Environmental and Policy Analysis of Renewable Energy Enabling Technologies

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By

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Abstract

For intermittent electricity generation sources such as wind and solar energy to meet a large fraction (>20%) of the nation's electricity supply, two enabling technologies, energy storage and long distance transmission, will need to be deployed on a large scale. This research uses life-cycle analysis to evaluate the environmental performance of energy storage and transmission technologies in terms of their compatibility with the goals of deploying renewable energy systems. Metrics were developed to evaluate net efficiency, fossil fuel use, and greenhouse gas emissions that result from the use of enabling technologies with both conventional and renewable energy sources.

Storage technologies that are economically and technically mature for deployment in the near term include pumped hydro storage, compressed air energy storage, and battery energy storage. Since pumped hydro storage is unlikely to be expanded due to environmental considerations and geographic constraints, compressed air energy storage is the most likely technology for large-scale storage of wind energy. Batteries may play an increased role for distributed energy systems such as solar PV.

In terms of environmental impact, energy storage systems are mostly "pass through" technologies. The "life-cycle" components of energy storage systems, such as construction and O&M are a relatively small fraction of net environmental impact for most technologies. Only the fuel delivery component of CAES produces a large amount of energy use and emissions, especially compared to emissions and energy use from fossil energy production.

Since the energy use and CO_2 emissions from energy storage systems are largely a function of the primary generation source, the lowest efficiency technologies such as PSB-BES will result in the greatest energy use and emissions, particularly when coupled to highly polluting sources. The net GHG emission rate from PSB-BES is about 15% higher than the VRB-BES or PHS. The unique hybrid-CAES system has lower GHG emissions than any other storage technologies when coupled to fossil sources. When coupled to coal, GHG emissions from CAES are at least 25% lower than any other storage technology.

Considering both transmission and distribution provides additional insights into the actual environmental impact of electricity generation technologies. While the impact of T&D construction and O&M is relatively small, T&D losses can significantly increase the impact from fossil sources. This issue is of particular concern when considering large-scale development of the nation's extensive lignite resources in the upper Midwest. Emissions related only to the T&D of lignite-derived electricity will typically exceed 100 kg/MWh.

Integrated renewable/storage/transmission systems can be an alternative to conventional generation systems. Wind/CAES can be deployed on a large scale, and demonstrates high levels of fossil energy sustainability, delivering more than 5 times the amount of electrical energy from a unit of fossil fuel than the most efficient combustion system available. The GHG emissions from a wind/CAES system are about 20% of the lowest emission fossil system in existence. Both wind/PHS and Solar PV/BES also demonstrate superior performance to fossil energy systems in terms of energy sustainability and GHG emissions for intermediate and peaking generation.

Since the environmental impact of energy storage systems reflect the primary generation source, their use is not necessarily positive in terms of air emissions. Near term deployment of energy storage will likely take advantage of low cost off-peak energy from existing coal plants. The unique “grandfathering” provisions of the U.S. Clean Air Act allow for increased output from these older plants that produce high levels of emissions. Energy storage provides a loophole that could be used to increase output from these plants, instead of building cleaner alternatives. A proposed CAES plant that has been permitted will effectively produce SO_2 at a rate more than 10 times the amount allowed by law for a new power plant. Its effective NO_x emission rate could be as high as 5 times greater than legally permitted for a new plant. This loophole has been largely overlooked, and should be examined critically if new technologies for generation of peaking and load-following power are to be compared equally to the use of energy storage with existing coal-fired power plants.

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1. Introduction

This study evaluates environmental and policy aspects of the large scale deployment of two "renewable energy enabling" technologies: energy storage and long distance transmission. These technologies enable renewable energy to perform in a manner similar to conventional energy sources and will be necessary if renewable energy is to provide a large fraction of the nation's electrical energy supply.

1.1 Background

Current methods of producing electrical energy in the U.S. produce significant environmental impacts and have limited long-term sustainability. In 2003 the U.S. derived about 70% of its electricity from fossil sources, including coal, natural gas, and oil.[1] The bulk of the remaining electricity was produced by nuclear energy, and hydroelectric sources. Figure 1.1 illustrates the major fuel sources for U.S. electricity generation.

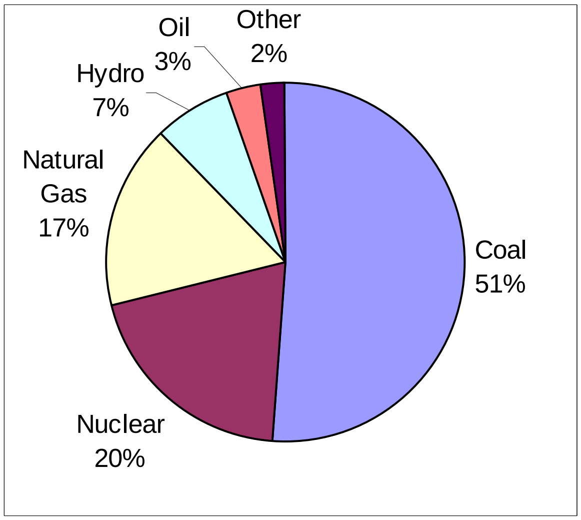

Figure 1.1: Distribution of Energy Sources for Electricity Generation in the U.S. (2003 Data)[2]

The four major sources of electricity in the U.S. (coal, nuclear, natural gas, and hydro) are considered by many to be unsustainable due either to their large-scale environmental impact, or to limits of fuel source availability.

The U.S. has abundant coal resources, with no significant limits on supply for hundreds of years, even at greatly increased consumption rates.[3] Electricity generation from coal is considered unsustainable due to the production of waste products that have significant impacts on land, air, and water. Among the major byproducts of coal combustion are sulfur dioxide (SO_2) and nitrogen oxides (NO_x), which are precursors to acid rain.[4] Electricity generation from coal in the U.S. in 2000 produced over 11 million tonnes of SO_2, and over 4 million tonnes of NO_x.[5] Coal combustion also produces a number of other pollutants with significant environmental and health effects, such as fine particulates that contribute to regional haze and respiratory conditions, and mercury, which is a potent toxin that bioaccumlates in animals and humans.[6] Coal combustion's most significant byproduct, in terms of volume, is carbon dioxide (CO_2), a greenhouse gas that is considered largely responsible for anthropogenic climate change.[7] The production of CO_2 is fundamental to the combustion process, and unlike mercury and oxides of sulfur and nitrogen, CO_2 cannot be easily filtered or chemically reduced through commercially demonstrated technologies. Carbon sequestration from coal, involving capture, transport, and disposal, has yet to be tested on any significant scale, and its economic costs and environmental impacts are largely unknown. Large-scale restrictions on carbon emissions represent an uncertain future for significant expansion of electricity generation from coal.

Nuclear power is also not significantly constrained by the availability of fuel. U.S. reserves of uranium can supply the existing reactor fleet for many hundreds of years, even with the relatively inefficient "once-through" cycle currently used in the U.S.[8] Reprocessing and breeder cycles would provide an essentially infinite supply of nuclear fuels. Nuclear power is considered by many to be unsustainable due to the production of radioactive waste products that remain highly toxic for many thousands of years. Concerns about the risks associated with spent nuclear fuel, as well as the potential for accidents and weapons proliferation have led to significant opposition to the expansion of nuclear power. As a result of an unfavorable economic climate driven in part by this opposition, no new nuclear plants have been ordered in the U.S. since 1979, and many utility observers see large-scale expansion of conventional or advanced nuclear power (including breeder cycles or fusion) unlikely in the near future.[9,10]

Natural gas generation is often perceived as a much cleaner source of energy than coal or nuclear power, although it does produce significant quantities of CO_2. Natural gas generation is limited by the security and sustainability of fuel supplies in the U.S. Concerns about long-term availability of natural gas are illustrated by recent increase in cost, with the average price of natural gas in the U.S. roughly doubling between 1999 and 2003.[11] The limitations of cost and fuel availability will likely limit growth of natural gas based generation.[12]

Hydroelectric generation is not significantly expandable in the U.S. and most other parts of the developed world.[13] In addition, there is increasing pressure to remove existing large dams because of the significant environmental impacts on river ecosystems.[14] Many environmentalists do not consider large hydroelectric facilities a "green" source of energy.

Concerns about the environmental impacts and long term sustainability of these conventional power sources have increased pressure on governments and electric power providers to generate more electricity from renewable energy sources. Many environmentalists envision a world fueled almost entirely by clean, renewable sources of energy. Yet the "basket" of available power sources fitting this description is surprisingly small. Advanced unconventional water-based electricity generation systems, such as tidal, wave, and ocean thermal electric generation, are still far too immature in terms of economics and technical capabilities, and may have serious environmental consequences.[15] Geothermal electricity generation is geographically limited, and has proven to be a depletable resource.[16] Biomass energy sources also have significant limitations. Biomass is perhaps the most land intensive form of electrical energy production and must compete against food production and other land uses.[17] It remains to be seen if society will accept large-scale cultivation of dedicated energy crops.

Ultimately, it is likely that wind, and to a lesser extent solar energy, may be the primary near-term sources of renewable electricity generation. Wind energy is currently the most economic and technologically mature source of renewable electricity generation among those with large growth potential. Advances in wind turbine technology, including development of larger machines has led to significant cost reductions in recent years. In terms of busbar cost (average cost of energy produced at the power plant,) wind is now competitive with many new sources of power in areas with sufficient wind resources.[18] The use of wind energy in the U.S. and worldwide has increased substantially over the last decade, with an increase from about 1500 MW to over 6000 MW of peak capacity between 1993 and 2003.[19] Many state and local governments have mandated renewable portfolio standards that require a certain percentage of electricity to be generated from renewable sources.[20] Much of this new capacity is expected to be met with wind power.

Solar photovoltaic generation is significantly more expensive than many traditional sources, but shows promise as a source of valuable peak-demand energy (particularly in the U.S.) if sufficient cost reductions and efficiency gains occur.

Currently only a very small fraction (<1%) of the U.S. electricity supply is generated by wind and solar energy,[21] but there is significant opportunity for growth in the use of these resources. The potential from these renewable energy sources is vast: the combined wind resources in the upper Midwestern states is sufficient to meet the electrical energy needs of the entire U.S., if the limitations of intermittency and transmission can be overcome with the use of enabling technologies.[22]

Intermittency is a significant limitation to solar and wind based generation. Intermittency significantly reduces the fraction of time energy is produced by a renewable resource.
A wind turbine generator rated at 1 MW peak capacity will produce anywhere between 0 and 1 MW at any particular moment in time, but on average will produce significantly less than half its rated power. The uncontrollable and somewhat unpredictable nature of wind generation is a significant burden on electric power systems. In addition, turbines located in many parts of the U.S. produce more than average amounts of power during the spring, when energy is least valuable, and less than average amounts of energy when it is most valuable: during summer afternoons. While the fact that “the wind doesn’t always blow” and “the sun doesn’t always

shine" may be cited as the limiting factors for the use of intermittent renewables, it is the changes in output that often cause the most problems in some areas. Wind energy ramp rates can be very high, going from no output to full power in as little as one hour. Solar PV generation can produce even more rapid swings in output. Electric power systems can accept only a limited amount of energy from sources that perform in this manner. Energy storage can address these issues by smoothing renewable generation output and increasing reliability, predictability, and economic value of renewable energy sources.

The other major factor limiting the use of wind energy in particular is resource location. Areas with large amounts of wind resources are largely in the Midwestern U.S., while major load centers are concentrated on the east and west coasts. Long distance transmission allows Midwestern wind energy to supply energy to distant load centers. Increased transmission capacity also increases the "spatial diversity" of wind resources, increasing the overall use of wind energy in a large system.

The combination of intermittency and resource availability prevents renewable energy sources like solar and wind generation from providing a significant fraction of the nation's power supply without the use of enabling technologies. It is important to determine if these enabling technologies are compatible with the goals of deploying renewable energy, including increased energy sustainability, lower greenhouse gas emissions, and reduced use of polluting fossil energy sources. Many "life-cycle" studies of wind and solar PV systems (without storage) have demonstrated these favorable qualities.[23] If enabling technologies must be deployed for renewable energy to provide large amounts of electrical energy, then these enabling technologies must also have favorable environmental characteristics to produce the desired environmental benefits.

1.2 Objectives of this Work

To understand the potential environmental impacts of enabling technologies, the degree to which enabling technologies are needed must first be established. This work creates a basic intermittency cost model in an attempt to find a “break even” cost for energy storage in the Midwestern U.S. The results of this model are used to estimate how much wind can be used before storage becomes economically necessary for further use of this intermittent resource. The quantitative results of this model are combined with a qualitative discussion of the system-wide requirements of energy storage and transmission that are needed for intermittent wind energy to provide a large fraction of the nation’s electrical energy.

To evaluate the environmental impacts associated with electricity storage and transmission, several “life-cycle” metrics are developed. The primary measures of environmental impact used in this work are total fossil energy usage and greenhouse gas emissions. These metrics are then applied to a number of storage technologies considered economically and technically mature, including compressed air energy storage (CAES), pumped hydro storage (PHS), and battery energy storage (BES). Similar analysis is performed on transmission and distribution systems, including both conventional AC and high voltage DC technologies.

The evaluation of energy storage and transmission system components ultimately allows for a “systems approach” to equitably compare renewable energy sources to traditional energy sources. Several models of dispatchable renewable energy systems, which combine generation, storage, and transmission, were created to compare the environmental performance of intermittent wind and solar PV to fossil and nuclear based generation.

This work also evaluates energy storage and long distance transmission used with conventional energy systems. While energy storage and transmission have been described as "renewable energy enabling" technologies, they also can provide substantial economic benefits to traditional generation sources, including coal. As with renewable energy systems, this work takes a life-cycle approach to examine the environmental consequences of the use of energy storage with fossil electricity generation.

This evaluation forms a framework to examine existing clean air regulations, and how the use of energy storage effectively circumvents emission standards for new power sources. Current emissions regulations do not sufficiently address the potential negative impacts that may result when energy storage is combined with older coal fired power plants. This work provides a detailed analysis of the actual emissions that result from the construction and use of a new energy storage facility, compared to non-storage alternatives, and illustrates the energy storage "loophole" that exists in U.S. power plant regulations. Policy options to address the use of energy storage in an environmentally friendly manner are evaluated in terms of feasibility and effectiveness.

This thesis makes several contributions to the interdisciplinary field of energy and environmental analysis. Major contributions include:

- Adding to the understanding of the limits of intermittent sources in conventional electric power systems.
- Development of new metrics to compare energy storage systems to other electric power technologies.
- Providing new life-cycle analysis on several different energy storage and transmission technologies.
- Enabling a more equitable environmental comparison between intermittent and firm sources of power.
- Addressing previously unconsidered aspects of policies regulating new energy technologies.

1.3 Review of Literature

1.3.1 Limits of Renewable Energy without Energy Storage

Many researchers have addressed the impacts and limitations of intermittent energy sources in electric power systems that do not incorporate energy storage. While these studies are ultimately addressing the same issue, the impacts of intermittency, their goals and focus are quite diverse. Some research examines the specific technical impacts on system operation. An example includes work by Belanger and Gagnon[24] who evaluate a scenario where wind provides 11% of the total energy into a system that is largely hydro, therefore very flexible. At this penetration rate they find considerable system disruption, resulting in alteration in river flows that could have unacceptable environmental consequences. The study concluded that extra spinning backup would be required, although the study did not account for import/export capacity, nor a large geographical dispersion of wind turbines. A significant amount of research has been performed on technical impacts of large wind deployment in Europe. An example is work by Dany[25] who discusses the substantial increase in generation reserves necessary for wind integration in Europe, but does not quantify the costs.

There have been a number of studies that examine the economics of wind energy use in small power grids. Examples include Tande[26] and Beyer and Degner,[27] who found that wind energy can economically provide large amounts (up to about 30%) of the energy on a small systems that use flexible, but expensive diesel generators. However, these studies are of limited use when examining the wind energy in large systems, particularly those in the U.S. that rely heavily on relatively inflexible coal and nuclear generation.

Studies of the economic costs of wind intermittency in large power grids tend to take two approaches. Some studies evaluate the decreased *value* of wind energy as more wind is used in an electric power system. Examples include Grubb[28] and Munter[29] who both find that value of wind falls with increased use, but arrive at significantly different conclusions. A 1988 study by Grubb estimates that the value of wind falls by about 50% when wind contributes about 50% of total demand over a large area in England. However, Grubb's models provide a level of flexibility to conventional power systems that is probably overly optimistic, and more recent models tend to be far more conservative. Munter's study finds that the value of wind can fall to 0 or less at wind contribution as low as 25% of total energy in South Denmark. A study in the U.S. by Hirst and Hild[30] found that the value of wind dropped by more than 2/3 when wind produces about 25% of a system's electrical energy.

Most studies in the U.S. evaluate the additional *costs* imposed on system operation by wind intermittency. In a 1993 report, Wan and Parsons[31] review the results of early integration studies and conclude that achieving 10% of a systems energy with renewables would not impose significant technical or economic burdens. A significant number of studies of wind integration costs were completed more recently. A summary of 4 such studies is provided by Parsons et al.[32] These studies tend to confirm that wind providing 10% of energy imposes little addition cost, but none of these studies examine the costs of very high wind energy penetration. These results of these and several other studies are discussed in more detail in Chapter 2.

1.3.2 Benefits of Energy Storage to Traditional Generation

The advantages of energy storage to traditional generators have been extensively reviewed. Examples include Boyd et al.,[33] Price,[34] and Linden[35] who all conclude that several current energy storage technologies including CAES and BESS can provide economic benefits to existing generation systems

1.3.3 Methods and Metrics of Environmental Life-Cycle analysis

A variety of metrics have been developed in an attempt to compare different energy systems from a net energy perspective. Spreng[36] presents a comprehensive review of energy analysis methods, but this review makes little attempt to utilize energy accounting as a measure of environmental impact. The limitations of energy accounting as a measure of sustainability have been discussed by a few authors, including Chwalowski,[37] Leach[38] Specific application of energy sustainability metric to energy storage system has been applied by Rydh,[39]although the metrics used by Rydh are not broadly applicable for comparisons across broad classifications of technologies. An extensive review of the methods and metrics of environmental life-cycle analysis applied to electric power systems is provided by Meier.[40] Meier discusses the standard metrics used to evaluate energy sustainability including energy payback ratio, and life-cycle energy efficiency, and demonstrates their inherent limitations as comparative metrics. Meier also concludes that metrics currently used by the National Renewable Energy Laboratory [41,42,43,44] are among the most useful for comparisons across technology groups. The primary sustainability measurement used in this work is based on the NREL metrics.

1.3.3 Environmental Analysis of Energy Storage Systems

Many technical and economic comparisons of energy storage systems have been performed. Reviews by Kondoh et al.[45] and Cavallo,[46] conclude that pumped hydro storage (PHS), compressed air energy storage (CAES), and advanced battery energy storage (BES) are the most economic storage systems for large scale energy storage for intermittent renewables. A review of technologies by the Electricity Storage Association[47] concludes that in addition to lead-acid batteries, flow battery technologies, including Vanadium and Polysulphide batteries are the most economic for large scale application.

Most environmental analysis of PHS focus on biological, hydrological, or aesthetic issues. Examples include work by Simmons and Neff,[48] Clugston and U.S. Fish and Wildlife Service,[49] New England River Basins Commission, [50] and U.S. Bureau of Reclamation[51] that consider ecosystem alteration, and biological impacts. Several pumped hydro projects have been proposed since the passage of the National Environmental Policy Act (NEPA), which require an environmental impact statement (EIS) for most major hydro projects. Examples include the Summit Energy Storage Project[52] and the River Mountain Project.[53] The various studies and EIS documents in the literature address the significant impacts on land and water from PHS construction and use, but do not consider net energy impacts or upstream emissions which are the focus of this work.

While no life-cycle energy or emissions studies of PHS systems were located, a number of life-cycle studies have been performed on conventional hydro projects, which are similar in nature to PHS. Studies by Gagnon and Van de Vate,[54] Rashad and Ismail,[55] Navrud,[56] Oak Ridge National Laboratories,[57] and Uchiyama[58] found very low life-cycle energy requirements and greenhouse gas emissions from hydro project construction and operation. However, ongoing studies by Fearnside[59] and Gagnon[60] have found decaying biomass in flooded reservoirs can have significant GHG consequences, although this appears to be limited to projects in tropical regions. This is an active area of research. Most other environmental analyses on dams focus on other environmental and social impacts, such as such as land use and displacement of native populations, and disruption of natural habitats.

Several authors have evaluated the net efficiency of CAES including Zaugg and Stys[61] and Najjar and Zaamout[62] These works do not perform a complete life-cycle assessment, nor do they assess environmental impacts. Since CAES has many similarities to gas turbines, previous analyses of this technology are directly applicable. Studies by Meier and Kulcinski[63] and Spath and Mann[64] found significant life-cycle impacts from natural gas production and transmission

Interest in potential large scale use of electric vehicles resulted in a number of life-cycle studies of batteries, including lead-acid batteries. Environmental assessments of lead-acid batteries include work by Tsoulfas et al.,[65] Socolow and Thomas,[66] Cobas-Flores et al.,[67] Lankley and Micheael[68] and Steele and Allen.[69] Wronski[70] and Rade and Andersson[71] reviews life-cycle material requirements for electric vehicle batteries. Steele and Allen (1996)[72] discusses recycling impacts. Since many of these studies focus on transportation, their conclusions compare life-cycle impacts of electric vehicles compared to conventional combustion engines. While these conclusions are not particularly relevant to this work, the data and analysis of the batteries themselves were used in this analysis.

There is limited assessment of flow batteries, a more recent technology likely to be used for energy storage applications. Several economic comparisons have been published include work by Lotspeich[73] and McDowall.[74] A life-cycle assessment of several flow battery technologies has been performed by Rydh,[75,76] including a life-cycle comparison between Vanadium and Lead-acid batteries. The Tennessee Valley Authority[77] prepared an environmental impact statement for the proposed Regenesys polysulphide battery, which focuses primarily on land use and potential toxic chemical release.

1.3.4 Environmental Analysis of Transmission and Distribution Systems

Most environmental analysis of electric transmission systems focus on aesthetics, land use, wildlife impacts or possible health effects related to EMF. Examples include studies by DeCicco and Beyea,[78] Hammons,[79] Knoepfel,[80] and Hull and Bishop.[81] Among the more significant conclusions from this body of work is that high voltage DC is generally preferable to conventional AC due to its overall lower footprint for a given power rating.

The review of literature performed for this work, as well as other published reviews such as Bergeson and Lave[82] and Curran et al.[83] have found that the effects of T&D are generally ignored or addressed superficially by most life-cycle studies. There are a few international studies related to the life-cycle energy studies related to T&D systems, including Dethlefsen et al.,[84] who examines the T&D system in Sweden and Uchiyama[85] who examines T&D in Japan. In both of these studies, the analysis of T&D is a relatively minor part, with little details regarding methods or comprehensive results.

There are a number of life-cycle studies on individual T&D system components. The results of many of these studies were incorporated into this work to develop system-wide analysis. Examples of component studies include a comparative LCA on transformer insulators performed by Sakai and Hoshino[86] Preisegger et al.[87] who found net environmental benefits of sulfur hexaflouride compared to other insulating materials. Studies by Kunniger and Richter[88] and Erlandsson and Edlund[89] found wood to be superior to other materials in terms of energy usage and GHG emissions for utility power poles. This study also used previous life-cycle studies of transformers performed by the Green Design Initiative.[90]

1.3.5 Environmental Analysis of Integrated Renewable Energy/Storage Systems

A very large number of studies have been published on the energy and environmental performance of wind turbines. A recent review of results is provided by Lenzena and Munksgaardb.[91] However, no comprehensive environmental performance analysis of a combined wind/CAES or wind/PHS system was found. A number of studies have been published describing the technical and economic performance of combined wind/storage systems.

Sorenson[92] published an analysis in 1976 that found wind/storage systems could produce "baseload" performance from wind energy. Previous evaluation of the technical performance of a combined wind/pumped hydro has been performed by Loewus and Millham[93] and Bollmeier.[94] The use of CAES for wind energy storage has been suggested at least as early as 1990 by Bogdanic and Buden.[95] More recently, Cavallo analyzed the various storage and transmission technologies and concluded that a wind/CAES/HVDC system is the most likely scenario for large scale use of wind energy.[96,97,98] Cavallo models such systems and find such systems can provide high capacity factors and reasonable economic performance compared to conventional systems. Similar analysis has been applied to systems in China by Lew et al.[99] DeCarolis and Keith[100] provides an economic analysis of more modern wind/CAES/HVDC systems considering carbon taxes on fossil sources, and discusses emission reduction benefits of a wind/CAES system. The economic and technical performance of a specific wind/CAES system in Texas has been analyzed by Desai et al.[101] and Desai and Pemberton.[102] None of the above studies performs a comprehensive life-cycle analysis, nor to they provide details results about fuel usage over a variety of operating scenarios.

