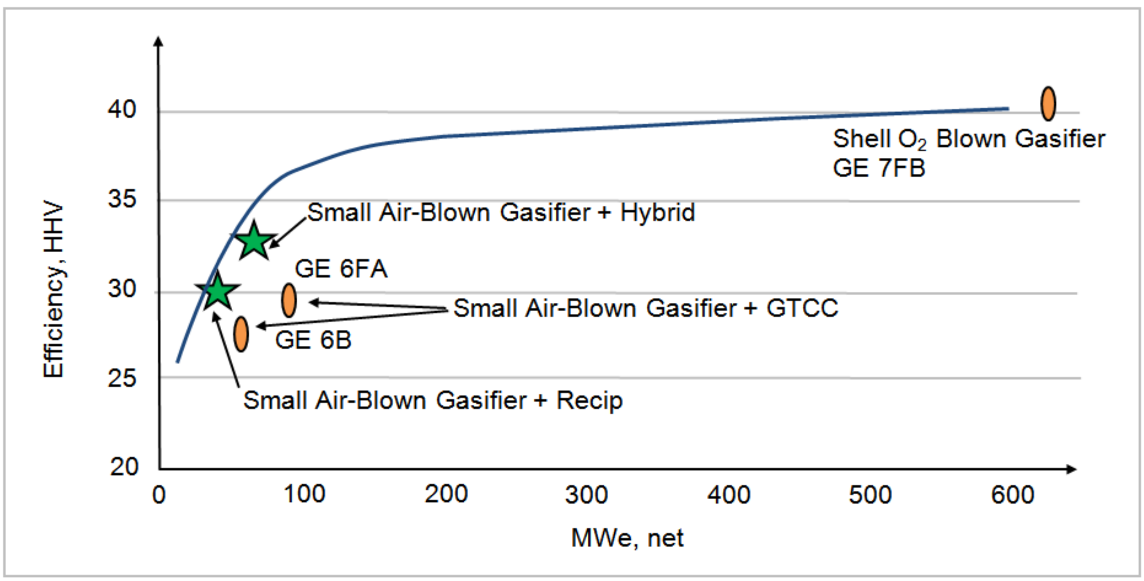
Source: (10)

Exhibit A-12 PC Plant Staffing Requirements vs. the Plant Size



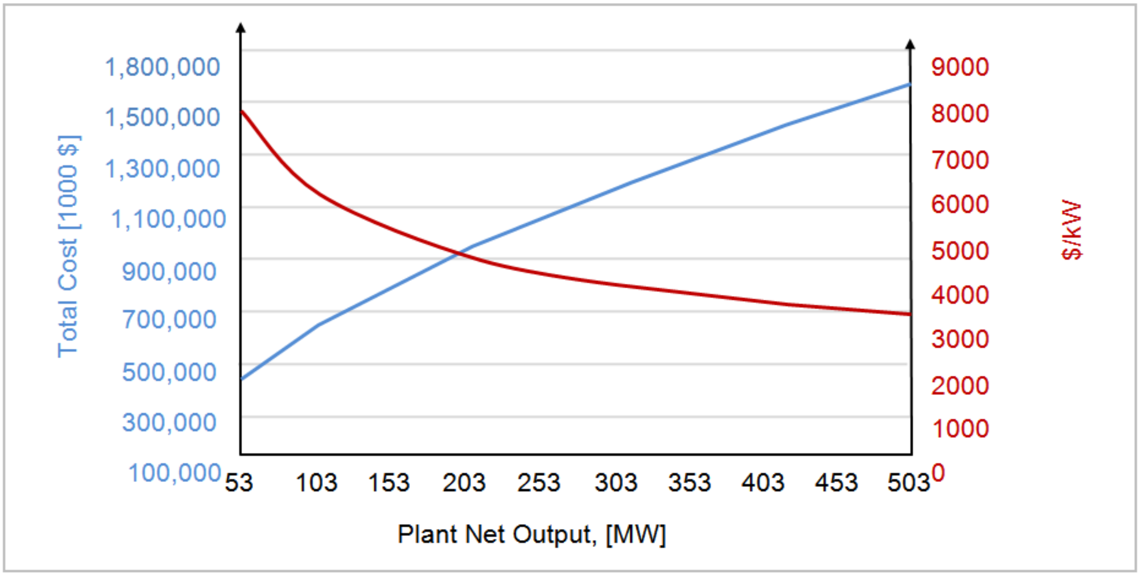
Source: (10)

Exhibit A-13 Smaller Plants Have Historically Been Less Efficient



Source: (37)

Exhibit A-14 Cost of Electricity Changes of a Shell IGCC with the Plant Size



The production cost advantages of multiple identically packaged small IGCC units have not been explored by the industry. Henderson's Law (40) (41) shows that in manufacturing and assembly industries, there is a 10 percent to 25 percent cost reduction per unit for each doubling of total units produced. There are no known studies in the electric power industry that confirm this law observed in other industries. Commercial experience with small numbers of multiple units suggests that other factors may act to dilute the potential savings predicted by Henderson's Law. These factors include varying site conditions that force design changes and market conditions, which may force price changes for key materials and components.

In addition to the size and type of a plant, plant's age is a factor in its expected performance and costs. Plants undergo a performance decline with age while older plants also utilize less efficient technologies.

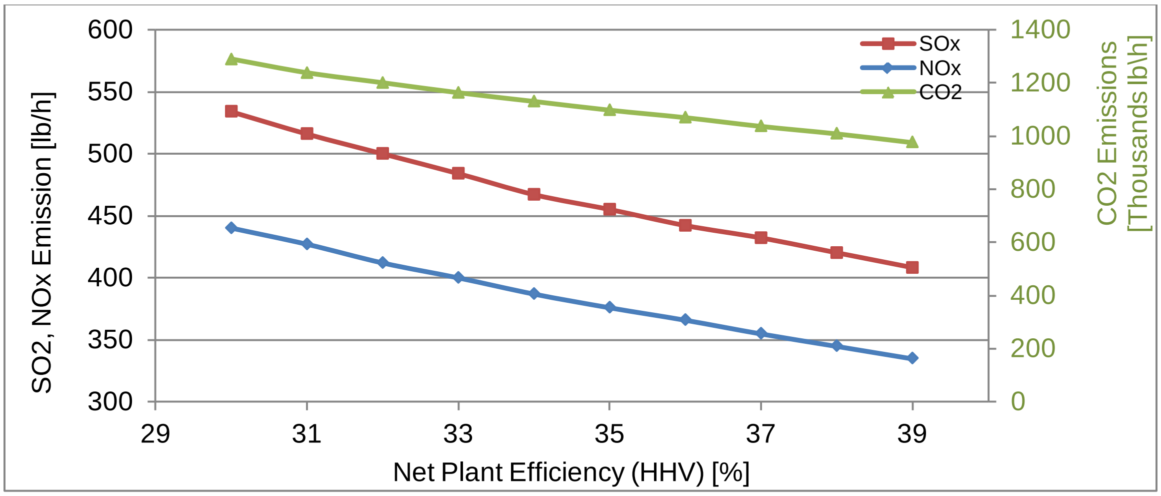
Environmental Impact

A wide range of CO_2 emission reduction policies have been debated, including cap and trade, a carbon tax, renewable mandates, and EPA emissions regulation. Among coal-based power generation technologies, IGCC lends itself to carbon capture more readily and at lower incremental cost compared to other coal conversion technologies. The environmental benefits of gasification stem from the ability to achieve extremely low SOx, NOx, and particulate emissions from burning coal-derived gases.

Other types of coal burning power plants can implement specific processes to meet the environmental regulations. To mention a few, the selective catalytic reduction (SCR) plant removes NO_x and filters the flue stream to remove the particulate matter. Flue gas desulfurization (FGD) plants remove SO_x, while using chemically reactive beds to remove mercury, amine processes remove H_2S, and carbon capture (CC) removes CO_2. These processes are expensive. Decreasing emissions per MWh can also be achieved by increasing the total efficiency of the power generation and is an alternative to physically removing the pollutants. Reduction in selected emissions with increased efficiency is shown in Exhibit A- 15. These efforts have a long history. Emergence of supercritical PC plants after the subcritical PC plants by utilizing steam at increased pressure and temperature is an example of such efforts.

The lower the efficiency of the plant, the greater the need for fuel to produce the same amount of energy output when compared with a more efficient plant. This also means a higher amount of pollutants are generated when the plant is less efficient. An estimate of such trends is shown in Exhibit A- 15 for a supercritical PC plant operating at a capacity factor of 85 percent. More efficient plants are, therefore, cleaner to operate.

Exhibit A- 15 Efficient Plants are Cleaner



Note: Supercritical PC without Carbon Capture, CF=85%; Net Plant Output 550 MWe

Based on (37)

Small Plants

In this report, small power plants are defined as plants smaller than 90 MW output but a strict definition of a small power plant would be application and environment or any other criteria dependent. Historically, small power plants are usually of lower efficiency and used as peaking units, for special standalone applications, or for distributed generation applications.

Technical Characteristics

Exhibit A- 16 represents Worley Parsons Internal Data based on firing Eastern Bituminous coal. Comparative cycle performance calculated using GateCycle with common boundary conditions (cond. press., etc.) (10).

Exhibit A- 16 Typical Efficiency and Operating Conditions of Small Non-Reheat Plants

MWe	Design Values	Efficiency, HHV
50	1250 psig/950 F	33
25	1250 psig/950 F	29
10	850 psig/900 F	26

Source: (10)

Some of the technical concerns surrounding loss of performance associated with small plants are explained earlier in this report, for example, the IGCC and the lack of a proper fit of the large-scale gasifier technologies such as the Radiant Syngas Coolers (RSC) to small plants due to their physical size and cost. The currently available small coal-based power plants are usually older plants that utilize lower process temperatures and pressures and therefore offer lower efficiencies (Exhibit A- 16). A comparison of the efficiencies shown in Exhibit A- 16 for the small plants to the Exhibit A- 2 for the large plants illustrates this point.

Alternative process components exist as potential solutions to deal with such problems although they may come at higher costs. For example, an alternative type of gasifier configuration exists that may be better suited to application on a small scale (42). This alternative modular gasifier (42) is a modification of the Wellman-Galusha type unit, used commercially in the 1930s through the 1960s for coal gasification. It is currently marketed by Hamilton Maurer International, Houston, Texas. The small modular gasifier is an air-blown, fixed-bed type unit equipped with a lock hopper for ash removal. This type of gasifier is also capable of better turn-down (to 25 percent vs. 85 percent for the larger units). It may also have better load-following capability. Finally, this alternative is partly based on modular design concepts, and this inherently takes better advantage of Henderson's Law. The alternative gasifier type is an air-blown, fixed-bed unit coupled to gas-firing reciprocating engines or a gas turbine combined cycle. A heavy fuel-oil burning diesel engine is added to fire tars and oils left over from the gasification process (the larger oxygen blown gasifiers destroy and gasify the tars and oils).

Results of the current investigation are summarized below. These results indicate the types of configurations that are likely to have the best chance for success in making energy efficient coal-fired small power plant with lowest cost of electricity.

Small coal-fired CHP-capable power plant concepts are based on the use of variable number of air blown gasifiers. Depending on unit size and need for steam export the following building blocks may be used:

- Air Blown Gasifier (such as one provided by Hamilton Maurer International) that is a modification of the Wellman-Galusha gasifier.
- Reciprocating Engines (Compression Ignition or Spark Ignition). Two manufacturers are currently known to be developing these types of engine specifically for firing low-Btu/low-methane gas:

- Jennbacher, a unit of the General Electric Company, provides a spark ignition type of engine producing a nominal 1500 kWe with an efficiency of approximately 37 percent on an LHV basis.
- Wartsila provides a compression ignition type of engine producing a nominal 2000 kWe.

Some of the other attributes of a gasifier coupled with a reciprocating engine are as following compared with PC or CFB type plants:

- Ability to Co-Fire Biomass: The air-blown modular gasifier can co-fire significant quantities of biomass. This can mitigate the carbon footprint of the plant, and possibly reduce fuel costs.
- Ability to Add Capacity Incrementally: If power and/or steam demand grows over time, gasifier and engine modules can be added relatively easily. Some up-rate of selected components may be required, such as the coal-feeding system and related solids handling equipment. With a PC or CFB, the output of the plant is essentially fixed during the design and difficult to change.
- Reliability/Availability: Any given level of reliability or availability may be achieved by adding one or more spare modules (N+1 gasifiers, etc.). PC and CFB plants usually have a single boiler and steam turbine. The plant reliability and availability heavily dependent on that single set of components.

Economic feasibility

A capital cost was developed for a nominal 43 MWe rated plant comprised of 8 modular gasifiers (including gas cleanup) and 22 reciprocating engines (rated at 2 MWe each). Relatively small engines are used because these engines can operate using the low-Btu/low-methane syngas produced by the small air-blown gasifier.

The capital cost was also developed for a gas turbine version of the modular air-blown gasifier plant. This particular design utilizes a GE Frame 6B gas turbine with a heat recovery steam generator and steam turbine generator. This plant requires a 14 modular gasifiers, and produces a nominal 60 MWe. A hybrid variation of this plant was evaluated with the addition of a diesel engine to fire the residual tars and oils from the gasifier. In the non-hybrid plant configuration, residual tars and oils were sold as a byproduct. The hybrid plant produces a nominal 74 MWe.

There is a relationship used in manufacturing called Henderson's Law. Although a thorough application of this law has not been proven in the manufacturing of the power plants, a similar logic is thought to apply to selected plant components (10). The relationship is dependent on the cost elasticity with regard to output. Empirical data shows that this factor ranges between 10 percent and 25 percent cost reduction per unit for every doubling of output. The curve in Exhibit A- 17 shows Henderson's Law for a power plant where the initial unit is $6,000/kW and using the lower end of Henderson's cost elasticity factor (10 percent).

Exhibit A-17 New Generation Cost with Many Units

Source: (10)

Consider a 1,000 MW coal plant without carbon capture; according to NETL analysis in 2009, it would cost roughly $1600/kW, or $1.6 billion. Scaling that plant down to 10 MWe using conventional cost estimating scaling rules, the smaller plant would cost approximately $9,000/kWe, or $90 million. Using Henderson's Law, the same output of 1,000 MW but manufactured as one hundred 10 MW units, the cost would be roughly $6,000 /kW, or $60 million per each, or $6 billion. The 10 MW plant is not a miniature version of the 1000 MWe. There will be significant differences in design and performance. Thermal efficiency is likely to decrease from a nominal 40 percent to around 25 percent, assuming use of an eastern bituminous coal. Actual commercial experience indicates that use of Henderson's law is compromised by siting, local environmental requirements (permits) and market conditions (squeeze on raw materials). Practically, manufacturing 100 units would allow for a significant portion of fabrication and assembly processes to be automated, driving costs out of the process. While a 1,000 MW plant would require the majority of the construction and assembly to take place onsite, one hundred 10 MW units would see a significant portion of construction and assembly packaged in the factory and shipped to the various sites.

If a similar comparison is made to a 1000 MWe and a 10 MWe plant, both with carbon capture of a nominal 90 percent, The following is likely: The capital cost of the 1000 MWe plant will be around $2900/kWe for a total cost of $2.9 billion. The thermal efficiency will be about 28 percent HHV. The 10 MWe plant is likely to cost about $16,200/kWe or about $162 million per each. Efficiency will be about 18 percent. Total costs for 1000 MWe will thus be around $16.2 billion. Using Henderson's law again could reduce overall costs.

The cost savings expected by high volume production of nearly identical units might be in the range of 5 percent to 10 percent per doubling, or about 40 percent in the most optimistic case.

There are additional costs associated with distributing one hundred 10 MW units associated with land purchase, coal delivery, and CO2 handling; the carbon capture is already included in the cost discussed above. Differences in site characteristics can make individual site placements vary widely. It must be emphasized that reducing merely the capital cost is not a guarantee for the economic success of the plants because smaller plants have lower efficiencies that can translate into higher operational costs. Changing the plant design might become a necessity to increase the energy efficiency of the plant or to control the emissions within the required limits.

The above discussion of the Henderson's law applies to conventional pulverized coal (PC) or fluid bed combustor (CFB) type units. Recent investigations indicate (42) that a different approach, relying on small modular gasifiers coupled to reciprocating engines or small gas turbines offer greater potential to standardize on plant design and realize the advantages of modularity. The small modular gasifiers are likely to be less sensitive to varying coal properties, which can significantly affect the design of small PC or CFB boilers, potentially compromising the benefits of Henderson's Law.

Environmental Impact

For the last century, coal-fired power plants have become progressively larger and more efficient, and have incorporated significant measures to reduce emissions of selected pollutants. Relatively recent innovations in coal plant design have included the circulating fluid bed (CFB) boiler as an alternative to the PC boiler, and the Integrated Gasification Combined Cycle (IGCC). The IGCC units built during the last several decades have relied on large oxygen-blown designs, providing clean syngas to one or more frame type gas turbines. These machines were originally designed for firing natural gas or distillate oil, and have been modified to successfully fire syngas.

As PC and CFB plants are scaled down in size, several trends are expressed that are inherent in the fundamentals of design, construction and operation of these units.

Among these trends, thermal efficiency decreases as a function of size. This occurs because of several factors:

- Reduced throttle pressure and temperature (for plants below about 250 MWe)
- Simplification of the steam cycle to eliminate reheat (for plants below about 90 MWe)
- Reduction in the number of stages of feedwater heating
- Reduction in the adiabatic efficiency of the steam turbine generator

Effects of reducing the plant size are discussed in previous sections and shown in Exhibit A- 11-Exhibit A- 15.

Plants with smaller sizes are considered less efficient (Exhibit A- 13). This is mostly due to historical reasons as related to the efficiency of the power generating equipment and also the space restrictions imposed on the design by the physical size of the plant.

Typical emissions from various power plants are shown in Exhibit A- 18 and Exhibit A- 19. Generally speaking, the environmental targets and performance depend on the location of the plant and the type of the technology and the fuel used. As explained previously in this report, changing the plant size is linked to efficiency (Exhibit A- 13) which changes the emissions. However, the graphs shown in Exhibit A- 18 are for small plants generated using simulation software such as GTPRO, Thermoflex, and Gatecycle depending on the plant type. The basis for sulfur emissions shown in Exhibit A- 18 is as following:

- PC: Wet limestone scrubber, 95% capture
- CFB: In-bed capture, 95% @ Ca/S = 2.4 (molar)
- Gasifier (all cases, Lo-Cat II by US Filter), 99% capture
- PFBC: In-bed capture, 95% @ Ca/S = 2.0 (molar)
- NGCC: No sulfur assumed in natural gas

The gasifier sulfur removal applies to four sub-cases, Gasifier + Boiler, Gasifier + Gas Turbine, Gasifier + Engine, Gasifier + Hybrid. The NOx emissions provision for the models shown in Exhibit A- 18 is as following:

- PC: Low-NOx burners, SCR
- CFB: SNCR
- Gasifier NOx produced in power conversion equipment, see below
- PFBC: SNCR
- NGCC: Low NOx burners + SCR
- Power Conversion NOx
    - Boiler: Low NOx burners, SNCR
    - Gas Turbine: SCR
    - Diesel Engine: SCR

The SCR used on gas turbines for syngas firing. The basis for CO generation/reduction modeling shown in Exhibit A- 18 is as the following:

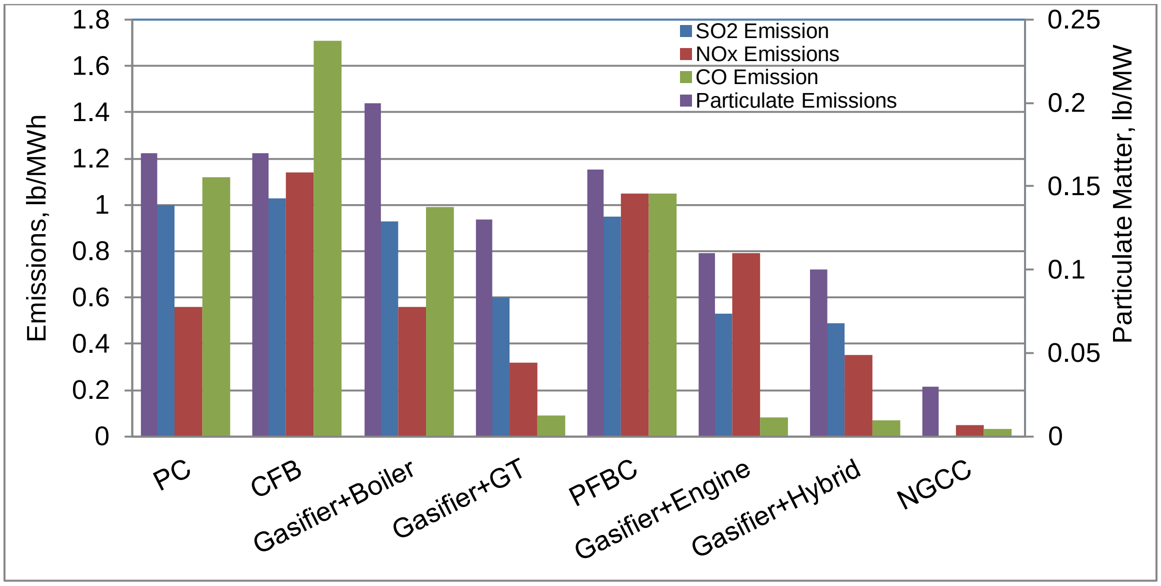
- PC: Excess air management, overfire air
- CFB: Excess air management
- Gasifier CO produced in power conversion equipment, see below
- PFBC: Excess air management
- NGCC: Combustor design
- Power Conversion CO
    - Boiler: Excess air management
    - Gas Turbine: Combustor design
    - Diesel Engine: No controls

The following were utilized as means of managing the particulate emissions in the modeling:

- PC: Electrostatic precipitator (ESP)
- CFB: Bag filter

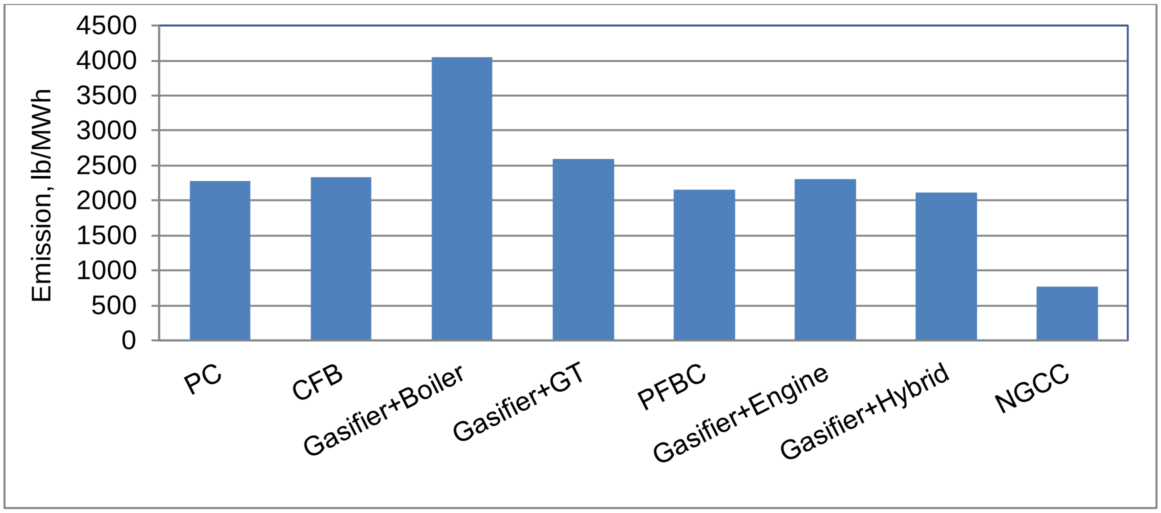
- Gasifier: Cyclones + ESP
- PFBC: Two-Stage Cyclones + Bag filter
- NGCC: Combustor design
- Gas Turbine: Combustor design
- Recip Engine: Particulate trap
- Hybrid: (see GT and recip engine, above)

Exhibit A- 18 Typical Emission Levels from Various Power Plants



Source: (10)

Exhibit A- 19 CO2 Emissions



Source: (10)

The tentative environmental targets shown in Exhibit A- 20 are taken from the New Source Performance Standards (NSPS) as amended in February 2006 (43). Emissions of the small plants could be exceeded by smaller plant, e.g. NOx emission for the circulating fluidized bed, as is shown in Exhibit A- 18. This is evidence pointing at the need for an alternative plant design and therefore economy of scale to improve as the size is reduced.