There is a substantial body of work on the environmental performance of PV systems deployed without storage. Examples include Meier and Kulcinski[103] and Keoleian and Lewis.[104] There are also a number of environmental assessments of integrated PV/Battery systems including work by Alsema,[105] Celik,[106] and Johnson et al.[107] These existing studies evaluate stand-alone systems using lead-acid or nickel cadmium batteries sized to deliver power for off-grid applications. Recent work by Rydh[108] evaluates the performance of PV systems with advanced batteries, but the analysis is based on continuous duty, not peaking duty, which was the primary focus of this study. Existing studies have demonstrated PV/BESS systems to be superior to fossil-based systems, in terms of resource sustainability and GHG emissions, but limited by the energy intensity of the storage system compared to most other non-combustion energy systems. There are a number of studies of the technical or economic performance of PV/battery systems for peaking duties. These studies, include work by Marwali,[109] Chowdhury and Rahman,[110] Borrowy and Salameh,[111] Muselli et al.[112] and Largen et al.[113] were used to estimate the battery size requirements for this work.

1.3.6 Environmental and Policy Assessment of Fossil/Storage Systems

A review of literature found that most policy and legal concerns related to future energy storage systems involve unique aspects of individual technologies. Examples include a discussion of potential impacts of magnetic fields from the use of superconducting magnetic energy storage by Wolsky,[114] and a discussion by Moy[115] of the legal concerns related to hazards associated with the use hydrogen gas for energy storage.

Most research appears to overlook potential negative air emissions consequences of utility scale energy storage used with existing sources. For example, Gallob[116] and Baumann[117] discuss the potential environmental benefits of using SMES energy storage, focusing mainly on increased utilization and efficiency of existing plants, and decreasing the need for new plants. There are a number of studies that directly or indirectly analyze the use of environmental impacts of energy storage, including CAES, with fossil plants, including Bradshaw and Brewer[118] and Lee and Hall.[119] However, these studies generally do not compare the use of storage with older, dirtier plants, with the constructing newer, cleaner plants. These studies also do not consider the compatibility of increasing output at older plants with existing clean air regulations. This area of study is particularly suited to a more comprehensive, interdisciplinary approach, which combines a technical analysis of existing generation, with a legal and policy analysis of the intent and goals of existing U.S. clean air legislation.

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2. The Need for Renewable Energy Enabling Technologies

Two general categories of renewable energy enabling technologies are analyzed in this work: energy storage and long distance transmission. A study of these technologies is motivated by the limitations of generating electric power with intermittent solar and wind resources.

This chapter presents a basic analysis of the limitations of intermittent energy sources without the use of energy storage and increased transmission. It also provides a discussion of how renewable enabling technologies can provide economic benefits to traditional generation sources. The result of this analysis demonstrates the high level of motivation that exists for the development and use of energy storage and long distance transmission in the U.S.

2.1 The Limitations of Wind Energy without Energy Storage

It is often quoted that wind energy can provide up to 10-20% of a system's demand. Beyond this point, it is hypothesized, wind energy becomes too expensive due to the problems imposed by wind intermittency. The question of how much wind energy can be integrated into an electric power system is economic as much as technical. As the use of wind energy increases its value drops, or its cost rises, depending on one's perspective. The origin of the 10-20% value is unclear, but it appears to hold up reasonably well as a *rough* estimate of the potential role of wind energy.

The purpose of this section is to provide an overview of the technical issues associated with the use of wind energy, and provide a basic economic analysis of the cost of wind energy integration. Wind energy systems must be effectively integrated into the existing power system, which is fundamentally based on providing instantaneous response to electric demand. Wind energy can be described as a source of negative demand, which is highly variable, largely uncontrollable, and somewhat unpredictable. The use of wind energy introduces additional variation in normal electricity demand patterns. When a relatively small amount of wind is added to an electric power system, this variation can be accommodated by utilities, just as normal changes in demand are accommodated. As the use of wind energy increases, its output variations add additional technical and economic burdens on the system. Energy storage is an effective method of dealing with intermittency, and allows greater use of wind energy than would otherwise be possible. To determine the limits of wind energy without storage, and the potential benefits of energy storage, the economic effects of wind energy on electric power systems must be evaluated.

2.1.1 Operation of Conventional Electric Power Systems

Electric power systems must respond to the instantaneous consumer demand, which constantly varies as a function of time of day and season, depending on the requirements for heat, light, and other services provided by electricity. Instantaneous electricity demand is dominated by the daily demand cycle, illustrated by Figure 2.1, a set of four weekly demand curves in the year 2001 for the service territory of Madison Gas and Electric (MGE), a regulated utility located in Madison, Wisconsin. The plots are smoothed curves based on average demand in one-hour increments. Each of the four plots begins on a Monday, and there is a noticeable drop in demand during the weekends. Figure 2.1 also demonstrates the seasonal variation in demand, driven by heating, cooling, and lighting. The peak demand is driven by air conditioning requirements in late afternoons on hot summer days. Minimum demand generally occurs in the spring, when heating and cooling loads are at a minimum.

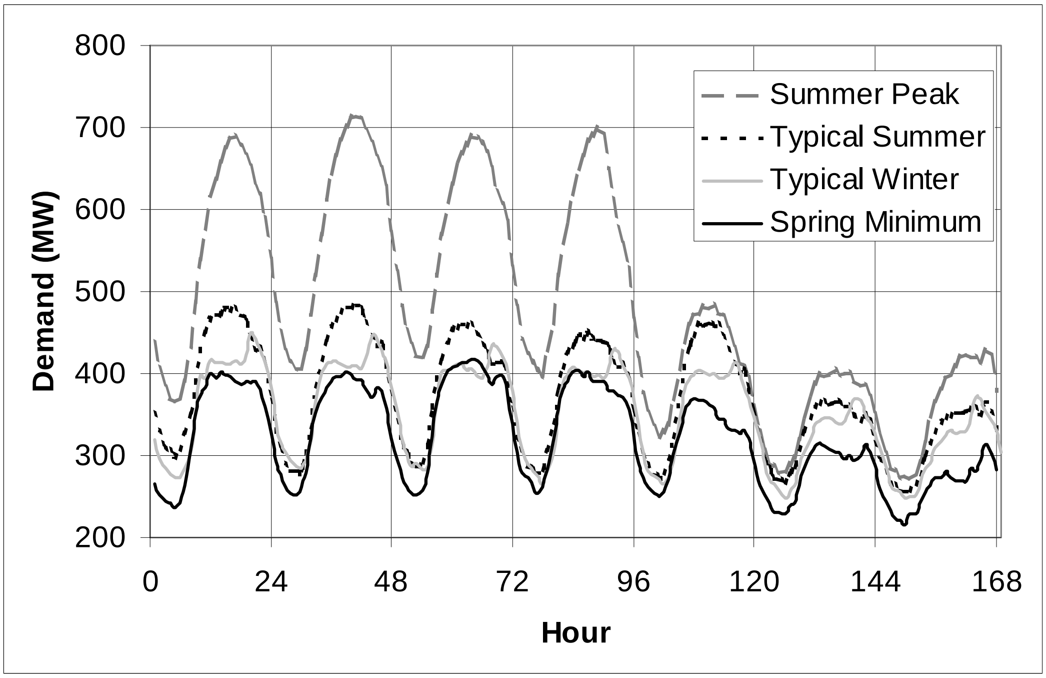

Figure 2.1: Weekly Load Patterns for Madison Gas and Electric (2001 data)[1]

There are a number of important features on this graph that heavily influence the manner in which utilities construct and operate electric generation facilities, including wind. The most obvious is the presence of large, rapid swings in power output on a daily basis, typically equal to 30% to 40% of the peak load. However, these swings are also very predictable. Utilities can accurately predict demand on a day-ahead and hour-ahead basis, using historical records, weather forecasts and a variety of modeling techniques that have been updated and refined over the many decades of regulated electric utility service.[2] This predictability is used to dispatch various power plants in a "merit order" based on the marginal cost of producing electricity.

The economic planning and dispatch requirements of an electric power system can also be examined using a load duration curve, provided in Figure 2.2. A load duration curve is created by re-ordering the hourly demand data from greatest to least demand for all 8760 hours in a year. The integration of this curve provides the total energy demand. This shape of this curve can influence the maximum economic utilization of wind energy in an electric power system.

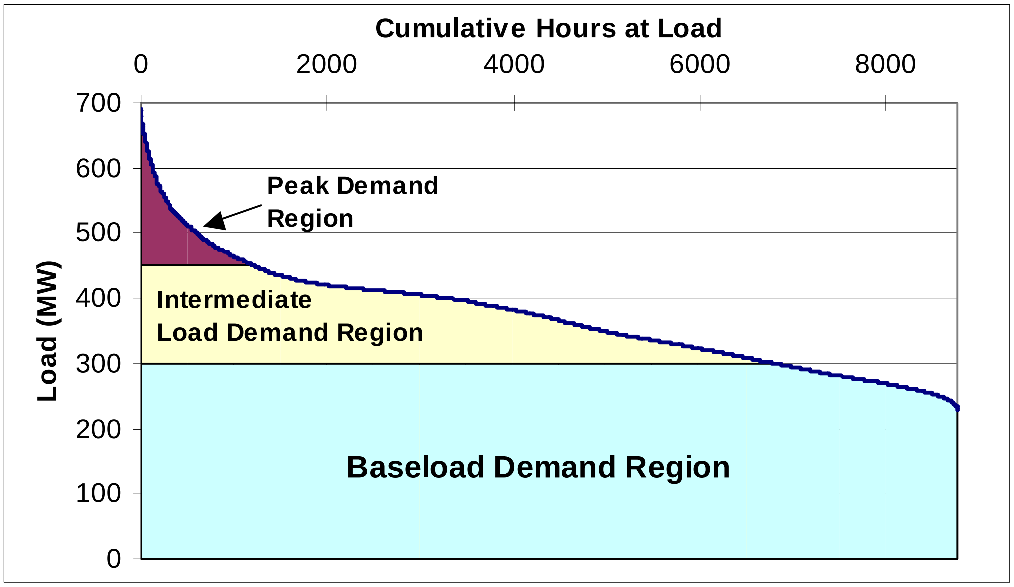

Figure 2.2: Load Duration Curve for MGE (2002)[3]

While Figure 2.2 is for a specific utility, the shape of load duration curves for the U.S. are quite similar from region to region. For planning purposes, there are three loosely defined regions on this curve: baseload, intermediate load, and peaking.

A baseload plant is one that either remains at constant output, or varies its load by a relatively small amount. A large fraction of a system's energy can be met with baseload power plants, as illustrated by the MGE load duration curve in Figure 2.2. In the year 2002, MGE sold a total of 3.26 TWh of electrical energy. The minimum demand of 228 MW occurred on May 6 at 6:00

am. A power plant that produced a constant 228 MW over the year would produce a total of 2.00 TWh, or 61% of MGE's total demand. This means that despite the tremendous variations in load, a plant that does not or cannot vary load could meet well over half of MGE's electricity supply. An analysis of 7 utility systems in the U.S., including large utility areas in California, Texas, New England, Pennsylvania, Wisconsin, and Minnesota found that about 60% of total demand could be met with plants that do not cycle.[4] An even greater fraction of the total demand is met by plants whose output is almost always constant. For MGE, 65% of the load is met by plants whose output can remain constant for 99% of the time.

Baseload plants are used to "fill" most of the bottom half of the load duration curve because they have characteristics that are suited for continuous operation with low operation costs. Intermediate load plants are typically used to fill the daily demand "bump" in the mid-day, illustrated in Figure 2.1. Peaking plants primarily provide energy during the summer peak, and may operate for only a few hundred hours per year.

Using these basic characteristics of electricity supply and demand, including the hourly load data used to create Figure 2.2, an evaluation of the economic limitations of wind energy without storage can be performed. Sections 2.1.2-2.1.5 describe several progressively more advanced economic models that examine the economic advantages of using energy storage with wind energy generation.

2.1.2 Wind Energy in an Ideal Electric Power System

An electric power system that consists entirely of generators that could quickly respond to rapid fluctuations in demand with no cost penalties would be ideal for the use of wind energy. In such a system, the production cost of wind energy generation would simply be a function of capital and operating costs, expressed in a simplified form (excluding taxes) by equation 2.1.

$$\text{Cost (\$/MWh)} = \left(\frac{\text{ICC} \bullet \text{CCR}}{8766 \bullet \text{CF}} \right) + \text{O \& M} \tag{2.1}$$

The first term in equation 2.1 is the capital, or fixed cost per delivered MWh, where ICC is the installed capital cost ($/MW), CCR is the annual capital charge rate (%/yr), CF is the annual average capacity factor, and 8766 is the average number of hours in a year. The remaining term is the operating, or variable cost components, which is expressed as a single operation and maintenance (O&M), term expressed in $/MWh electricity produced. For fossil or nuclear plant, the variable cost in equation 2.1 would include the cost of fuel.

A limitation in the economic use of all generation plants is their capacity factor. Capacity factor is defined as the actual annual energy production divided by the annual energy production if the plant ran at full power at all times. Capacity factor is limited by two separate factors: availability and demand.

Availability reflects the fact that any piece of machinery must occasionally be stopped for a variety of reasons including maintenance, repair, and refueling. The availability factor describes the fraction of time a plant is available to produce power, and may be as high as 90-95% for a fossil or nuclear plant, and even slightly higher for a modern wind turbine. However, for a wind turbine there is the additional aspect of fuel (wind) availability. As a result, the average capacity factor of a wind turbine is much lower, depending on wind resources. Capacity factors for wind turbines range from close to 0% in places with very poor wind resources, to 45% in areas with excellent wind resources. Wind turbines considered economic generally are sited in areas that produce capacity factors from 25-40%.

The net capacity factor of a plant may be reduced by insufficient demand. Figure 2.2 illustrates the fact that at any given time, a large fraction of a generator fleet is sitting idle. As a capacity factor of any generator drops, the resulting cost of electricity increases, because the fixed capital costs are divided over a smaller amount of electricity actually sold. This limitation applies to any type of generator, including wind turbines.

Returning to the example of an "ideal" electric power system, with its ability to vary output without limitations, MGE could hypothetically construct 228 MW of wind energy generation, which at an average capacity factor of 33% would provide about 20% of the total energy supplied in this system. The cost of electricity from this system would be about 4.6 cents/kWh, using representative values of $1000/kW for total installed capital cost, a 12% annual capital charge rate, an average annual capacity factor (CF) of 33%, and O&M cost of $5/MWh.[5] If more than 228 MW of wind energy generation is constructed, there is a probability that wind energy would be produced when there is no demand (assuming no increase in minimum demand.) This excess energy must either be exported or curtailed (wind turbines must be shut down temporarily.) If it is assumed that the utility cannot sell this excess wind energy (which is not entirely unreasonable for reasons addressed in section 2.2.1.), then the energy must be "spilled," which decreases the overall capacity factor of the wind energy system.

The effect of spilled energy can be incorporated into equation 2.1 by including a spill rate term SR, representing the fraction of wind energy which is effectively unused.

$$\text{Wind Energy Production Cost (\$/MWh)} = \left(\frac{\text{ICC} \bullet \text{CCR}}{8766 \bullet \text{CF} \bullet (1\text{-SR})} \right) + \text{O \& M} \qquad (2.2)$$

The net capacity factor of the curtailed wind system is now equal to $\text{CF} \bullet (1\text{-SR})$ which is always less than the maximum theoretical capacity factor if any wind energy is spilled. The resulting cost is illustrated in Figure 2.3, which demonstrates the marginal production cost of wind energy as a function of spill rate for a hypothetical wind farm, using the cost data used earlier in this section. The values used are representative of a modern, Midwestern windfarm, but are not intended to be definitive.

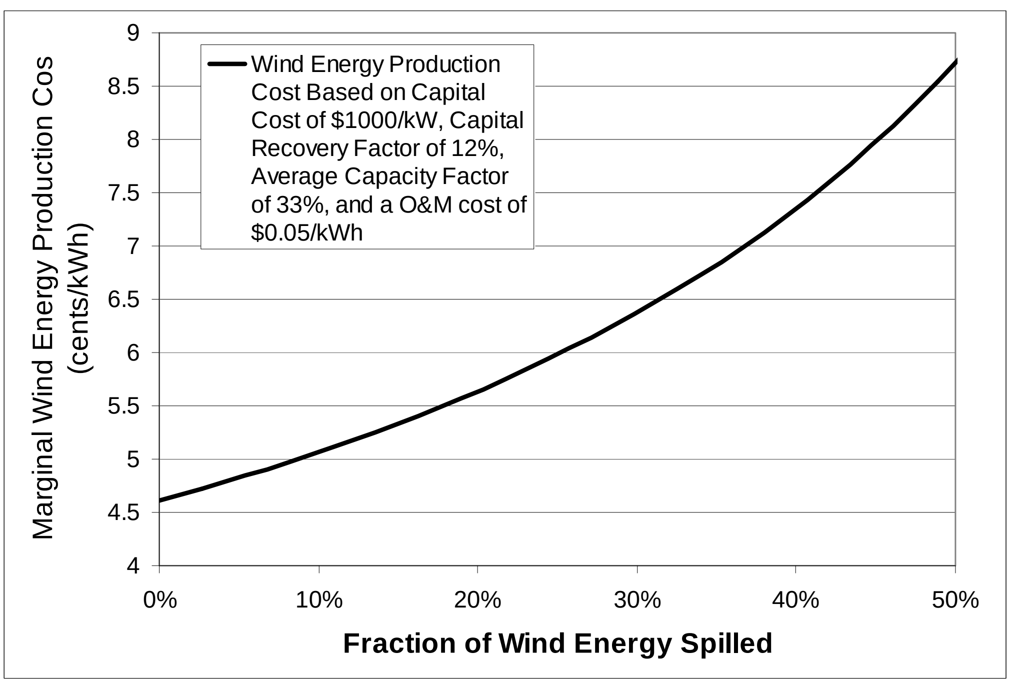

Figure 2.3: Wind Energy Production Costs as a Function of Annual Spill Rate

As wind energy capacity is constructed beyond the point of the minimum demand of an electric power system, the spill rate and average production cost increase, due to the effective decrease in capacity factor.

The spill rate that would occur in an ideal system can be estimated by comparing wind generation data to load data. An Excel spreadsheet model was developed which superimposed actual hourly wind energy production from a wind farm located in the Midwest[6] on the MGE hourly demand data for 2002. In this model, the size of the wind farm was scaled to provide differing levels of supply. At each hour in time, the model compares demand to wind production, and any energy that cannot be used is recorded as "spilled" energy. The model calculates the spill rate by summing the total amount of energy spilled, and dividing this value by the total wind energy produced. The average capacity factor of the wind farm for this model was 34%, which can be compared to wind turbines in western Wisconsin that produce energy with a CF of about 25%[7], or turbines in western Minnesota that produce a annual CF of about 35%.[8] An entire year's worth of data was used to account for seasonal variations in demand and wind energy production.

Figure 2.4 shows the results of one possible scenario over a two-week period. In this case, wind energy capacity of 418 MW is annually providing about 35% of the system's total energy. The area under the lighter shaded curve represents the total energy demand, while the solid dark line is wind energy production. On four occasions in this two-week period, the wind energy supply exceeds demand by as much as 150MW, and will need to be curtailed (spilled.) The dark shaded area is this spilled energy, which is wind energy that the utility cannot sell, and as a result, raises the average cost of the wind energy it can sell.

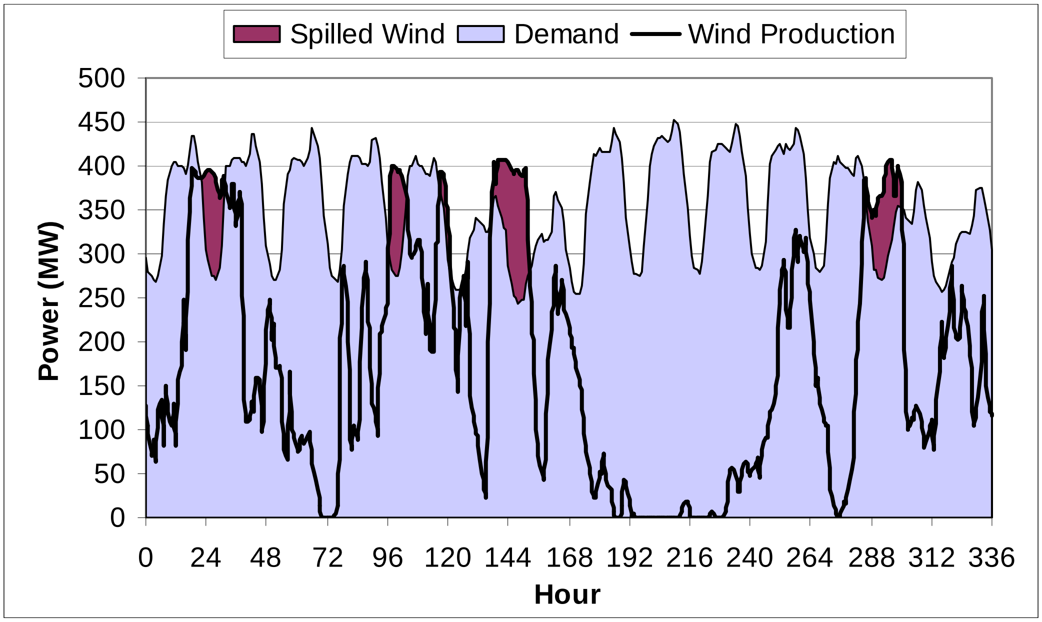

Figure 2.4: Wind Energy Production Superimposed on a MGE Hourly Load Data for a Two-Week Period

As the wind energy capacity is increased, a greater fraction of the system's energy will be provided by wind, but more wind energy will be spilled, increasing the average cost. Using the annual spill rates determined by the model illustrated in Figure 2.4, the cost of wind energy can be calculated using equation 2.2. Figure 2.5 illustrates the results of combing the spill rate data with the cost curve in Figure 2.3

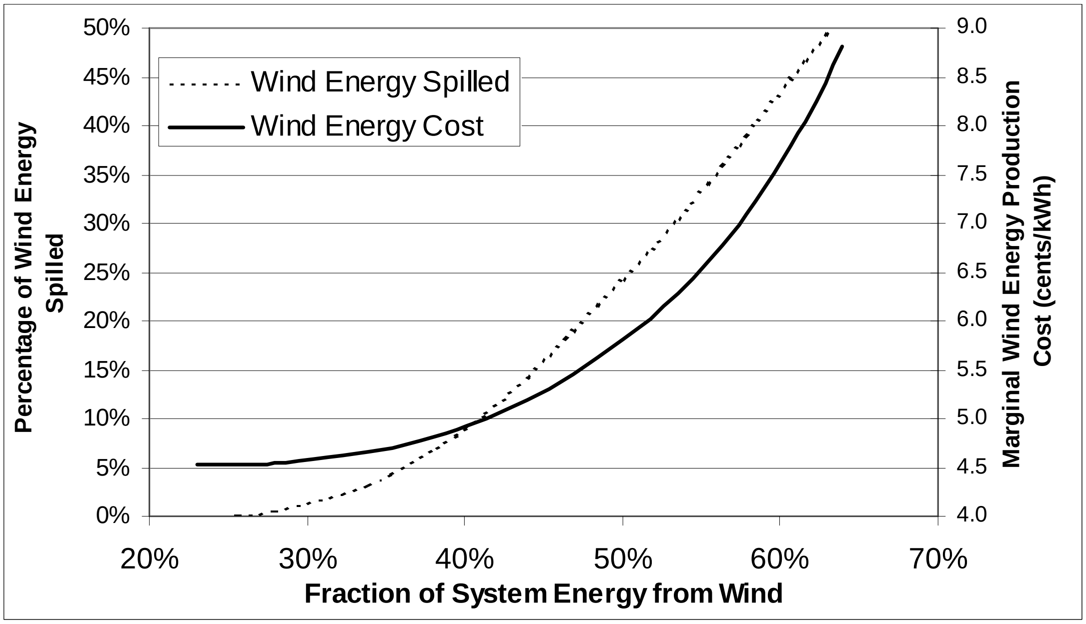

Figure 2.5: Spill Rate and Production Cost as a Function of Wind Energy Contribution for the Ideal System

The wind energy cost curve in Figure 2.5 is the marginal cost, or cost of the next additional amount of wind energy introduced into the system. In this figure, the cost of wind is constant, at about 4.5 cents/kWh to the point where wind provides 25% of the total demand. Beyond this contribution, additional wind energy has higher costs. At some point, the cost of wind energy will exceed an acceptable price to a utility or consumer, and alternative generation will be deployed. One alternative generation source would be the combination of wind energy and storage. With storage, less of the wind generation will be spilled, which will reduce the cost of wind energy at higher contribution. However, storage adds both capital costs and losses due to storage inefficiencies. As a result, the cost of wind with storage will be higher than wind without storage, at least at low penetration of wind energy. These issues are discussed in more detail in Chapter 6. One estimate for the effective "adder" resulting from the use of storage is about 1.5 – 2.0 cents/kWh.[9] The combination of wind and storage provides an alternative to wind without storage, or alternative sources. In Figure 2.5, the cost of wind at low contribution is 4.5 cents/kWh, and if the storage “adder” is 2.0 cents/kWh, then the combined wind storage cost would be about 6.5 cents/kWh. This value represents the “breakeven point” at which wind with storage becomes more economic than simply increasing the use of wind without storage. If the goal is to economically maximize the use of wind energy, then storage becomes necessary when the incremental cost of wind without storage is greater than the cost of wind energy with storage, or when the “spill cost penalty” exceeds the “storage cost penalty.” In Figure 2.5, wind energy can deliver more than 50% of the system’s energy before storage becomes the most cost effective method of further increasing the share of wind energy.

While this model provides a start in understanding the limitations of wind energy use, there are several other factors to consider. Among the more important of these is the existence of “must run” baseload generators in conventional electric power systems, which is addressed in section 2.1.3.

2.1.3 Wind Energy in an Electric Power System with Baseload Capacity

Returning to the load duration curve in Figure 2.2, it is important to recognize that an electric utility attempts to meet electricity demand at all times at the least cost. It does so by constructing and operating power plants with characteristics that best match the variation in demand. As discussed in section 2.1.1, utilities can rely on a very large fraction of their energy to be delivered by power plants that do not need to substantially vary load, and they plan and build around this fact.

In the Midwest, baseload demand is met almost exclusively with nuclear and coal-fired units. Nuclear units are held at constant output because their operational cost is very low relative to the cost of cycling the units. Nuclear plants are also limited in their generation ramp rate, so utilities do not risk turning down nuclear units if there is a high probability that demand may suddenly increase. A nuclear power plant cannot simply spill excess energy, and to indicate the relative cost of cycling, it can be noted that plant operators have actually sold electricity at negative prices during periods of very low demand rather than reduce the power output of the plant.[10] As a result, it is extremely unlikely that a nuclear unit of any type currently used or licensed for use in the U.S. would ever be used to respond to variations in wind energy production.

Baseload coal units are more flexible, and generally have the ability to cycle to respond to energy demand. However, in all cases, operators of baseload coal plants avoid reducing their output to below minimum operational levels, typically around 50% of full output.[11] These units have low operational cost while running, but high costs associated with startup and shutdown, so utilities charge very low rates for power during periods of low demand to avoid the substantial economic penalties associated with shutting these units down.[12]

The existence and use of baseload power plants reduces the amount of wind energy that can be economically integrated into electric power systems. These baseload plants eliminate much of the bottom half of the load duration curve from use by wind energy. Much of the area under the curve in Figure 2.2 is effectively “filled” by must-run units, whose output cannot fall below a certain amount without incurring substantial operational and economic penalties. The fraction of the baseload demand met by must-run units depends on the utility and generation mix. For MGE, this situation might be fairly flexible. Baseload is met by a pair of 125 MW coal boilers, which could be reduced to a minimum combined output of around 125 MW total, or about 50% of their maximum output. Utilities with a large fraction of nuclear generation have less ability to reduce minimum output, which decreases system flexibility and ability to incorporate wind generation.

This limitation was incorporated into the spreadsheet model, by removing a fraction of the baseload demand to which wind energy can contribute. Figure 2.6 illustrates a hypothetical case, similar to Figure 2.4, including the constraints of must-run baseload units.

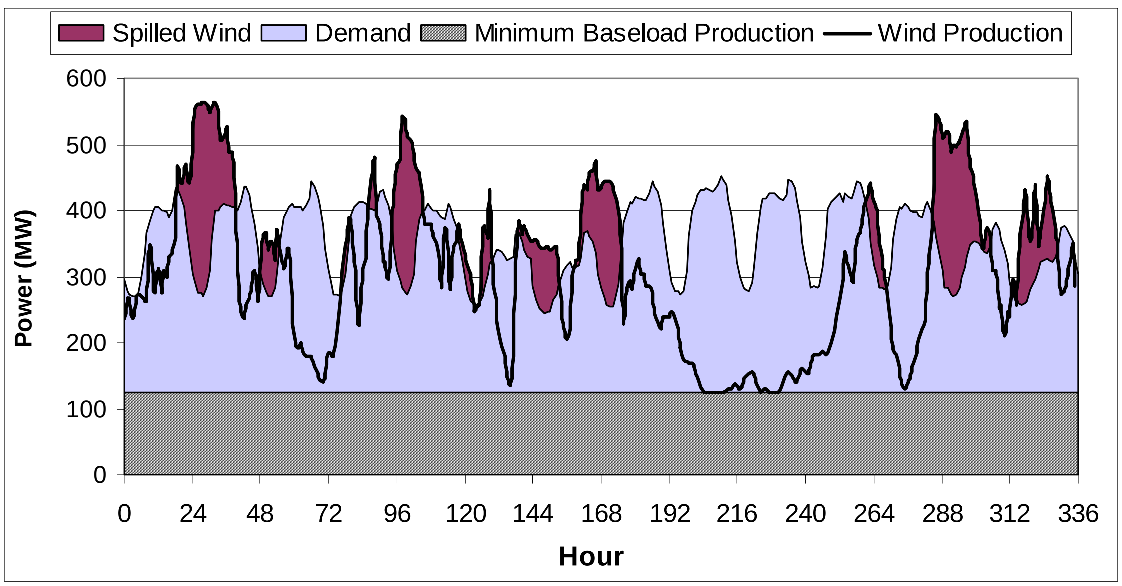

Figure 2.6: Wind Energy Production Superimposed on a MGE Hourly Load Data for a Two-Week Period Considering Production from "Must-Run" Baseload Plants

In Figure 2.6, the wind energy production curve is shifted upwards (so that actual wind production is less than on the illustrated curve by an amount equal to minimum baseload production.) In this case, meeting 35% of system demand with wind increases the spill rate substantially compared to the scenario in Figure 2.4. This increased spill rate can then be used to calculate the production cost of wind energy using equation 2.2.

The spill rate is determined in the same manner as before, but the model has a new input parameter: the minimum baseload production, which varies depending on system generation characteristics. Two systems were simulated in this work. The first is a more flexible system, such as the MGE example with minimum baseload supply of 125 MW, which means the generation system can be turned down to about 55% of the minimum yearly demand of 228 MW. The second system represents a less flexible system, which might include some nuclear capacity, where the system could be turned down to 200MW, or about 90% of minimum demand.

In addition to including must-run baseload units, this second scenario incorporated additional wind capacity from a second site. Combining wind production data from two sites increases spatial diversity and more realistically simulates a likely supply of wind generation. The first data set is identical to the one used in the MGE example in section 2.1.2. The second data set uses an average capacity factor of 38%, which could be expected from wind farms in many parts of Minnesota, Iowa, or perhaps offshore in Lake Michigan.

Figure 2.7 illustrates the results of this analysis. The initial cost of wind energy is slightly lower at about 4.3 cents/kWh. However, with so much baseload capacity “off limits,” wind energy generation costs increase more rapidly than in Figure 2.5. In this case, the marginal cost of wind energy increases by 2 cents/kWh when wind is providing less than 40% of the systems total supply. As with the previous model, it is assumed that all of this system’s remaining generation capacity is capable of responding to wind energy variation completely, and without additional costs.

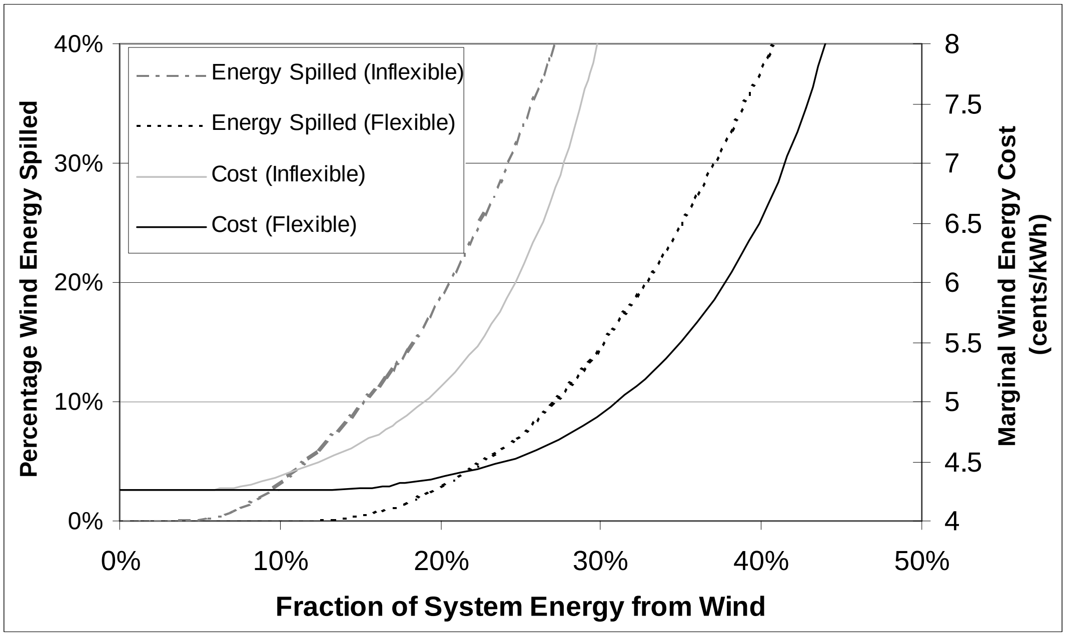

Figure 2.7: Wind Energy Spill Rate and Production Cost as a Function of Wind Energy Use in Flexible and Inflexible Power Systems

2.1.4 Additional Integration Costs Due to Intermittency

A significant weakness in both of the simple models described in sections 2.1.2 and 2.1.3 is that they do not account for additional costs that occur from responding to highly variable wind output. In these models, all power plants are allowed to cycle in response to variations in wind supply without additional costs. In reality, the uncontrollable supply of intermittent wind energy effectively creates additional variations in system demand, which increases system operation costs.

The increased cyclical loading that intermittent wind sources create can be observed by superimposing wind generation data on hourly load data. Figures 2.8 and 2.9 show ten-day hourly load curves with and without an amount of wind energy sufficient to supply 15% of the total demand. The dark curve is the normal system demand (load) without wind. The lighter curve represents the effective system demand (load) with wind. In this case, wind energy is considered a source of negative demand, since it is not a controllable source of supply. These curves represent the remaining amount of energy that must be delivered by load following capacity.

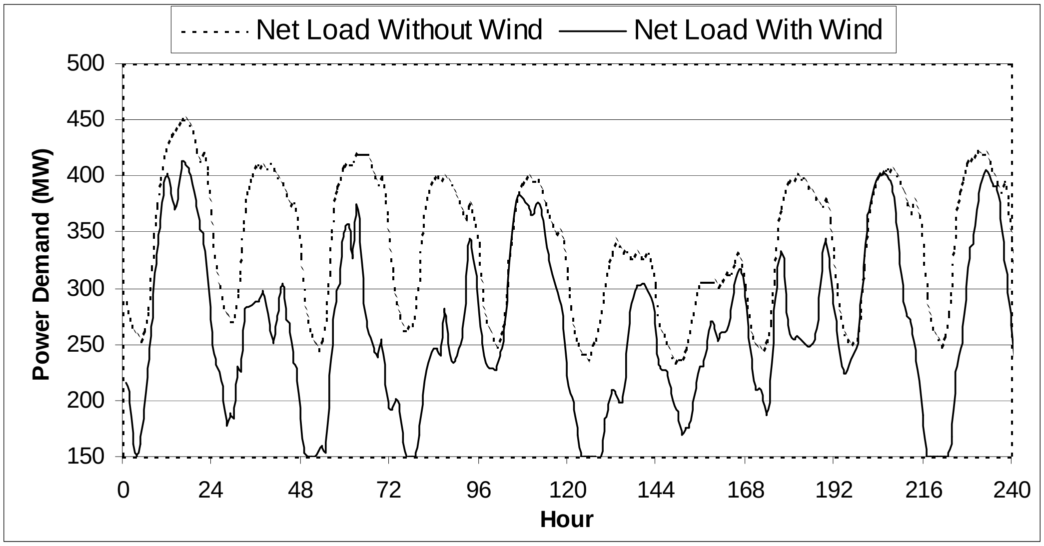

Figure 2.8: Simulated Hourly Load With and Without Wind Energy (Spring 2002)

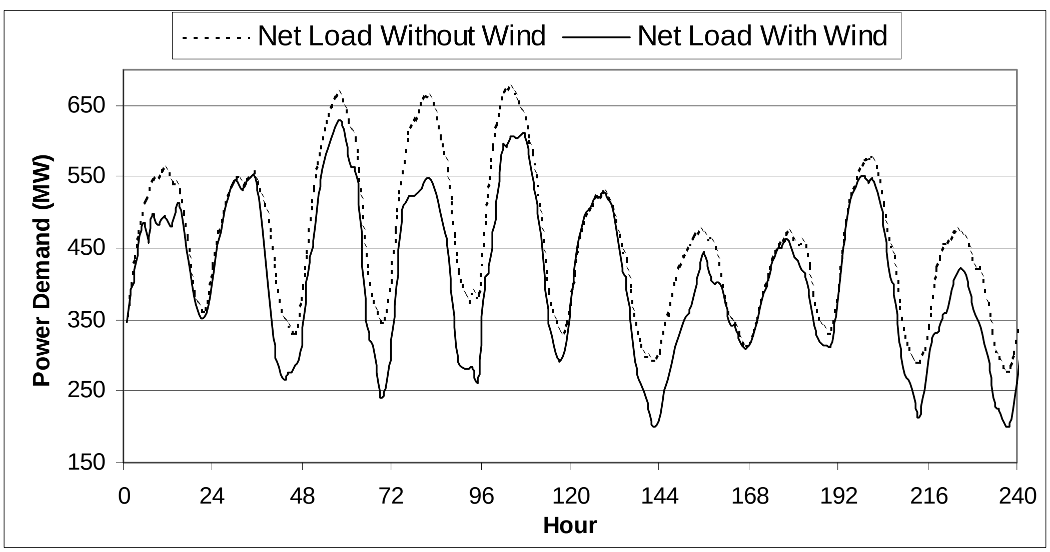

Figure 2.9: Simulated Hourly Load with and without Wind Energy (Summer 2002)

A number of features that are observable both qualitatively and quantitatively in these figures result in increased operating costs. First, the use of wind energy increases the short-term variability of the net load, and the required ramp rate of system generators. While utilities are almost always adjusting their power output, ramping does result in added costs, and utilities would like to minimize variations in load as much as possible. In the case illustrated by Figures 2.8 and 2.9, the average ramp rate increases about 12% from 7.4 MW/hour without wind to 8.3 MW/hour with wind. In addition, fluctuations in wind energy increase the number of times the system passes through 0 in terms of generator ramping (generally from increasing load to decreasing load or vice versa). The number of “zero crossings” increases roughly 17% from 5/day without wind to 5.7/day with wind. Finally, the fluctuations in wind energy produce a greater number of startup and shutdowns of intermediate load and peaking power plants. Each additional startup cycle incurs additional fuel costs, and increased O&M costs.

The use of wind energy at the level illustrated in this case also decreases the overall predictability of the total system load, which may result in increased operational costs. The variation of daily system demand without wind is typically quite predictable, and utilities generally know well in advance when individual generators will be needed. Utilities schedule generators and certain power purchase contracts on a day-ahead and hour-ahead basis. The use of wind energy may reduce the short-term and long-term predictability of the system to the point where generators may not be online when needed, or (more likely) generators are kept on when not needed. Utilities also may be unable to effectively schedule wholesale power transactions. The potential impact of predictability is striking in Figure 2.10. In this figure, wind generation substantially reduces demand on day 3 (hours 48-72), and greatly reduces the need for firm, load following capacity. On the very next day, however, limited wind output results in the need for nearly all of the conventional (non-wind) generation capacity.

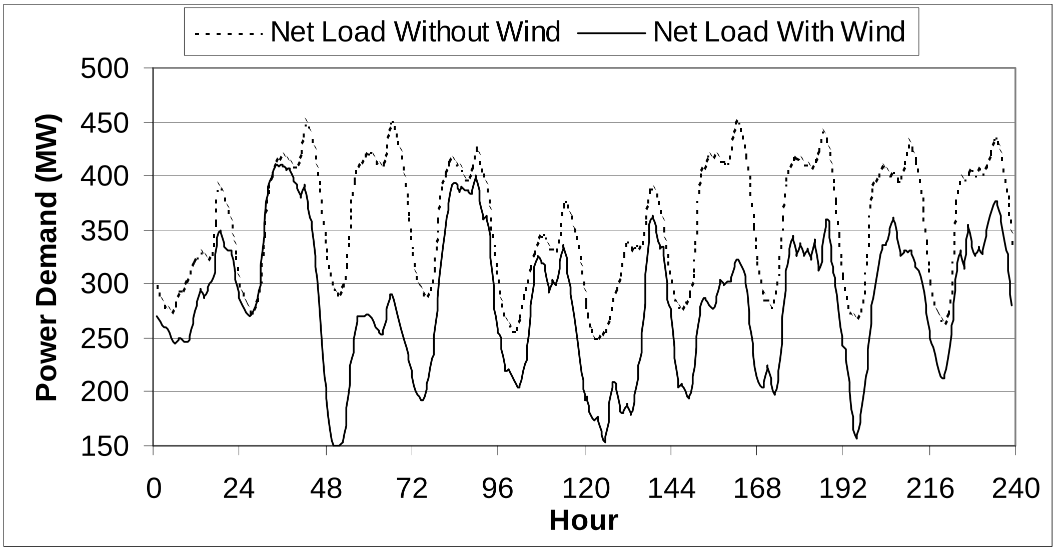

Figure 2.10: Simulated Hourly Load With and Without Wind Energy (Winter 2002)

A number of techniques have been developed to predict the availability of wind generation, which reduces the penalty associated with unpredictability. However, no forecast is 100% accurate, and studies have found wind forecasting errors can incur increased costs for utilities that use a substantial amount of wind in their generation portfolio.[13]

If the costs associated with increased ramping, plant start-up, and predictability can be quantified, they can be added to the "curtailment costs" evaluated in section 2.1.4. The combination of these costs can improve the wind cost curves generated in Figure 2.7. This would provide a more accurate assessment of the economic conditions necessary for the use of storage with wind energy. However, quantifying the various costs associated with plant ramping and startup requires extensive knowledge of the individual generator characteristics, as well as sophisticated modeling tools. Only recently have utilities and researchers attempted to account for the costs associated with integrating intermittent wind energy.

2.1.5 Utility Studies of Intermittency Costs

Utilities have begun the process of quantifying the operational costs that are incurred when wind energy is added to an electric power system. A review of literature found seven U.S. studies that estimate the incremental cost penalties associated wind energy integration.[14-20] Each study evaluates one or more of the three general categories of operational impacts of wind energy: short term, long term, and reserve requirements. Short term and long term variations are described in section 2.1.4, and include the increased cost of responding to wind energy variation (increased ramping, uncertain unit commitment, limited certainty of market conditions etc.) Reserve requirements consider the additional cost of spinning reserves and standby reserves that are required for sources that cannot be reliably "controlled" such as wind.

Table 2.1 summarizes the results of these studies, providing the fraction of energy provided by wind and the intermittency cost penalty, or "adder" which must be added to the production cost calculated by equation 2.2 to derive the total cost of wind energy. There are several major limitations in applying these results when calculating the intermittency penalty associated with wind energy without storage. First, each study uses different methods and evaluates different operational impacts of wind energy. Second, many of these studies quote wind energy penetration in terms of power capacity, which is the ratio of installed wind capacity to peak power demand. This makes it difficult to determine the actual fraction of the load supplied by wind, which is a more useful measure of the ability of wind energy to provide meaningful contribution to an electric power system. For the cases where the actual energy fraction are not reported, it is assumed that the energy fraction is equal to ½ of the power fraction, which is a reasonable approximation for typical utility load profiles and wind energy capacity factors.

Third, these studies do not address certain additional costs that may occur as a result of wind energy use, such as increased O&M costs from increased plant cycling and efficiency reduction due to non-optimal generator loads. Finally, the fraction of energy provided by wind in these studies is relatively low, with the largest use of wind energy at 12% of total supply.

Table 2.1: Results of Utility Wind Integration Cost Studies

Study	Location	% Peak Capacity	% Total Energy	Cost Adder (cents/kWh)
PJM[14]	East Coast	0.12	0.06*	0.03
Xcel[15]	Minnesota	3.5	1.75*	0.2
Pacificorp[16]	Northwest	20	10*	0.55
BPA[17]	Pacific Northwest	5.9	2.95*	0.18
WE Energies[18]	Eastern Wisconsin	29,15,7	12,6,3	0.29, 0.28, 0.25
CA[19]	California	4	2	0.17
GRE[20]	Minnesota	4.3,16.6	2.4,9.5	0.32, 0.45

*Indicates that % total energy is assumed to be ½ of % peak capacity

The maximum integration cost in Table 2.1 is only about 0.55 cents/kWh, with wind providing about 10% of system energy. The WE Energies study shows a smaller impact, with an integration cost of about 0.29 cents/kWh at 12% of energy supplied by wind. These studies indicate that a 10% energy supply from wind should have a relatively small effect on system costs. For a wind turbine producing electricity at 4.5 cents/kWh, the 0.29 cent and 0.55 cent penalty represents an increase of 6.4% and 12.2% respectively.

Since the goal of this study is to combine the “intermittency penalty cost” evaluated in Table 2.1, with the “curtailment cost” demonstrated in Figure 2.7, the data in table 2.1 must be extrapolated to higher levels of wind energy use. Figure 2.11 provides a plot of integration cost data from table 2.1. Only the WE Energies and Great River Energy studies provide data over a variety of wind deployment scenarios, so these studies provide the only data sets from which cost curves can be generated. Since each of studies employed different models on unique systems, so no single function can be derived from the entire data set.

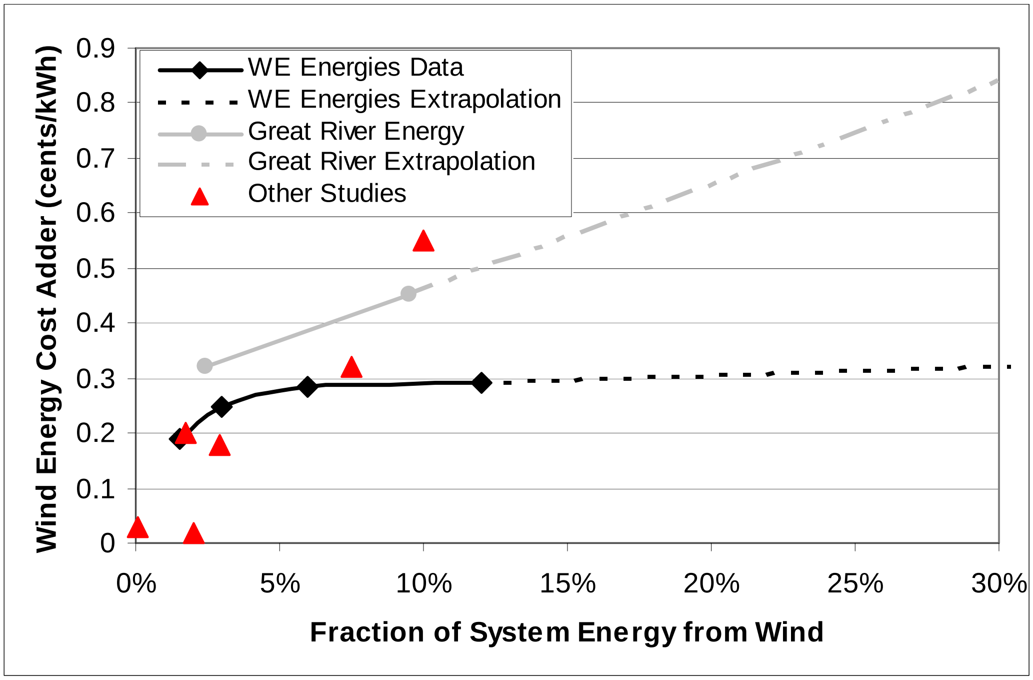

Figure 2.11: Wind Integration Costs as a Function of Wind Energy Provision

The ability to extrapolate the wind cost data in Figure 2.11 is limited by knowledge of individual system characteristics and would require sophisticated modeling tools using proprietary data. (The studies in Table 2.1 were performed by utilities or by contractors with access to utility data.) Without additional knowledge about system characteristics, it is not possible to reliably estimate the shape of the curves beyond the data points at 10-12%. It has been suggested that the curve will begin to rise sharply as the amount of wind energy begins to effect system reliability and stability, but lack of industry experience or extensive modeling makes any plot purely conjectural.[21] For this reason, two curves are projected in Figure 2.11: conservative linear extrapolations of the WE Energies and Great River Energy data.