Exhibit A- 20 Selected Environmental Targets

	New Units		Reconstructed Units		Modified Units	
	Emission Limit	%Reduction	Emission Limit (lb/MMBtu)	% Reduction	Emission Limit (lb/MMBtu)	%Reduction
PM	0.015 lb/M Btu	99.9	0.015	99.9	0.015	99.8
SO_2	1.4 lb/MWh	95	0.15	95	0.15	90
NOx	1.0 lb/MWh	N/A	0.11	N/A	0.15	N/A

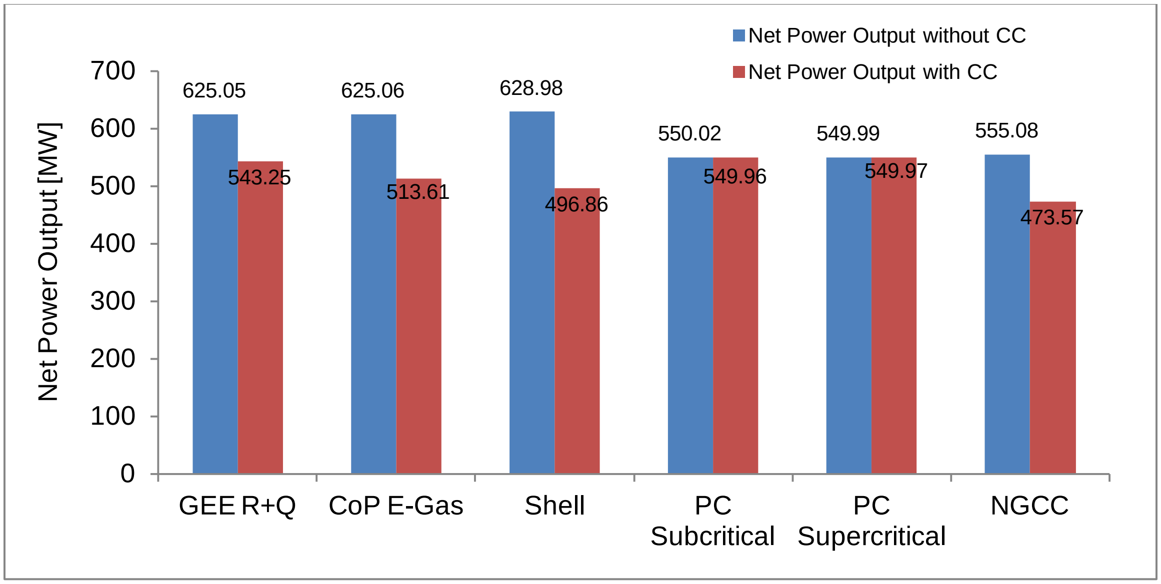
Source: (43)

Cost and Performance baseline for Fossil Energy Plants

A recent publication presents the cost and performance baseline data for the fossil energy plants including IGCC, sub and supercritical PC, and NGCC plants (44). The following charts are a few selected graphs from this reference. The description of these plants is given in Exhibit A- 21.

There are 6 IGCC plants discussed in this report: 3 are without carbon capture and based on General Electric Energy (GEE) gasifier, Conoco Philips (CoP) E-Gas Gasifier, and a Shell gasifier. The other three IGCC plants are the same three but with carbon capture. The combustion turbine (CT) used in these plants is assumed to be advanced F-class design. Detailed description of the processes is provided in the literature (39). The “R” and “Q” for the GEE IGCC stand for radiant syngas cooler and quench coolers. The carbon capture achieves 90 percent capture of CO2. The characteristics of all the studied plants are shown in Exhibit A- 22 through Exhibit A- 27. The coal used in the studies for the coal power generation technologies is Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb.

Exhibit A- 21 Net Output of the Plants



Source: (39)

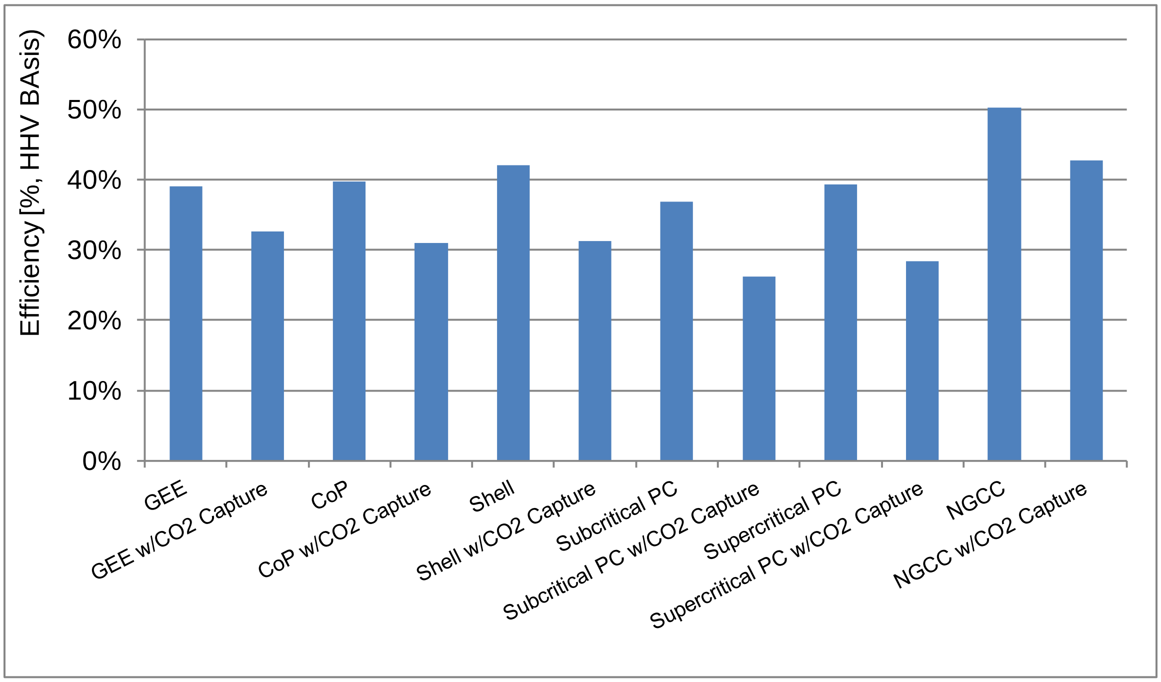
Exhibit A- 22 Description of the Plants

Case	Unit Cycle	Stem Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	Oxidant	H_2S Separation/ Removal	Sulfur Removal/ Recovery	CO_2 Separation
1	IGCC	1800/1050/1050	2xAdvanced F class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	
2	IGCC	1800/1000/1000	2xAdvanced F class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
3	IGCC	1800/1050/1050	2xAdvanced F class	CoP E-Gas™	95 mol% O_2	Refrigerated MDEA	Claus Plant	
4	IGCC	1800/1000/1000	2xAdvanced F class	CoP E-Gas™	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
5	IGCC	1800/1050/1050	2xAdvanced F class	Shell	95 mol% O_2	Sulfinol-M	Claus Plant	
6	IGCC	1800/1000/1000	2xAdvanced F class	Shell	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
9	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD*/ Gypsum	
10	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD*/ Gypsum	Amine Absorber
11	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD*/ Gypsum	
12	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD*/ Gypsum	Amine Absorber
13	NGCC	2400/1050/1050	2xAdvanced F class	HRSG	Air			
14	NGCC	2400/1050/1050	2xAdvanced F class	HRSG	Air			Amine Absorber

*Wet Flue Gas Desulfurization (FGD)

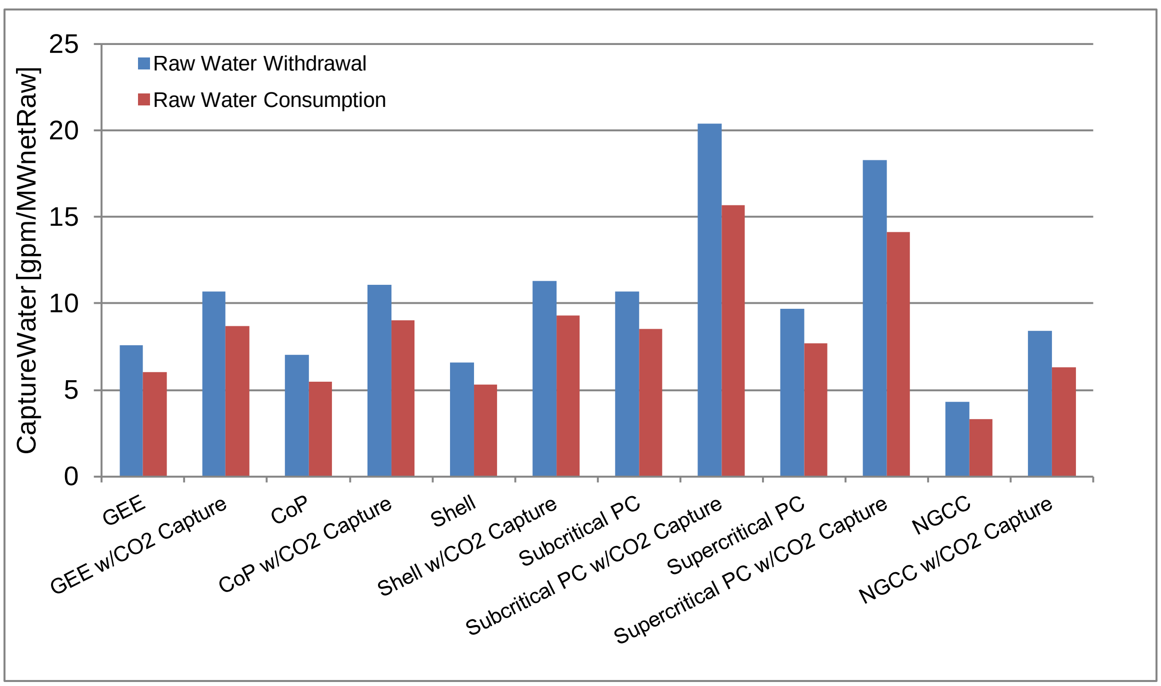
Source: (39)

Exhibit A- 23 Net Plant Efficiency (HHV) of the Plants



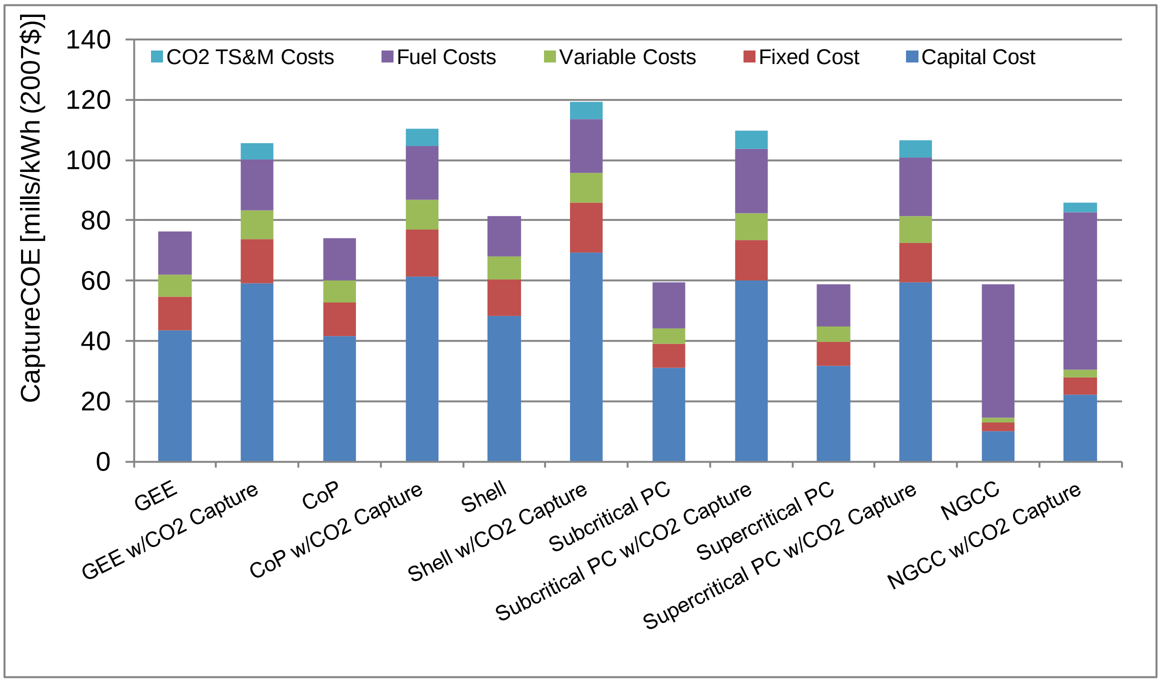
Source: (39)

Exhibit A- 24 Raw Water Withdrawal and Consumption of the Plants



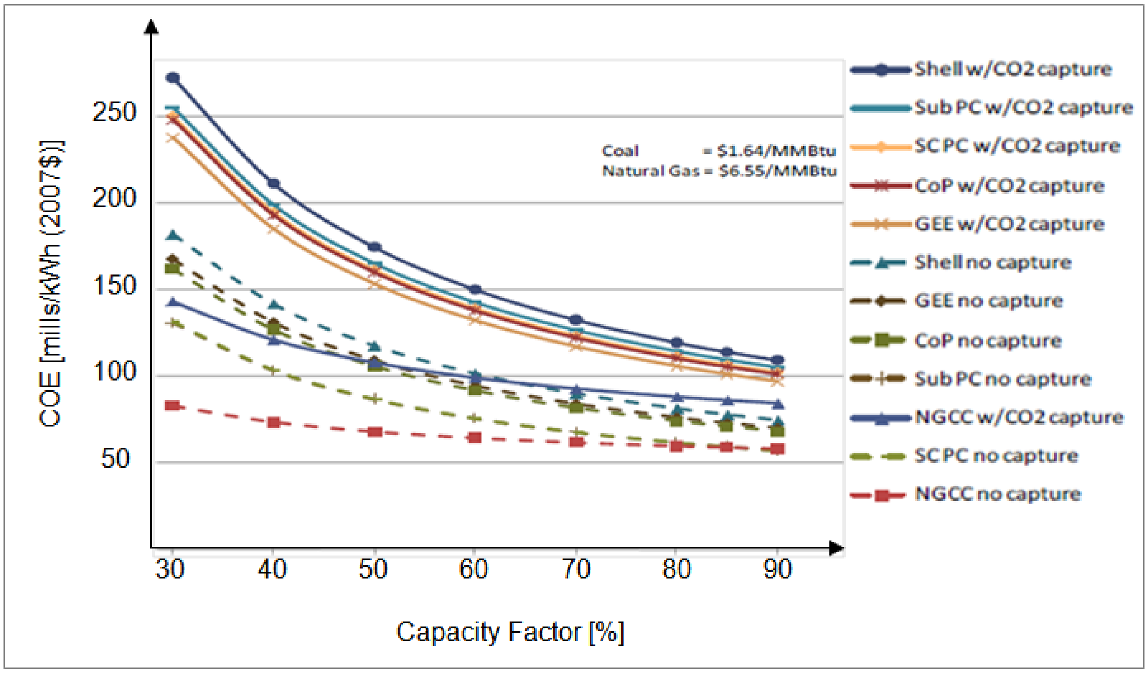
Source: (39)

Exhibit A- 25 COE by Cost Component of the Plants



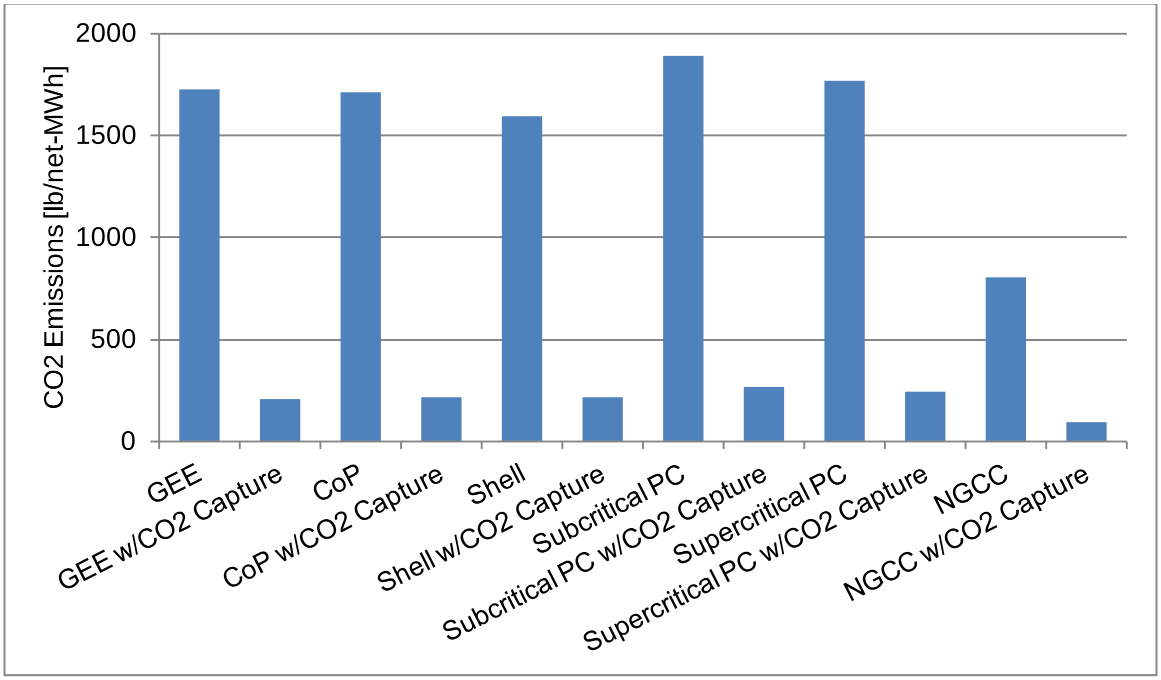
Source: (39)

Exhibit A- 26 COE Sensitivity to Capacity Factor for the Plants



Source: (39)

Exhibit A- 27 CO2 Emissions of the Plants Normalized by Net Output



Source: (39)

Exhibit A- 28 Selected IGCC Plants with Cogen Applications

Plant	Type	COD	MW	Power Block	Application	Integration	Gasifier	Fuel
Frontier	Refinery	1996	40	6B	Cogen	Steam/Air/ N2	GE	Pet Coke
Shell Pernis	Refinery	1997	120	206B	Cogen/H2	Steam	Shell	Oil
Sarlux	Refinery	2000	550	3-109E	Cogen/H2	Steam/N2	GE	Pet Coke
Motiva	Refinery	2000	180	2-6FA	Cogen	Steam	GE	Oil
Exxon Singapor	Refinery	2000	173	2-6FA	Cogen	Steam	GE	Oil
Nexen/ Opti	Refinery	2008	160	2-7EA	Cogen	Steam	Shell	Asphaltene

Source: (45)

Application of IGCC in CHP

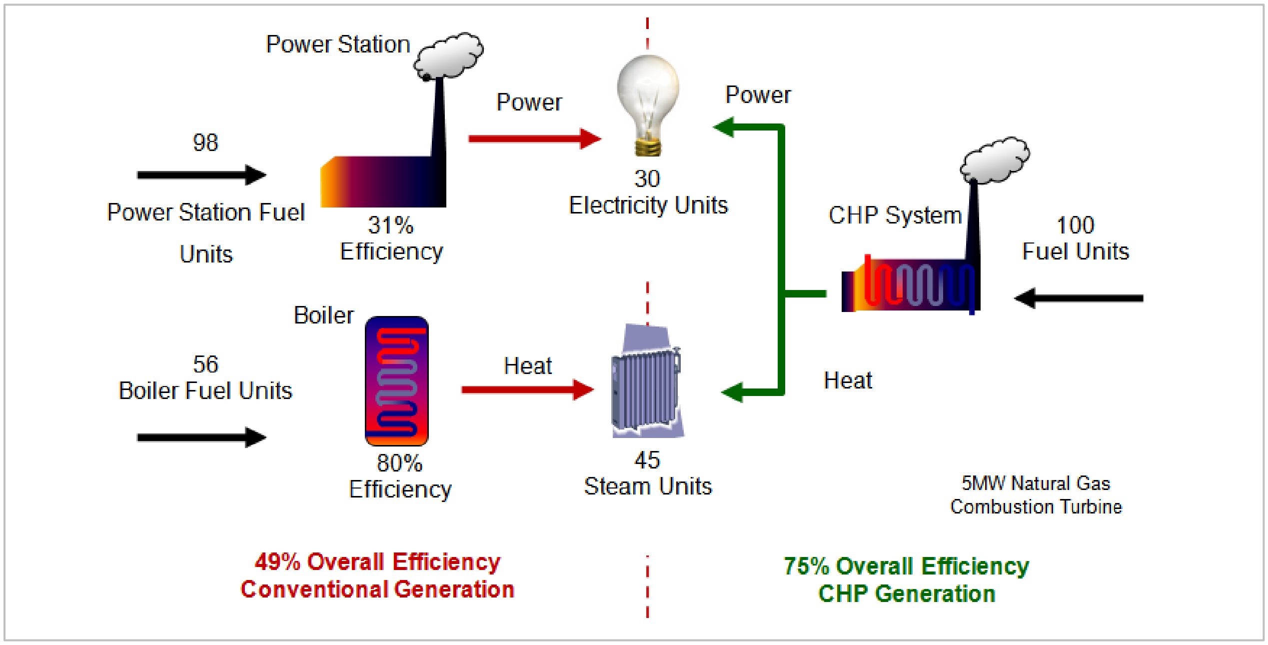
Gasification can be utilized not just in power generation but also in a number of other industries. Methanol, ammonia, and hydrogen production are a few examples. It can also be used in co-generation when the techno-economic circumstances are favorable. Hydrogen is a chemical that is used in the cat-cracking unit of the oil refineries to convert the heavy hydrocarbon to the more valuable lighter ones. Cogeneration uses part of the heating value of the syngas to generate steam and this steam is directly used for heating purposes.

IGCC has also been used for cogeneration and methanol production (45). The Sarlux plant shown in the above table is the world's biggest IGCC plant (46). It is located in Sardinia, Italy, at the Saras Oil Refinery in Sarroch (the second largest European refinery). The plant is fed 1.1 million metric tons per year of the tar-like residue produced by vacuum visbreaking at the refinery. The products include 551MWe (net) of electricity; 285 metric tons of process steam for the refinery; and 20 million standard cubic feet a day of hydrogen. The Sarlux show that to successfully use the IGCC for cogeneration and/or other application, they need not only to be at a location where fuel, water, and other feed material are available but also where there is a need for the products such as a refinery with the need for hydrogen or where there is need for space heating.

Appendix B – CHP Options

Combined heat and power, technologies provide both electrical and thermal energy simultaneously. In 2008, the U.S. Environmental Protection Agency (EPA) published a Catalog of CHP Technologies as an online resource (47). According to EPA, overall CHP efficiency can reach 75 percent, which is 26 percent higher overall efficiency in comparison with conventional generation (Exhibit B-1).

Exhibit B-1 Conventional Generation Efficiency versus CHP Efficiency



Data source: (47)

CHP reduces energy cost, improves reliability, improves power quality, improves environmental quality, and provides conservation of national energy resources (48).

The United States has historically been both adaptive and innovative. In this case, the U.S. could learn from various CHP experiences around the world. Denmark, for example, made a remarkable transition to a more distributed, renewables-rich, CHP-rich electric system. The next sections analyze factors enabling Denmark's CHP and its possible application in the United States.

Key Similarities Between the US and Danish Electric Systems

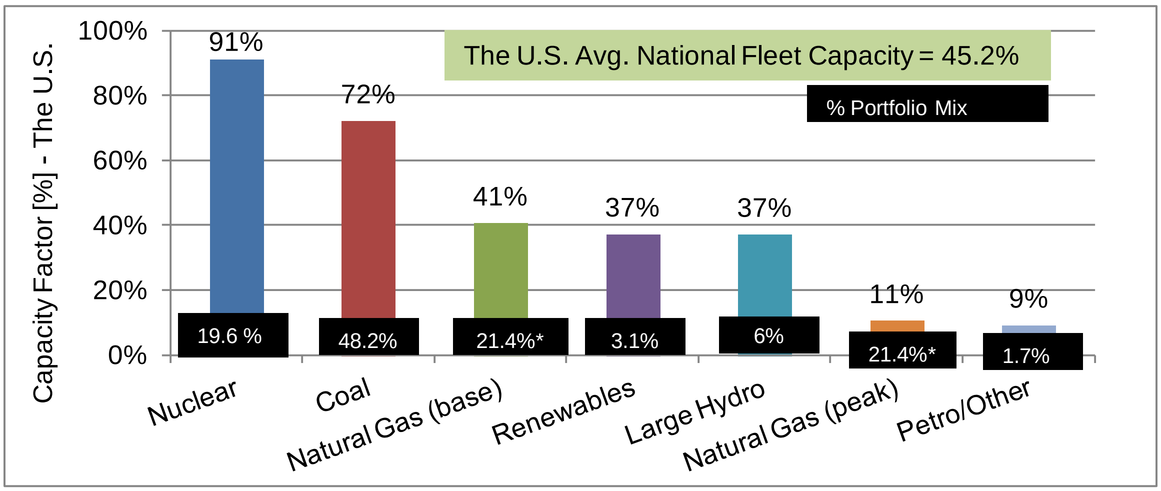
Danish transition to more efficient and environmentally friendlier energy sources is considered one of the most successful in the world. While it is true that Denmark and the US have differences in vision, existing infrastructure, geography, energy policy requirements, pricing mechanisms, and cell structure, there are some key similarities that suggest the process Denmark has followed for the last 25 years is viable in the US. Considering Denmark's energy position in

1985 with heavy reliance on fossil fuels for power, heating, and transportation, and the beginning stages of the rollout of renewables, it looks very much like the US energy position in 2005.

Both Denmark and the US under-utilize their installed generation with a national fleet average capacity factor less than 50 percent (the US at 45.2 percent and Denmark at 38.8 percent). See Exhibit B- 2.

In the case of Denmark, the large amount of wind generation, which has lower capacity factors than baseload generation such as nuclear and coal-based generation, brings down the national fleet average capacity factor. If the United States targets a 20 percent renewables mix, the country could expect the national fleet average capacity factor to decrease, since a majority of U.S. renewables tend to be low capacity factor resources such as wind and solar.