With these caveats in mind, the total cost of wind energy without energy storage is estimated by adding the intermittency cost values in Figure 2.11 to the wind curtailment costs in Figure 2.6. Figure 2.12 shows the results, based on two scenarios. The first “flexible case” uses the lower cost system data from Figure 2.7 and the lower integration costs estimated by WE Energies. The second “inflexible system” uses higher cost system data from Figure 2.7, and the higher integration costs estimated Great River Energy. These two curves create an envelope of likely marginal wind energy costs, although neither curve is a worst or best case, given the uncertainties and limits of this model.

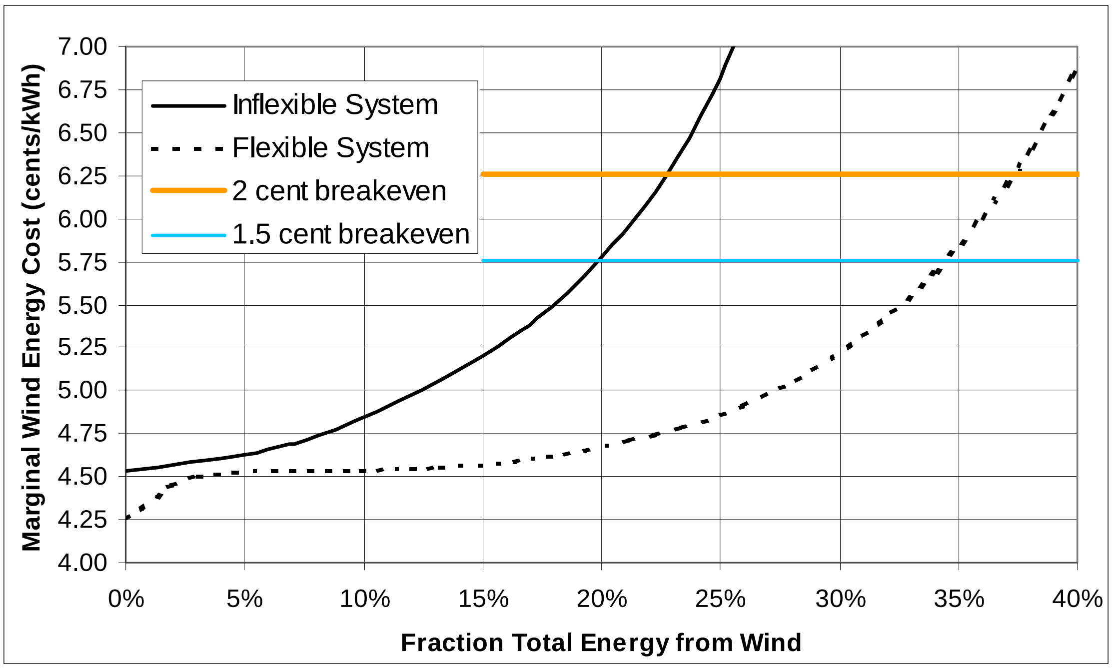

Figure 2.12: Wind Energy Cost as a Function of Energy Penetration

Figure 2.12 provides a measure of the economic impact of wind intermittency when deployed without storage. Unlike traditional energy sources, the cost of adding wind energy to a system depends highly on the nature of the system, reflected in the cost envelope in Figure 2.12. Exact quantification of the cost, or the rate of cost increase depends on many variables, but it is clear that there is a substantial increase in wind energy cost at system penetration as low as 15% of total energy from wind. This rapid rise in cost decreases the economic competitiveness of wind energy, a situation that can be partially mitigated with energy storage. Economic considerations will require the use of energy storage if wind is to provide an amount of electrical energy equal to other generation sources, such as fossil, nuclear, or hydroelectric generation, each of which often contributes greater than 50% of a region's electrical energy demand.

2.2 Wind energy and the Need for Transmission

Long distance transmission is another enabling technology for wind energy. In some cases, transmission may provide an alternative to energy storage to increase the amount of wind energy that can be used in an electric power system. Regional trade of wind energy allows various utilities to increase the overall flexibility of the electric power system, increasing economic use of wind energy even without storage. Transmission also increases spatial diversity of wind energy resources, and greater capacity credit. The most significant use of long distance transmission will likely be in connecting areas with large wind resources to major load centers.

2.2.1 Benefits of Intra-regional Trade Enabled by Transmission

The various models described in section 2.1 all ignore the ability of a region to import and export power as a method of increasing wind energy penetration. Intra-regional trade of energy may allow some regions to increase their use of wind energy. This is particularly beneficial when systems with different technical characteristics can be connected. An example would be connecting a region with large amounts of hydro resources, but poor wind resources, with an area with large amounts of inflexible coal or nuclear generation and good wind resources.

The use of import/export capacity should be examined critically, however, if wind energy is to be deployed on a large scale, and not in isolated regions as it is currently used in the U.S. The use of transmission as a method of addressing intermittency may leads to erroneous conclusions about the ability to wind energy to economically serve load. Denmark is commonly cited as an example of the ability of wind to serve a large fraction of a regions energy supply, with the nation deriving roughly 15% of its electrical energy from wind generation in 2002.[22] This high level of wind energy use is partially enabled by Denmark's large import/export transmission capacity to Germany, Sweden, and Norway. Norway provides particular benefits because its electric power system is based primarily on large scale hydro systems with built-in storage.[23] If this export/import capacity was reduced, this would increase operational burdens on the Danish power system, increasing costs, and possibly requiring energy storage. Export/import transmission capacity can be effectively reduced if surrounding regions derive a large amount of electrical energy from wind power.

2.2.2 Benefits of Increased Spatial Diversity and Capacity Credit

Capacity credit describes the reliability of an electric generator to be able to provide energy on demand. A typical fossil or nuclear generator can be scheduled well in advance to be available when needed. As an example, a fossil generation plant may have a 97% chance of being available when needed, so a 100 MW plant would have a capacity credit of 97 MW. Wind turbines cannot be relied on to have performance anywhere close to this level of reliability. The actual capacity credit that should be applied to wind generation is an active area of research, but many utilities currently assign a very low or zero capacity credit to individual turbines.[24] The use of very low capacity credit for turbines is partially based on a common utility measure of reliability, which is generator availability under peak load conditions, typically hot summer days. Unfortunately, wind turbine generation in many parts of the U.S. is well below average under these conditions, which reinforces current negative attitudes regarding the capacity credit of wind turbines. Utilities regard wind energy almost exclusively as a mechanism to meet renewable portfolio standards, receive tax benefits, or decrease overall fuel consumption and emissions from load-following plants.

A highly developed transmission network could link highly diverse wind energy resources, resulting in decreased intermittency impacts of wind energy and increased capacity credit.[25] Research has demonstrated a non-zero capacity credit for wind generators that are spatially diverse, meaning wind turbines may have the ability to offset traditional baseload generation.[26] If the capacity credit of spatially diverse wind turbines is high enough to offset generation capacity, this could increase wind energy use by effectively shifting the "minimum baseload production" in Figure 2.6 downward. This could effectively increase the economic use of wind energy, even without storage, by decreasing the amount of "must run" capacity required in the system. As a result, transmission provides a potentially more economic alternative to storage in certain circumstances.

2.2.3 Access to Wind Resources Enabled by Transmission

Potentially the most important reason for increased transmission capacity is to provide access to the vast untapped resources of wind energy in the Midwestern U.S. The need for long distance transmission for renewable energy is demonstrated by a map of wind energy resources currently considered economically exploitable, provided in Figure 2.13.

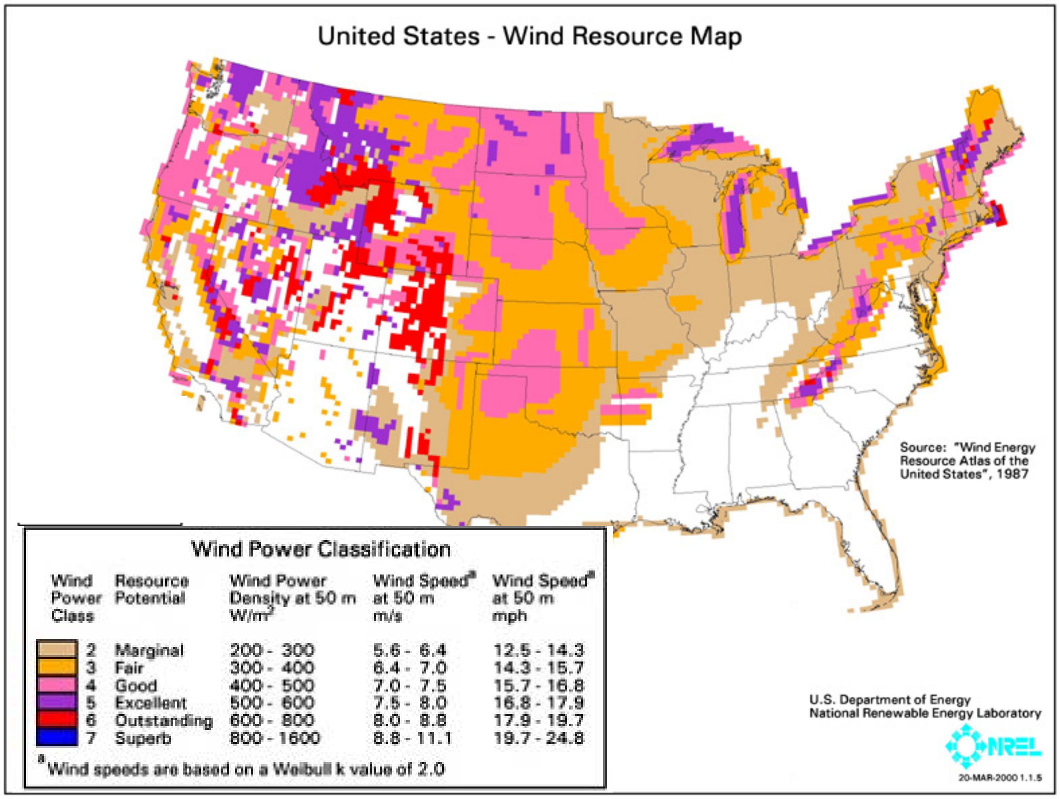

Figure 2.13:Distribution of Economic U.S. Wind Resources [27]

Areas with class 4 or better are the most economically competitive for development of wind energy, but some class 3 resources are being developed. This map shows that the major low-cost wind resources are located in the upper Midwest and Rocky Mountain states. The areas that are most compatible with very large scale wind energy deployment, in terms low population density and limited impact on scenic areas, include northwestern Iowa, western Minnesota, and the Dakotas.

Wind resources in the upper Midwestern U.S. have the theoretical potential to provide most of the entire 2003 U.S. electricity demand, in terms of energy.[28] In 2003, a total of about 1200 MW of wind energy was in operation in the region, which produced only about 0.1% of the nations electricity supply.[29] Unfortunately, this region is extremely constrained in its ability to export power.[30] Significant transmission upgrades will be required if the U.S. is to tap into its significant reserves of wind energy located in the upper Midwest.

2.3 The Need for Enabling Technologies to Achieve National Wind Energy Goals

The basic analysis performed in sections 2.1 and 2.2 can be used to provide a “big picture” viewpoint of possible wind energy utilization in large regions of the U.S., or in the nation as a whole. It is not overly simplistic to claim that wind energy is currently the only renewable energy technology economically competitive with coal and nuclear power, and that renewable energy proponents have placed great expectations upon this technology capturing a significant share of U.S. electricity generation.[31] It is useful then to evaluate the fraction of the nation’s electrical energy that can be met with wind energy with and without enabling technologies.

A simple regional model was developed to evaluate the need for both energy storage, and transmission, in the context of meeting specific national goals for the use of wind energy. The model divides the country into five regions, based on their proximity to areas with good wind resources. Figure 2.14 provides a map of the U.S., divided into these 5 resource regions. Additional details are provided in Appendix A.

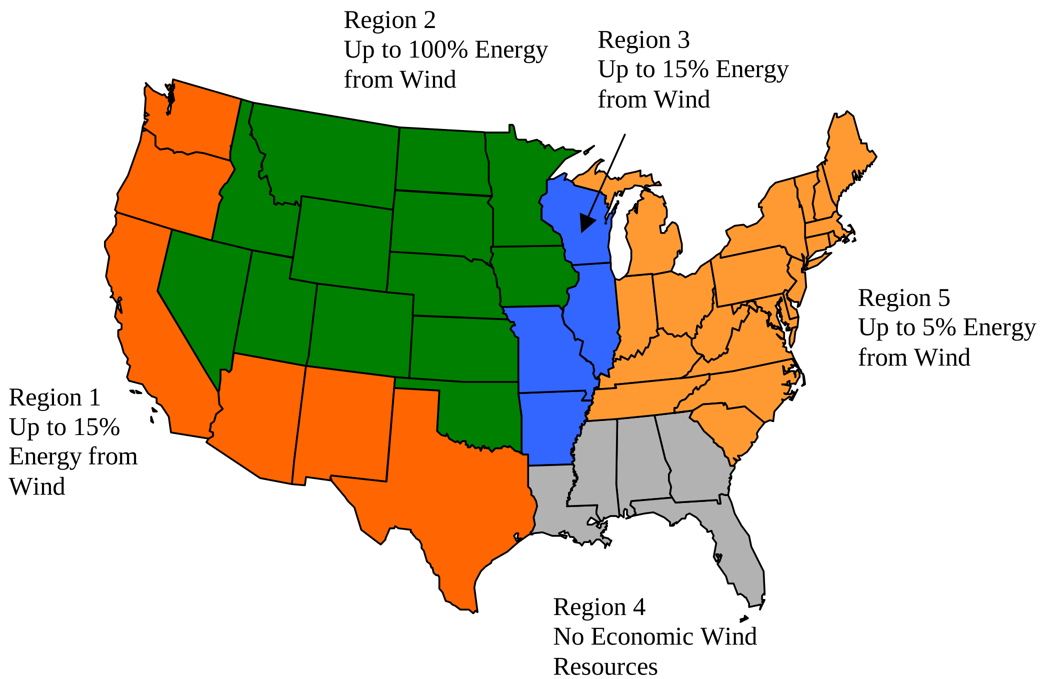

Figure 2.14: Wind Resource Regions Used to Evaluate the Potential Use of Wind Energy in the U.S.

Region 1 includes far western and southwestern states. These states have good wind resources, but in the case of Oregon and Washington, they are located in the eastern part of the states, with little transmission. Texas also has excellent wind resources, but they are concentrated in the western part of the state where there is little population and limited transmission.

Region 2 includes remaining western and many midwestern states. Each of these states has very large wind resources, and in most cases could produce wind energy exceeding their demand.

Region 3 includes four midwestern states with moderate wind energy resources.

Region 4 includes southeastern states with virtually no exploitable wind resources.

Region 5 includes all remaining eastern states. Many of these states have considerable wind energy resources, but it is unclear how much of the actual wind potential can be exploited in these densely populated areas.

This model assumes that all regions except Region 2 are ultimately constrained in their ability to meet electrical energy demand using wind generation due to resource and siting limitations. As a result, achieving a large national wind energy goal may rely on large utilization of wind energy in Region 2. The goal of this model was to determine the fraction of electrical energy supplied by wind in Region 2 necessary to meet a range of possible national wind energy goals. This value can be compared to the amount of energy that can be economically supplied without the use of energy storage.

The model is described by the relationship

$$F_2 = \frac{F_{US}D_{US} - (F_1 D_1 + F_3 D_3 + F_5 D_5)}{D_2} \tag{2.3}$$

where F is the fraction of the regions electricity demand met by wind energy and D is the total annual electrical energy demand in each region in year 2001.[32] This simple model holds demand in each region constant. Subscripts indicate regions where $_{US}$ represents the entire U.S. The values for F_1, F_3, and F_5 are determined by the wind energy resource constraints in each of the three regions, while F_{US} is the desired goal for national wind energy use.

Two scenarios were evaluated. The first “transmission constrained” scenario considers limited transmission system expansion, which limits bulk transfers of power from the Midwest to the eastern states or far western states. In this scenario, each region relies mostly on its own wind energy resources. Figure 2.15 shows the results with three possible curves, representing the “aggressiveness” of wind deployment in Regions 1, 3, and 5. The low wind curve represents 0%

wind energy in Region 5, with 2% in Regions 1 and 3. The medium wind curve represents 2% in Region 5 and 8% in Regions 1 and 3. This number represents a fairly aggressive but possible target, given the limitations on land use, particularly on the east coast. The high wind curve represents 5% wind energy in Region 5 and 15% in Regions 1 and 3.

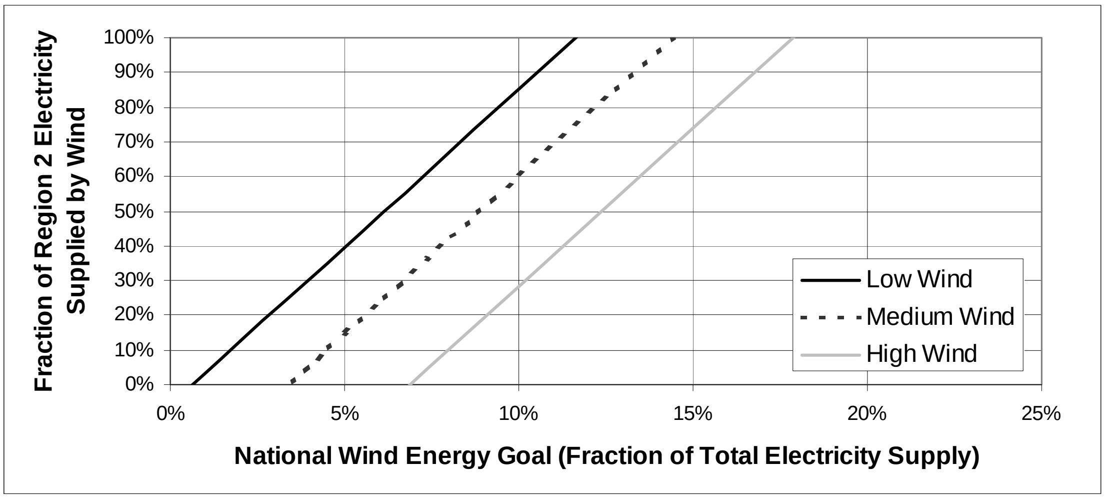

Figure 2.15: Region 2 Wind Requirements to Meet National Wind Energy Goals with Transmission Constraints

In all cases, the values chosen for F in the resource constrained regions are not considered definitive, but represent a fairly reasonable range of values, perhaps generous considering likely opposition to wind siting in scenic and populated areas in the various regions. These values in the high wind case are very aggressive, particularly for the east coast where the 5% target would require about 27,000 MW of wind energy generation, compared to an installed base in 2003 of only about 257 MW. This development would likely require extensive use of offshore wind resources in the Atlantic, as well as controversial deployment in the eastern mountains. An example of the challenges faced in deploying this amount of wind energy is the proposed 420 MW Cape Wind project, planned for Nantucket Sound off the coast of Massachusetts, which faces considerable local opposition.[33] The high wind case would also require substantial transmission expansion, especially in the West and Southwest.

Appendix A provides additional details about the model parameters, which can be used to generate curves for any desired values of F and D for the various regions.

Assuming the medium wind deployment is realistic, achieving a national wind energy goal of 10% would require about 60% of the electricity in Region 2 to be derived from wind, an amount that would require extensive use of energy storage. Even if 100% of the electrical energy in Region 2 was derived from wind energy, wind would not equal nuclear power (about 20% of U.S. energy supply) under the very aggressive “high wind” scenario.

Figure 2.16 considers a second scenario, which substantially increases transmission export capacity out of the high wind regions. It considers a large scale, coordinated building effort, of 10-15 new very high capacity long distance power lines, which could carry energy out of region 2 to major load centers within 1000 km of significant wind energy resources, such as eastern Missouri, Northern Illinois, East Texas, and the Pacific Northwest. These lines could carry up to about 30 GW, equal to the capacity of 30 large baseload power plants. This new transmission capacity is coupled to wind generation using storage, to increase its effective capacity factor to 75%, a value which is based on models developed in Chapter 6. This is an aggressive building plan, considering there are only four such major long distance “export” transmission lines in the U.S., and new transmission lines are difficult to complete due in part to strong local opposition. However, it is assumed that the perceived environmental benefits of these projects, which would deliver an amount of energy equal to about 6% of the 2001 U.S. electricity demand, would allow this scenario to be possible. The curves in Figure 2.16 are based on equation 2.3, but where D_{US}

is reduced by the amount generated by the export capacity. All other resource constraints in this scenario are the same.

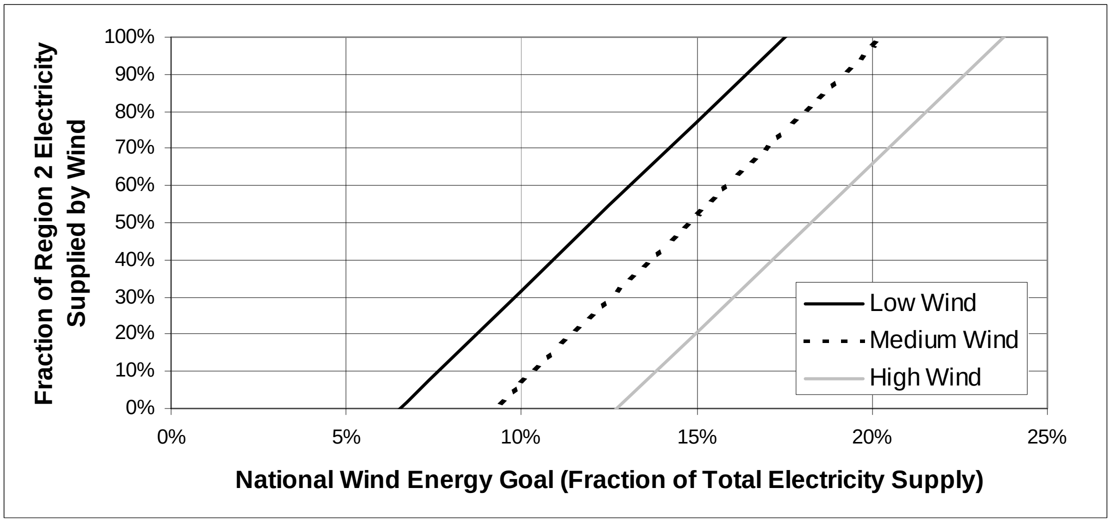

Figure 2.16: Region 2 Wind Requirements to Meet National Wind Energy Goals with New Transmission and Storage Capacity

The increased transmission/storage scenario increases the ability of wind to meet a larger fraction of the U.S. energy supply, although achieving a national share equal to 20% would require more than 60% of the electricity in Region 2 to be produced by wind generation, even in the “high wind” scenario. Regardless of what specific target is desired, it is clear that both energy storage AND new transmission capacity will be required to meet large scale national goals for the deployment of wind energy in the U.S.

2.4 The Benefits of Energy Storage to Solar PV Generated Electricity

Solar photovoltaic (PV) generation has the advantage of being a distributed generation source, generating energy at the point of demand, which potentially reduces the transmission and distribution requirements. Solar PV is also cited as a valuable source of peaking power, with generation occurring when electricity is needed most, and most expensive. A simple analysis demonstrates that for solar PV to be significant in reducing the need for peaking power capacity, storage will be required.

PV generation without storage is limited in its ability to offset traditional peaking power generation for two reasons. First, solar generation peak and electricity demand peak are non-coincident by several hours. Second, solar electricity generation can experience rapid swings in output due to weather phenomenon, such as passing clouds. Distributed PV generation would limit the effects of such events, but a high concentration of solar PV deployed in a relatively compact area could produce relatively large changes in output that would have to be addressed with increased spinning reserves, or energy storage.