Exhibit B- 2 US and Denmark Capacity Factors by Type



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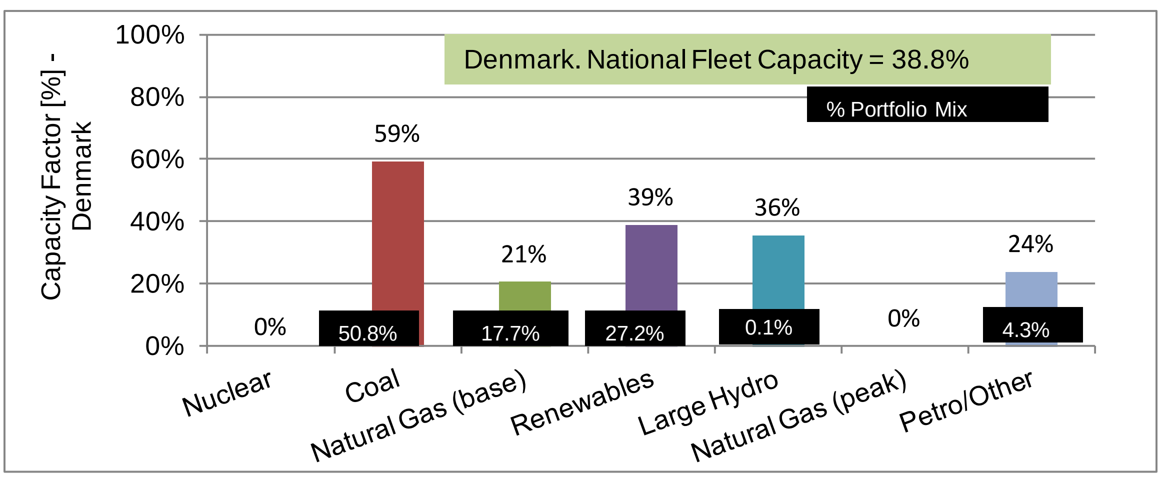
Data Source: (8)



Data Source: (49)

Excluding the nuclear component, the generation portfolio in the U.S. and Denmark are similar in average capacity by type and in portfolio mix.

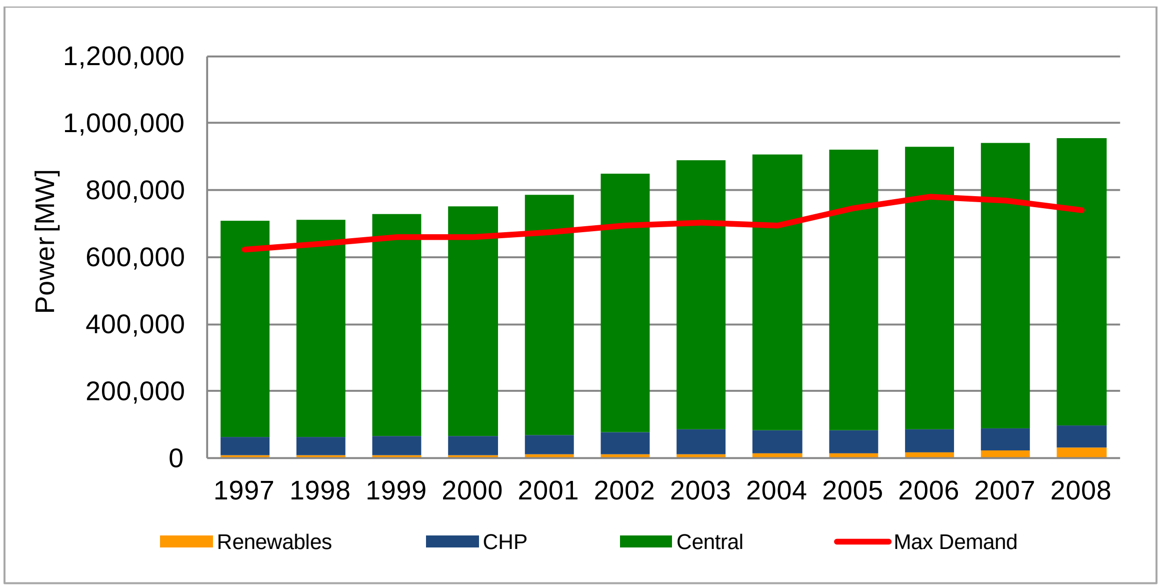
The electricity consumption trends in Denmark and the US are fairly flat; increasing 1.3 percent per year in the US and 0.8 percent per year in Denmark over the last dozen years. By comparison, the gross domestic product for the US grew 404 percent between 1980 and 2007, while Denmark's economy grew 78 percent during the same period.

In both countries, coal-based generation represents about half the generation portfolio mix (Exhibit B- 2) with the United States at 48.2 percent and Denmark at 50.8 percent.

Both countries have growing gas-fired generation components of their generation fleets. Over the last dozen years, Denmark's natural gas generation has grown 71 percent to represent 17.7 percent of the generation mix in 2007. Over the last dozen years, the U.S. natural gas generation has grown 84 percent to represent 21.4 percent of the generation mix in 2008.

The U.S. capacity and electricity consumption trends today are similar to the early years of Denmark's transformation when comparing the last few years in Exhibit B- 3 U.S. Energy Contribution (1997-2008) for the U.S. to the first few years for Denmark in Exhibit B- 5. The U.S. renewables and CHP portion in 2006 – 2008 look much like Denmark in 1990–1992, and the U.S. has several of the same drivers in place to follow Denmark's path.

Exhibit B- 3 U.S. Energy Contribution (1997-2008)



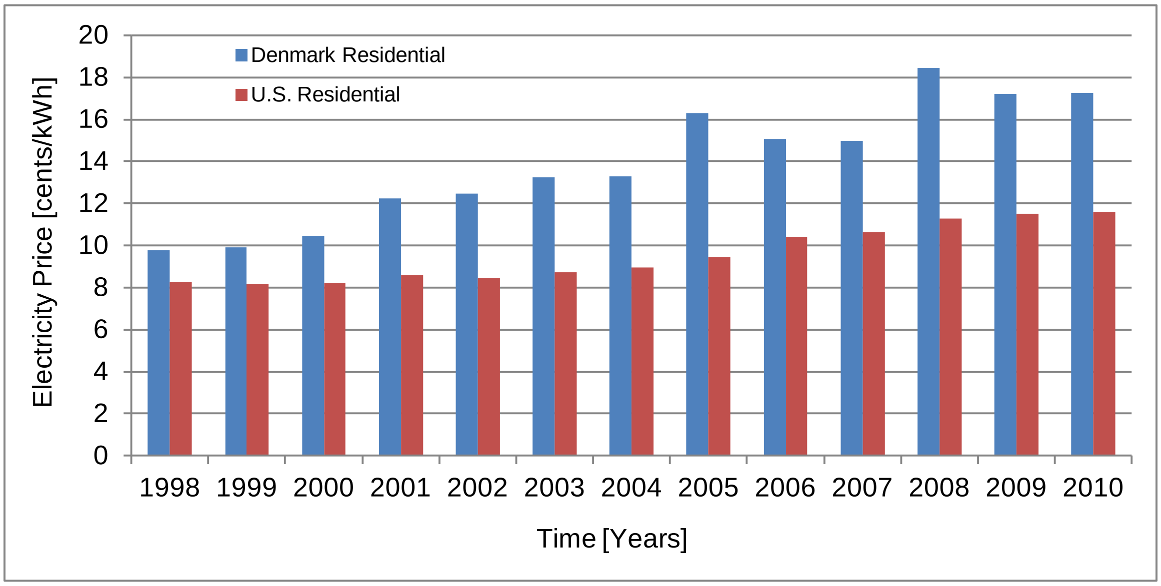
Source: (8)

Both Denmark and the U.S. rely little on others for electric supply. The U.S. imports roughly 0.8 percent of the total MWh consumed per year, while Denmark has been a net exporter over the last decade with the latest data from 2007 showing it as an exporter of about 2.5 percent of the total MWh produced.

Structurally, the electric industries in the U.S. and Denmark have similarities in electricity markets, privatized independent transmission operators, and privatized locally governed distribution companies. The number of utilities, independent transmission operators, and regulatory authorities are different largely because the U.S. population is 55 times larger than Denmark, but the structures of the respective electric industries are similar.

There are similarities in the rise in electricity rates over the last decade (Exhibit B- 4) for both countries.

Exhibit B- 4 Residential Electricity Rates ($/kWh)



Data Source: (49), (7)

Key Differences Between the US and Danish Electric Systems

The previous section discusses the similarities between the U.S. and Danish electric systems, but there are some key differences as well. For example:

- U.S. capacity and consumption are much greater than in Denmark as the sizes of the countries are vastly different.
- The U.S. has domestic coal, while Denmark imports coal.
- U.S. renewables supply about 3 percent of electricity consumption, while Denmark's renewables supply 29 percent of electricity consumption.
- U.S. CHP is 8 percent of electricity production while Denmark's small CHP is 18 percent and large CHP is >63 percent of electricity production.
- Unlike the U.S., Denmark has significant coal-based CHP.

- Unlike the U.S., Denmark has significantly decreased its large-scale fossil power-only unit production since 1990.
- Denmark makes significant use of feed-in tariffs.
- Denmark has significantly fewer regulatory agencies governing the electric industry.

According to the American Wind Energy Association (AWEA), there are several major differences between Denmark and the U.S. that suggest a basis for much greater expansion of wind in the U.S.:

(1) Denmark is small; the U.S. is not:

> Although the U.S. has nearly twice as much installed wind equipment as Denmark, wind generates only 0.5 percent of our electricity, far below the 10 percent threshold identified by most analysts as the point at which wind's variability becomes a significant issue for utility system operators.
>
> Denmark is also so small geographically (half the size of Indiana) that high winds can cause many of its wind plants to shut down almost at once—in the U.S., wind plants are much more geographically dispersed (from California to New York to Texas) and do not all experience the same wind conditions at the same time.

(2) Denmark has transformed its national power system; the U.S. has not:

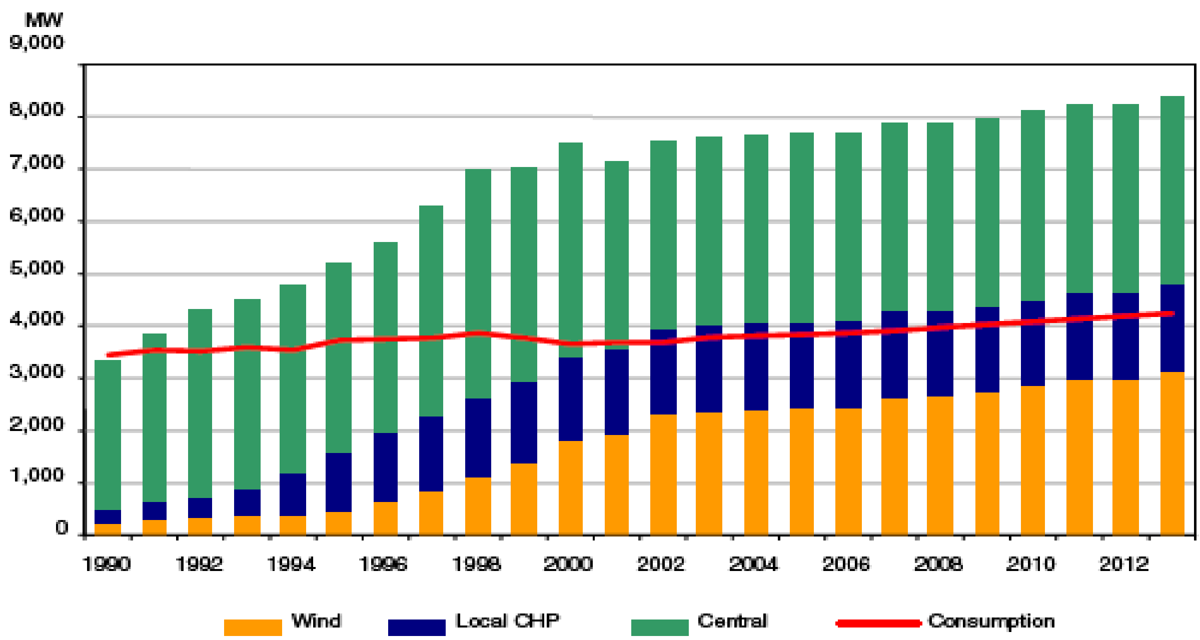
> Rapid development of wind and new small-scale power plants within the past five years has brought Denmark to the point where power produced by so-called non-dispatchable resources in the country's West exceeds 100 percent of demand in the region. At many times, this excess generation leaves the country scrambling to increase electricity export capabilities to handle the surplus. This situation is essentially unimaginable in the U.S.

(3) Danish wind plants are typically small; U.S. wind plants are not:

> Denmark's approach encourages community involvement, but places particular stress on low-capacity distribution networks (at the "end of the line" on transmission systems). In the U.S., our larger wind plants require advance transmission planning, but feed into main transmission lines and do not affect the customer distribution network.
>
> In Denmark, wind has been extremely successful, and utility system operators are now taking steps to manage that success; the U.S. has not dealt with its energy problems so decisively. (24)

The large numbers of CHP and wind power plants in Denmark are due to energy policies and supporting pricing mechanisms. The large number of CHP power plants is because they are more efficient than a conventional power plant, the government incentivized CHP development for energy efficiency purposes, and the Danish district heating system represented a very good start in that direction. On the other hand, wind power plants were developed because of a need for clean (renewable) energy. A similar situation existed in the United States. CHP plants were developed due to a need for more efficient generation in businesses and some cities, while wind power plants were developed to reduce emissions. To compare the development of power generation in West Denmark and the United States, see Exhibit B- 5 and Exhibit B- 3 U.S. Energy Contribution (1997-2008): there is a similarity between where the United States today compared to where West Denmark was in 1990. In 1990, Denmark had 33.9 percent of total electricity production from CHP and 2.5 percent from wind power. In 2008, the United States had 0.8 percent of its total electricity production from CHP and 1.3 percent from wind power. Both Denmark and the United States had energy policies and pricing mechanisms in support of developing CHP and wind power generation. However, the United States' geographic size, organization (separation into different states), state policies, and short-term tax credits have slowed this development.

Exhibit B- 5 Development of Power Generation in Western Denmark



Source: (50)

CHPs in Denmark are used mostly for district heating systems while in the United States CHPs are used for industrial processes and localized heating/cooling systems. Thermal energy cannot be transmitted long distances. That is one of the reasons why the district heating is only 5 percent of the total heating system in the United States.

Denmark's CHP-wind case shows that the main CHP-wind integration problem is a fluctuation in the produced power because CHP depends on the heat demand while wind plant production is wind dependent. Denmark solved this problem by using neighboring countries to "store" energy. In comparison with Sweden's and Germany's power production, Denmark's export/import is very small and it does not disturb neighboring power systems. In contrast, the United States is a much larger producer/consumer than its neighboring countries, Canada and Mexico, and it cannot use their power systems for balancing purposes.

Both Denmark and the United States have energy policies that support CHP and wind power plant development. The problem in the United States is that some legislative bodies are at the federal level while others are at the state level. If the state polices and federal policies do not work together, there will always be barriers to installing more CHP plants. Much of this policy issue rests with a lack of education about the energy efficiency and environmental advantages associated with poly-plant applications such as CHP.

Feasibility of Danish Hybrid CHP/Wind Structure in the US

In the United States only a few of the large cities have district heating and, except for a few industrial processes, very little CHP. In most of our large power plants, process heat is expelled into the atmosphere via cooling towers or into lakes and cooling ponds and not into other processes. This waste of heating energy is the difference between ~39 percent thermal efficiency and ~80 percent thermal efficiency.

In Denmark, conversion to CHP was incentivized not only at the utility level, but also at the municipality and industrial levels. This could be a future initiative in the US. If the federal government, states, and/or utilities incentivized commercial and industrial consumers to look for ways to improve their operations with CHP and other poly-plant applications, this could greatly increase the energy efficiency in the US.

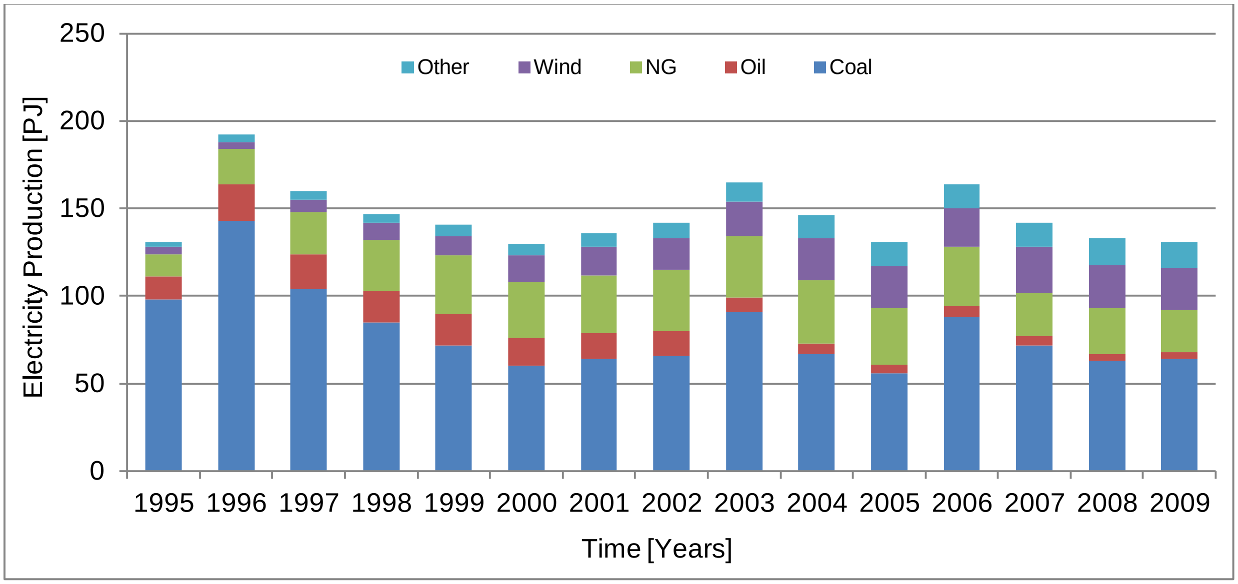
In addition, Denmark has an initiative for the mass production of electric vehicles and implementation of an extensive recharging and battery swap infrastructure. This will act as storage capacity for the country's wind power generation capability (51). With "two million electric cars in circulation ... [such an infrastructure] would provide a standby capacity around five times the size of Denmark's needs ... with smart charging systems charging batteries when the power's plentiful, and even feeding power back into the grid when necessary." (52)

Although wind energy only produces about 2 percent of the current electricity demand in the United States, the U.S. Department of Energy, in collaboration with wind industry experts, has drafted a plan that would bring the U.S. installed wind capacity up to 20 percent of the nation's total electrical supply.(53)

Key Factors Enabling Denmark CHP

At the heart of Denmark's domestic energy picture is its use of renewables to satisfy a significant portion of the domestic electricity consumption. This is accomplished as a hybrid wind/CHP generation model. In 2009, domestic electricity consumption was 124,331 terajoule (TJ). With distribution losses (6,490 TJ), the resulting domestic supply of electricity was 130,821 TJ (49). As a share of Denmark's domestic energy supply, renewables supplied 38,415 TJ, or 29.3 percent, of the domestic electricity consumption. Of this, wind supplied 19 percent and all other forms of renewables supplied 9 percent of the domestic electricity consumption. Exhibit B- 6 shows Denmark's growth of the wind power and other renewables share in domestic electricity production over the last decade.

Exhibit B- 6 Electricity Production by Fuel

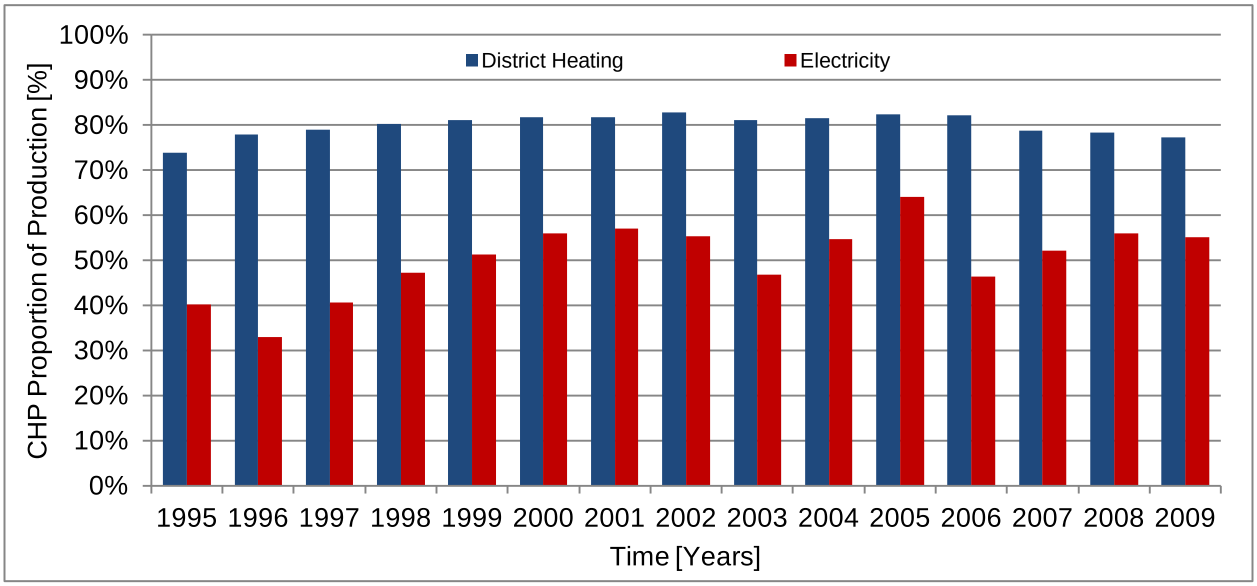


Data source: (49)

This high penetration of renewables in Denmark contrasts with the low penetration level (<3 percent) in the US today. Denmark renewables penetration in 1994 was about 5 percent, so it could be a good example of transformation in the electric industry for the US over the next 15 years.

Denmark also has significant CHP resources applied to electricity production and district heating, which allows the country to efficiently use the large amount of heat generated by thermal electric technologies. In 2009, 55 percent of thermal electric production (less wind and hydro) came in the form of CHP (see Exhibit B- 7). CHP also represents 80 percent of all district heating supply.

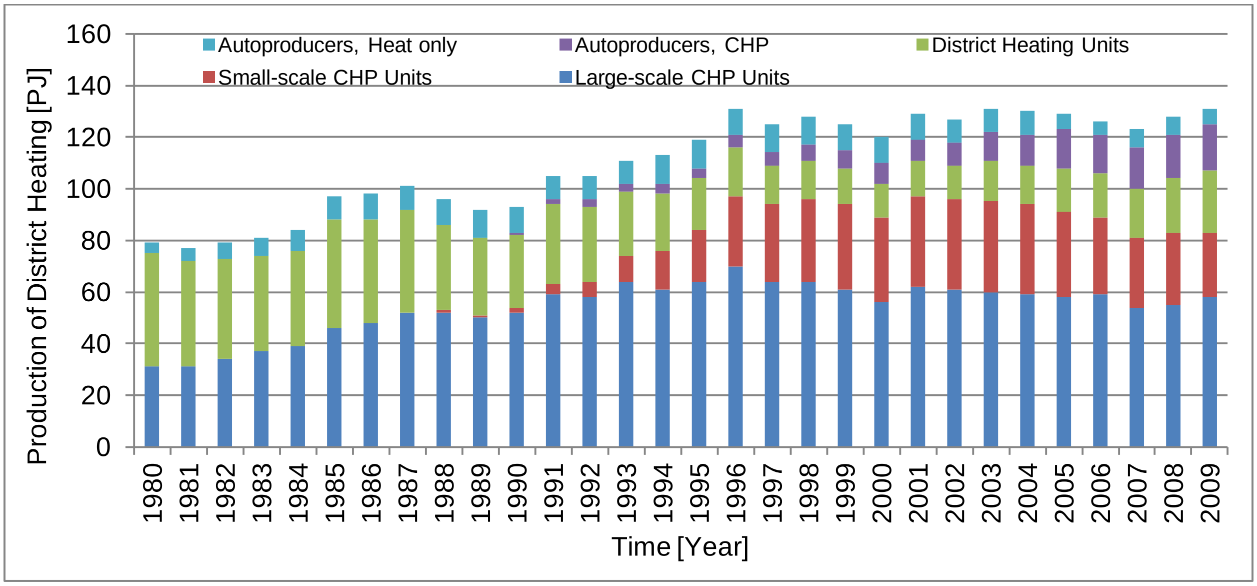
Exhibit B- 7 CHP Portion of Electricity and District Heating Production



Data source: (49)

District heating in Denmark has grown 65 percent since 1980 (79 PJ in 1980, 131 PJ in 2009) as a matter of energy and environmental policy. Although Denmark, like Europe as a whole, has used district heating for more than a century, this significant growth in the last 30 years suggests that new district heating infrastructure can be installed in population centers if the energy policy supports it. From Exhibit B- 8, one can see that the growth has been with CHP applications.

Exhibit B- 8 District Heating Production by Type of Producer



Data source: (49)

It is important to note that Denmark's growth of CHP coincides with its growth of renewables, both structured within the cell structure where wind turbines and small CHP units are distributed.

Understanding the Danish energy sector transformation is difficult for US energy industry professionals to grasp because there were so many simultaneous "moving parts" in the transformation. Yet, this is proving to be the case for change in the US. One of the issues most frequently pointed to when considering Denmark as an example of energy sector transformation is the price of electricity.

In the US, it is common to use the DOE Energy Information Administration (EIA) data for analysis and comparison; however, it is not consistent with the data published for comparative purposes by the European Commission. The differences seem to be in the treatment of taxes and subsidies. The table in Exhibit B- 9 shows the data comparison between European Commission and EIA data for selected countries.

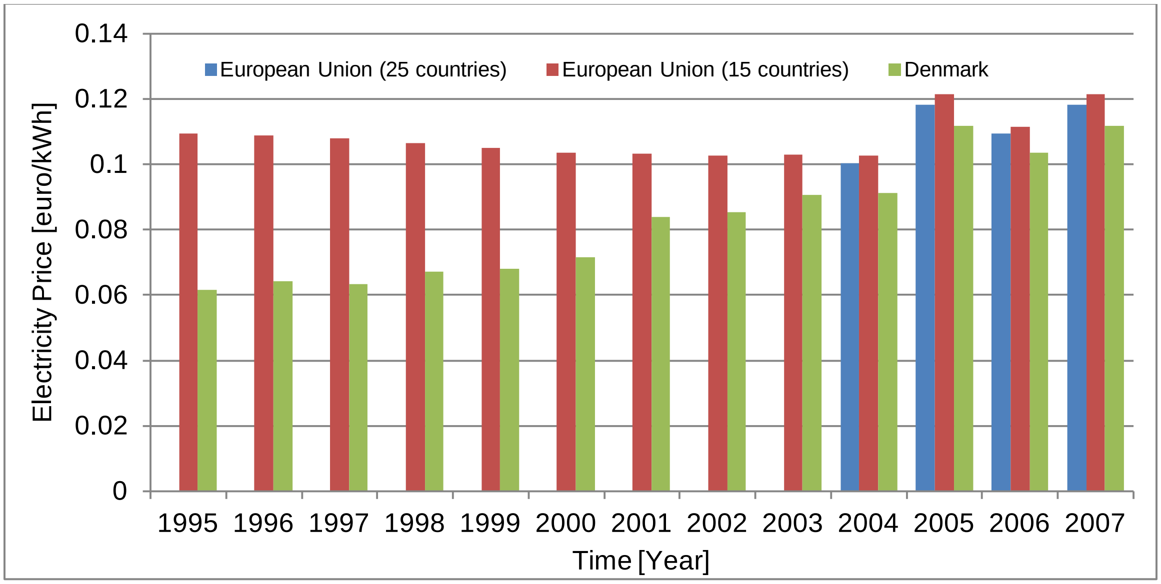
Exhibit B- 9 Comparison of Reported Residential Electricity Prices

Country (2007 data-Exch. rate 1.46)	European Commission Database (€/kWh and $/kWh)		US DOE Energy Information Administration ($/kWh)
Germany	€ 0.1433	$ 0.209	$0.263
Denmark	€ 0.117	$ 0.171	$0.344
France	€ 0.0921	$ 0.134	$ 0.156
Italy	€ 0.1658	$ 0.242	$ 0.258
Norway	€ 0.1361	$ 0.199	$ 0.132
UK	€ 0.1254	$ 0.183	$ 0.219
Netherland	€ 0.1400	$0.204	$ 0.285

Data source: (7)

Exhibit B- 10 below shows the trend in Denmark's residential electricity rates compared to the European Union. While Denmark has experienced high growth in its electricity rates due to support for the transformation of the energy sector, the rates are not out of alignment with the rest of Europe. According to the European Commission database the average 2009 residential electricity rate in Denmark was 0.1239 euro/kWh, or $0.1784/kWh (at the 12/31/2009 exchange rate). For comparison, from the EIA Electric Power Annual 2008, the average price of residential electricity in the US was $0.1126/kWh; from the European Commission database the 2008 average price of residential electricity in Denmark was €0.1203/kWh, or $0.1672/kWh (at the 12/31/2008 exchange rate).

Exhibit B- 10 Denmark Residential Electricity Prices



Source: (54)

Historically, the people of Denmark have been very conscious of the interplay between energy and the environment. Denmark ranked 10th in the world for "Living Green" by a 2007 Readers Digest survey with the capital, Copenhagen, being recognized as one of the most environmentally friendly cities in the world. Much of this success can be attributed to far-reaching national policies on energy and environment coupled with actionable policies at the municipal level.

As worldwide concerns over global warming grew in the 1980s, Denmark found itself with relatively high carbon dioxide emissions per capita, primarily due to the coal-fired power plants that had become the norm after the 1973 and 1979 energy crises of the 1970s. Denmark turned to renewable energy to help decrease both dependence on other countries for energy and combined emissions. Denmark adopted a 2005 carbon emissions target of 22 percent reduction from the 1988 levels. The Danish Energy Agency recently reported that total CO_2 emissions per capita decreased 18 percent between 1990 and 2007.

As a lesson for the United States, there are at least six key factors that enabled the Danish model to be successful:

- Vision
- Previous infrastructure
- Geographical location
- Energy policy requirement
- Pricing mechanism
- Cell structure

Danish Energy Vision

During the oil crises of the 1970s, Denmark realized its economic vulnerability because of its great reliance on oil in transportation, electricity, and heating. From the Danish vision came supporting policy that led to investment in the new direction (55). The cornerstones of the Danish vision are:

Focus on energy savings and renewable energy development – Denmark established a priority on energy savings and diversity of energy supply. This included building efficiency, incentivizing development of renewables, driving CHP into district heating, municipal heat planning, a nationwide natural gas grid, and an ambitious use of a green tax.

Decoupling of energy consumption and economic growth – Denmark drove privatization of the electricity industry, provided for significant development of new energy technologies, and created a basis for long-term investments in efficiency in energy supply. This also allowed Denmark to set aggressive targets for reducing emissions.

Expansion of CHP and decentralized heating supply – Denmark pushed the expansion of the district heating network to not only buildings, but also homes. The expansion of the network enabled use of excess heat from power plants and the establishment of numerous distributed CHP plants by municipalities, industrial complexes, and third parties. The goal was to drive significant improvements in efficient energy use, which explains the stable gross energy consumption in parallel with steady gross domestic product growth.

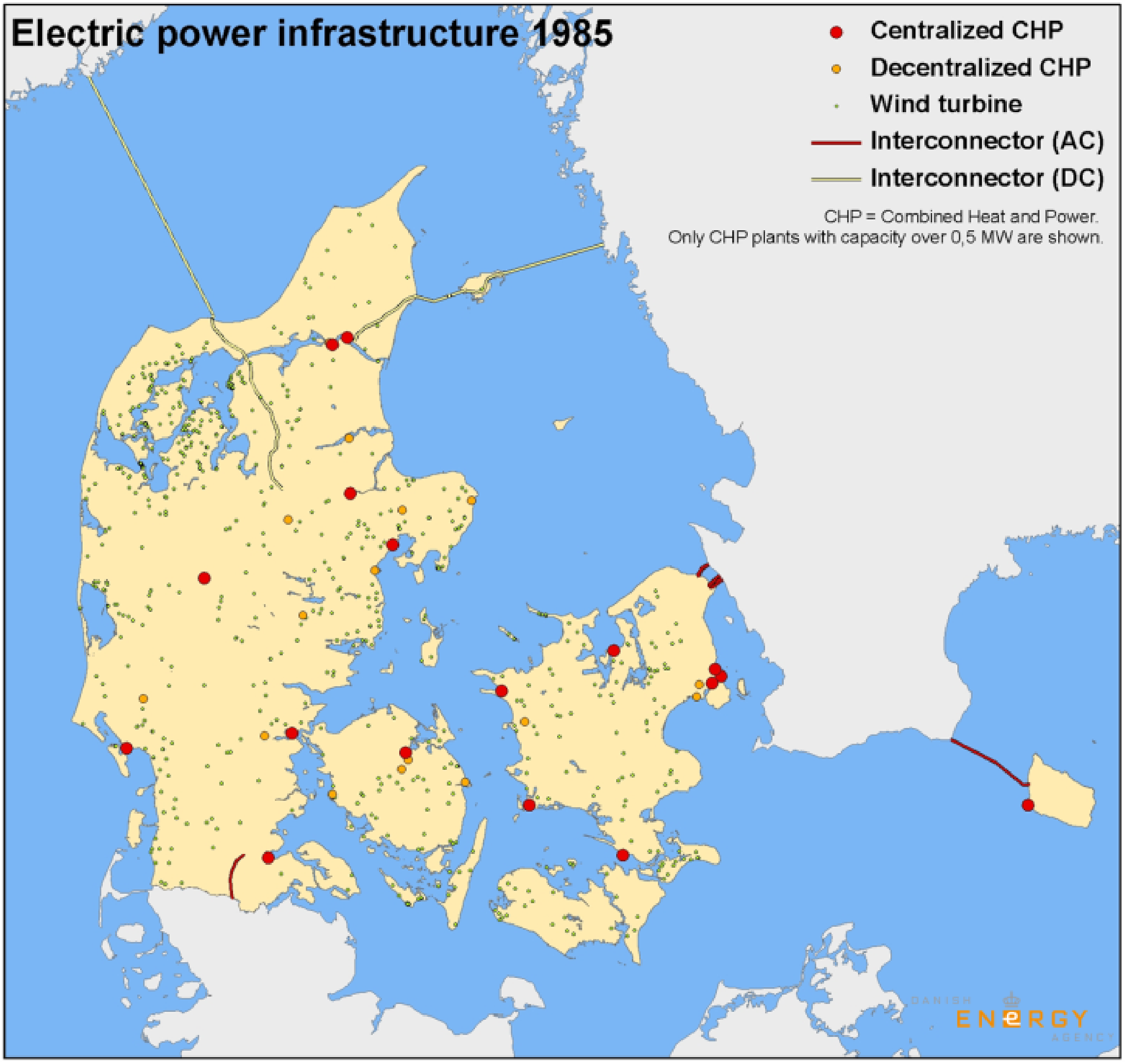
Renewable Energy – While expanding the role of CHP, Denmark incentivized CHP fuel choice toward renewable sources (wood, waste, straw). In addition, the early development of renewable energy technology such as offshore and onshore wind turbine technology was mapped as a national priority to technology jobs growth.

This transformative vision directly affected the remaining five key factors of the Danish model.

Previous Infrastructure (56)

In the 1970s, Danish power demands were supplied by a number of large thermal power plants that were located along the coast, close to large cites. See Exhibit B- 11. At that time, 30 percent of heat demand was met by district heating systems (DHS). The district heating systems were heavily dependent on oil because they used waste heat from the large oil power plants and heat from oil-fired heat boilers that were located close to the heat demand. In 1979, the heat law was implemented. The target was to use natural gas instead of oil, to increase use of waste heat from cogeneration, and to use biomass as heating fuel where natural gas could not be used. Municipalities indentified "collective" heat supplies suitable for district heating or gas, and matched buildings with individual heating solutions. From 1990 to 1998, a large number of existing coal, oil, and gas heat-only plants were converted to gas CHPs (if gas was available).

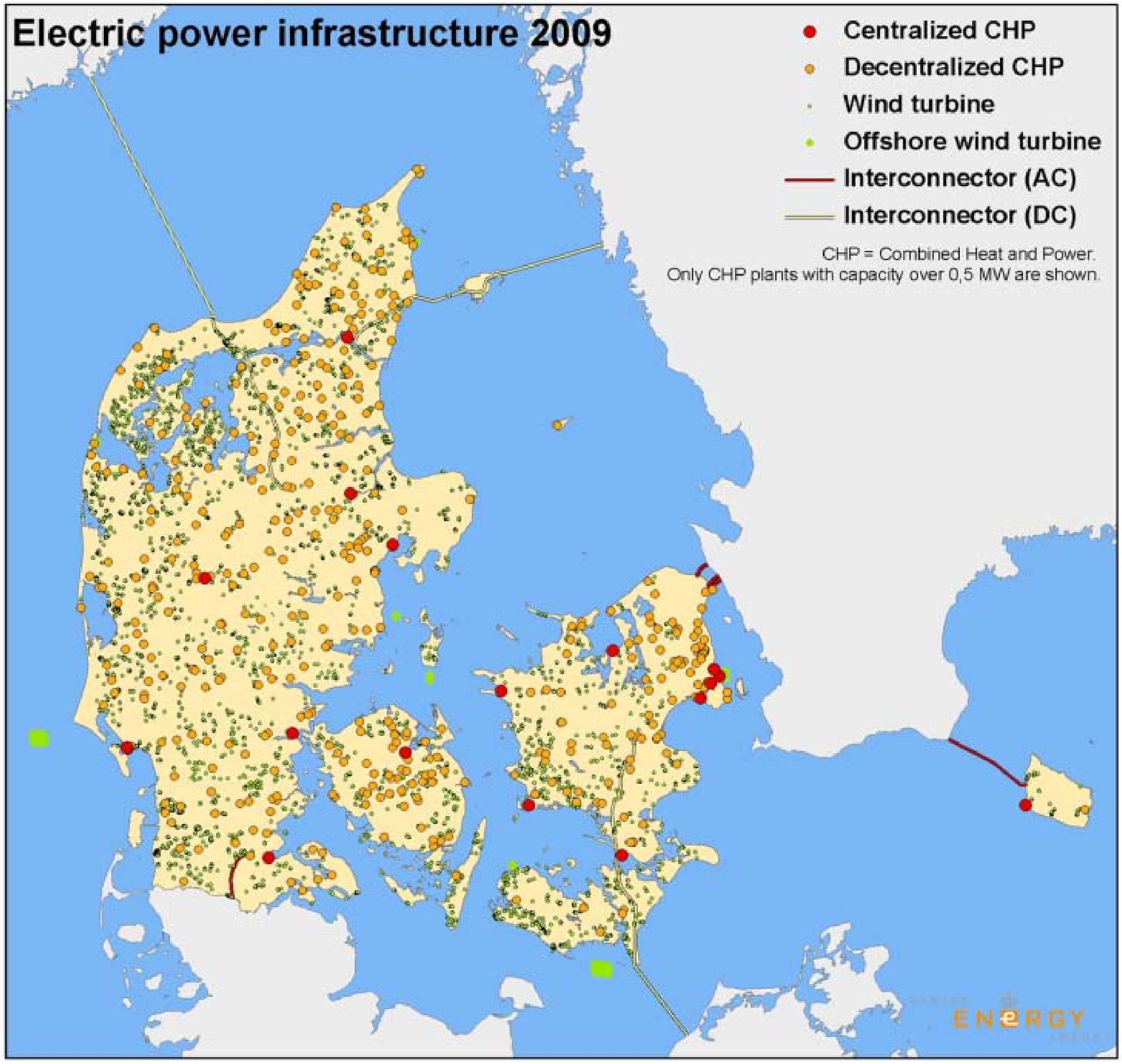
Exhibit B- 11 Electric Power Infrastructure 1985



Source: Danish Energy Agency

Denmark has not only converted existing district heating to CHP, but also has added new district heating (CHP-based) over the last 30 years. Exhibit B- 12 shows the significant growth in distributed CHP.

Exhibit B- 12 Electric Power Infrastructure 2009



Source: Danish Energy Agency

Geographic Location

Exhibit B- 12 indicates that Denmark has very good wind resources. The surrounding ocean and long country axis perpendicular to the prevailing winds provides Denmark with a unique opportunity to develop a high capacity of renewable resources. In addition, the northern climate is best suited to heating needs being served by district heating systems in municipalities of all sizes as well as industrial complexes. This enables Denmark to take advantage of highly energy efficient CHP in all areas of the country.

Moreover, the Danish power system is successful due to strong interconnections to neighboring areas and efficient international power markets. Denmark is separated into West and East Denmark without any electrical connection between the two of them (a high voltage direct current, HVDC, link is planned to be in operation in 2010 (57). West Denmark is connected with an AC-link to Germany and with five HVDC links to Norway and Sweden. East Denmark is connected to Germany with one HVDC link and to Sweden with an AC-link.

The main CHP-Wind integration problem is fluctuation in the produced power because CHP depends on the heat demand while at the same time wind plant production is wind-dependent.

Energy Policy Requirements

Until the early 1970s, Denmark was heavily dependent on imported oil. Since the first and the second oil crisis in 1973-1974 and 1979, respectively, until 1990, the focus of the country's energy policy was to become less dependent on oil imports. Since 1990, the main energy policy goal has been reduction of CO_2 emissions. The table in Exhibit B- 13 shows the Danish energy policy objectives and how they have been met (58).

Not only were CHP and renewable energy supported by policies and the government's energy plan, but they were also supported by different pricing mechanisms as well.

Exhibit B- 13 Danish Energy Policy Objectives

Period	Objective	Objectives Met by
1972-1990	To become less dependent on oil imports	Energy savings (house insulation)
		Increasing oil production
		Oil replacement mainly with coal and natural gas
		Expansion of CHP usage
		Introduction of different renewable sources
1990-2005	To reduce CO_2 emission by 20 percent before 2005	Technologies of coal-fired plant generation are replaced by different technologies: energy conservation, decentralized CHP, and renewable energy
1990-2010	To reduce CO_2 emission by 25 percent before 2010	Increasing number of CHP and renewable energy sources
2008	50 percent of electricity must come from renewable resources	

Source: (58)

Pricing Mechanism

To support investments in new wind power plants, Denmark developed a support pricing mechanism such that investors will recover investments within 10 years for land turbines and 14 years for offshore wind farms (59).

To support investments in CHP, the following pricing mechanisms were established (56; 60):

- Feed-in tariffs (from 1980s to 2005)—CHP plants received bonuses (a fixed amount or a share of the electricity price, or based on the fuel price) for each kWh generated or fed into the network. This tariff was accompanied by obligations for transmission system operators to buy power from CHP plants at market price.
- Direct financial support—fixed tariff for each kWh (in 1992 it was 0.015 Euro/kWh and in 1997 it was reduce to 0.0095 Euro/kWh);
- Fiscal support—in the form of a tax exemption or an accelerated depreciation for new CHP investments.

This economic support was so attractive to distributed (local) CHP plants, that a number of new, small heating districts were established.

The CHP expansion was fast after the direct financial support mechanism was established, and very soon 60 percent of all houses were heated with district heating. This caused a new problem because the number of uncontrollable small CHPs increased significantly.

Cell Structure

In the late 1980s, Denmark had a few large CHP units located close to major cities. These CHP units were used for district heating systems and to provide a unidirectional power supply of high voltage (400 kV or 150 kV) to end users (50). This situation changed when the heat law and supporting pricing mechanisms for small CHPs were implemented. To overcome this problem, the feed-in tariff approach was changed such that there is no obligation to buy from the local CHP, and CHP plants above 25 MW do not receive any support. At the same time, CHP plants larger than 5 MW were obligated to sell electricity they produce at market prices. This new system reduced excess electricity production from the CHP stations.

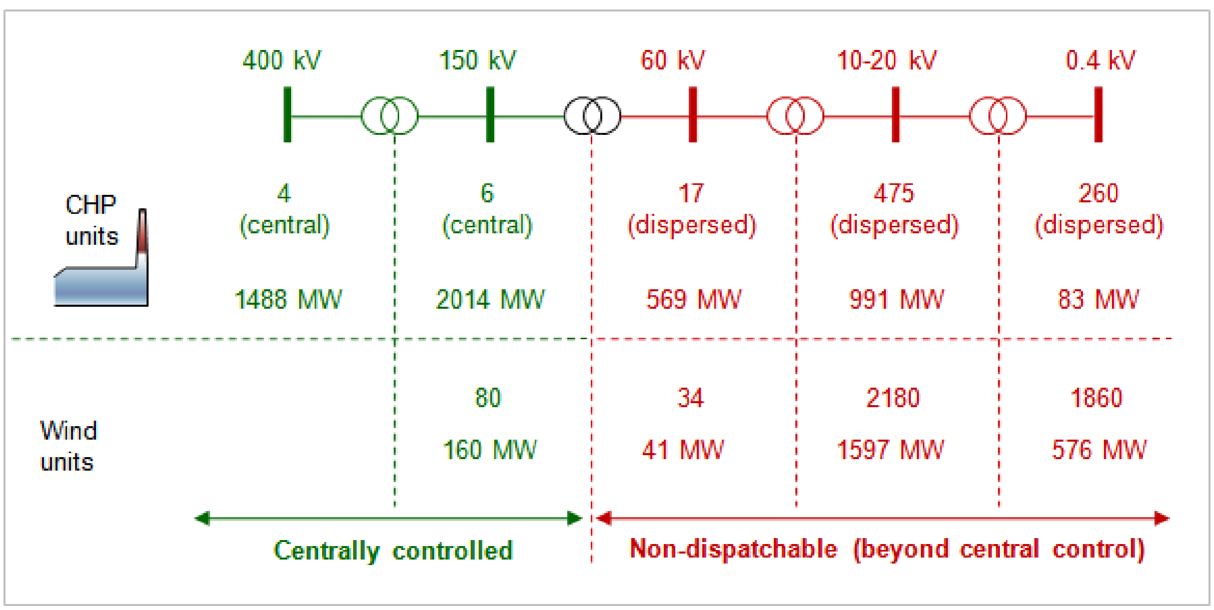
Before January 2005, CHP units produced heat and power according to a three-tariff system (fixed-time tariffs) and heat demand. Since January 2005, all CHP units larger than 10 MW have been required to participate in the national energy market (61) (57). To maximize profit, operators of a CHP plant determine a bidding strategy based on the forecasted day-ahead electricity price, the heat price, and the plant's marginal operating cost. The CHP marginal costs are calculated based on the day-ahead forecasted heat demand and number of operational hours. If a CHP unit is equipped with heat storage, it will be able to separately produce heat and power and to follow the spot price signal. A CHP plant without heat storage will have a constant rate of production.

Danish CHP units are mostly located at the distribution level, and they cannot be directly controlled by a transmission system operator (TSO), but they are indirectly controlled by a market price signal. In addition to participation in the power market, some CHPs also participate in regulating and reserve power markets by signing bilateral agreements with TSOs. The CHP has to be able to bid a minimum 10 MW and be ready within 15 minutes to participate in the regulating and reserve power markets (57).