The potential benefits of energy storage to PV generation can be observed by comparing PV generation to electricity demand on an hourly basis. A number of PV units have been installed on schools in Madison, Wisconsin, and historical data in 15-minute increments is available on the Internet.[34] Figure 2.17 shows the output from two of these individual PV units, along with the combined total output data from five separate sites. The data is for the first week of July 2002. Each PV unit is rated at about 2 kW at peak output.

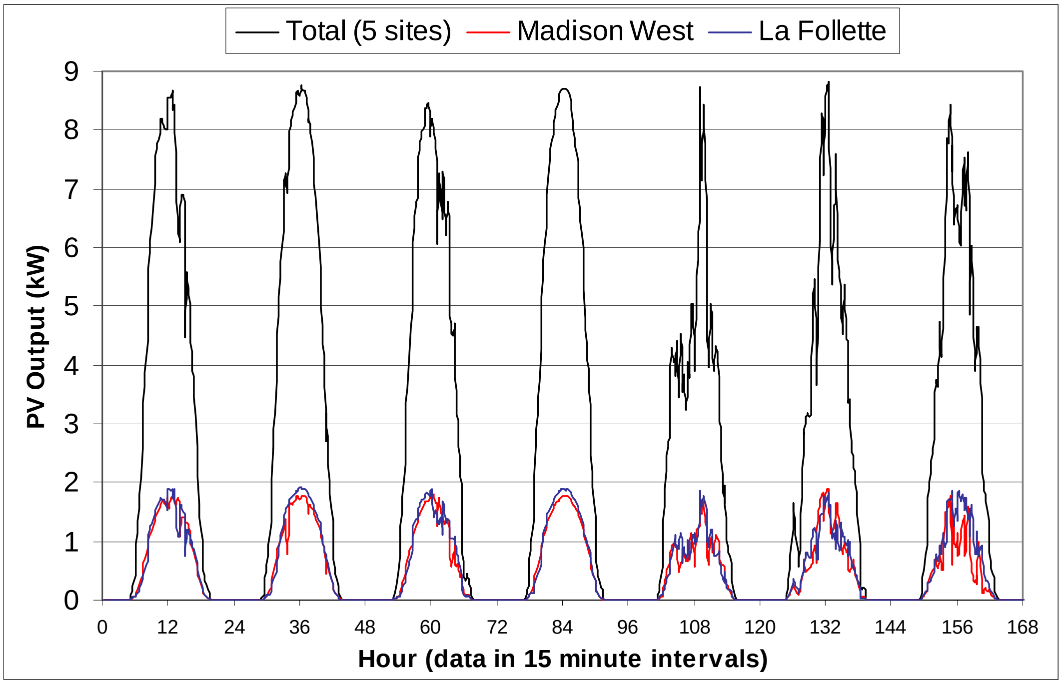

Figure 2.17: Time-Dependant Power Output for Five PV Sites in Madison, WI, July 1-7, 2002

The roughness of the output has been somewhat smoothed by spatial diversity, but there are still substantial variations. During this month, the combined PV output often varied by more than 10% in a 15 minute interval. The five sites are not particularly diverse, with a cluster of three located roughly 6 km from the other two sites. If large amounts of solar PV is concentrated in an area, the large swings in output would need to be addressed with increased operational reserves, which could quickly change output, or energy storage.[35]

Energy storage would also provide benefits in addressing the substantial time difference between peak solar output and load. Figure 2.18 demonstrates the hourly electricity demand for MGE from July 1-7, 2002, superimposed on the daily production from the solar PV units from Figure 2.17. In this case, the PV system output from Figure 2.17 has been multiplied by a factor of 20,000, for a total peak rating of about 200 MW.

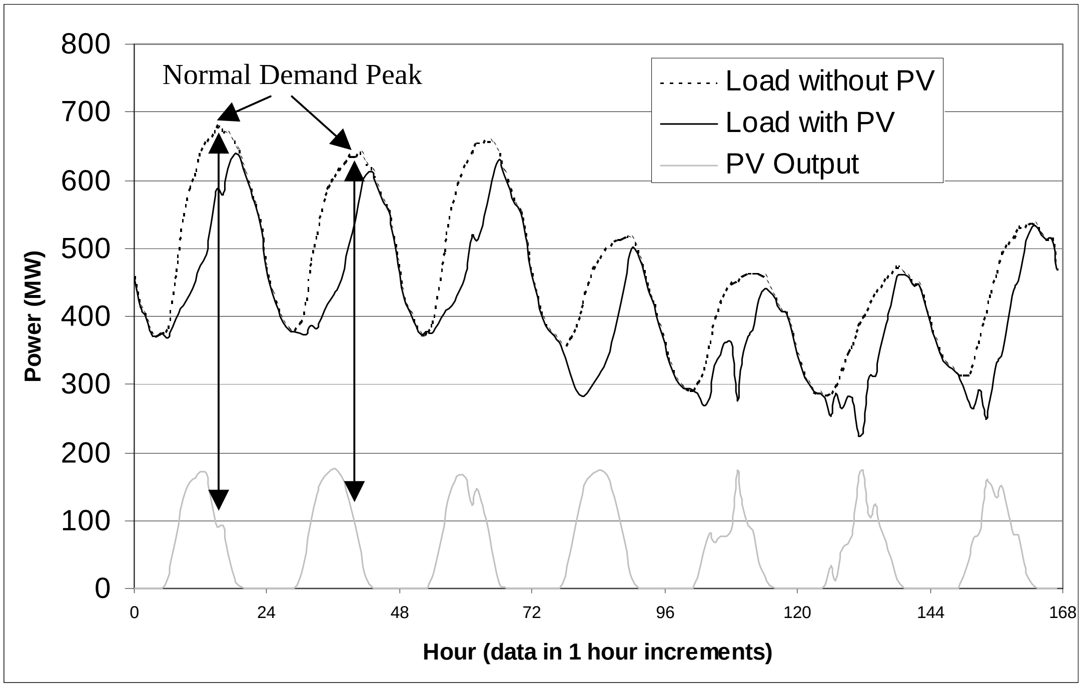

Figure 2.18: MGE Simulated Hourly Load With and Without 200 MW of Solar PV for July 1-7, 2002

The brown curve is the normal load without PV, demonstrating a fairly smooth and predictable curve. The dark blue curve considers PV generation a source of uncontrollable negative demand, so the PV generation has been subtracted from the normal demand, producing a "net load" curve with PV. This new load has become sharper, with a number of irregularities. It can be assumed that some, but not all of these irregularities would be filtered by spatial diversity.

While the PV system has provided energy benefits to the system, the use of solar PV without storage provides little benefit in terms of reducing the peaking capacity requirements in the MGE system. By 4-5 pm, when normal electric demand reaches maximum, the solar output has already fallen substantially and is dropping rapidly. This effect would be somewhat reduced by the use of tracking solar arrays, but such systems are more expensive than non-tracking units, and often cannot be installed on many rooftop systems. Figure 2.19 illustrates the effect of shifting the PV output by three hours using storage. The peaking capacity requirements in this case have been significantly reduced, and the use of storage would also remove most of the short-term variability in the PV output.

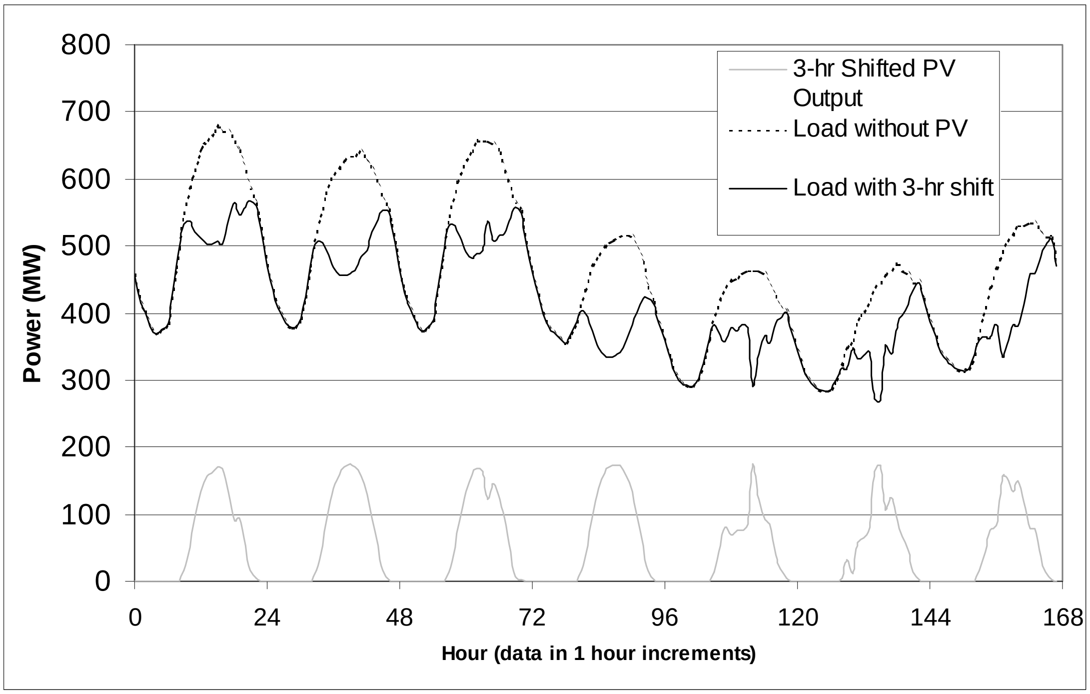

Figure 2.19: MGE Load With and Without 200 MW of *Time Shifted* Solar PV

2.5 Use of Energy Storage and Long Distance Transmission in Conventional Electric Power Systems

While energy storage and long distance transmission are referred to in this work as renewable energy enabling technologies, these technologies also have the potential to provide economic advantages to more traditional energy sources. Energy storage systems and long distance transmission system may be constructed to provide a variety of services to existing and new fossil and nuclear-based energy systems.

2.5.1 Benefits of Energy Storage to Traditional Generation Sources

Most energy is stored in the form of primary fuels such as coal, uranium or water, and converted into electrical energy on demand. Limitations in the economic and technical ability and of generators to quickly convert primary fuel into electricity has motivated the use of energy storage long before large-scale renewable energy systems were considered. Energy storage can provide three general categories of services to electric power systems:

1) Provision of demand responsive energy. Energy storage can respond rapidly to variations in demand, by both producing electricity on demand, and “absorbing” excess supply. This ability creates a number of opportunities to couple energy storage with traditional sources. First, it can decrease cycling of baseload coal units, increasing their efficiency and decreasing their O&M costs. Second it replaces natural gas and petroleum with lower cost coal and uranium for peaking fuels. Nuclear generated electricity particularly benefits from this application due to its limited cycling ability.
2) Reserves. Energy storage systems are often superior for providing power reserves. They can generally respond to rapid swings in demand, without the cost associated with partially loaded boilers or turbines. Most pumped hydro facilities represent a significant source of spinning reserve, and several large batteries have been constructed primarily to provide spinning reserve. Energy storage can also provide standby reserves or “black start” capacity for large power plants that is typically provided by large diesel generators or gas turbines.
3) Distribution of generation and transmission resources. Energy storage systems can replace electricity generation in areas where generation would be difficult to build for a variety of reasons. It can also provide an alternative to increased transmission capacity.

Partial deregulation of the electric power industry has created interest in energy storage among independent power producers who could to take advantage of the large daily swings in the wholesale cost of electric power. Figure 2.20 provides an example of the hourly market price of electricity on one particular location (which is representative of prices through the region) in the PJM interconnect (Pennsylvania, New Jersey, Maryland) from February 16-23, 2004.[36]

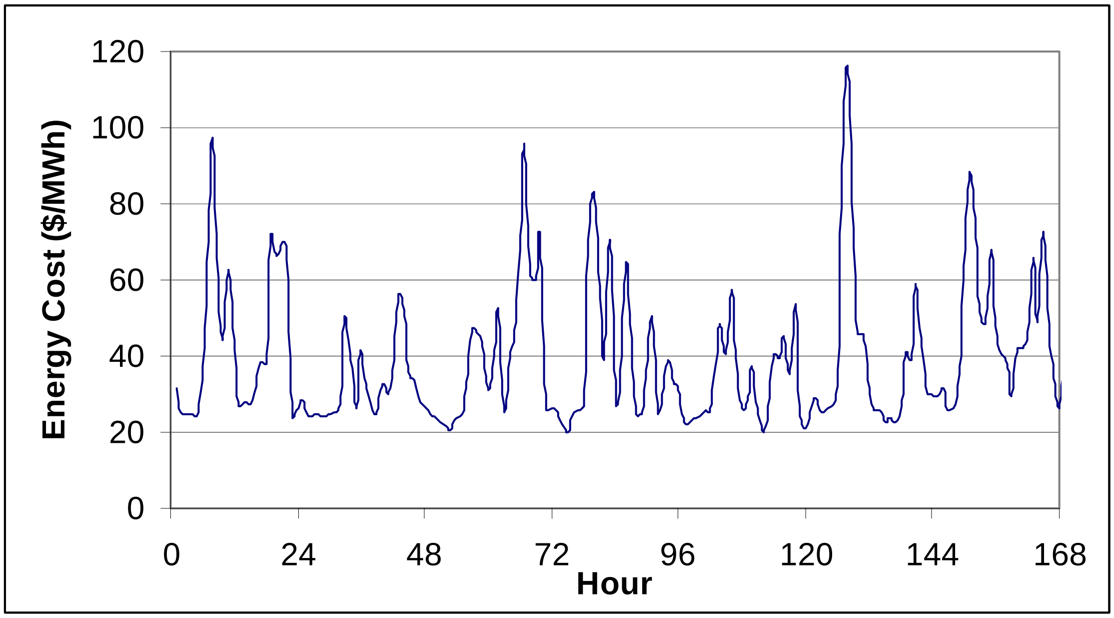

Figure 2.20: Hourly Wholesale Price of Electricity in the PJM Interconnect, February 16-23, 2004

Energy storage provides a unique opportunity for price arbitrage, with the ability to purchase inexpensive off-peak power and resell it at times of higher demand. High natural gas prices increase the motivation for the use of energy storage for peaking and load following generation, and in 2003, there were at least three active proposals for over 3000 MW of new energy storage, to be used with traditional generation sources.

2.5.2 Long Distance Transmission

Long distance transmission enables the use of three general classes of electricity production technologies, based on the fuel source: fuels that cannot be moved for technical reasons, such as hydro and wind power; fuels that cannot moved for economic reasons, such as low density lignite coal; and fuels that be cannot moved for social or policy reasons, such as the use of coal in southern California. Since coal (especially lignite coal) is relatively expensive to transport, and difficult to site in populated areas, several long distance "coal by wire" transmission lines have been constructed in the U.S., with additional projects being actively pursued.[37,38] Long distance transmission enables otherwise uneconomic coal resources to be effectively integrated into the electric power system.

2.6 Conclusions

The majority of the electric power used in the U.S. is provided by baseload energy sources. Most of this baseload energy is derived from sources considered by many to be environmentally harmful. Wind energy is currently the only renewable energy source capable of providing competitively priced baseload energy. Yet without enabling technologies, including storage and transmission, wind is only capable of economically providing a relatively small fraction of the nation's electrical energy requirements. It is likely that large-scale deployment of wind energy systems in the U.S. will require the extensive development of new long distance transmission and energy storage.

Even without large-scale deployment of renewable energy, new development of transmission and energy storage is likely, given its benefits to traditional systems. For these reasons, it is important to examine the various environmental consequences of deployment of energy storage and transmission technologies used with both renewable and traditional energy sources.

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3. Methods and Metrics

To accurately assess the environmental impact of renewable enabling technologies and to provide a uniform comparison between these technologies and other energy supply systems, a uniform set of metrics was derived. These metrics focus on analyzing the life-cycle environmental impacts of each energy supply technology.

3.1 Life-Cycle Environmental Impact Assessment

The evaluation of renewable enabling technologies is based on environmental life-cycle assessment. Life-cycle assessment (LCA) is a general accounting methodology that considers various environmental impacts produced by a product over its lifetime.[1] A typical life-cycle analysis may consider such issues total energy use, consumption of various natural resources, and releases of environmentally harmful waste products to air, land, and water. Each of these impacts is measured for the construction, operation, and decommissioning of the evaluated product. Many life-cycle analyses focus primarily on energy consumption, because environmental impact generally proportional with energy use.

There are two basic tools used in life cycle assessment, Process Chain Analysis (PCA) and Economic Input/Output (EIO).[2] The PCA method uses material inventories and process flows to evaluate energy usage at each stage of product manufacture and use. A complete PCA requires knowledge of the quantity of each material (steel, plastic, etc.) in a product, and also an understanding of the total energy and emissions associated with manufacturing each of the materials. This method of life-cycle analysis also requires an understanding of the energy and emissions involved with many different manufacturing processes.

Complete material inventories are often not available, and manufacturing data for complete systems is often difficult to estimate. Manufacturing may require hundreds of integration steps, some of which may be proprietary and difficult to evaluate. In many products, such as batteries and electrical equipment, the manufacturing energy exceeds the energy required to obtain raw materials. Economic Input/Output methods avoid such difficulties by using estimates of the relationship between energy and the monetary value of materials and processes. The EIO method requires an accurate accounting of purchases of energy and fuels throughout the manufacturing process. Groups in several countries have performed this accounting across many manufacturing sectors. In the U.S., an EIO database is currently maintained by the Green Design Initiative at Carnegie-Mellon University that estimates energy use and emissions related to the dollar value of 485 products and service categories, based on the U.S. Department of Commerce's commodity model of the U.S. economy.[3] This database includes EIO data on many common manufactured products such as metal products, structures, transportation equipment, and chemicals.

In general, PCA assessments are more difficult, but often more accurate than EIO assessments.[4] Since EIO aggregates data across entire industries, the specific product being evaluated (a particular $20,000 automobile, for example) is likely different than the average product ($20,000 worth of automobile averaged across the entire industry). To maximize both accuracy and ease, a hybrid-LCA approach is often used, where the majority of the product assessment uses PCA, with EIO used where PCA would be too difficult, or complete information is not available.[5] For example, evaluation of a wind turbine may require an estimation of the amount of energy required to manufacture a steel tower, and an electric generator. The most accurate method of estimating energy usage for the steel tower would be a PCA assessment using data that establishes the relationship between the mass of a material (steel) and its embodied energy. The generator consists of many different materials, and involves manufacturing processes that are difficult to assess. It is far easier to estimate the embodied energy in the generator by obtaining its monetary value, and using an EIO estimate for electrical apparatus. This study uses this hybrid approach, with PCA used for most material assessment, and EIO used to assess system operation and maintenance (O&M), certain manufacturing steps, and other less material-intense activities.

3.2 Metrics for the Evaluation of Energy Storage Systems

The evaluation of energy storage systems in this study focused on their energy usage and greenhouse gas emissions, using several different metrics: storage system efficiency, life cycle efficiency, life-cycle greenhouse gas emission rate, and the storage system energy/power ratio.

3.2.1 Storage System Efficiency

The most important technical parameter of an energy storage system is the "round trip efficiency," which represents the conversion efficiency during the storage and generation cycle. Since all storage facilities incur losses, the round trip efficiency is less than 100%. Storage efficiency is an important environmental parameter, because losses require an increase in primary electricity production, resulting in increased environmental impacts. The electrical AC-

AC roundtrip efficiency of the storage conversion process may be expressed as the storage energy ratio (ER_s), defined as:

$$ER_s = \frac{kWh_{in}}{kWh_{out}}. \tag{3.1}$$

Since the energy ratio measured by equation 3.1 is effectively the inverse of efficiency, it is greater than 1 for all energy storage systems except CAES, which is a hybrid storage-generation system described in Chapter 4. While the ER_s reflects the losses that occur in the power conversion stages, additional storage-related inefficiencies occur from electricity transmission and losses that may occur over time in the storage medium.

Additional transmission losses are due to the extra "path" that electricity must travel due to the use of storage. Figure 3.1 shows a highly simplified transmission infrastructure from generation to load. Generation occurs at a voltage typically between 10 and 21 kVAC, which is stepped-up to a much higher transmission voltage for maximum efficiency. The voltage is then stepped-down (generally several times) through transmission and distribution substations before final load. The use of energy storage requires additional transmission components, including an additional transformer step-down and step-up stage, and the incremental transmission line "path" that electricity must travel from generator to load.

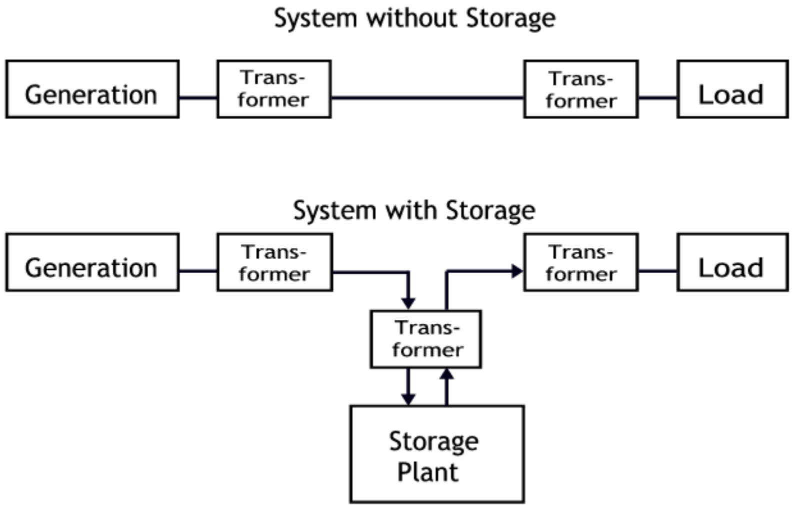

Figure 3.1: Additional Transmission Components Required by Energy Storage

Storage medium losses occur due to the time-related degradation of the storage medium, such as evaporation or seepage of water in pumped hydro reservoirs. Figure 3.2 is a generalized energy flow diagram showing the sources of losses associated with energy storage.

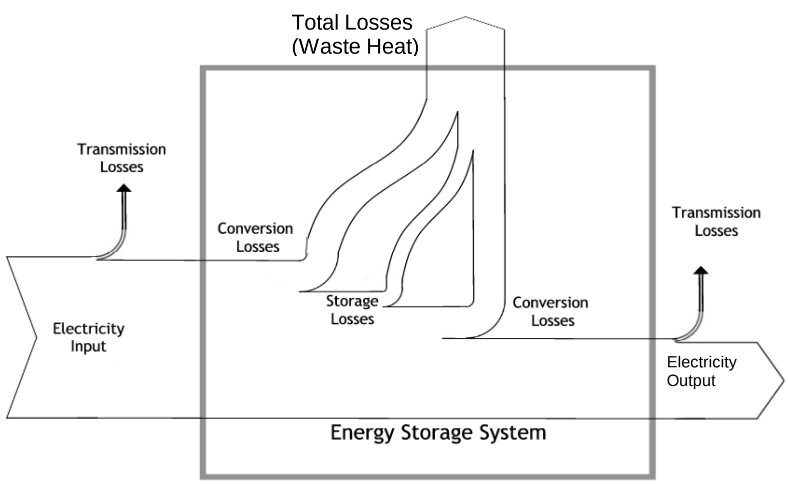

Figure 3.2: Energy Flow in an Energy Storage System

The total net energy ratio, ER_{net} can be calculated by including transmission losses resulting from the use of storage in addition to losses associated with the storage process.

$$ER_{net} = ER_s \cdot ER_T \cdot ER_M \quad (3.2)$$

The multipliers in equation 3.2 are ER_T, which is the transmission loss multiplier and ER_M, which is the medium loss multiplier. Each of the factors in equation 3.2 are equal to or greater than 1.

3.2.2 Life Cycle Energy Requirements and Efficiency

In addition to the electricity stored, energy is required to construct, operate, and decommission an energy storage facility. This “embodied” energy can be considered part of the overall life-cycle efficiency of an energy storage system. To calculate this life cycle efficiency, energy associated with construction and operation must be assessed.

Energy associated with storage plant construction, EE_S, can be expressed in terms of energy per unit of storage plant constructed (GJ_t/MWh_e). To calculate the energy requirements of plant construction *per unit energy stored*, EE_S must be divided by the total amount of energy stored over the life of the plant.

$$\text{Construction energy requirement per unit energy stored} = \frac{EE_S \bullet P}{E_S^L} \quad (3.3)$$

Where P is the storage plant size in MWh_e and E_S^L is the total amount of electrical energy (MWh) stored over the lifetime of the storage plant.