In 2007, more than 50 percent of the total Danish production capacity came from dispersed resources (small and medium CHP and wind power plants) that were located at distribution level (50). For example, Exhibit B- 14 shows West Denmark CHP and wind generation capacity per voltage level (62; 50). Dispersed resources transformed the Danish distribution network from a passive power user to an active power producer. This transformation caused the following problems (50):

- Less accurate security analysis due to variable wind power and missing local generation information
- Distribution protection relays malfunctioning (the relays trip local generators for a fault on transmission grid)
- Bidirectional power flow
- Non-selective under-frequency load shedding that disconnects both load and local generators
- More complex and time-consuming supply restoration process
- Uncontrollable reactive power flows between distribution and transmission systems due to variable wind power and the heat-constrained operation of CHP plants

Exhibit B- 14 Generation Capacity per Voltage Level, West Denmark 2008

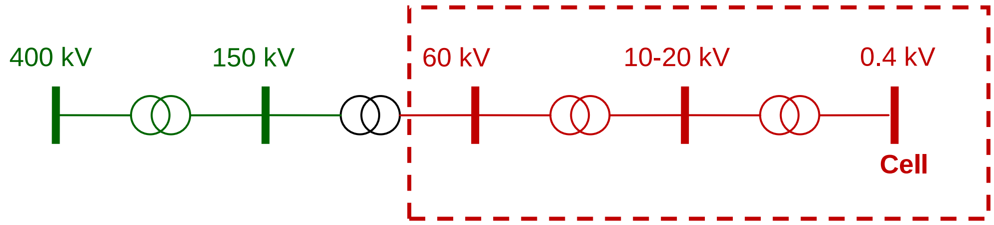


Source: (50)

To overcome these issues, there was a need for (50):

- Closer integration between TSOs and distribution system operators (DSO)
- A new communication system that includes the entire infrastructure
- Renovation of local grids and production to support system stability
- Non-prioritized operation for local CHPs
- Active usage of dispersed passive generators
- Integration of dispersed generation resources into virtual power plants that can be controlled
- "Separation" of the distribution network into cells—each radially operated 60 kV network was defined as a cell (Exhibit B- 15) to find the area that is responsible for reactive power problems

Exhibit B- 15 Danish "Cell"



Data Source: (51)

As result of the above needs, in 2004, a Cell Controller Pilot Project (CCPP) was initiated by Eltra (the former Danish TSO) and continued by Energinet.dk (the current Danish TSO). The cell was defined as each radially operated 60 kV network with its own controller. The main CCPP objective was to design, develop, implement, and test a cell concept. The cell concept was a new communication and control system that enabled cell(s) to disconnect from the main grid and to work as an island (with the possibility of voltage and frequency regulation) and/or the ability of cell(s) to black-start to support a controlled island operation in case of severe grid fault or black out. However, in normal operation, each cell was required to operate in parallel with a high-voltage power system. Input data to the cell controller were loads, as well as generation measurements, while the controller outputs were control actions on generators, feeders, and main power circuit breakers. To support the cell concept, the cell controller has to be able to:

- Monitor, on-line, supply/demand inside the cell
- Control active and reactive power inside the cell
- Control voltage (using synchronous generation automatic voltage regulation) and frequency (using synchronous generation speed governing system)
- Operate transformer, wind turbines, and load feeder breakers, remotely
- Island cell(s) during severe grid faults

- Shed load and generation in case of power imbalance
- Control voltage, power, and frequency of an island
- Synchronize cells back to parallel operation with the transmission grid
- Support black-start in case of black-out
- Communicate to/from TSO and DSO supervisory control and data acquisition (SCADA) systems

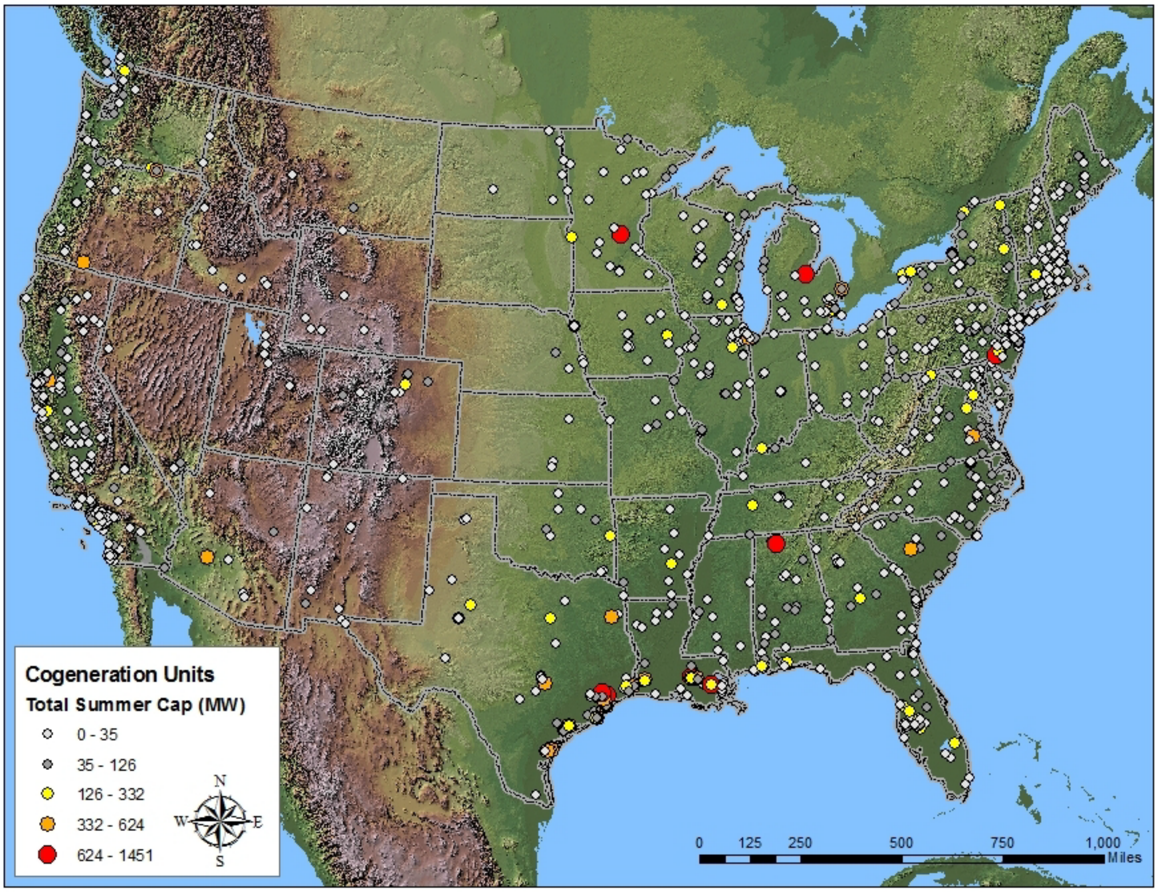
The partial CCPP implementation and testing of measurements, monitoring and data communication systems were completed during 2007, while actual pilot implementation and testing were from 2007 to 2009. The CCPP should be completed in 2011 when the entire pilot cell will be controlled by the cell controller.

The Danish "cell" approach should be applicable to any network that has the proper infrastructure. A possible barrier may be the type of information that should be exchanged between different entities.

The US CHP and Wind Power Systems

Today, CHP and wind power plants provide about 11 percent of total generation capacity in the United States (7). CHP produces ~ 84 GW, which is ~ 8 percent of total U.S. power generation capacity. Wind power plants produce ~ 35 GW(63), which is 3 percent of total U.S. power generation capacity. Exhibit B- 16 shows the CHP locations the United States.

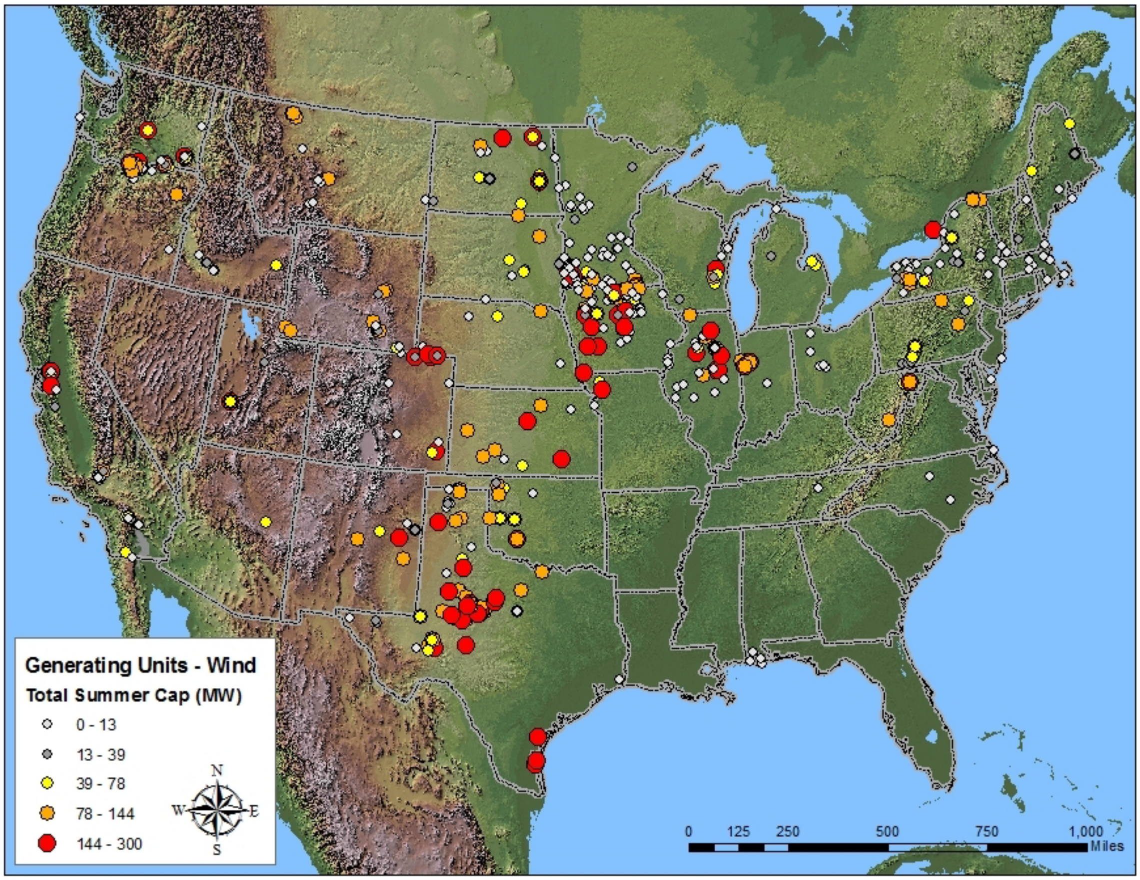
Exhibit B- 16 CHP Location (2010)



Source: (6)

Exhibit B- 17 shows wind power plant location in the United States. Both CHP and wind developments were driven by needs for clean and energy-efficient power supply. Some key factors for Denmark's success can be found in the United States as well. However, these key factors took a different turn in the United States.

Exhibit B- 17 Wind Power Plant Location (2010)



Source: (6)

Previous Infrastructure

The United States started CHP development similarly to Denmark. The first commercially successful steam district heating system in the United States was established in 1877. According to Ulloa (64), there were about 150 DHSs mainly used to serve consumers located in urban areas in 1909. The urban DHS development was stopped when electrical power plants were located farther from the urban areas (due to the plant size and technology in use) and people started to use low-price oil and natural gas for heating. Today, less than 5 percent of the nation's heating and cooling needs are served by a DHS:

- Con Edison operates the largest district heating system in the United States. It provides steam for heating, hot water, and air conditioning to 1,800 customers in Manhattan, New York (65)
- NRG Energy operates district energy systems in Harrisburg (270 customers), Minneapolis (~ 100 buildings), Pittsburgh (~ 25 buildings), San Diego, and San Francisco (~170 buildings) (66)

- Seattle Steam Co. operates a district heating system in Seattle. It provides heat to 200 buildings (67)
- Metro Nashville District Energy System provides steam and chilled water to 40 buildings (68)

While the number of urban DHSs declined, the number of institutional DHSs increased, and today there are over two thousand institutional facilities that use DHS for heating and cooling (64).

Energy policy requirements – As Denmark was, the United States was hit by the first oil crisis in 1973-1974. The main goal of the country's energy policy was to achieve energy self-sufficiency by 1980 (63). In 1978, the National Energy Act was signed. The National Energy Act included five different laws (63):

- The National Energy Conservation Policy Act
- The Power Plant and Industrial Fuel Use Act
- The Public Utilities Regulatory Policy Act (PURPA)
- The Energy Tax Act
- The Natural Gas Policy Act

PURPA has been the most important act that increased use of CHP in industry and development of renewable power plants. PURPA required utilities to interconnect with qualifying cogeneration and small power production facilities.[1] Until 2005, the utilities had a mandatory obligation to (69):

- Purchase from qualifying facilities
- Sell to qualifying facilities
- Provide parallel operation
- Interconnect qualifying facilities
- Transmit from a qualifying facility, if it agrees, to any other electric utility

After 2005, the utilities were able to terminate these obligations if the qualifying cogeneration or small power production facility had nondiscriminatory access to the real-time wholesale market. PURPA successfully stimulated industrial CHP capacity expansion from ~12,000 MW in 1980 to more than 45,000 MW in 1995. In 1999, the U.S. Combined Heat and Power Association published a vision: to double CHP capacity by 2010. In 1999, generation capacity was about 57

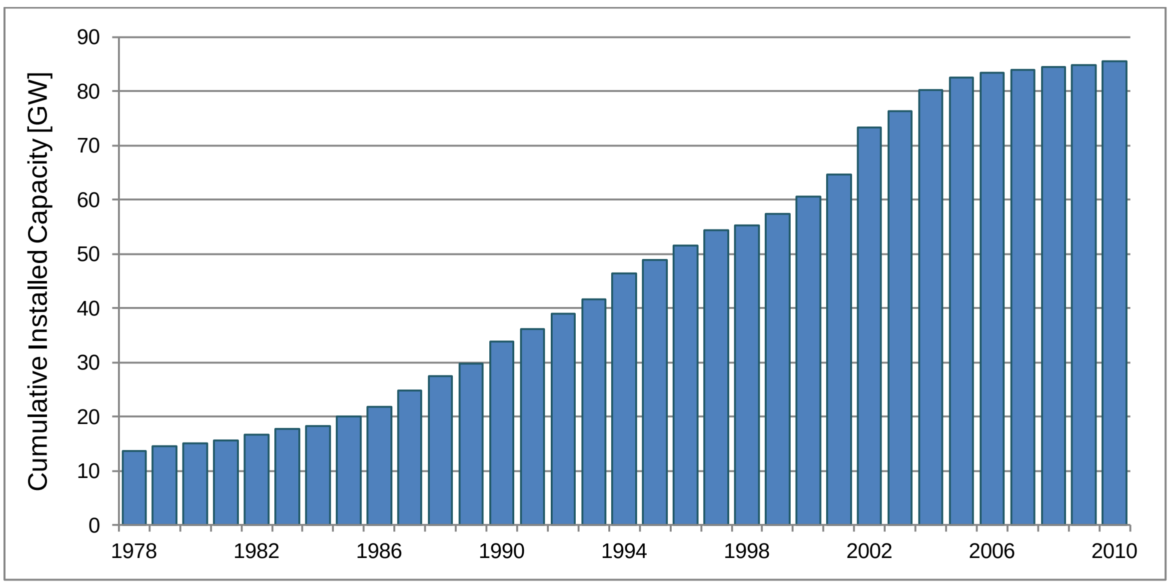
[1] FERC defined qualifying facilities as "a generating facilities of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources" and cogeneration facilities as "generating facilities that sequentially produce electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy." (79)

GW, which leads to the 108 GW goal in 2010. Since 1999, CHP capacity has increased 47 percent, and in 2010 there were about 85 GW from CHP plants (Exhibit B- 18).

The slow growth was partially because of (21; 70):

- Interconnection issues: CHP requires connection to the grid for backup and selling excess power.
- Regulated fees and tariffs: Today, utilities calculate their revenue based on kWh sold, and they do not have incentives to encourage CHP installation because CHP will reduce energy that is bought from the utility. Furthermore, stand-by rates have to be reviewed. These rates are often set as if all CHP systems on a given utility will simultaneously fail.
- Input-based emissions regulation: The input-based emission standard defines emission per unit of fuel input, and it does not account for recovered heat. Thirty-one states use this regulation. Only Texas and California use output-based emission standards that define emission limits based on the amount of pollution produced per unit of useful output.
- Tax treatment: CHP does not fall into a specific tax depreciation category and its depreciation period can range from 5 to 39 years.

Exhibit B- 18 CHP Development in US



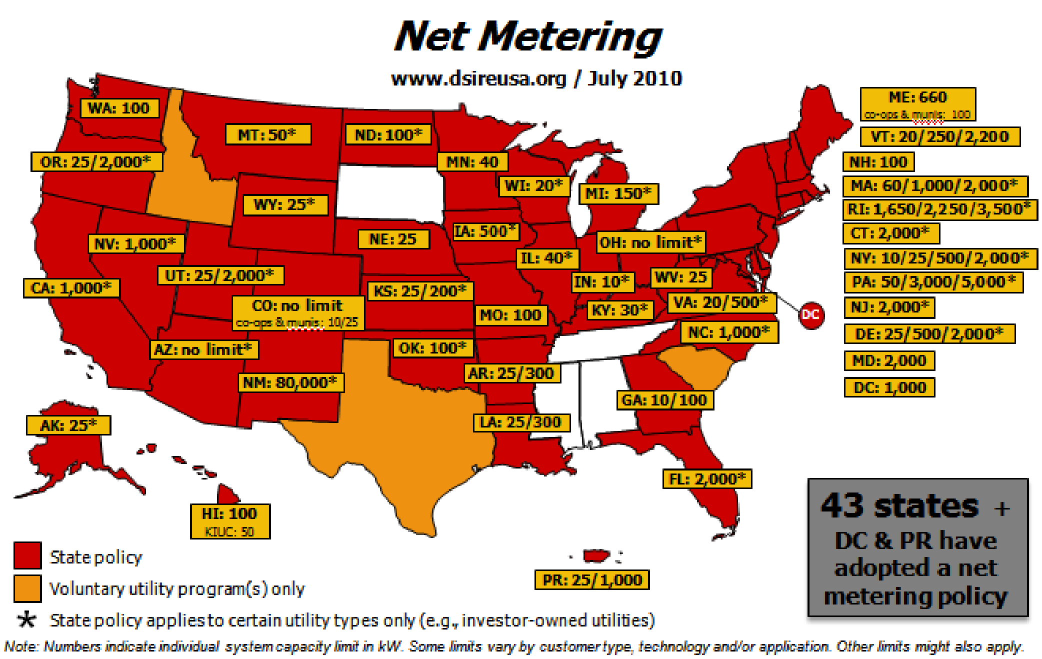
Data source: (6)

Renewable portfolio standard (RPS) is the second standard that increased use of wind power sources. RPSs are state policies by which each state requires utilities to provide some minimum amount of power from renewable energy sources by a certain year.

However, RPSs indirectly put barriers to CHP: according to one study (71), RPSs promote more wind/solar sources (for example, it is suggested that 75 percent of the RPS should come from wind in Illinois). Since there is no waste heat in these two technologies there is also no potential for CHP. Until 2007, only five states (Connecticut, Hawaii, Maine, Nevada, and Pennsylvania) included CHP in their RPSs. Furthermore, some states (such as Connecticut, Pennsylvania, and Nevada) were planning to issue energy efficiency credits for CHPs. Frequently, CHP plants' negative emissions are not taken into consideration when comparing them with conventional generation resources. It is expected that the number of CHP plants will increase in the future since in 2009, the thirteen states—Colorado, Connecticut, Hawaii, Massachusetts, Michigan, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, Utah, and Washington—included CHP and/or waste heat in their RPSs (72). Wind generation capacity growth is the most supported by RPSs. Twenty-four states have mandatory RPSs, while some states have non-binding goals (73). The U.S. Department of Energy reported that 20 percent of total electricity from renewable sources by 2030 is a realistic goal.

Net metering is an electricity policy that provides the possibility for renewable generator owners to sell power back to the grid. Exhibit B- 19 shows net metering rules today by individual state. PURPA is a federal law and each state has the right to adopt it or not. Some states—such as Alabama, Alaska, Colorado, Maryland, Mississippi, Montana, South Carolina—did not follow PURPA at all (74). Some other states such as Arkansas, Connecticut, Florida, Indiana, Louisiana, Massachusetts, New Mexico, Oklahoma, and Oregon developed interconnection guidelines under PURPA. Some states—such as Arizona, Arkansas, Colorado, Hawaii, Kentucky, Main, Massachusetts, Minnesota, New Mexico, and Oklahoma—passed a net metering rule under different state acts by 2003 (74).

Exhibit B- 19 Net Metering



Source: (75)

Pricing mechanism – The pricing mechanisms adopted in the United States are mostly tax related. For example:

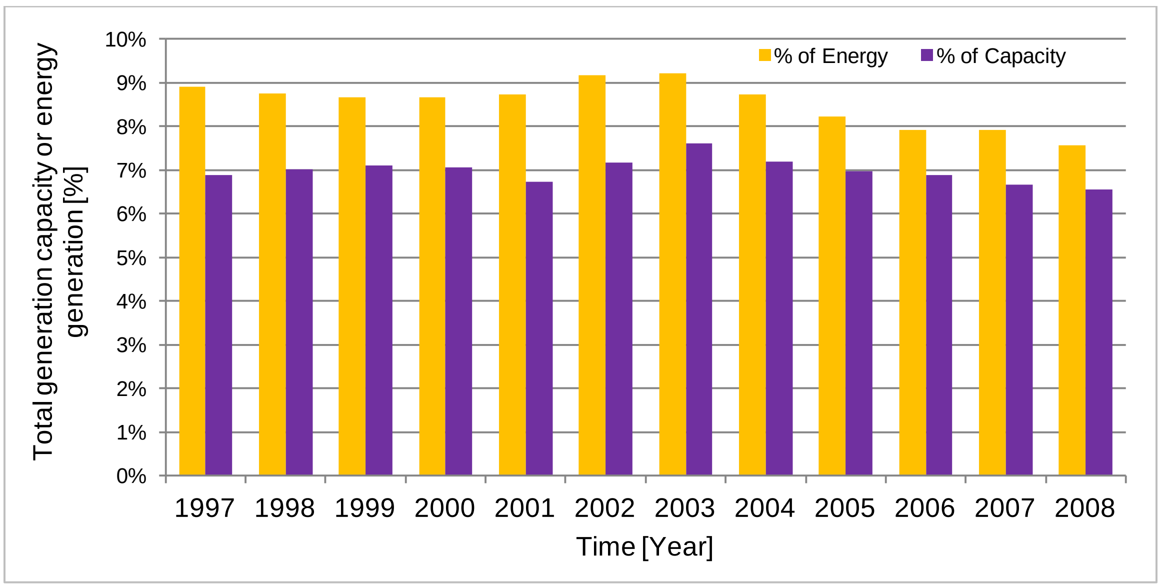
A CHP investment tax credit was signed into law on October 3, 2008. The CHP investment tax credit provides a 10 percent tax credit for the first 15 MW of the system up to 50MW of capacity; this will be valid through 2016 (21).

Renewable electricity tax credits provide $0.022 /kWh for wind and $0.022 /kWh for other eligible technologies during the first 10 years of operation (76).

Residential and Business Energy Tax Credits provided 10 percent to 15 percent of the investment in conservation or alternative fuels technologies.

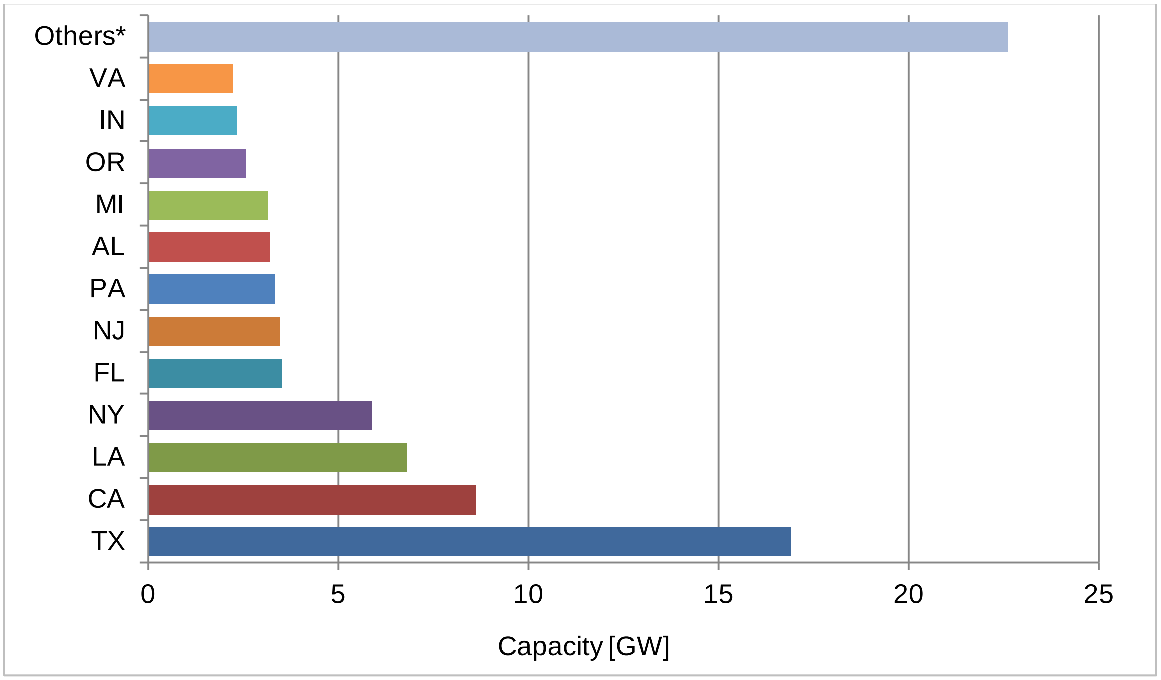
Today, CHP capacity is about 7 percent of total U.S. generation capacity and CHP meets about 8 percent of total US energy demand (Exhibit B- 20). Exhibit B- 21 shows CHP capacity distribution per state. As can be seen, Texas has around 17 GW CHP capacities, California 8.5 GW, Louisiana 6.8 GW, and New York 5.8 GW. All other states have less than 5 GW of CHP capacity installed.

Exhibit B- 20 CHP as Percent of Total Generation Capacity and Total Energy Generation



Data source: (8)

Exhibit B- 21 CHP Capacity per State

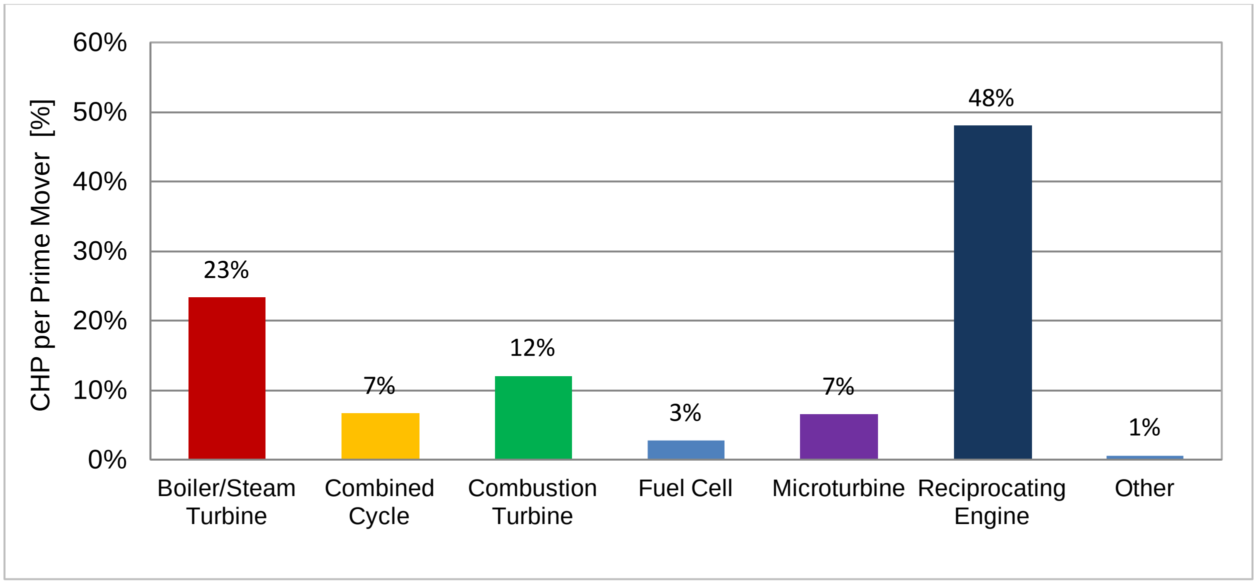


*All other states

Data source: (77)

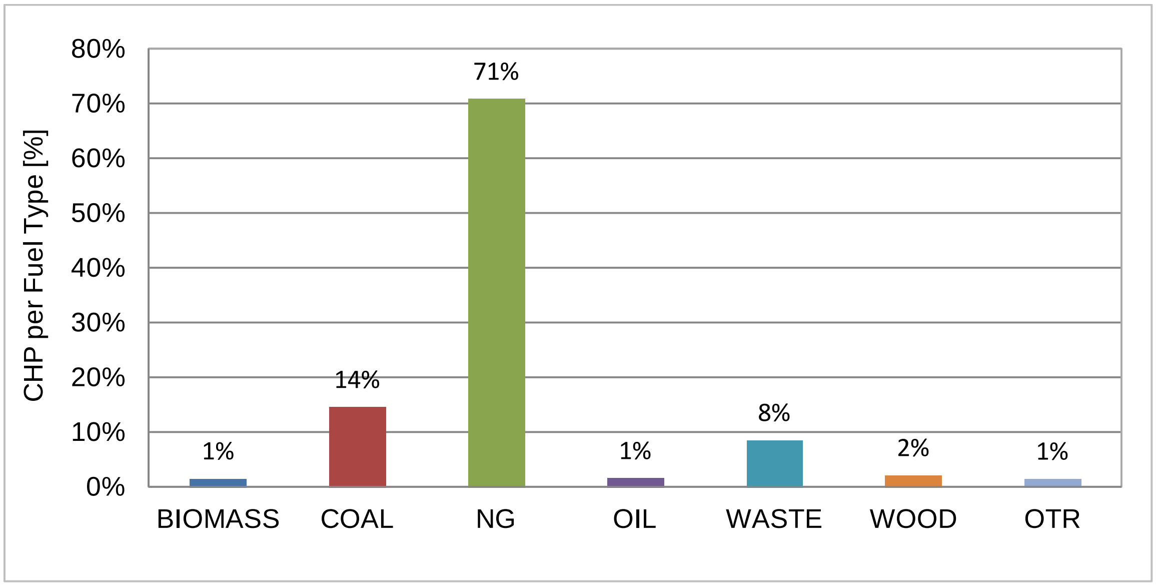
Almost 48 percent of CHPs have a reciprocating engine as the prime mover, 23 percent have steam turbines, 12 percent are combustion turbines, combined cycle and microturbine are 7 percent, and 3 percent are fuel cell (Exhibit B- 22). Natural gas (71 percent), coal (14 percent), and waste (8 percent) are major fuel types that are used in US CHPs (Exhibit B- 23). Since 2000, natural gas CHP is the preferred technology in the United States. In second place is biomass, while coal is not so favorable (Exhibit B- 24).

Exhibit B- 22 Percent of CHP per Prime Mover (2010)



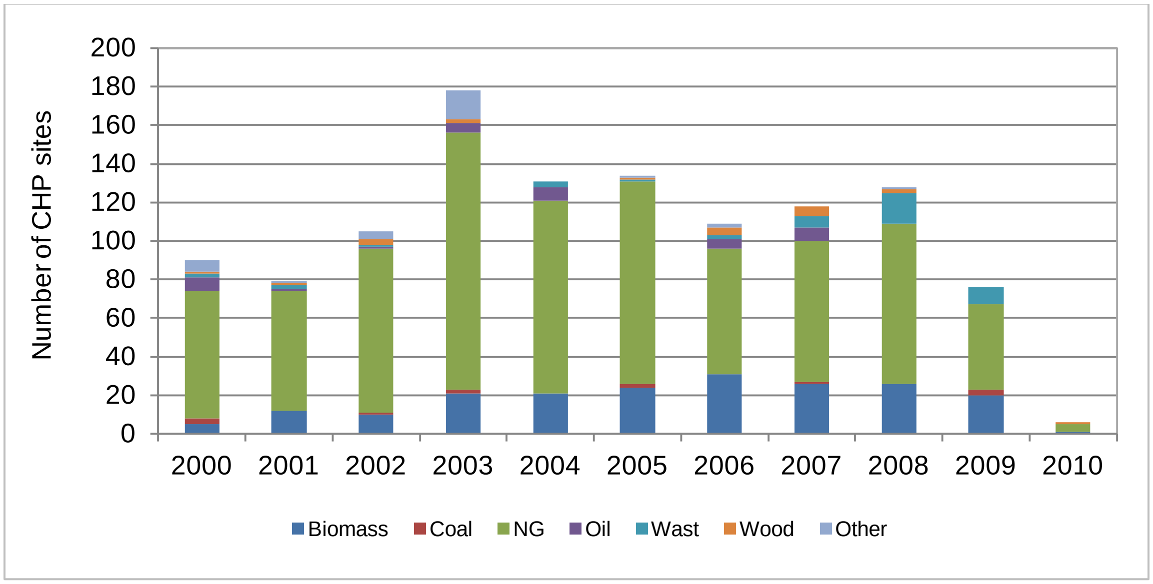
Data source: (8)

Exhibit B- 23 Percent of CHP per Fuel Type (2010)



Data source: (8)

Exhibit B- 24 Number of New CHP Sites per Year and Fuel Type (2010)

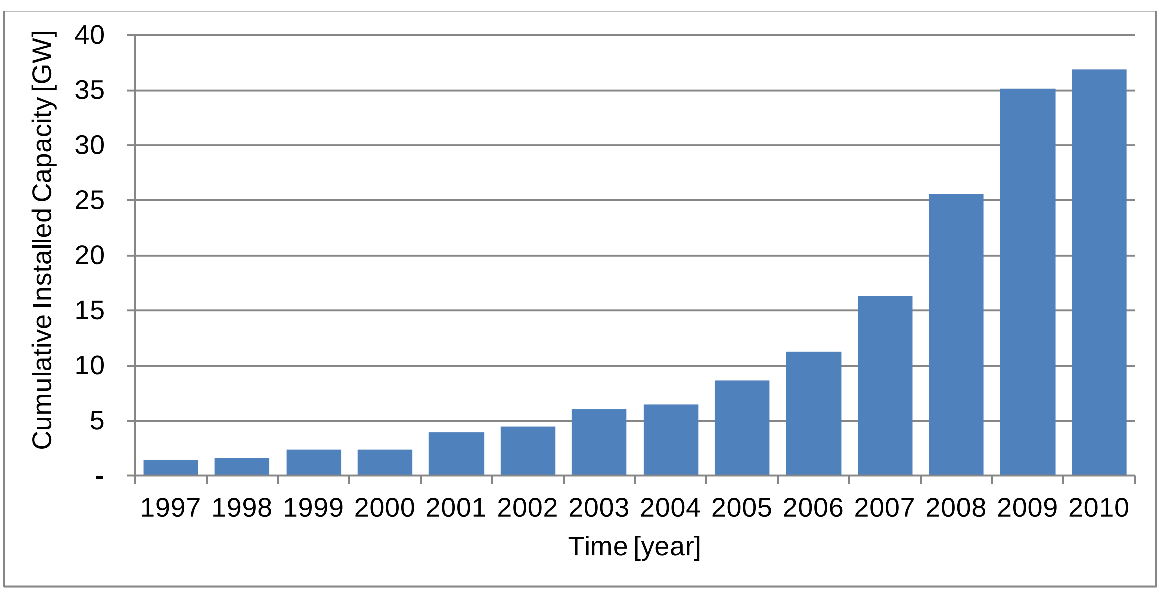


Data source: (8)

In the United States, the preferable CHP fuel is natural gas. Further detailed research should be undertaken on U.S. CHP plants that are using coal.

Exhibit B- 25 illustrates development of wind power plants in the U.S. PURPA, RPS and net metering all increased use of wind power sources in the United States. In 2000, wind power generation capacity was about 3 GW. Since 2000, wind power generation capacity has increased more than 1000 percent, and in 2010 there were about 37 GW from wind power plants.

Exhibit B- 25 Wind Power Plants Development in US



Data source: (6)

Increased Energy Efficiency Using CHP

Small Coal Fired Distributed Generation Plants Operating in a Combined Heat and Power Mode

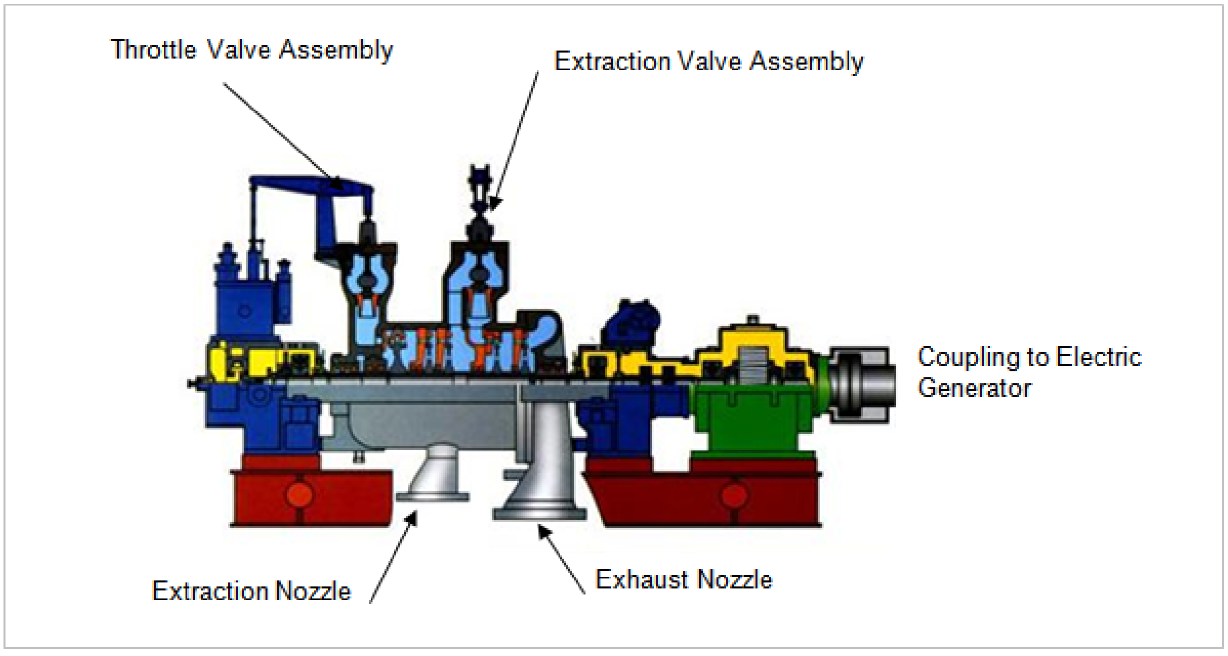
Several small coal-fired electric generating technologies have been described elsewhere in this report. This discussion will explain how the systems operate to provide both heat and power. The design and operation of each type of plant will vary to some extent, and is a function of the underlying technology. The basic design and operation of each type of plant is described below.

Pulverized Coal and Fluid Bed Combustor

These two technologies are very similar in their design and operation. Both rely on a conventional steam cycle in which the boiler generates high pressure steam (typically 1500 psig/950F for a 50 MWe plant). The steam expands through the steam turbine to about 100 psig. At this point, for many applications, the steam turbine is provided with an intermediate set of valves. Steam is extracted from the turbine just upstream of these valves and sent to the export steam header.

The rest of the steam is allowed to expand through the balance of the steam turbine stages to condenser pressure. The intermediate valves act to maintain the extraction steam pressure at a set value, regardless of the amount of steam extracted. The electrical power output of the steam turbine is reduced by the energy forfeited by the extracted steam. Exhibit B- 26 below is an illustration of a typical turbine of this type.

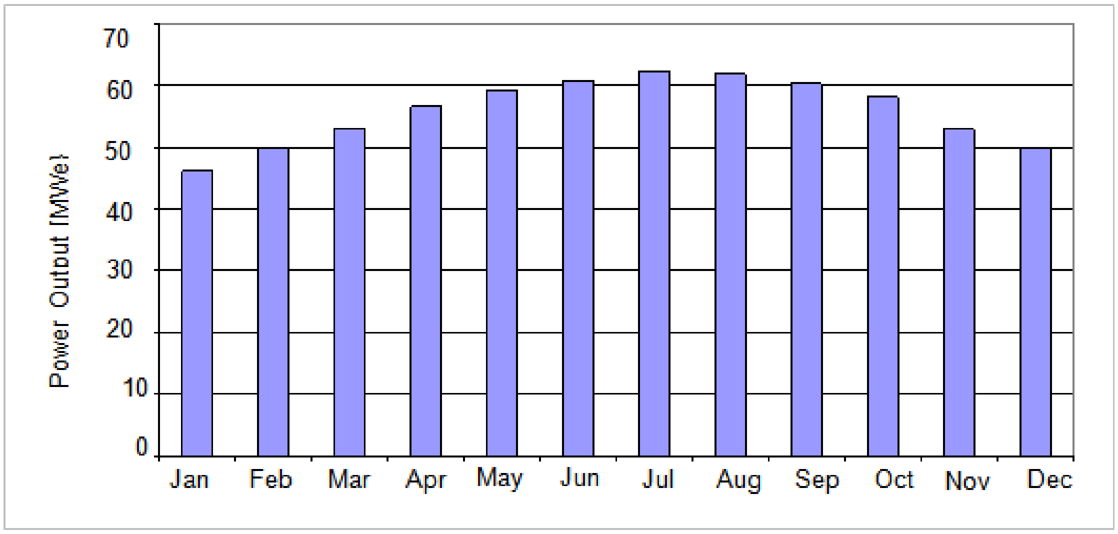
Exhibit B- 26 Typical Automatic Extraction Steam Turbine



Source: (10)

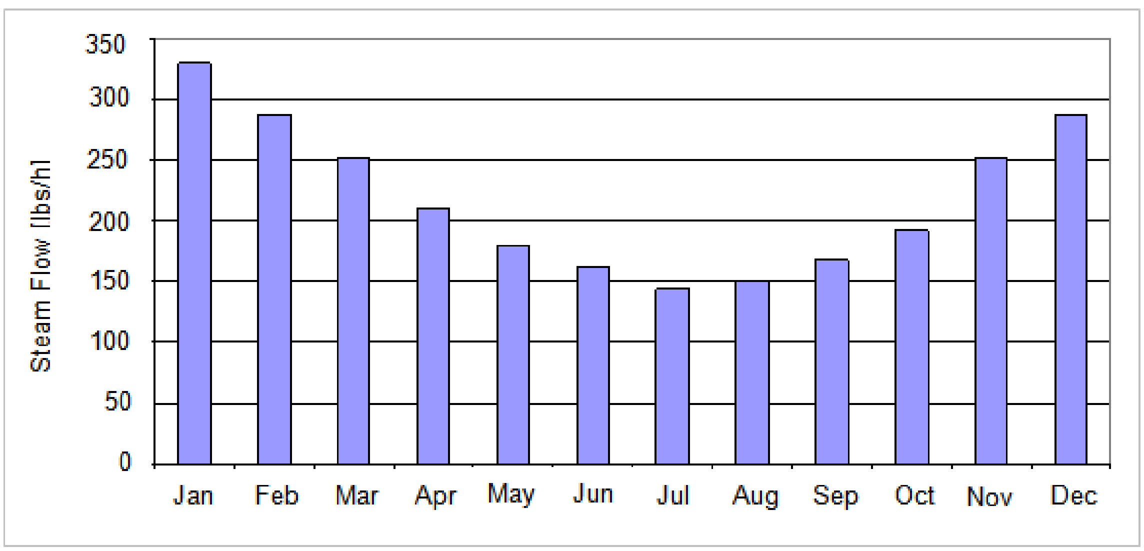
Exhibit B- 27 and Exhibit B- 28 below illustrates a typical set of power output and extraction steam quantity characteristics over a typical calendar year for a CHP plant supplying steam to meet heating demand for a large facility or district.

Exhibit B- 27 Steam Turbine Power Output Variation by Month-Typical Year



Source: (10)

Exhibit B- 28 Extraction Steam Flow Variation by Month-Typical Year



Source: (10)

Modular Gasifier + Gas Turbine

The modular gasifiers produce syngas for firing in one or more gas turbines. The gas turbine is equipped with a heat recovery steam generator (HRSG), recovering waste heat from the turbine exhaust, and generating steam for a steam turbine. The steam turbine design is similar to that described above, with an automatic extraction valve. The gas turbine electric output remains constant, but the steam turbine electric output varies in a manner similar to that described above for the PC/FBC cases.

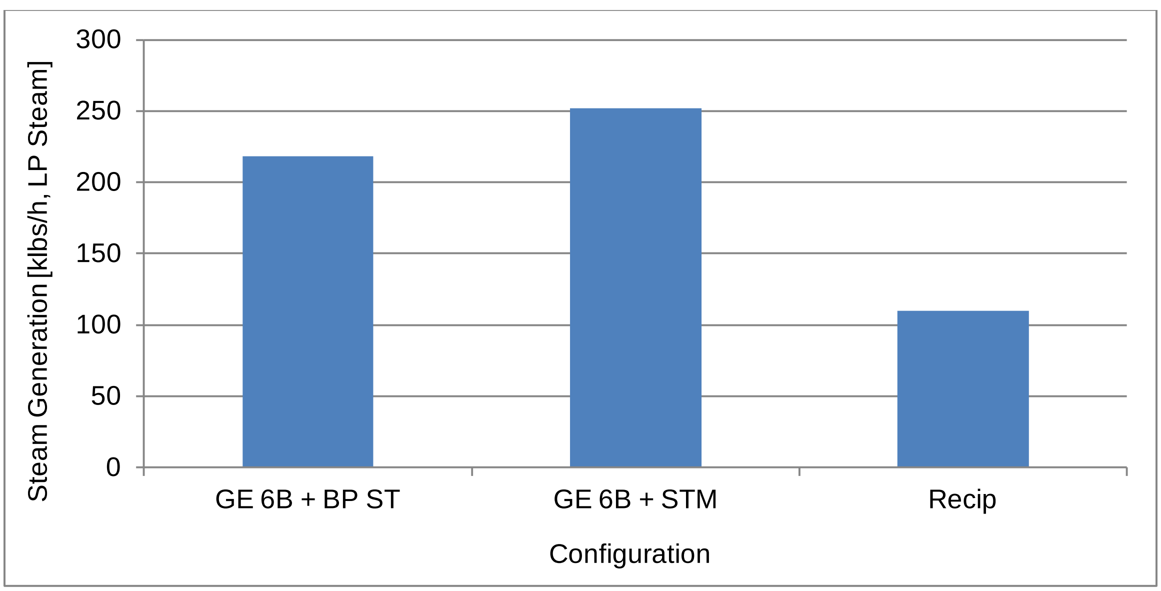
Modular Gasifier + Reciprocating Engine

The gasifiers produce syngas that is fired in a series of reciprocating engines (compression ignition or spark ignition types may be used).

Waste heat produced by reciprocating engine types is not available in the same quantity as for the gas turbine case. This is because the exhaust gas flow from a reciprocating engine (of comparable power to a gas turbine) is significantly reduced. The figure below (Exhibit B- 29) compares the total amount of steam produced by three prime mover configurations:

Gas Turbine/HRSG generating steam for a back pressure type steam turbine. The characteristic for an automatic extraction steam turbine will be very similar.

Exhibit B- 29 Typical Steam Generation for Different Prime Movers and HRSG's



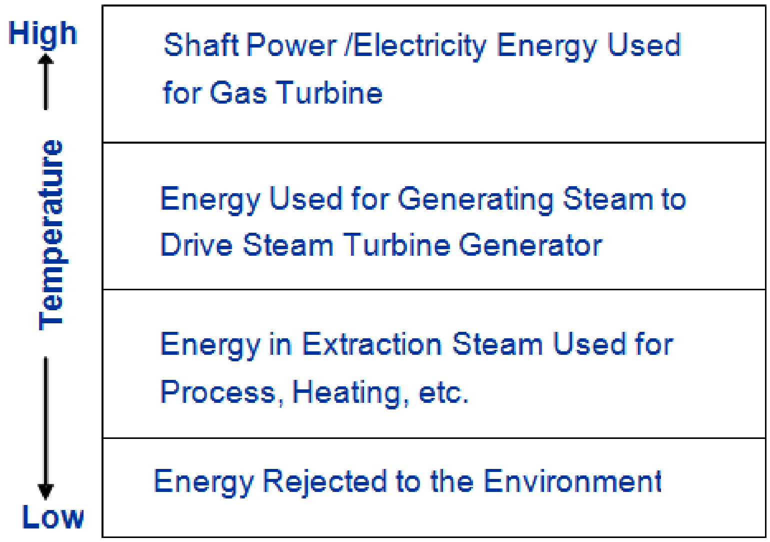
Source:(10)

Benefits of Combined Heat and Power

The steam generated by utilization of waste heat from heat engines such as gas turbines and reciprocating engines can be used for additional electric power generation or for other beneficial uses. These include process heating for industry, district heating for densely populated urban areas, large complexes such as hospitals, shopping malls, etc. The thermodynamic benefits of using this heat are based on consideration of the first and second laws of thermodynamics.

A complete description of the thermodynamics involved is beyond the scope of this report. However, a simplified diagram, presented below (Exhibit B- 30), illustrates the basic principle involved in a Gas Turbine with HRSG, steam turbine, and extraction steam.

Exhibit B-30 Combined Heat and Power Utilization of Thermal Energy



The diagram illustrates how energy cascades from one beneficial use to the next, until it is at too low a temperature to be of value. Thus, a gas turbine operating in a simple cycle rejects a considerable amount of energy to the environment (heat sink). The steam-bottoming cycle extracts more electrical power from the energy cascade, and the extraction steam provides useful heating. One salient point must be made that is not evident from the simple diagram above. As useful work is extracted from the energy cascade, the temperature is reduced. As the temperature is reduced, the energy becomes less valuable thermodynamically, and able to generate electricity at progressively lower efficiency. Using the lower tier of energy for process or district heating, therefore, may provide a beneficial tradeoff versus using it to generate incremental amounts of electricity.

Interest in combined heat and power (CHP) technologies has increased over the past decade because there is a need for more efficient use of energy; in some cases, the technologies could also enhance energy reliability. CHP is a form of distributed generation, usually co-located with heat demand. A CHP plant has a very high efficiency because it produces both electrical and thermal energy simultaneously. CHP plants can burn a variety of different fuels, such as natural gas, coal, oil, and alternative fuels (biomass, geothermal, wood, solar, etc.). They also can have different prime movers, such as reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells. Today, 9 percent of the global power generation is provided by CHP (17), but the diversity in fuels and prime movers offered by CHP may provide an important integration platform for distributed renewable sources in the future.

For a valid comparison between CHP efficiency and that of conventional generation, the conventional generation efficiency should be calculated as a weighted sum of power station and boiler efficiency. CHP efficiency may be defined in several different ways because each part of a CHP unit has its own efficiency. When CHP is calculated, it is appropriate to denote what efficiency measures are used.

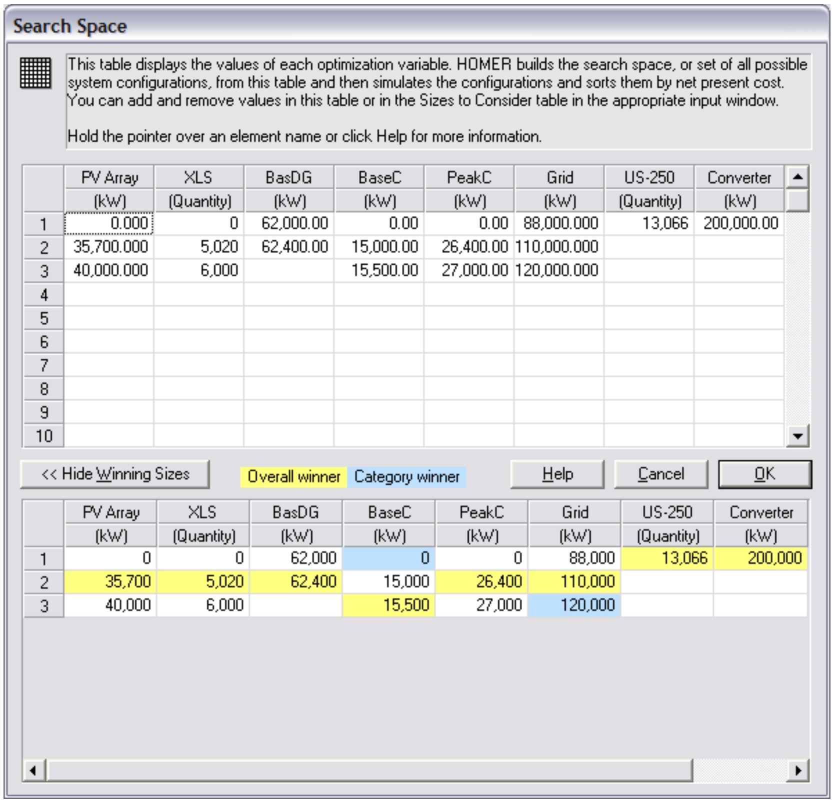
Appendix C – System Level Modeling of the Smart Grid City of the Future

Technical analysis of the Smart Grid City 2020 was performed using renewable software package HOMER(29) from the National Renewable Energy Laboratory. HOMER is an optimization tool designed to analyze and optimize use of different DG renewable and non-renewable energy portfolios while connected to or disconnected from the grid. For the purpose of this analysis, new fuel and new generator type had to be defined. The new fuel is coal and new generator type is a coal generator. Both the fuel and the generator characteristics are flexible enough to define the fuel cost, generator efficiencies, and carbon dioxide and other environmental emissions. The optimization algorithm can also include cogeneration. In addition to the coal generator, wind and photovoltaic power sources are used. These renewable power sources are based on commercially available devices. Wind and PV profiles from Wisconsin are used. The output of each energy source is defined over an upper and lower limit. HOMER does the optimization to determine the optimal generation portfolio for a given daily demand profile. The daily demand profile is a daily profile from MISO adjusted to have 162 MW average value and 194 MW peak value. This daily profile is replicated over a 25-year period. The optimization is performed over the lifetime of the resources and with the assumption that 45 percent of the needed energy would come from the grid. These features are sufficient to simulate and optimize all of the generation options previously discussed in this report.