To estimate E_S^L we must know both the estimated life of the storage plant, and its annual production rate, or capacity factor. Lifetimes of energy storage facilities are highly variable depending on technology, and discussed in detail in Chapter 4. The maximum capacity factor (as defined in section 2.1.2) of an energy storage plant is 50%, which would result in the plant always either generating, or storing at full power. Most storage plants currently in operation have capacity factors of 10-25%, with about 20% being typical.[6]

Operational energy requirements per unit of energy stored (excluding stored electricity) is described by EE_{op} (GJ_t/GWh).

The net energy requirements for each unit of electricity delivered to load by an energy storage system can be calculated by summing the net energy ratio (equation 3.2) and the additional life cycle energy requirements (equation 3.3 and EE_{op}.) The inverse of this value can be expressed as the life-cycle efficiency, η_S^L.

$$\eta_S^L = \frac{1}{\mathrm{ER}_{\mathrm{net}} + \left(\mathrm{EE}_{\mathrm{op}} + \left(\frac{\mathrm{EE}_{\mathrm{S}} \bullet P}{\mathrm{E}_{\mathrm{S}}^{\mathrm{L}}}\right)\right) \bullet \eta_t} \tag{3.4}$$

where η_t is the thermal to electric energy conversion efficiency, which accounts for the difference in quality between thermal energy and electrical energy. Both EE_S and EE_{op} are expressed in terms of primary thermal energy, since the majority of energy related to construction and operation results from the combustion of fossil fuels.[7]

The uniform treatment of η_t is an important limitation to the calculation of life-cycle efficiency, and is discussed in more detail in section 3.4.

3.2.3 Greenhouse Gas Emissions

The life-cycle greenhouse gas emissions from electricity delivered by an energy storage facility originate from three major sources: generation of electricity to be stored, storage plant operations, and construction of the energy storage facility. GHG emissions are generally reported in terms of CO_2-equivalent (CO_2e) emissions, and include non CO_2 greenhouse gasses such as methane (CH_4) and nitrous oxide (N_2O). Greenhouse gas emissions are typically reported in the numerically equivalent terms of g/kWh, kg/MWh, or tonnes/GWh.

The life-cycle emissions rate EF_S^L (kg CO_2e/MWh) describes the average emissions per unit of energy delivered to the consumer by the energy storage unit. The rate is calculated in a manner similar to the life-cycle efficiency.

Emissions related to stored electricity are a function of the emissions factor for primary electricity generation, EF_{gen}, and the net energy ratio, ER_{net}. Life-cycle emissions related to storage plant construction may be expressed as the total construction-related emissions divided by the lifetime output of the storage plant, similar to the life-cycle energy calculated in equation 3.3. Emissions related to plant operations are given by EF_{op}. The complete life-cycle emissions factor, EF_S^L is then defined as:

$$EF_S^L = \left(EF_{gen} \bullet ER_{net}\right) + EF_{op} + \left(\frac{EM_S \bullet P}{E_S^L}\right) \tag{3.5}$$

where EM_S (kg CO_2e/MWh_e) is the emissions per unit of storage plant constructed.

3.2.4 Energy/Power Ratio

An energy storage system consists of both an energy component and a power component. The energy component is the storage vessel, and the storage medium, which may be water, air, an electrolyte, or some other medium. The power component is a power converter, which may be a water or gas turbine, or a battery stack.

The energy and power components are generally independent of one another in terms of size. As an example, a storage system may be able to deliver 50kW for 8 hours, or 400 kW for 1 hour, both of which have identical storage capacity (400 kWh) but with different power components. The energy/power ratio of an energy storage system is defined as the amount of time the system can deliver full rated power. The energy/power ratio, which describes the relative size of the energy storage and power components, is unrelated to the energy ratio (ER) described in section 3.2.1, which is a measure of storage plant efficiency. Storage facilities are designed for local conditions and requirements, which results in substantial differences in the energy/power ratio (MWh/MW) for different applications and different technologies. This ratio can vary from about 1 hour for power quality battery systems, to 30 hours or more for some pumped hydro facilities.[8] However, most bulk energy storage facilities planned or in place are sized by economic constraints to deliver energy during one to two 8-hour peaking loads, so the energy/power ratio is generally between 8 and 16 hours. Variations in the energy/power ratio produces some degree of inconsistency, since the energy storage component is a large fraction of the embodied energy, particularly in BES systems.

3.2.5 Summary of Energy Storage Metrics

Using equations 3.1-3.5 we can summarize the basic values that describe the basic energy and GHG emissions performance of any energy storage system.

> **ER_{net}**: a multiplier that increases the primary electrical energy requirements and emissions per unit of energy stored (MWh_{in}/MWh_{out})
> **EE_S**: the "embodied" energy associated with storage plant construction per unit of storage required (GJ_t/MWh_e)
> **EE_{op}**: the operational energy requirement per unit of energy stored and delivered by the storage system to the load (GJ_t/GWh_e)
> **EM_S**: the "embodied" emissions associated with storage plant construction per unit storage required (kg CO_2e/MWh_e)
> **EF_{op}**: the operational emissions factor per unit of energy stored and delivered by the storage system to the load (kg CO_2e/MWh_e)

3.3 Metrics for the Evaluation of Electricity Transmission and Distribution Systems

The evaluation of transmission and distribution (T&D) systems is motivated by providing an equitable comparison between traditional energy sources and renewable alternatives. Typically, life-cycle analysis of electric power generation provides measures of impact at the "busbar" representing the impact per unit electricity produced by the power plant. If the impacts of electricity actually used are to be measured accurately, the effects of T&D must be considered. Consideration of T&D is important for two reasons. First, T&D losses act as multipliers, not adders, which means they tend to magnify the effects of high environmental impact sources. Second, T&D effects are largely a function of proximity between source and load, which varies depending on the generation technology.

This proximity effect is of particular importance to renewable energy sources including wind and solar PV. For wind, the great distances between resource and load will likely mean greater than average transmission distances, requiring greater amounts of transmission infrastructure and losses per unit of delivered energy. For PV, generation of electricity at the load eliminates most or all of the T&D path for generated electricity. In this case, only by adding T&D affects to traditional sources can the full benefits of distributed sources such as solar PV be recognized.

3.3.1 T&D Loss Effects

In terms of energy use, the most significant impacts of T&D systems are due to losses that occur between generation and load. The T&D loss rate, L_{td}, is typically between 3% and 12%. Losses in the transmission system require an increase in the system size to produce a desired output. This multiplier effect can be written as:

$$\text{Installed Power Capacity (MW)} = \frac{\text{Delivered Power Capacity (MW)}}{1 - L_{td}} \tag{3.6}$$

This multiplier effect increases both the system size (power) and the required input energy (fuel). As an example, a LCA may evaluate the total impacts from a generator that delivers 1 MWh of electricity to the load, at a rate of 1 MW. If the total T&D loss rate is 10%, the analysis will actually need to consider the production of 1.11 MWh by a plant 1.11 MW in size.

3.3.2 Other T&D Life-Cycle Energy Requirements

Losses in the T&D system can be combined with the T&D construction and operation components to derive a life-cycle energy requirement for energy delivered by an electric generator. These additional adder terms include EE_{op} for the T&D system, and the normalized construction energy, which is calculated in a manner similar to equation 3.3:

$$\text{Construction energy requirement per unit energy transmitted} = \frac{EE_{td}}{E_{td}^{L}} \qquad (3.7)$$

Where EE_{td} is the embodied energy in the T&D system, and E_{td}^{L} is the amount of energy transmitted by the T&D system over its lifetime.

3.3.3 Greenhouse Gas Emissions Resulting from Electricity T&D

Losses from transmission and distribution, along with construction and O&M of T&D equipment results in increased greenhouse gas emission related to electricity generation. The net emissions resulting from electricity delivered by T&D system can be calculated using the life-cycle components, similar to equation 3.5. This can be described by an emissions factor which includes T&D, EF_{TD}, (kg CO_2e./MWh) given by:

$$EF_{TD} = \left(\frac{EF_{gen}}{1 - L_{td}}\right) + EF_{op} + \left(\frac{EM_{td}}{E_{td}^{L}}\right) \qquad (3.8)$$

where

EF_{gen} is the life-cycle GHG gas emissions factor for electricity generation.
EF_{op} is the Emissions Factor due to operation of the T&D system.
EM_{td} is the embodied emissions associated with T&D system construction.

3.3.4 Application of T&D Metrics

The T&D metrics derived in this section must be applied appropriately for equitable comparison of generation sources. For example, many analyses consider the effect of coal or nuclear generation at the point where these plants enter the local transmission grid. A comparison between these and a distant wind source would require adding the additional transmission requirements to deliver the wind energy to approximately the same distance to load as the nuclear or coal plant. However, comparison between PV system and any other centralized generation facility must add on the entire T&D system to the centralized source, since the PV system effectively includes all transmission and distribution.

3.4 Metrics for the Evaluation of Integrated Renewable Energy/Storage Systems

An energy storage system may be electrically coupled to a renewable energy source to create an energy system that is equivalent to a traditional fossil or nuclear energy source.

3.4.1 System Boundary

An integrated renewable energy system includes renewable energy generation, energy storage, and certain transmission components.

Figure 3.3 illustrates the system boundary for a complete “dispatchable renewable” energy system. The assessment of such a system includes the entire life cycle of the generation system, storage system, and transmission. The elements of the energy storage sub-system are shown in the dotted box in Figure 3.3

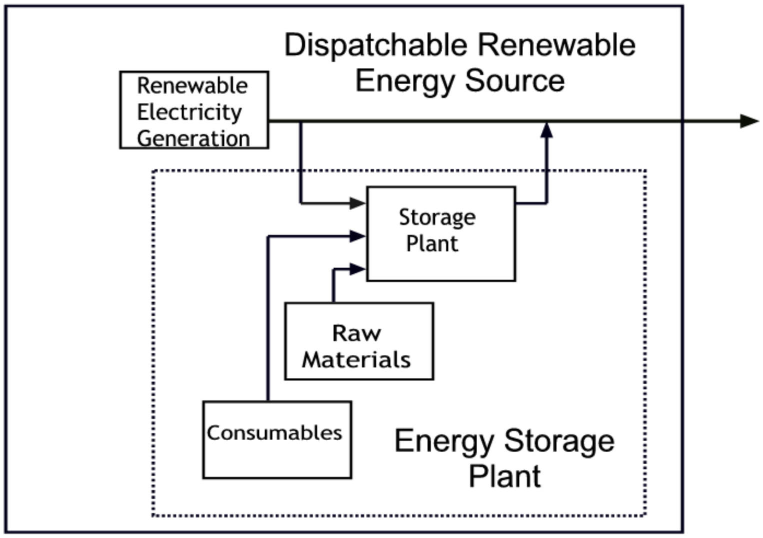

Figure 3.3: System Boundaries for an Energy Storage System and a Dispatchable Renewable Energy Source

3.4.2 Life Cycle Energy Efficiency

Since environmental impact is generally proportional to energy consumption, an electricity system should preferably have a very high energy conversion efficiency, where as little primary energy as possible is needed to produce electrical energy.

One metric of this conversion efficiency is the life-cycle energy efficiency, which could be measured by:

$$\eta_L = \frac{\text{Delivered Electrical Energy}}{\Sigma \text{All Energy Inputs}} \tag{3.9}$$

where energy inputs include all energy including fossil fuels, uranium, and renewable fuels such as wind, solar and geothermal inputs. This calculation would be essentially useless, since there is a very large variability of both resource sustainability and environmental impact associated with these energy sources.

A more valuable metric of environmental performance is the life-cycle fossil efficiency, where only fossil energy inputs are considered in equation 3.9. This metric is useful for a number of reasons. First life-cycle fossil fuel efficiency provides a measure of energy resource sustainability, especially since fossil fuels account for more than 70% of electricity generation and 85% of the total energy used in the U.S.[9] In addition, fossil energy consumption is a more accurate indicator of environmental impact than total energy consumption, since fossil energy sources generally have much greater environmental impact than renewable energy sources.

The energy sustainability metric used in this work is defined as the fossil-fuel efficiency, or electrical energy produced per unit of fossil thermal energy.

$$\eta_L = \frac{\text{Delivered Electrical Energy Out}}{\Sigma \text{All Fossil Thermal Energy Inputs}} \tag{3.10}$$

This measurement is a reasonable indicator of energy sustainability, and many analyses use some formulation of this metric. For this assessment, *all* primary energy is assumed to be derived from fossil sources.

Life cycle efficiencies for conventional fossil sources are typically less than 50% and are limited by thermal conversion processes and fuel delivery requirements. For example, a combined-cycle gas turbine with a plant thermal efficiency of 50% has a life-cycle fuel efficiency of about 42%, mostly due to losses in the fuel delivery system.[10] The net life-cycle fossil fuel efficiency of renewable energy systems may be substantially greater than 100%, since their fossil fuel requirements are typically much less than their production of electrical energy.

A renewable energy system could have a life-cycle efficiency of less than 100% and still be superior to a fossil based system in terms of energy resource sustainability. A unit of natural gas energy that produces 0.4 units of electrical energy from a combustion system could alternately be used to construct a wind energy system that, over its lifetime, delivers 0.9 units of electrical energy. In this case the renewable system produces less energy than it takes to construct it, yet it still produces more than twice the amount of electrical energy than would be extracted by combustion. This example illustrates the counter-intuitive result that it may be quite reasonable for a renewable energy system to consume more energy than it produces.

Equation 3.10 is expressed as fossil fuel efficiency, but this metric can also be applied to sources whose input energy is derived from any input fuel mix including both conventional and renewable fuels. In this case, η_L represents the input energy multiplier, or energy return on investment, as each unit of energy produced by the energy system requires an amount of input energy equal to the reciprocal of η_L. The energy inputs considered in this metric must be measured consistently for this definition to be valuable. The energy input component can be calculated in terms of electrical or thermal energy. Using thermal energy input is a more meaningful measure, as it requires less estimation of thermal-electrical conversion, since greater than 96% of the energy used in the U.S. is derived from thermal sources.[11] However, the large variations in energy source impacts makes the energy return on investment metric less useful as an environmental performance indicator than the fossil fuel efficiency metric.[12]

In all cases, η_L ignores the energy content of the renewable energy inputs, and assumes that there are no significant opportunity costs or environmental impacts associated with extracting energy from renewable sources. Ignoring the energy content of renewable fuels has certain problems and limits the relevance of η_L as a comparative metric. For example, the use of solar PV energy incident on a rooftop may have little environmental impact, but it does incur opportunity costs, since a solar PV array displaces the opportunity for solar water heating, an application which may have greater environmental benefits. The use of wind energy has a variety of environmental impacts from avian mortality,[13] to possible effects on local climate.[14] Significant environmental impacts that are unique to the use of renewable fuels need to be incorporated into an appropriate sustainability metric for accurate comparison.

In addition to ignoring the energy content of renewable fuels, there are other significant limitations to the sustainability metric defined in equation 3.10. First, it values all fossil energy inputs equally, with the "value" of 1 unit of natural gas energy equal to 1 unit of coal energy. Fossil energy sources are obviously not equal in terms of economic cost, sustainability of supply, or environmental impact. However, this variation is not nearly as great as that between fossil and renewable energy sources.

In addition, the life-cycle metric defined by equation 3.10 does not account for the differences in time when both input and output occur. This limitation is quite common in energy assessment; most assessments simply sum inputs and outputs and divide, regardless of when inputs and outputs occur.[15] This scenario is not necessarily inaccurate when inputs and outputs occur in similar time frames. For example, most emissions from coal and natural gas energy production occur at roughly the same time the energy is put into the system. For many other systems, particularly renewable energy systems, most energy and emissions are “invested” before energy production begins.

A simplified example illustrates the potential problem in a direct comparison between systems with time-dependant energy inputs. Two different electricity systems (fossil and renewable) may produce 1 unit of electrical output per year over 10 years. The renewable system would require 20 units of input energy at the beginning of year 1, and no input afterward. The fossil system would require 2 units of energy per year over the 10 year system lifetime.

Traditional LCA would claim equivalent life-cycle efficiencies of 10/20 or 50% for both systems. An economic life-cycle analysis of these two systems would likely find a much different result if future costs were discounted to their net present value. There are legitimate reasons why appropriate discounting should be applied in this situation. Financial discounting occurs for a variety of reasons, including risk of default or other financial failure. The situation with energy systems is similar. There is a real chance that the renewable system will be damaged or destroyed before the end of its projected lifetime. This is just one reason why time-dependant inputs and outputs should probably be discounted.[16] Most life-cycle analysis ignores the issue of time-dependent impacts. Issues related to discounting of environmental benefits and impacts are well understood and discussed in the field of environmental economics, but these issues are not sufficiently addressed in the fields of life cycle analysis and energy accounting.

Despite these limitations, the metric described in equation 3.10 provides a good “first-order” approach to understanding the comparative environmental impacts of various energy systems.

Equation 3.10 is most accurate when comparing generation technologies that use similar "types" of energy inputs, such as renewable energy sources. Regardless of the limitations of the η_L metric, however, the results often demonstrate very large differences between energy systems, often by a factor of 10 or more. While this does not necessarily mean that one system has 10 times greater impact, it does provide an relative indicator of sustainability and environmental impact, since energy use is generally proportional to environmental impact.

3.4.3 GHG Emission Evaluation

The life-cycle greenhouse gas (GHG) emission rate is a more easily definable indicator of environmental performance for electric power systems. The GHG emission rate can be calculated in a manner similar to the net energy requirement. Greenhouse gas emissions from the initial construction of dispatchable renewable energy systems result from current reliance on fossil fuels for manufacturing and transportation.

The life-cycle greenhouse gas emissions rate from electricity produced by a dispatchable renewable energy system is calculated in a manner similar to the life-cycle efficiency.

$$EF_{net} = \frac{\sum \text{GHG Emissions}}{\text{Delivered Electrical Energy}} \tag{3.11}$$

While equation 3.11 describes the net emission rate, it provides little insight into the origin of emissions and their calculation. Specifically, the calculation of EF_{net} from a system using energy storage requires an understanding of how much electricity is placed into storage.

The net emissions factor for a generation source using energy storage system, EF_{net}, is the weighted average of the emissions of energy stored and energy not stored:

$$EF_{net} = \left[EF_{gen} \bullet (1 - f_{stor})\right] + \left(EF_S^L \bullet f_{stor}\right) \tag{3.12}$$

where EF_{gen} is the emissions factor from primary electricity generation, and f_{stor} is the average fraction of energy stored. EF_S^L is the emissions factor for the energy storage system, given by equation 3.5, which is supplied by the generation source described by EF_{gen}.

As discussed in section 3.4.2, neither energy output, nor greenhouse gas emissions are discounted in 3.11 or 3.12. While virtually all assessments that use the “emission per electrical output” valuation of GHG emissions do not discount future emissions, there are a number of reasons why some time-dependent formulation of GHG emissions should be added to equations 3.11 and 3.12. First, there are emissions risks associated with systems that “invest” all their emissions up-front. Second, delaying GHG emissions into the future may have certain benefits, such as the ability to deal with them from a technological standpoint. An alternative metric that some analyses use is the GHG payback time, which indicates the amount of time it takes the production of electricity from non-combustion energy sources to offset their initial emissions.[17] This method eliminates some problems, but introduces others, such as ignoring emissions associated with O&M, as well as insufficiently addressing variability of energy production and product lifetimes. An emissions rate, such as provided in equation 3.11, is the only method that provides for comparison across a wide range of technology categories.

3.5 Metrics for the Evaluation of Storage Systems used with Fossil Energy Sources

As discussed in Chapter 2, near term deployment of energy storage systems will likely be dominated by their use with fossil energy sources. Both the fossil-fuel efficiency and GHG emission rates described in section 3.4 can be applied to fossil/storage systems.

Potentially more important, however, is the evaluation of local or regional emissions of a variety of air pollutants, including mercury, SO_2, NO_x, and particulates. The use of energy storage with existing fossil energy sources may raise or lower these emissions, depending on how the system is used.

The emissions rate of a pollutant X that result from the operation of an energy storage system can be calculated in a manner similar to the life-cycle emission rate of GHG. Since most concern regarding pollutants is regional in nature, this assessment ignores life-cycle components such as construction and maintenance.

Calculation of this pollution emission rate is complicated by the interaction between the storage system and the generator, as discussed in Chapter 2. As a result, the emission rate due to storage is the product of the ER_{net} and the *marginal* emission rate of the generator, which considers the improved efficiency of the generation plant due to the use of storage. To this must be added the point source emission rate from the storage plant. Finally, the use of energy storage for ancillary services, such as spinning reserve, results in a decrease in emissions. This produces a storage emission rate of pollutant X, EF_S^X, defined by

$$EF_S^X = \left(EF_{gen}^X \bullet ER_{net}\right) + EF_{op}^X - EF_{ancillary}^X \qquad (3.13)$$

where

EF_{gen}^X is the marginal emission rate of x

EF_{op}^X is the emission rate of X by the storage system itself

$EF_{ancillary}^X$ is the emissions offset of using storage for ancillary services

EF_S^X is the emission rate that can be used to compare the net air emissions from an energy storage system to an alternative source for peaking or load following generation.

3.6 Life-Cycle Efficiency and Emissions from Current Generation Technologies

Table 3.1 provides a summary of fossil fuel efficiency and GHG emissions from existing electricity generation sources, based on previous work.[18,19] These results do not consider energy storage for intermittent sources.

Table 3.1: Life-Cycle Emissions from Electric Power Plants

Generation Source	Fossil Combustion Efficiency (%)	Life-Cycle Fossil Fuel Efficiency, η_L (%)	Combustion-Related Emission Rate (kg CO_2e/MWh)	Total Life-Cycle Emission Rate (kg CO_2e/MWh)
Coal	30-40	25-35	900-1300	920-1330
Natural Gas Combined Cycle	40-50	35-42	380-440	420-530
Solar PV	N/A	400-1500	0	20-70
Nuclear	N/A	1600	0	13
Wind	N/A	2100-2600	0	15

Table 3.1 illustrates that renewable and nuclear technologies produce significantly more energy from a unit of fossil fuel than fossil-combustion technologies, along with much lower levels of GHG emissions. However, the intermittent nature of solar and wind energy means that such a direct comparison is of questionable value.

In addition to consideration of renewable intermittency, Table 3.1 also does not include the effects of transmission and distribution. Including the effects of energy storage and T&D provides a more equitable comparison between intermittent and dispatchable sources of electric power. These effects are evaluated in Chapters 4-6.

3.7 Chapter References

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4. Environmental Analysis of Electrical Energy Storage Systems

Electricity is generally stored by creating or altering an intermediate product through a reversible process. An example is using electricity to alter raise the potential energy of water by pumping it to a higher location, a process referred to as pumped hydro storage (PHS). While PHS is the most common storage system, a number of other technologies have been developed for storing electrical energy for large-scale applications.

4.1 Available Energy Storage Technologies for Intermittent Renewables

Figure 4.1 provides a diagram of nearly every electrical energy storage technology that is commercially available.

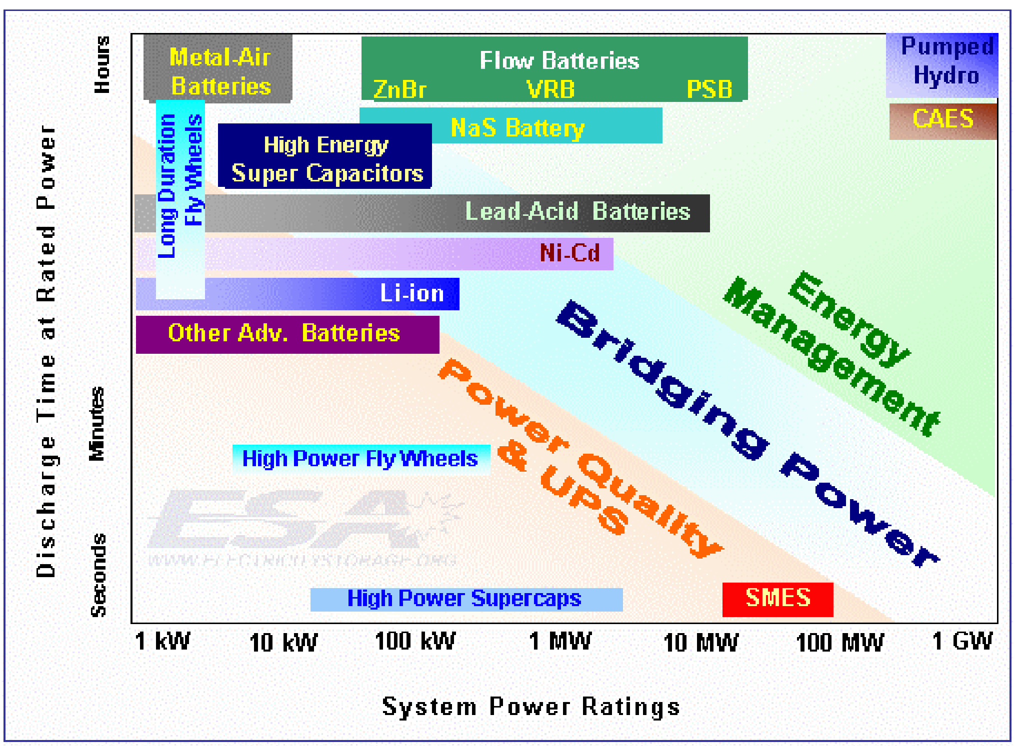

Figure 4.1: Power and Energy Ratings for Currently Available Energy Storage Technologies (Courtesy Electricity Storage Association**)**[1]

The x-axis in Figure 4.1 represents the system power ratings for the various energy technologies, while the y-axis shows the amount of time the storage technology can deliver rated power. Figure 4.1 shows three regions. In the lower left is the region of power quality and UPS (uninterruptible power supply.) These technologies are primarily suitable for momentary interruptions of power to end users, and currently dominated by the lead-acid battery. The upper left hand corner also represents technologies suitable for small-scale renewable applications, such as off-grid PV and wind system. The intermediate band is “bridging power.” This region represents storage technologies that can deliver larger amounts of energy and power to “bridge” the gap of large system failures. An example would be to deliver power to a commercial building or industrial facility during a short outage. Another use is to provide “black start” capability, or the power needed by a power plant to bring it back online. The third band, energy management, represents large energy storage systems that can provide large amounts of power, typically for several hours.