Exhibit C - 1 shows input data to the HOMER optimization algorithm and the resulting output from it. The incremental costs of energy resources are approximately constant, and therefore the results are at their limiting values. If the incremental costs were linear or nonlinear, the optimal values would be somewhere between the upper and lower limits. From the HOMER characteristics, it seems that it uses a dynamic programming optimization approach. This means that the resulting optimal point would be global regardless of nonlinearity.

Exhibit C - 2 summarizes the optimization results. Some of the results require further discussion. The Smart Grid City objective is to supply 45 percent of its energy demand from the grid. Energy can be purchased under different contract types and schedules. HOMER can simulate three different purchasing arrangements. This will decide which firm generation resource will supplement the renewable resources and whether the standby generation for intermittent resources will come from the grid or the local distributed generator.

Exhibit C - 1 Inputs and Outputs of HOMER Optimization Procedure



Search Space

This table displays the values of each optimization variable. HOMER builds the search space, or set of all possible system configurations, from this table and then simulates the configurations and sorts them by net present cost. You can add and remove values in this table or in the Sizes to Consider table in the appropriate input window.

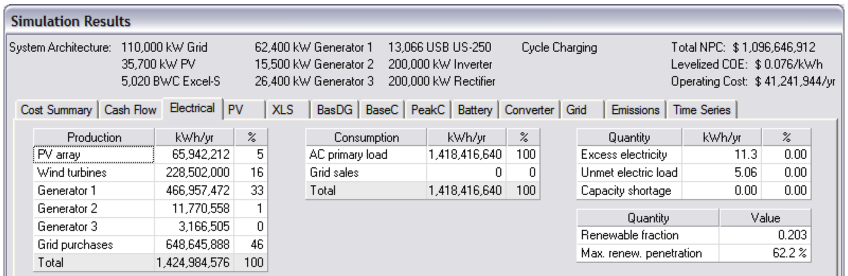
Hold the pointer over an element name or click Help for more information.

	PV Array (kW)	XLS (Quantity)	BasDG (kW)	BaseC (kW)	PeakC (kW)	Grid (kW)	US-250 (Quantity)	Converter (kW)
1	0.000	0	62,000.00	0.00	0.00	88,000.000	13,066	200,000.00
2	35,700.000	5,020	62,400.00	15,000.00	26,400.00	110,000.000		
3	40,000.000	6,000		15,500.00	27,000.00	120,000.000		
4								
5								
6								
7								
8								
9								
10								

<< Hide Winning Sizes | Overall winner | Category winner | Help | Cancel | OK

	PV Array (kW)	XLS (Quantity)	BasDG (kW)	BaseC (kW)	PeakC (kW)	Grid (kW)	US-250 (Quantity)	Converter (kW)
1	0	0	62,000	0	0	88,000	13,066	200,000
2	35,700	5,020	62,400	15,000	26,400	110,000		
3	40,000	6,000		15,500	27,000	120,000		

Exhibit C - 2 Generation Portfolio Optimization Results



Simulation Results

System Architecture: 110,000 kW Grid; 35,700 kW PV; 5,020 BWC Excel-S; 62,400 kW Generator 1; 15,500 kW Generator 2; 26,400 kW Generator 3; 13,066 USB US-250; 200,000 kW Inverter; 200,000 kW Rectifier; Cycle Charging

Total NPC: $ 1,096,646,912
Levelized COE: $ 0.076/kWh
Operating Cost: $ 41,241,944/yr

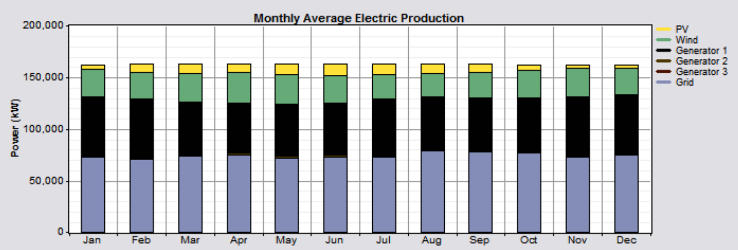
Cost Summary | Cash Flow | Electrical | PV | XLS | BasDG | BaseC | PeakC | Battery | Converter | Grid | Emissions | Time Series

Production	kWh/yr	%
PV array	65,942,212	5
Wind turbines	228,502,000	16
Generator 1	466,957,472	33
Generator 2	11,770,558	1
Generator 3	3,166,505	0
Grid purchases	648,645,888	46
Total	1,424,984,576	100

Consumption	kWh/yr	%
AC primary load	1,418,416,640	100
Grid sales	0	0
Total	1,418,416,640	100

Quantity	kWh/yr	%
Excess electricity	11.3	0.00
Unmet electric load	5.06	0.00
Capacity shortage	0.00	0.00

Quantity	Value
Renewable fraction	0.203
Max. renew. penetration	62.2 %



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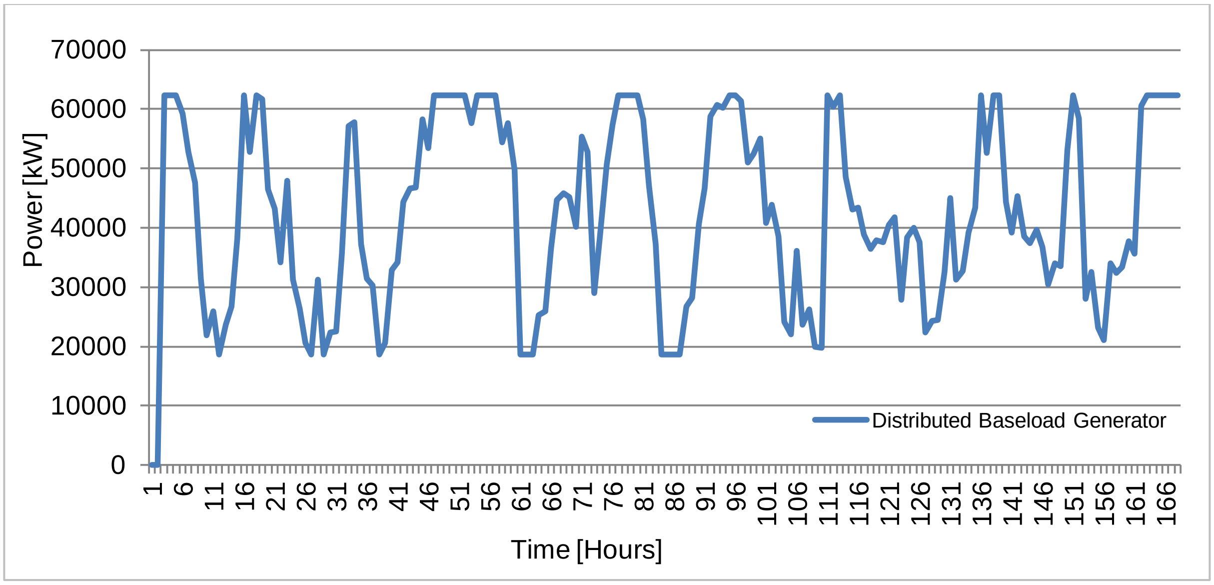
The Smart Grid city purchases 45 percent of its energy from the grid on the bulk power market and can be bought from the grid using three different approaches. In the first approach, the grid supplies a constant 45 percent of the Smart Grid city's power demand. This is equivalent to a 45 percent demand reduction. Cumulative energy bought from the grid over one year is 45 percent of the annual Smart Grid city energy. The second approach limits capacity from the grid to 45 percent of the annual maximum demand (194 MW). This capacity provides 45 percent of annual smart grid energy demand. This case is used to compare business as usual and Smart Grid city cases.

The third approach does not limit capacity that can be bought from the grid to 45 percent of maximum annual demand. The capacity is then used to provide 45 percent of annual Smart Grid energy. These approaches give similar results; however, distributed baseload generator output differs from case to case for a given generation mix. Exhibit C - 3 illustrates distributed baseload generation power output for the first approach.

Exhibit C - 3 Baseload Generation with Constant Supply from the Grid



The baseload distributed generation compensates for wind and solar fluctuations (Exhibit C - 4). The generator is used 8,760 hours per year and its capacity factor is 77 percent. If the generator is not capable of fast ramping up and down, it should be accompanied with storage or additional backup power should be supplied from the grid.

Exhibit C - 4 Wind Generation and PV Power Output

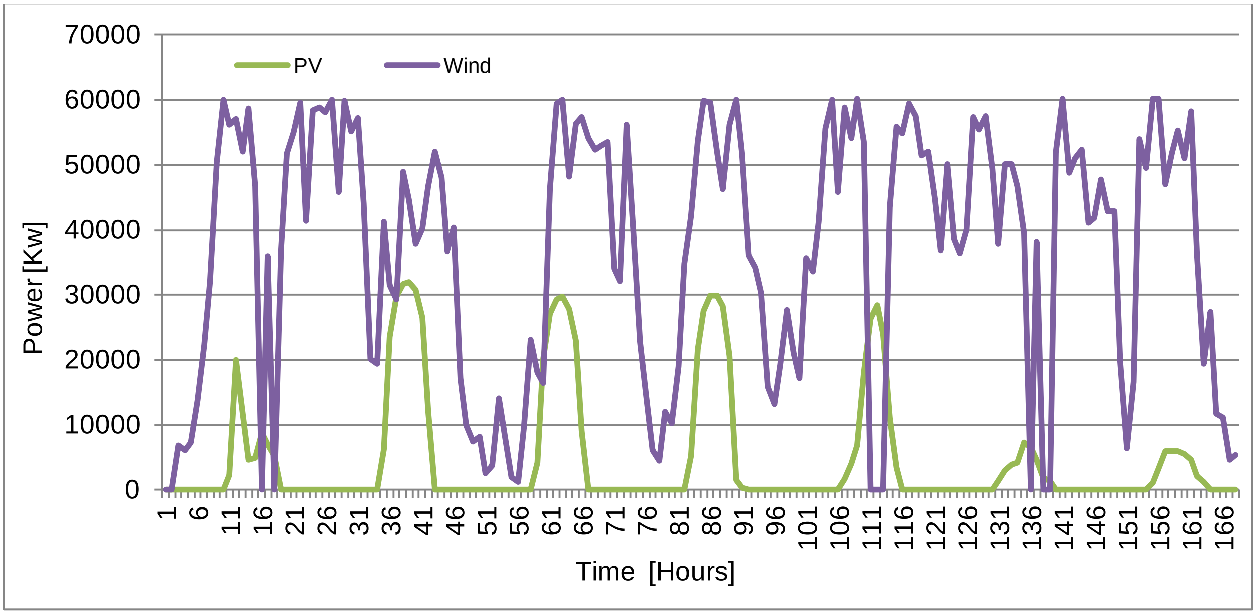


Exhibit C - 5 illustrates distributed baseload generator output for the second approach. The generator is utilized more, and the network is used to supplement wind and solar generation. For the given generation mix, wind generator and PV power on-demand, distributed baseload generation has 96 percent capacity factor and it will work 8,758 hours per year. This capacity factor is very high but if capacity that can be imported is limited to 45 percent, the baseload generation is the cheapest generation and it will work most of the time.

Exhibit C - 5 Baseload Generator Output – Capacity from Grid Less than 45%

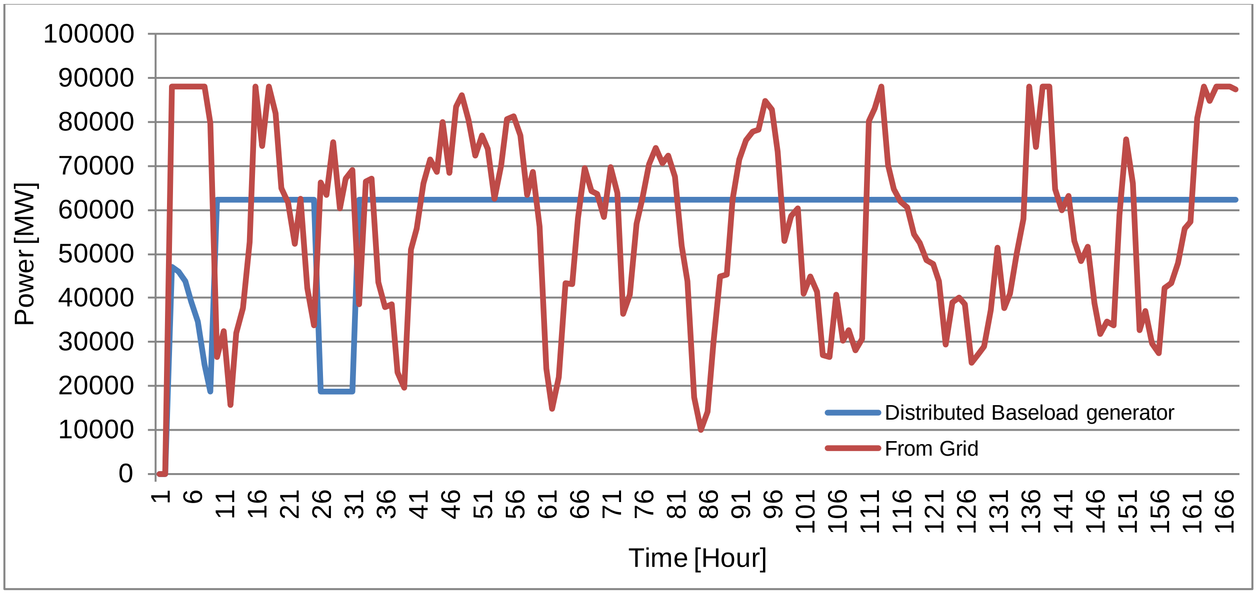
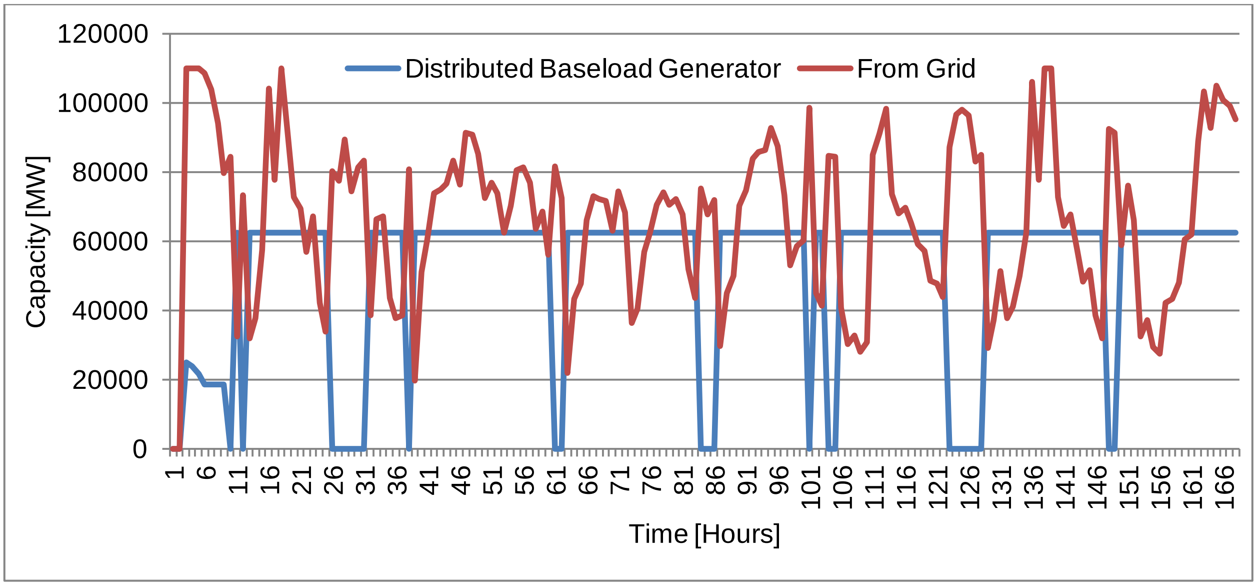


Exhibit C - 6 illustrates distributed baseload generator output for the third approach. The generator is more utilized than in the first approach because the network is used to supplement wind and solar fluctuations. However, it is less utilized than in the second approach because additional capacity that can be bought from the network allows buying cheaper power from the grid when the locational marginal price is lower than the distributed coal generation cost. For the given generator mix, wind generator and power and demand, the capacity factor of distributed baseload generation is 85 percent and it will work 7,884 hours per year.

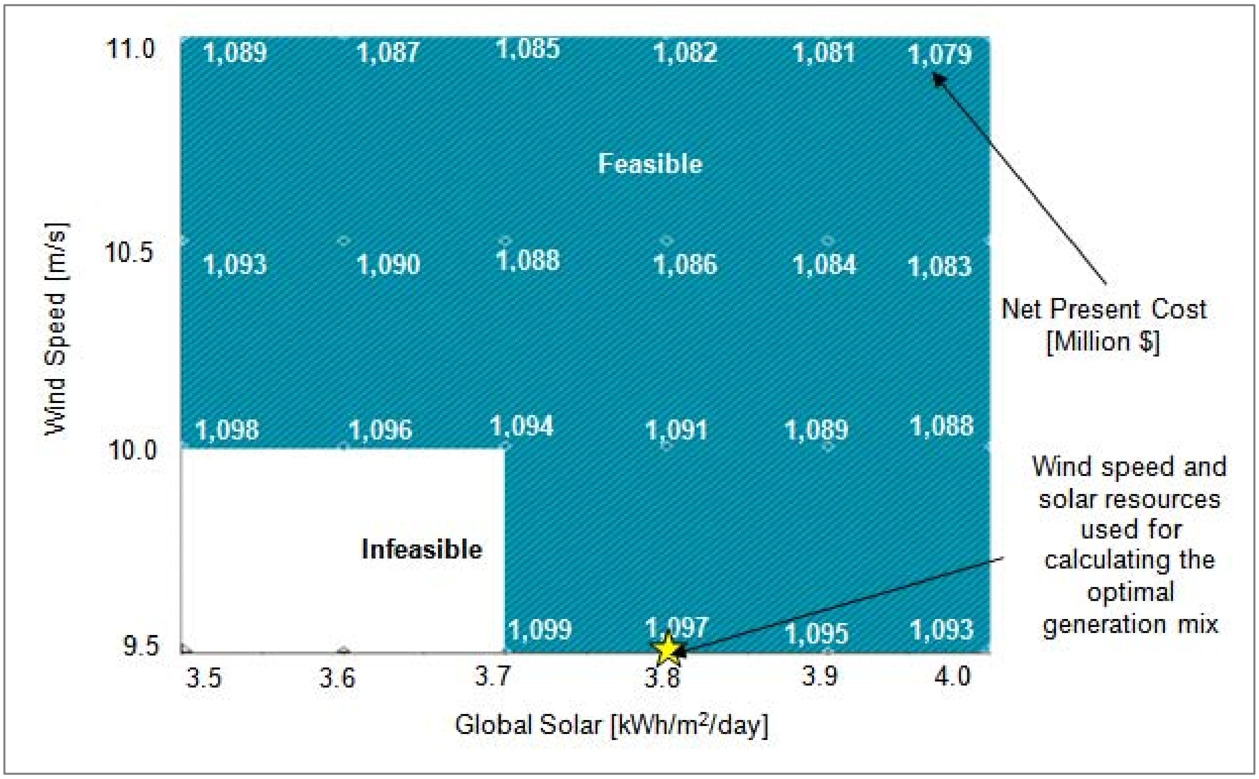
Exhibit C - 6 Baseload Generation Output – Capacity from Grid Greater than 45%



The given examples illustrate distributed baseload generation behavior for three different ways of buying 45 percent of annual energy for Smart Grid city's energy consumption from the grid. If the distributed baseload generation is not capable of load or wind/solar fluctuation following, additional back-up power from the grid is needed to firm up renewable generation.

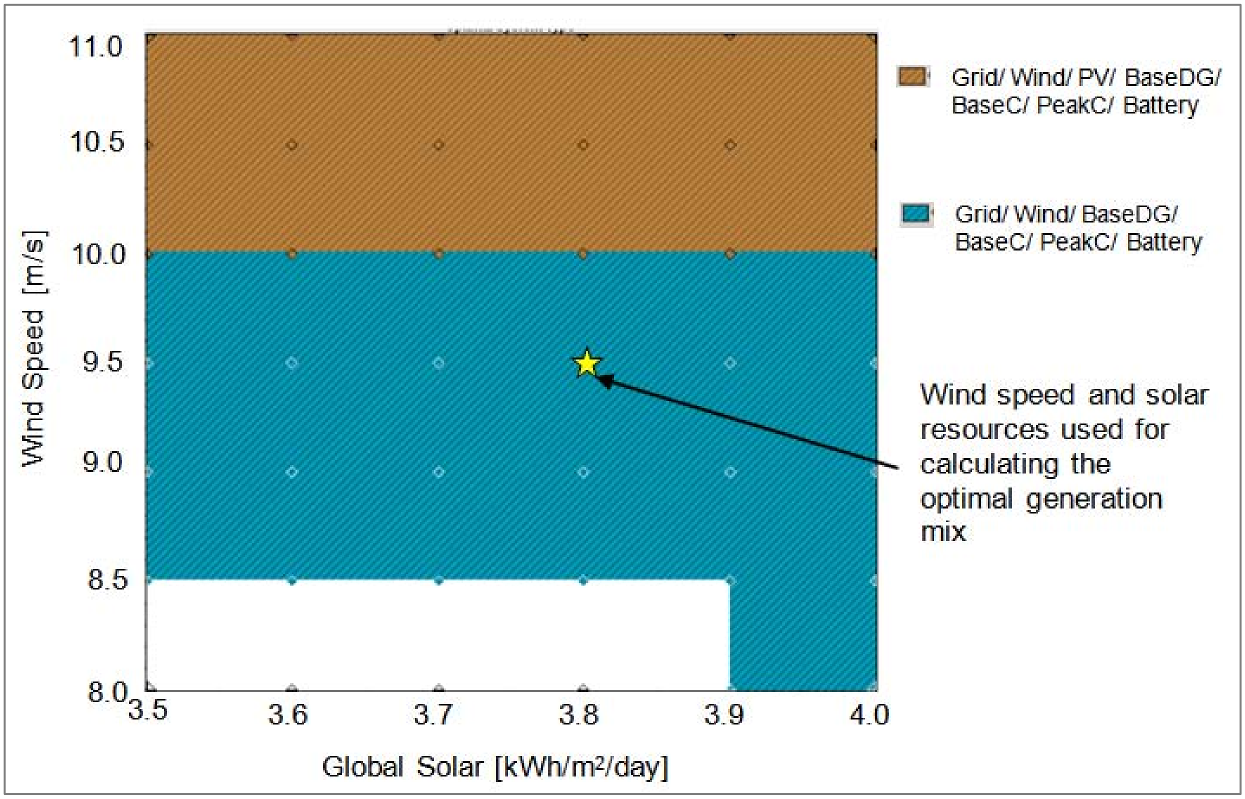
Generation mix for the Smart Grid city depends on the Smart Grid city's location. One assumption is that 20 percent of demand could be supplied from renewable power plants. This constraint will be satisfied only if there is enough wind power and PV power generation. Exhibit C - 7 illustrates a sensitivity analysis for the given generator mix. Wind speed can have the following values 9.5 m/s, 10 m/s, 10.5 m/s, and 11 m/s. Solar resources can take the following values {3.5, 3.6, 3.7, 3.8, 3.9, 4.0} kWh/m^2/d. The blue area represents all wind and solar values for which the optimal generation mix is a feasible solution. The white area represents wind and solar values for which the optimal generation mix is not a feasible solution. If wind speed drops below 10 m/s and solar resources drop below 3.7 kWh/m^2/day, the optimal generation mix cannot supply the Smart Grid city. The yellow star represents wind speed and solar resources used for calculating the optimal generation mix using HOMER.

Exhibit C - 7 Optimal Generation Mix Sensitivity Analysis



The set of feasible solutions increases if wind generation capacity can increase to 60 MW. Exhibit C - 8 illustrates a sensitivity analysis for this case. The optimal generation mix will not contain PV generation if wind speed increases above 10 m/s. The optimal generation mix will be infeasible if wind speed drops below 8.5 m/s and solar resources drop below 3.0 kWh/m^2/day.

Exhibit C - 8 Optimal Generation Mix



Maximum net grid purchase and coal price affect the optimal generation mix as well. Allowing coal price in $/kg, for distributed baseload generator, to be {0.06, 0.07, 0.08, 0.09, 0.10, 0.11} and maximum net grid purchase in MWh/year to be {620,000 MWh/year; 640,000 MWh/year; 660,000 MWh/year; 680,000 MWh/year; 700,000 MWh/year} the optimal system type is shown in Exhibit C - 9. There are two optimal generation mixes. The first is the same as the previous optimal generation mix. The second optimal generation mix does not include baseload generation owned by customers. The infeasible solutions with the given generation mix are for maximum grid purchases lower than 660,000 MWh/year and coal prices higher than $0.10/kg. 45 percent of annual energy is bought from the grid by paying the locational marginal price.

The main question is if the 55 percent of demand is more economical to supply from the grid or to use distributed resources. The answer depends on how far from the grid the Smart Grid city is. The capital cost for 1 km of transmission is $571,661/km assuming $335,540/km capital cost for 138 kV line and $236,121/km capital cost for 69 kV line (30), and assuming that the same length of 138 kV and 69 kV lines will be needed to connect the Smart Grid city to the grid. It is economical to buy the rest of the 55 percent of demand from the grid if the Smart Grid city needs less than 700 km of grid extension (Exhibit C - 10). The distributed resources are more economical if the Smart Grid city needs more than 700 km of grid extension.

Exhibit C - 9 Optimal Generation Mix

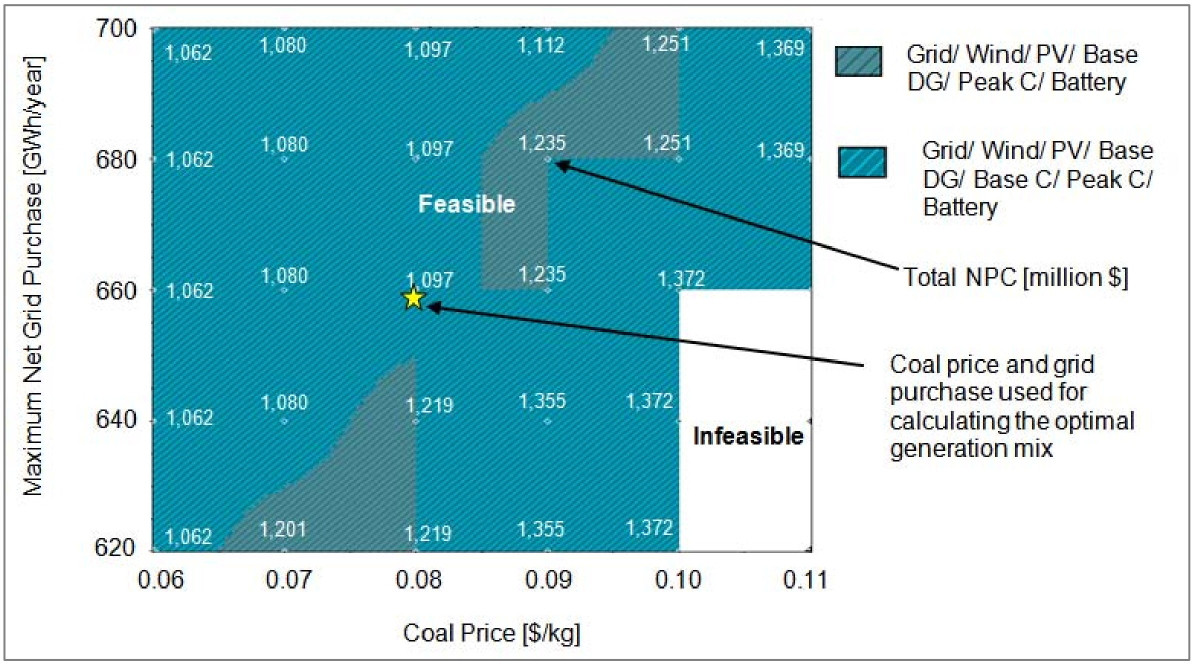
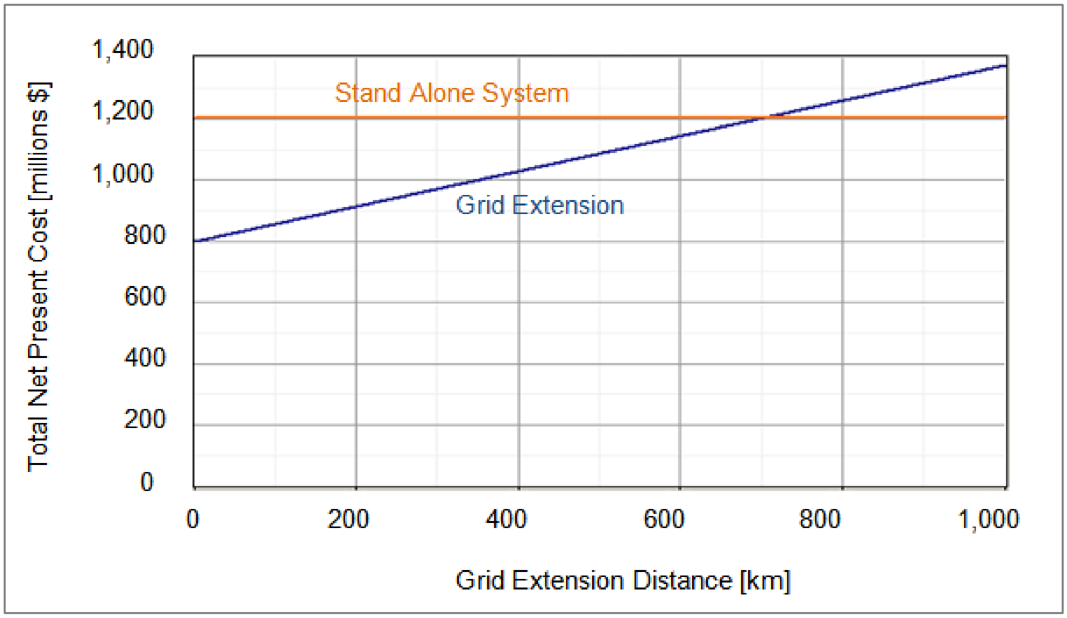


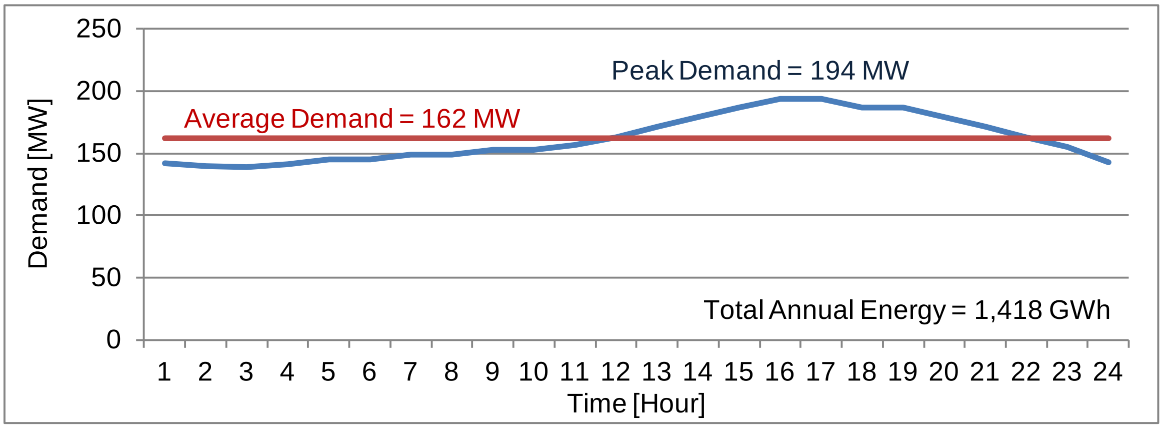
Exhibit C - 10 Breakeven Grid Extension Distance



Key assumptions in the above analysis include the calculation of capacity factor as number of operating hours divided by 8760 hours, and, maximum and average demand are used in the calculation instead of demand curve. Both assumptions are valid for the first level of economic analysis when low level of technical details is included into calculation. However, for full technical analysis these assumptions should be modified.

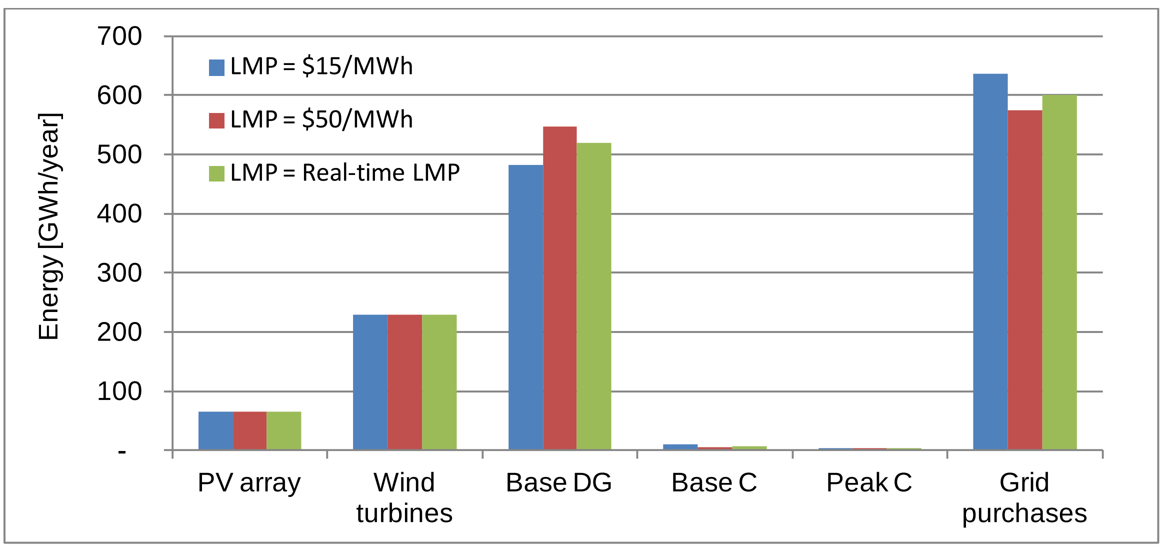
Generation production and capacity factor depend on locational marginal price and demand profile. To illustrate this we will use HOMER simulation for different technical simulations. Assuming that smart grid city has daily demand given in Exhibit C - 11for each day during one year and three different locational marginal prices ($15/MWh, $50/MWh and real-time LMP) generation production is shown in Exhibit C - 12.

Exhibit C - 11 Daily Demand Profile



Wind and PV power generation are the same for all three LMP prices because smart grid city requires 20 percent of demand to be supplied by renewable sources.

Exhibit C - 12 Electrical Production by Generation Type for Three LMPs



Base DG will produce 480 GWh if LMP is $15/MWh, about 550 GW if LMP is $50/MWh and 520 GWh if LMP is real-time LMP. Different Base DG will be compensated from the grid such that power bought from the grid is 635 GWh, 575 GWh and 600 GWh, respectively. Different generator output will affect generator capacity factor (Exhibit C - 13) and number of operating hours (Exhibit C - 14).

Exhibit C - 13 Capacity Factor for Three Different LMPs

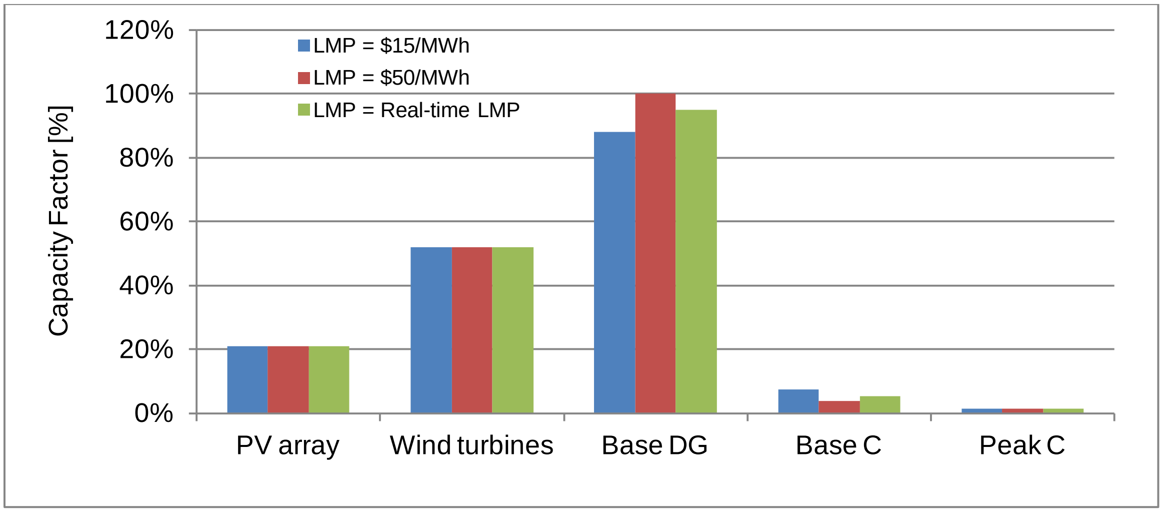
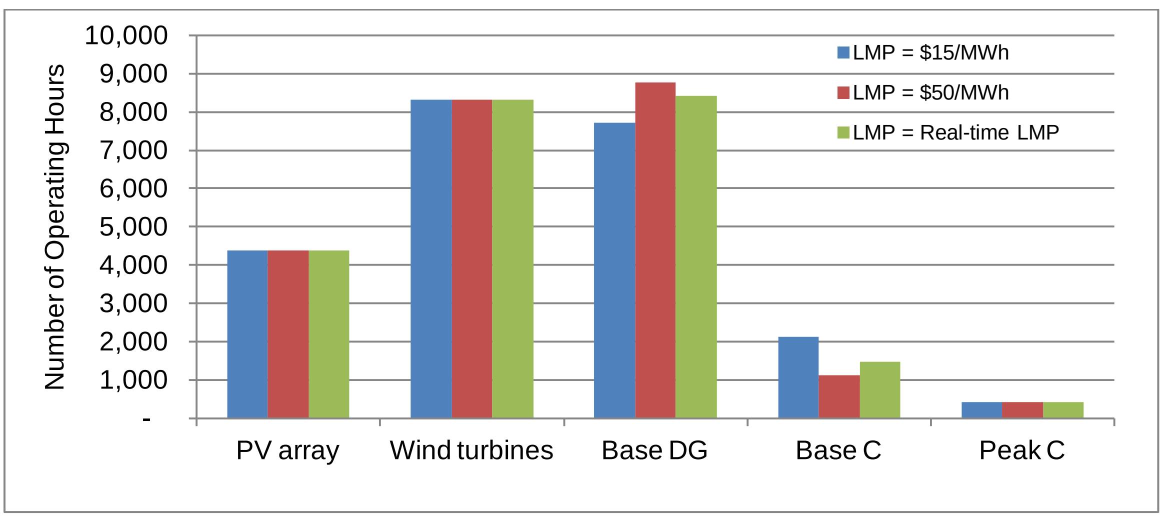


Exhibit C - 14 Number of Operating Hours for Three Different LMPs



In the first part of the section, capacity factor is calculated as number of operating hours divided by 8760. This approach is acceptable for the first level of economical analysis when low level of details is included into calculation and when it is assumed that generator works with full capacity when it is on-line. However, for detail technical analysis this is not valid assumption as it can be seen from Exhibit C - 13 and Exhibit C - 14. For example, wind turbines works around 8000 hours per year but its capacity factor is ~50 percent. The capacity factor in this case is calculated as generation total annual energy production divided by generation maximum annual energy production. This calculation does not assume generation maximum power output during operating hours.

Generators output also depend on demand profile. Assuming three different daily demand profiles (Exhibit C - 15) that all have 162 MW average and 194 MW peak demand and ~1,420 GWh annual demand and the same LMP ($15/MWh), generator outputs are given in Exhibit C - 16.

Exhibit C - 15 Daily Demand Profiles

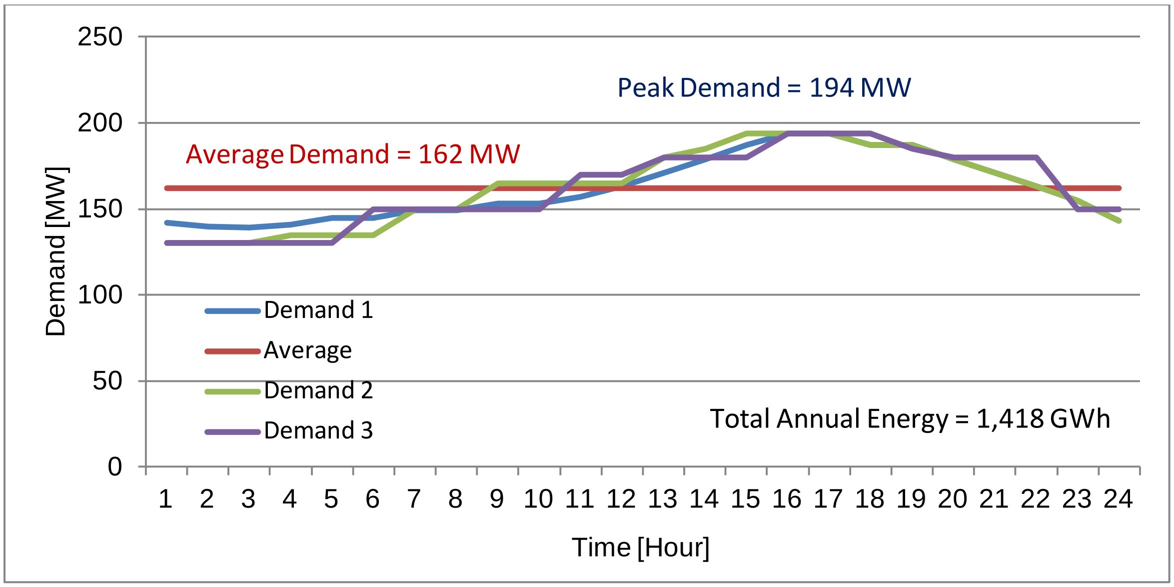
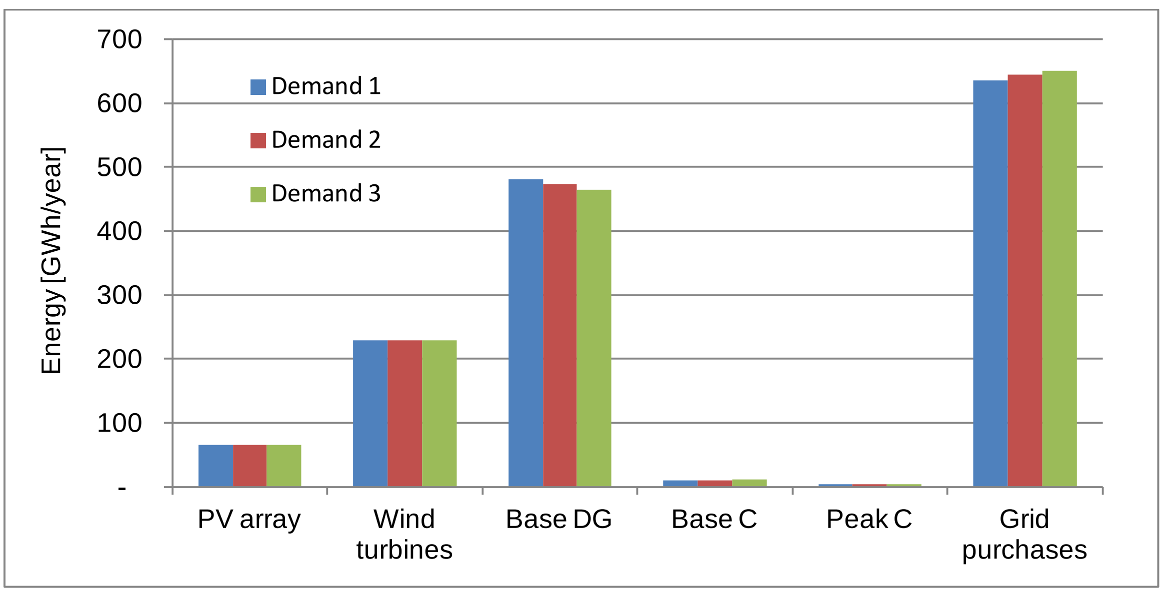


Exhibit C - 16 Electrical Production by Generation Type for Three Different Demands



Change in demand will cause different energy production by different generators. This will also affect capacity factor (Exhibit C - 17) and number of operating hours (Exhibit C - 18).

Exhibit C - 17 Capacity Factor for Three Different Demand Profiles

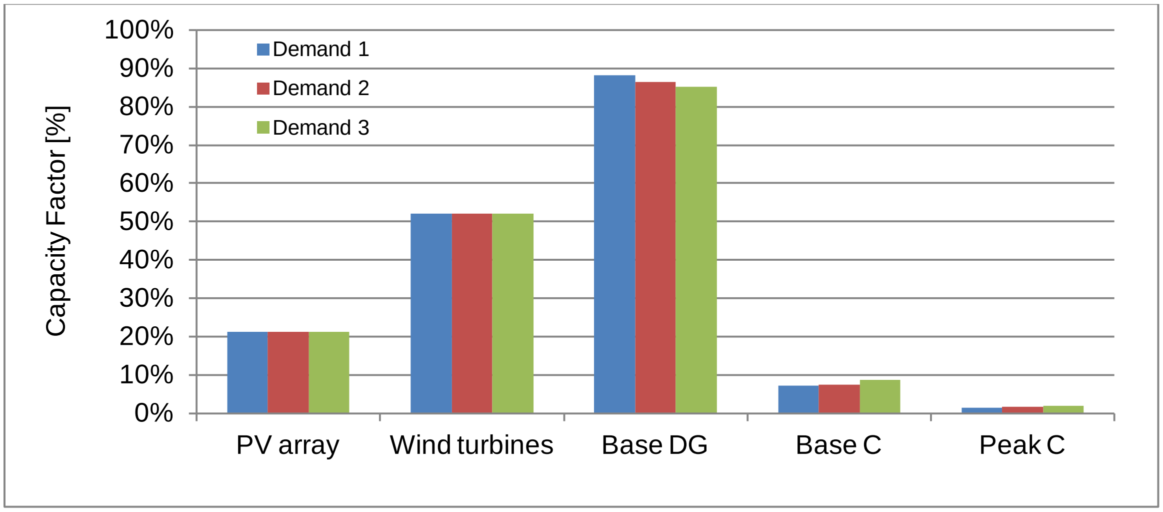
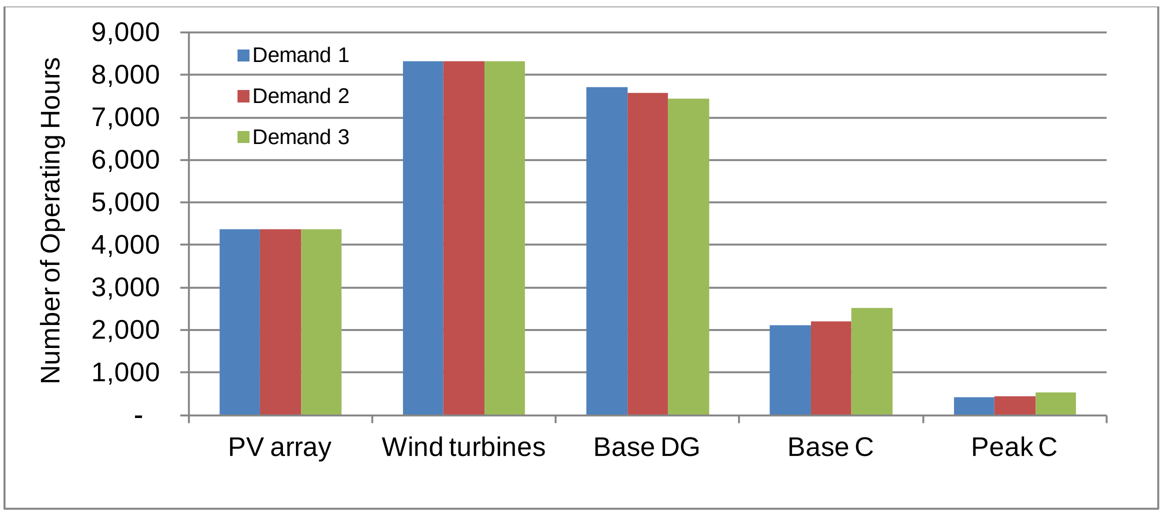


Exhibit C - 18 Number of Operating Hours for Three Different Profiles



Demand profile influences the generation output, capacity factor and number of operating hours. For detailed technical analysis, it is not enough to use average and maximum demand power, but estimated demand profile based on historical data should be included into analysis.

Conclusion

High level of economical analysis can be done using simplifying assumptions such as generator maximum output during operating hours, capacity factor that is calculated as number of working hours divided by 8760 hours, demand representation with average power, maximum power and annual energy consumption, etc. More detailed economical-technical analysis requires more technical details and the previous assumptions should be modified.

We are suggesting to run Smart Grid City of the Future simulate more detailed economical-technical analysis.