Since utility-scale storage of intermittent renewable sources requires both large power and energy requirements, this study focused on technologies illustrated in the upper right hand corner of Figure 4.1. Only three technology classes are currently economically viable for bulk energy storage: pumped hydro storage, compressed air energy storage, and advanced batteries. While these are the only technologies evaluated in this study, there are a number of other technologies that may provide economic alternatives for large-scale renewable energy storage in the future.

SMES (Superconducting Magnetic Energy Storage) stores electricity in a magnetic field by running current in loops of superconducting material. When first developed, the technology looked very promising for both large scale and distributed applications, due to very high round trip efficiencies and the potential low cost as a result of forecast improvements in materials.[2] However, SMES is still burdened with high capital costs,[3] and the technology is currently limited to the niche market of "power storage," due to its ability to deliver large amounts of power.[4] SMES units are generally applied in areas of weak electric grids, with large "shock loads" of large, sudden demand. Until there are additional fundamental breakthroughs in superconducting materials, SMES will remain too costly for bulk power storage.

Capacitors store energy in an electric field across charged conducting plates. Capacitors are typically used for high power, low energy applications like SMES.[5] Capacitors may eventually provide an alternative to batteries in smaller renewable storage applications currently dominated by batteries.

Flywheels store mechanical kinetic energy by spinning a mass to a high rotational speed. Flywheels now provide a competitive alternative to batteries in some small applications.[6] While it is unlikely that flywheels will ever be appropriate for bulk energy storage, local storage of PV power may be a possibility for this technology.

There are two other significant energy storage technologies not shown on Figure 4.1:

Thermal energy storage describes a number of different technologies. Thermal energy storage is often used as a load management tool by both utilities and customers to shift demand for electricity from peak to off-peak times. An example is the production of ice or chilled water during evening hours to use for cooling during peak periods. Thermal energy storage is also used with solar thermal electricity generation, a technology not considered in this study.

Hydrogen energy storage is considered by many to be the ultimate energy storage medium, but it can easily be disregarded in the near term due to its economic and technical limitations. The current cost of a hydrogen energy storage system, consisting of an electrolyzer, storage tanks, and fuel cell, is significantly greater than the cost of the other technologies evaluated.[7] In addition, it is much less efficient than the other storage technology evaluated.[8] Hydrogen may be more competitive as part as a complete storage-transmission system, an application discussed in Chapter 5.

In the near term, pumped hydro storage (PHS), compressed-air energy storage (CAES), and battery energy storage (BES), represent the most likely candidates for utility-scale storage applied to renewable energy systems.

4.2 Net Energy and Emissions - Pumped Hydro Storage

Pumped hydro storage (PHS) is the most widely used form of storage, with U.S. installed capacity exceeding 18 GW at 36 installations, and worldwide capacity exceeding 90 GW.[9] PHS stores hydraulic potential energy by pumping water from a lower reservoir to an upper reservoir. The amount of stored energy is proportional to the height difference (head) between the upper and lower reservoir and the volume of water stored. During periods of high demand, water is extracted through a turbine in a manner similar to traditional hydroelectric facilities. A schematic representative of PHS is shown in Figure 4.2. In addition to an upper and lower reservoir, a powerhouse must also be constructed, which is often underground.

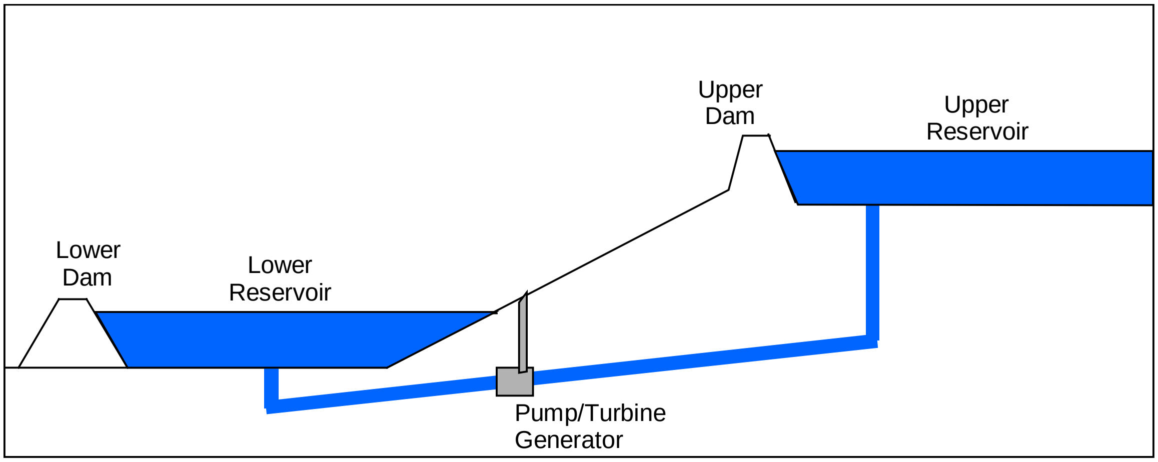

Figure 4.2: Pumped Hydro Storage

Since PHS is the dominant energy storage technology, it is the base technology to which other storage technologies should be compared. However, future development of pumped-hydro storage is limited due to environmental concerns and the lack of available sites.[10] Future PHS development may be limited to less land-disrupting schemes such as underground reservoirs.[11]

System Model

Several facilities, described in Table 4.1, were assessed to derive "average" values for PHS construction-related parameters, efficiency, and operational parameters such as O&M cost. The facilities chosen are representative of modern PHS facilities, all with completion dates after 1977. Only U.S. facilities were selected due to greater availability of construction and operation data. Only dedicated pumped-storage facilities were considered. Some hydroelectric facilities combine conventional generators with additional storage pump-turbines. An appropriate assessment of these projects would require allocating energy and emissions between the generation and storage components, as well as other tradition multi-purpose hydro uses such as irrigation and flood control.

Table 4.1: Modern U.S. Dedicated PHS Facilities Evaluated in this Study

Facility	Location	Completion Date	Capacity (MW)	Storage (MWh)
Bad Creek	Salem, SC	1991	1000	24,000
Balsam Meadow	Shaver Lake, CA	1987	200	1,600
Bath County	Warm Springs, VA	1985	2,100	23,100
Clarence Cannon	Center, MO	1984	31	279
Fairfield	Jenkinsville, SC	1978	512	4,096
Helms	Shaver Lake, CA	1984	1,206	84,000
Mt. Elbert	Leadville, CO	1981	200	2,400
Raccoon Mtn.	Chattanooga, TN	1978	1,530	32,130
Rocky Mtn.	Armuchee, GA	1995	760	6,080

4.2.1 Plant Construction and Decommissioning

Site Preparation and Reservoir Development

Most pumped hydro projects are large in scale, with sizes often exceeding 1000 MW and requiring construction or modification of two or more reservoirs and multiple dams. In a few cases the lower reservoir is a river or an existing lake.

The major components of energy utilization and emissions associated with construction of PHS dams and reservoirs include earth moving, rock quarrying, drilling and blasting, concrete manufacturing and transport, and installation of rock fill, earth, and concrete dams.

PCA and EIO data were utilized to calculate energy and emissions for each project based on the following parameters: amount of material moved to create reservoirs, total volume and composition of reservoir dams, total volume of rock displaced for shafts, tunnels and powerhouses, and the volume of installed tunnel and reservoir liners.

There is considerable variation in PHS projects based on diverse local topography and geological variations. PHS dams are typically earth- or rock-fill, which require substantially less construction energy than concrete dams.

Capital Equipment

Most of the capital equipment associated with PHS is the electrical system, including pump-turbines and motor-generator sets, as well as transformers, switchgear, and transmission systems. EIO data and capital equipment costs[12] were used to estimate total energy and GHG emissions.

Reservoir Carbon Emissions

The development of hydroelectric reservoirs can result in considerable GHG emissions.[13] Biomass cleared from the land prior to the construction of the reservoir creates a net increase in atmospheric carbon. In addition, flooded biomass decays both aerobically, producing carbon dioxide, and anaerobically, producing both CO_2 and methane. The amount of GHG generated depends on reservoir size, previous vegetation, and climate. The science of reservoir GHG emissions is relatively recent and includes many uncertainties related to methane production.[14] PHS development generally involves clearing and tree removal in a large percentage of the reservoir area, so this assessment assumes carbon emissions will result from the aerobic decay of biomass based on reservoir size. The GHG emissions associated with reservoir creation are a significant, but largely “reversible” source, since the reservoirs can be drained and replanted.

Decommissioning

This assessment considers PHS dams and reservoirs to be permanent, with decommissioning consisting only of capital equipment removal. Due to the very long operational lives of PHS, lakes created by PHS may become "socialized" during their long life, becoming a part of the accepted local ecology. Unlike most conventional hydroelectric projects, PHS has limited impact on river flow, so pressure to remove dams for fish migration or recreational purposes is reduced. A true decommissioning would require dam removal and subsequent land reclamation, which would be similar in energy intensity to initial construction of the earth and rock dams. Although not considered in this assessment, energy and emissions related to decommissioning can potentially be discounted due to their impacts at a future date.

Details of the PHS construction analysis are provided in Appendix B. Table 4.2 shows the results of the energy and emissions assessment for the construction and decommissioning of a typical PHS project. The table shows the energy requirement and associated emissions per unit of installed storage capacity.

Table 4.2: Life Cycle Energy Inputs and GHG Emissions Related to PHS Plant Construction

Component	**Construction Energy, EE_S (GJ_t/MWhe storage capacity)**	**GHG Emissions, EM_S (kg CO_2e/MWhe storage capacity)**
Dam Construction	104.8	9.7
Tunneling/Powerhouse Construction	86.7	8.1
Electrical Equipment	134.7	9.7
Balance of Plant	35.9	3.0
Reservoir Creation	0.1	4.3
Decommissioning	10.8	0.8
Total	**373.0**	**35.7**

4.2.2 Operation

Delivered Electricity and Energy Ratio

The net energy ratio is provided by equation 3.2, where ER_S represents evaporation and seepage in the upper storage vessel.

Most modern PHS plants operate with round trip efficiency of 75%-80%.[15] Efficiency data provided by the operating utilities includes both conversion efficiency and storage losses. A weighted average of the evaluated plants' efficiencies was used to derive an overall average PHS efficiency of 78%.

Ideal PHS sites are typically found in mountainous regions, which are often well away from load centers, resulting in substantial transmission losses. A 5% round-trip transmission loss factor is applied to electricity stored by PHS for this assessment, based on methods described in Chapter 5.

The net efficiency of an average PHS system is calculated at 74%, or a net energy ratio (ER_{net}) of 1.35.

Operation and Maintenance Requirements

Operation and maintenance includes all operations of the plant that have not been accounted for elsewhere. Energy and emissions data was calculated using EIO data for factory plant maintenance and administration, and O&M cost data from 24 U.S. PHS facilities.[16,17,18] This assessment assumes O&M costs are generally proportion to net facility output.[19]

4.2.3 Results

Table 4.3 shows the results of the pumped hydro life-cycle analysis. Additional details are provided in Appendix B.

Table 4.3: Energy and GHG Emissions Parameters for Pumped Hydro Storage

Parameter	**Life-Cycle Energy Inputs**	**GHG Emissions**
Fixed Components		
Construction - EE_S, EM_S	373 GJ_t/MWh_e storage capacity	35.7 tonnes CO_2e/MWh_e storage capacity
Variable Components		
O&M - EE_{op}, EF_{op}	25.8 MJ_t/MWh_e	1.8 kg CO_2e/MWh_e
ER_{net}	1.35 times generation energy	1.35 times source emissions

By applying typical PHS capacity factors and lifetimes, the average energy requirements and emissions factors per unit of electricity delivered by PHS can be calculated. Using a capacity factor (CF) of 20%, and a lifetime of 60 years, construction and operation-related energy requirements are 66 MJ_t/MWh_e and emissions are 5.6 kg CO_2e/MWh_e. Hydropower projects generally have much longer lives than traditional sources; as a result, the embodied energy and emissions related to PHS construction is divided over a longer life, resulting in lower impacts. Previous life-cycle research on hydropower has used lifetimes up to 100 years.[20] A substantially decreased capacity factor and lifetime would probably increase the input energy requirement to no more than 130 MJ_t/MWh_e, and the emission rate to as much as 12 kg CO_2e/MWh_e. The input energy requirement for PHS construction and operation is very small compared to the energy lost in the storage process. Each MWh_e delivered by a PHS facility to a consumer will require an electrical input of approximately 1.35 MWh (determined by ER_{net}), or 4860 MJ_e, which represents an additional energy requirement (losses) of 1260 MJ_e, compared to the 66 MJ_t of losses associated with construction and O&M.

4.3 Net Energy and Emissions – Compressed-Air Energy Storage (CAES) Systems

Compressed-air energy storage (CAES) plants in Germany and the U.S. have demonstrated their technical and economic viability for use as utility-scale energy storage.[21] The one existing U.S. facility is a 110 MW, 26 hour plant completed in 1991 by the Alabama Electric Cooperative (AEC) facility in McIntosh, Alabama.[22] While the low price of peaking fuels (oil and gas) reduced the economic competitiveness of CAES technology during most of the 1980's and 1990's, recent increases in fuel prices have prompted renewed interest in CAES.

In 1999, CAES Development Company (CDC) announced plans to build a 2700 MW facility in Norton, Ohio using an abandoned limestone mine as the storage vessel.[23] Another company, Ridge Energy Storage, has announced plans to develop CAES using salt domes in the Texas.[24] The use of CAES with existing or planned wind farms has also been proposed.[25,26]

Potential CAES sites have been identified in many areas of the U.S. (including the West and Midwest) and internationally.[27,28] If privately developed and operated CAES is successful, it may hasten the development of these sites. These plants may demonstrate the first large-scale profitable alternative to pumped hydro storage and may increase the use of CAES technology worldwide. A pumped hydro facility utilizing the Norton, Ohio limestone mine for the lower reservoir was proposed, but later cancelled, perhaps demonstrating favorable economics for CAES facilities when an underground air-tight cavern is available.[29]

Description of System

CAES systems are based on conventional gas turbine technology. A schematic diagram of a gas turbine and CAES system is provided in Figure 4.3. In a single-cycle gas turbine air is compressed and then combined with natural gas in a combustion chamber. Combustion produces high-pressure gas, which is then expanded through a turbine, which drives both a generator and the input air compressor. The principle of CAES is the utilization of the elastic potential energy of compressed air. Energy is stored by compressing air into an airtight underground storage cavern. To extract the stored energy, compressed air is drawn from the storage vessel, heated, and then expanded through a high-pressure (HP) turbine, which captures some of the energy in the compressed air. The air is then mixed with fuel and combusted in a low-pressure (LP) gas turbine. Both the high- and low-pressure expanders are connected to an electrical generator. Turbine exhaust heat is then captured in the recuperator to pre-heat cavern air (supplemented by gas burners.)

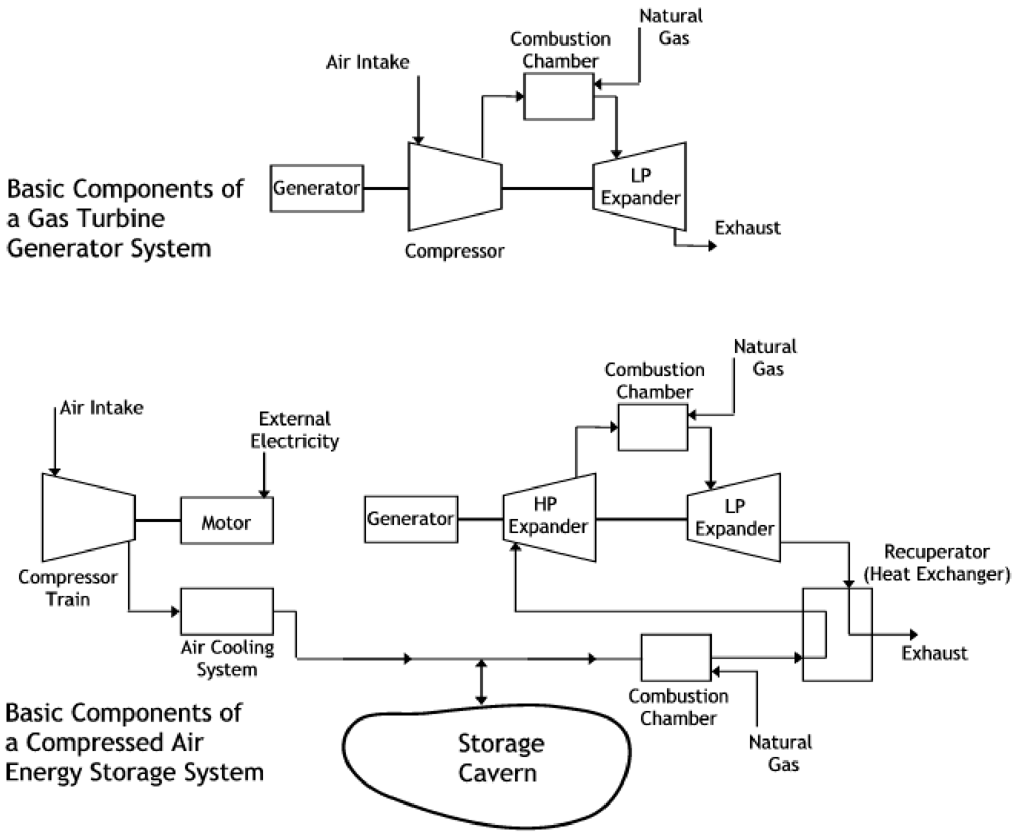

Figure 4.3: Schematic Diagrams of Gas Turbine Generation and Compressed Air Energy Storage

Unlike pumped hydro or storage batteries, CAES is not a pure storage system, because it requires combustion in the gas turbine. In this sense, CAES can be considered a hybrid generation/storage system. The storage benefit of pre-compressed air is the elimination of the turbine input compressor stage, which uses approximately 60% of the mechanical energy produced by a standard combustion turbine. Utilizing pre-compressed air, CAES effectively “stores” the mechanical energy that would be required to turn the input compressor, and uses nearly all of the turbine mechanical energy to drive the electric generator. The effect of CAES is the creation of a gas turbine with a heat rate of approximately 4500kJ/kWh, versus 9,500kJ/kWh for a conventional single-cycle combustion turbine. Of course, these gains are more than offset by the energy required to compress the air into the storage vessel.

The AEC's demonstration system uses a common shaft turbo machinery train, with both compressors and turbine expanders connected to a common motor-generator set via clutches.[30] The next generation of CAES designs use dedicated motor-compressors and generators which allow for optimally sized and more efficient equipment, as well as faster transition from compression to generation (or even simultaneous operation) which is important for wind-energy systems that experience rapid changes in energy output.

While based on gas-turbine technology and requiring natural gas fuel, CAES technology provides several advantages over gas turbines as a load-following source, enabling intermittent renewables to be competitive in the peaking power market. These include:

- Very fast ramp rates, greater than traditional peaking gas turbines due to the lack of input compressor inertia.[31] Fast ramp rates allow for load following, as well as potentially fast response to intermittent renewables.
- Nearly constant heat rate at variable load and ambient conditions due to the constant fuel/air ratio made possible by a regulated input airflow. CAES also avoids the decreased efficiencies experienced by gas turbines when compressing hot ambient air during daytime peaking conditions.
- Low capital costs and system complexities approaching those of single stage CT's, due to lack of steam cycle.

CAES System Model

The model for the evaluated system is the proposed Norton, Ohio facility, which was approved by the Ohio Power Siting Board in early 2002. If constructed, this facility would be the largest CAES system in the world, with peak output of 2700 MW, and a total energy storage capacity of 43.2 GWh (energy/power ratio of 16 hours.)[32] The storage cavern is an abandoned limestone mine with a volume of 9.6 million cubic meters. Since most CAES projects require the construction of a storage vessel, this study evaluates a salt-solution mined cavern, which is the likely type of storage vessel for many future CAES projects.[33]

4.3.1 Plant Construction and Decommissioning

Site Preparation and Mine Development

Site preparation primarily consists of land clearing and mine development. Salt solution mining consists of injecting heated water into a salt dome, and pumping out the resulting brine.

Capital Equipment

Capital equipment includes air compressors and associated cooling equipment, combustion turbine expanders, inlet air heat recuperators, AC electric generators, and transmission components. Other system components are similar to a natural gas plant of similar size.[34,35]

The use of natural gas fuel requires an increase in gas infrastructure, primarily pipeline and pumping stations. Energy and emissions data for the natural gas delivery systems and gas turbine components were derived from a previous study of natural gas systems.[36]

Decommissioning and Reclamation

A relatively small amount of energy is required for plant decommissioning and land reclamation. A 40-year plant life is used in this assessment, after which, all capital equipment is scrapped or recycled.

Table 4.4 shows the results of the energy and emissions assessment for the construction and decommissioning of a typical CAES project using a salt dome for air storage. The table shows the energy requirement and associated emissions per unit of installed storage capacity. Additional details are provided in Appendix C.

Table 4.4: Life Cycle Energy Inputs and GHG Emissions Related to Construction of CAES Systems

Component	**Construction Energy EE_S (GJ_t/MWh_e storage capacity)**	**GHG Emissions, EM_S (tonne CO_2e/MWh_e storage capacity)**
Cavern Development	16.2	1.2
Site & Buildings	36.7	3.0
Plant Electrical	65.9	4.7
Electrical T&D	14.2	1.0
Gas Infrastructure	130.5	9.2
Decommissioning	2.3	0.2
Total	**265.7**	**19.4**

4.3.2 Operation

Delivered Electricity and Energy Ratio

The net energy ratio, which includes the energy required to operate the air compressors, system auxiliaries, and cooling systems is calculated using equation 3.2, where ER_m represents cavern air leakage.

Previously installed CAES systems have energy ratios between 0.75 and 0.85.[37] Modern CAES facilities using dedicated compressor motors and generators, and improved cooling and heat recovery systems are expected to have a energy ratio of about 0.7.[38] The energy ratio for CAES systems is less than 1 because additional electricity is generated from natural gas combustion.

CAES site requirements result in transmission losses similar to those of PHS, and these losses increase both electricity and natural gas consumption.

Negligible leak rates have been demonstrated in both hard rock mines and salt caverns, resulting in an ER_m ~1.[39,40] No substantially energy-intensive maintenance on either a salt dome or hard rock cavern is expected over the life of the project.[41,42]

Natural Gas Delivery and Combustion

Previous studies of natural gas turbine systems demonstrate a substantial energy requirement for the exploration, production, and transmission of gas.[43,44] About 1 unit of natural gas is consumed to deliver 10 units of natural gas to a customer, which results in fairly substantial GHG emissions.

After heated air is extracted through a high-pressure turbine, it is mixed with natural gas fuel and combusted in the same manner as a traditional gas turbine. The heat rate (HR) of the combustion stage is 4536 kJ/kWh.[45] The largest component of direct plant emissions results from the combustion process. Using a standard emission factor of 0.503 g CO_2/kJ gas consumed, the CAES facility produces 228.3 kg CO_2e/MWh_e from the combustion of natural gas.[46]

Emissions Controls

Selective Catalytic Reduction (SCR) is commonly used in gas turbine power plants to reduce nitrogen oxide (NO_x) emissions.[47] SCR utilizes a catalyzed reaction between NO_x and ammonia (NH_3), which is injected into the exhaust gas stream. In the presence of a catalyst, NO_x, NH_3, and O_2 react to form nitrogen gas and water vapor. Energy inputs related to emissions controls are the production, transportation, and storage of ammonia, as well as the operations of the SCR equipment.

Life-cycle energy requirements and emissions evaluated by Spath and Mann[48] were adjusted to the CAES heat rate and emission standard[49] for this assessment.

Operation and Maintenance

Operation and maintenance includes all daily operations of the plant that have not been accounted for in construction or fuel usage. This includes repair and replacement of major mechanical and electrical components, as well as energy associated with cooling water acquisition and treatment. Energy and emissions data was calculated using EIO data and estimates for CAES O&M costs.[50]

4.3.3 Discussion of the Operational and Life-Cycle "Efficiency" of the CAES system

Calculating the overall efficiency of the CAES system is complicated by the use of supplemental fuel. The simplest method is to calculate the net thermal efficiency of the system:

$$\eta_{\text{thermal}} = \frac{1}{\text{HR} + \text{ER}_{\text{net}}} \tag{4.1}$$

where HR is the heat rate measured in kWh, reflecting the electrical energy content of the fuel.

While the η_{thermal} of the CAES system is only slightly greater than 50%, equation 4.1 ignores the substantial difference in quality between electrical energy and thermal energy. A more realistic evaluation is to calculate the net electrical efficiency of CAES storage by assigning an electrical energy value to natural gas based on the application. A common alternative to storage for peaking or renewable backup is a single-cycle gas turbine. The heat rate for a modern peaking turbine is about 9740 kJ/kWh (at full load and ISO ambient conditions) which corresponds to a thermal efficiency of 35%.[51] Each kWh produced by CAES requires 4649 kJ of natural gas, which if used in a peaking turbine would produce 0.48 kWh of electricity. Using this value it is possible to calculate the net electrical efficiency of the system:

$$\eta_{\text{electric}} = \frac{1}{(\text{HR} \bullet \eta_{\text{gas}}) + \text{ER}_{\text{net}}} = 0.83 \tag{4.2}$$

If the goal is to calculate the efficiency of the electrical storage process, or to compare CAES directly to other storage-only technologies, the amount of energy "generated" by natural gas combustion can be subtracted to isolate the storage efficiency of CAES:

$$\eta_{\text{storage}} = \frac{1 - (\text{HR} \bullet \eta_{\text{gas}})}{\text{ER}_{\text{net}}} = 0.71 \tag{4.3}$$

Calculated in this manner, the electrical storage efficiency of peaking CAES is 71%, which is slightly less than PHS. This method provides a reasonable measure of the efficiency associated with compressing and expanding air as a means of energy storage, but it is heavily dependant on assigning a electrical equivalency to natural gas. The electrical value of natural gas varies widely depending on application. While modern combined cycle gas turbines may have heat rates below 7000 kJ/kWh, such plants are uneconomical for peaking or intermittent backup. Alternatively, the heat rates of standard peaking gas turbines often exceed 10,000 kJ/kWh when operating under partial load or high ambient temperatures common in mid-day peaking conditions.

The life cycle efficiency for CAES can be calculated by replacing the ER_{net} term in equation 4.3 with the denominator term in equation 3.4.

$$\eta_S^L = \frac{1-(\mathrm{HR}\bullet\eta_{\mathrm{gas}})}{\mathrm{ER}_{\mathrm{net}}+\left(\mathrm{EE}_{\mathrm{op}}+\left(\frac{\mathrm{EE}_{\mathrm{stor}}\bullet P}{\mathrm{E}_{\mathrm{stor}}^{\mathrm{L}}}\right)\right)\bullet\eta_t} \tag{4.4}$$

Figure 4.4 provides a detailed flow of the life-cycle input energy requirements for 1 kWh of electrical energy delivered by CAES storage, including a 2.5% transmission loss rate on both the input and output sides of the system.

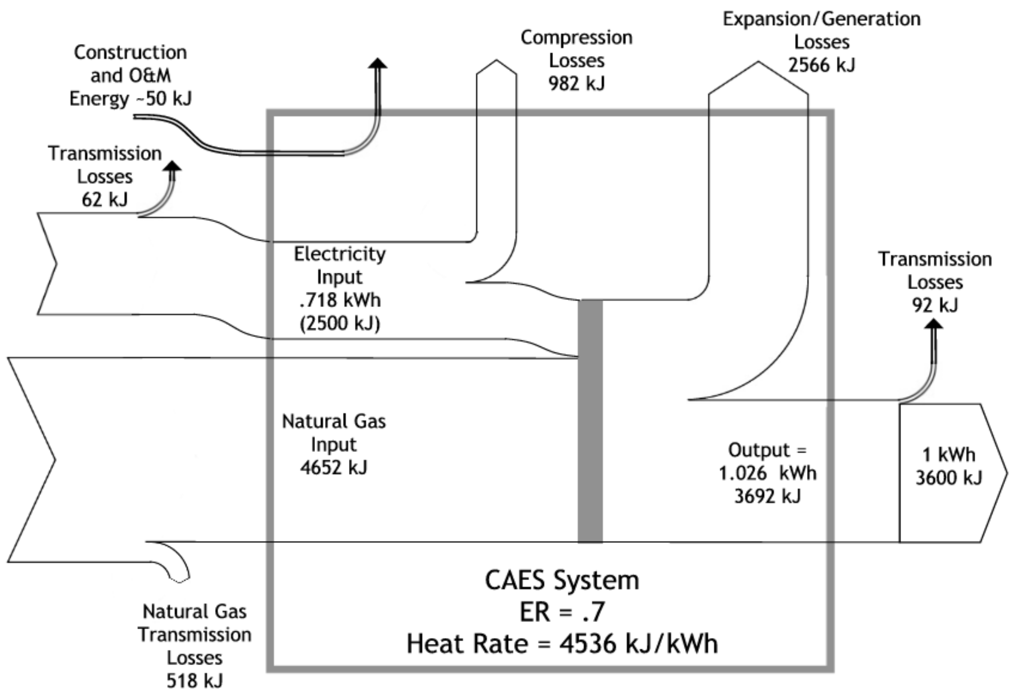

Figure 4.4: Energy Flow in Compressed Air Energy Storage

As can be seen, a majority of the energy requirements are from natural gas. A more detailed analysis of thermal losses in the CAES process is provided by Zaugg and Stys.[52]

4.3.4 Results

Table 4.5 shows the results of the CAES life-cycle analysis. Additional details are provided in Appendix C.

Table 4.5: Energy and Emissions Parameters for Compressed Air Energy Storage

Parameter	Life-Cycle Energy Inputs	GHG Emissions
Fixed Components		
Construction - EE_S, EM_S	266 GJ_t/MWh_e storage capacity	19 tonnes/MWh_e storage capacity
Variable Components		
Fuel	4649 MJ_t/MWh_e	234 kg/MWh_e
Fuel Delivery	518 MJ_t/MWh_e	51 kg/MWh_e
O&M & SCR	42 MJ_t/MWh_e	3 kg/MWh_e
Total Variable - EE_{op}, EF_{op}	5210 MJ_t/MWh_e	288 kg/MWh_e
ER_{net}	0.735 times primary energy	0.735 times source emissions

Average emissions and energy requirements can be estimated using a capacity factor of 20% and equipment life of 40 years. The generation of 1 MWh of electricity from CAES requires 0.735 MWh of electricity and 5270 MJ of thermal energy, of which only 49 MJ are related to construction and O&M, with the remainder comprised of natural gas fuel and fuel delivery. While the energy input requirements of natural gas exceeds the electricity requirements, it is possible to examine the energy distribution recognizing the greater "value" of electrical energy compared to thermal energy, as discussed in section 4.3.3. Figure 4.5 shows the distribution of CAES energy requirements considering the value of $1MJ_e = 2.5MJ_t$.

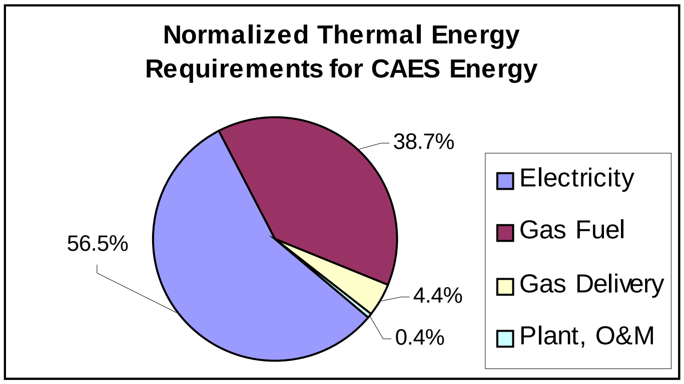

Figure 4.5: Distribution of CAES Energy Requirements by Source

Excluding primary electricity generation, the total GHG emission rate from CAES is 292 kg CO_2e/MWh. Direct CAES-related emissions mostly result from the combustion and transportation of natural gas.

4.4 Net Energy and Emissions - Battery Energy Storage (BES)

Utility battery storage is rare due to a variety of factors. Until recently, the only battery technology that was economically feasible was lead-acid batteries. These batteries are only marginally economic compared to non-storage alternatives such as diesel generators, and have substantial space and maintenance requirements. Lead-acid batteries also suffer from a limited life, which decreases rapidly if the battery is discharged below 30%.[53] This effectively reduces the energy density and increases capital costs. Lead-acid batteries are commonly installed in uninterruptible power supply (UPS) systems as well as off-grid applications such as renewable and fossil-based distributed power systems. There are a few utility-scale lead-acid BES systems in place. Two examples are the 20MW, 14MWh system in Puerto-Rico and the 10MW, 40 MWh system in Chino, California.[54] These systems are designed primarily to solve local power quality issues as opposed to bulk energy storage as demonstrated by their low energy/power ratio.

While lead-acid will likely be the choice for small renewable-storage systems for the near future, it appears that several new battery technologies are on the verge of surpassing the basic economic and technical performance of lead-acid batteries for large stationary applications. As a result, it is likely that future utility scale battery storage will be less likely to utilize lead-acid technology, but an analysis of lead-acid batteries is important for reference as the “base” technology.

Perhaps the most promising battery storage technology for large stationary applications to emerge recently is the flow battery. Flow batteries use liquid electrolytes that are pumped through a “stack” which contains either an ion-exchange membrane or an electrode array. Three electrolyte materials have been developed in recent years. These include Vanadium-Acid, Sodium-Bromide/Sodium-Polysulphide (trademarked as Regenesys) and Zinc-Bromine.[55,56,57] The Vanadium (typically referred to as Vanadium-Redox Battery or VRB) and Regenesys (referred to as Polysulfide Battery or PSB) batteries use an ion-exchange membrane similar to fuel cells, and are sometimes referred to as regenerative fuel cells (RFCs). These two technologies are the most flexible in size and best suited for very large storage applications, so they are the representative technologies evaluated in this study. Figure 4.6 shows a schematic of the basic RFC-type flow-battery components.

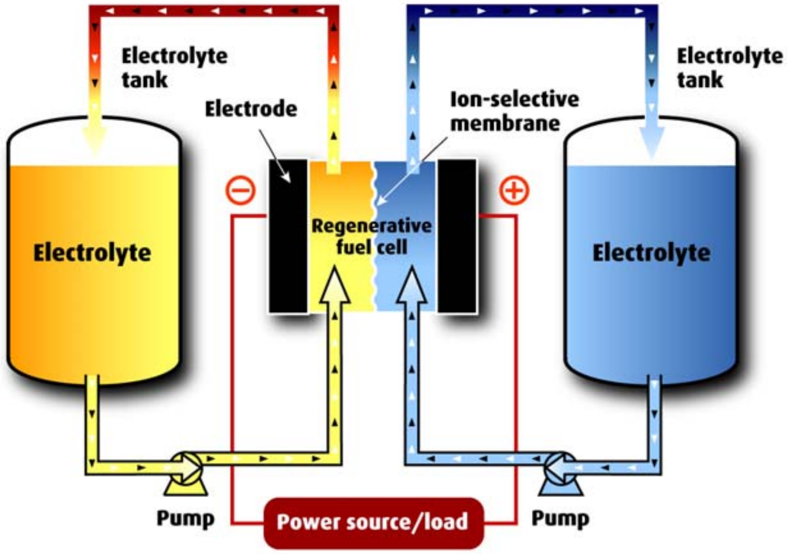

Figure 4.6: Flow Battery
(Courtesy Regenesys Technologies Ltd.)[58]

Features common to RFC-type flow batteries include:

- High depth of discharge (~100%)
- High cycle life (2000+ cycles)
- Flexibility in both power and energy, by the ability to vary both stack size and electrolyte tank size
- Reduced maintenance requirements
- Easier measured state of discharge
- Non- or low-toxicity components
- Size and shape flexibility of electrolyte storage
- Requirement of active components (pumps)
- Negligible hydrogen production with no venting or ventilation requirements

Large flow batteries are still in the very early stages of commercialization. A 2 MWh Vanadium battery was installed near Moab, Utah in 2003. A 15 MW, 120MWh Regenesys system was planned for installation near Columbus Mississippi, [59] but the Regenesys parent company discontinued technology development in the end of 2003.[60] The technology is still considered commercially viable and is now being pursued by other parties.[61]

Functional Unit Definition

This assessment assumes a large BES system with an energy/power ratio of 8 hours, which approximates the energy/power ratio of PHS and CAES systems. The lead-acid BES system is based on the Chino installation, while the PSB and VRB systems are based on the proposed TVA Regenesys project.

4.4.1 Plant Construction and Decommissioning

Site Preparation and Structures

A BES facility is typically much smaller than a PHS or CAES facility, largely because there are no geological requirements, fewer economy of scale factors, and because BES facilities can be placed close to the load. Site buildings are dependent on the type of battery: lead-acid batteries can be housed in a single enclosed structure, while flow batteries may use separate external storage tanks, depending on the application. The presence of potentially hazardous liquid electrolytes may restrict siting and require additional monitoring and containment equipment.[62] Figure 4.7 shows the basic features of a large 15 MW, 120 MWh flow battery system, including external electrolyte tanks, and an enclosed structure that contains the stack and PCS system. For a 120 MWh PSB, two freestanding electrolyte storage tanks are required, each with a volume of approximately 2 million liters.[63] A VRB system of similar energy capacity would require approximately 6 million liters of electrolyte.[64] The flow battery system would occupy approximately 1.6 hectares of a 5 hectare site.[65]

Figure 4.7: Artist's Rendering of a Complete Utility Scale BES system
(Courtesy Regenesys Technologies Ltd.)[66]

Capital Equipment

A complete BES system consists of the battery stacks, electrolyte materials and infrastructure, as well as the power conditioning system (PCS), which consists of AC-DC and DC-AC converters and regulators, and associated cooling equipment. The VRB and PSB are assessed equally for all components except for those related to the electrolytes and battery stack. Electrolytes were evaluated using PCA methods based on primary materials. Energy requirements related to the VRB battery stack are based on a previous study.[67]

For equal comparison, the lead-acid battery is oversized by 30%, due to its limited (70%) depth of discharge. During the plant lifetime, the lead-acid batteries will require replacement. This assessment considers the additional lead-acid battery components to be derived from a closed-loop recycling process.

Decommissioning

Decommissioning consists primarily of material scrapping and recycling, as well as site reclamation.

Results

Tables 4.6 and 4.7 show the results of the energy and emissions assessment for the construction and decommissioning of a complete BES system. Additional details are provided in Appendix D.

Table 4.6: Primary Energy Requirements for Installation of BES Systems

Component	Construction Energy Requirement, EE_S (GJ_t/MWh_e storage capacity)		
	Lead-Acid	**PSB**	**Vanadium Redox**
Battery Materials and Manufacturing	2017	943	1439
PCS and Balance of Plant	572	661	671
Transportation	132	87	79
Decommissioning and Recycling	98	64	64
Total	**2819**	**1755**	**2253**

Table 4.7: GHG Emissions Associated with Installation of BES Systems

Component	Construction GHG Emissions, EM_S (tonnes CO_2e/MWh_e storage capacity)		
	Lead-Acid	**PSB**	**Vanadium Redox**
Battery Materials and Manufacturing	144.9	66.8	102.7
PCS and Balance of Plant	38.1	47.0	47.7
Transportation	7.2	6.7	6.2
Decommissioning and Recycling	9.7	4.7	4.7
Total	**199.9**	**125.3**	**161.4**

4.4.2 Operation

Energy Ratio

While the electrochemical conversion efficiency for a battery cell can be very high, (in excess of 90% for the VRB,) additional loads substantially decrease the net efficiency of BES systems. Flow battery pumps decrease overall efficiency by approximately 3%, and active cooling requirements result in additional losses. Unlike PHS or CAES, batteries store and produce low voltage direct current, which requires solid-state AC-DC and DC-AC converters; losses associated with roundtrip AC-AC conversion are at least 4% and can be significantly higher depending on load conditions.[68] Manufacturer's data and operational experience for the complete BES system was used to derive an ER_{net} for each type.[69,70,71]

A substantial advantage of BES is the ability to place the unit at or near the point of use. There are no geologic requirements, and since there are no operation-related emissions, batteries can be placed near or in occupied buildings. BES units may be placed at substations for local voltage support, and may also provide additional economic benefits such as transmission and delivery (T&D) deferral and increased system reliability. This geographical benefit translates to substantially reduced transmissions losses associated with BES use as compared with CAES or PHS. Placement at substations reduces the incremental BES transmission distance to near zero.

Operation and Maintenance Requirements

There are no major consumables associated with BES operation, so additional energy requirements are derived primarily from system maintenance and repair. Energy and emissions requirements were calculated using EIO methods based on estimated annual maintenance costs.[72] Costs for lead-acid batteries are generally available, while O&M costs for flow-batteries is more difficult to assess due to a lack of an installed base. Flow batteries are expected to require substantially less maintenance then lead-acid batteries; primarily electrolyte evaluation, and periodic replacement of pumps and stack components. Large scale advanced BES systems do not require full-time manual supervision.

4.4.3 Results

Tables 4.8 and 4.9 show the results of the BES life-cycle analysis. Additional details are provided in Appendix D.

Table 4.8: Energy Parameters for BES Systems

	Lead-Acid	**PSB**	**Vanadium Redox**
Fixed Components			
Construction EE_S	2819 GJ_t/MWh_e stored	1755 GJ_t/MWh_e stored	2253 GJ_t/MWh_e stored
Variable Components			
O&M EE_{op}	62 MJ_t/MWh_e	54 MJ_t/MWh_e	45 MJ_t/MWh_e
ER_{net}	1.43 times primary	1.33 times primary	1.33 times primary

Table 4.9: GHG Emissions Parameters for BES Systems

	Lead-Acid	**PSB**	**Vanadium Redox**
Fixed Components			
Construction EM_S	200 tonnes/MWh_e storage capacity	125 tonnes/MWh_e storage capacity	161 tonnes/MWh_e storage capacity
Variable Components			
O&M EE_{op}	4.73 kg /MWh_e	4.3 kg /MWh_e	3.3 kg /MWh_e
ER_{net}	1.43 times primary	1.54 times primary	1.33 times primary

The average energy requirements and emissions factors associated with BES construction and operation can be calculated by applying an expected capacity factor of 20% and a battery life of 20 years. Excluding the stored electricity, life-cycle energy requirements are 706 MJ_t/MWh for Lead-Acid, 454 MJ_t/MWh for PSB, and 559 MJ_t/MWh for VRB. Lead-Acid emissions are 50.4 kg CO_2e/MWh while emissions for the flow batteries are 32.6 and 40.2 kg CO_2e/MWh for the PSB and VRB respectively.

4.5 Comparison of Storage Technologies

4.5.1 Construction Energy

BES systems have substantially greater (roughly 4-8 times) the energy requirements associated with plant construction compared to equivalent size PHS and CAES systems. Salt solution mining and earth dam preparation for CAES and PHS are relatively low in energy intensity compared with building structures to house battery components and electrolytes. The geologic components of CAES and PHS are also very long-lived compared to batteries. PHS and CAES use essentially energy-free storage media (water or air) as opposed to BES electrolytes, which require energy intensive mining and ore processing. Energy requirements for the power components of battery systems are also much higher than those for PHS and CAES. Turbines, compressors, and generators are simpler in terms of materials and manufacturing per unit power compared to battery electrodes, stacks, and PCS equipment. Batteries also require much more transportation energy, considering the large mass of electrolytes.

O&M energy requirements for BES systems are slightly higher than PHS or CAES systems, likely due to the comparatively complicated storage medium and power conversion equipment.

4.5.2 Operational Efficiency

The large variability in efficiencies makes a direct comparison between storage technologies complicated. The VRB has the highest net efficiency of about 75%, with PHS being only 1% lower. Both the lead-acid and PSB batteries have significantly lower round-trip efficiencies. The additional inefficiencies in PHS resulting from additional transmission is more than offset by the DC-AC conversion process, as well as heating, cooling and electrolyte pumping requirements from BES systems. As previously discussed, deriving a true efficiency for CAES requires a number of assumptions about the electrical "value" of natural gas, but the efficiency of the electricity storage component can be considered about the same as PHS.

4.5.3 Life-Cycle Energy and Efficiency

The parameters for calculating the life-cycle efficiency for each storage system are reported in Table 4.10.

Table 4.10: Life-Cycle Energy Parameters for Electricity Storage Systems

Parameter	**PHS**	**CAES**	**Pb-Acid**	**VRB**	**PSB**
Estimated Plant Life (years)	60	40	20	20	20
Estimated Capacity Factor (%)	20	20	20	20	20
ER_{net}	1.35	0.735	1.43	1.33	1.54
Construction and O&M* Energy Ratio (GWh_{in}/GWh_{out})	0.01	0.07	0.07	0.06	0.04
Fuel Energy Ratio (GWh_{in}/GWh_{out})	0	0.48	0	0	0
Life-Cycle Efficiency, η_S^L	**74%**	**65%**	**66%**	**72%**	**63%**

*Includes delivery of natural gas fuel for CAES

With the exception of CAES, the net energy requirements for storage systems are dominated by the input electricity, most of which is "passed through" the system. Identifying the sources of energy losses is of potentially greater value. Figure 4.8 shows the distribution of system losses for each MWh of electricity delivered by the energy storage system.

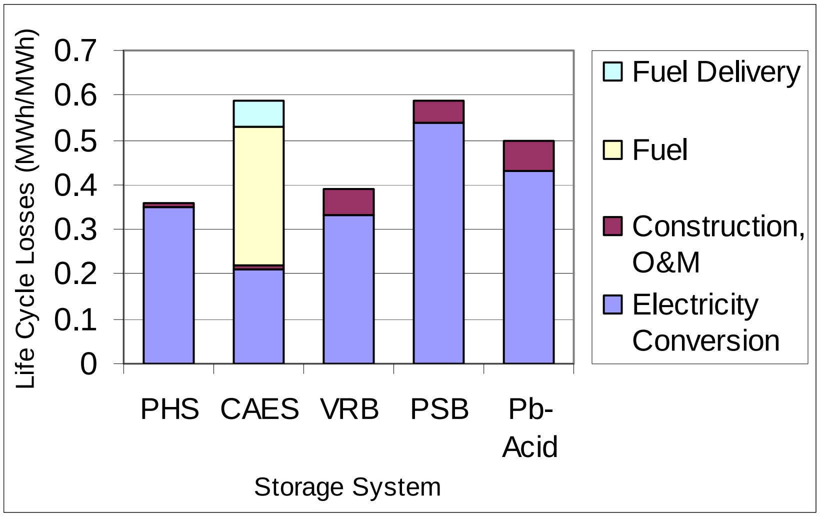

Figure 4.8: Life Cycle System Losses per MWh_e Delivered by Energy Storage

In the case of PHS and BES, the majority of losses occur due to storage inefficiencies, although considerable energy losses are associated with BES construction. Losses in the CAES system result primarily from natural gas combustion and storage conversion, however significant energy losses result from the transport of the natural gas fuel.

4.5.4 Life-Cycle Greenhouse Gas Emissions

Since greenhouse gas emissions are generally proportional to energy usage, the BES systems have substantially higher greenhouse gas emissions from construction and non-fuel related O&M than PHS or CAES systems of equivalent size. CAES has considerably higher emissions during operation than the other storage-only technologies due to its combustion of natural gas.

Figure 4.9 demonstrates the life-cycle GHG emission rate, defined by equation 3.5, as a function of the primary generation emission rate. For each storage technology, the Y-intercept value represents the life-cycle emissions resulting from construction and operation, calculated using the plant lifetimes and capacity factors in reported Table 4.11. The slope represents the net energy ratio.

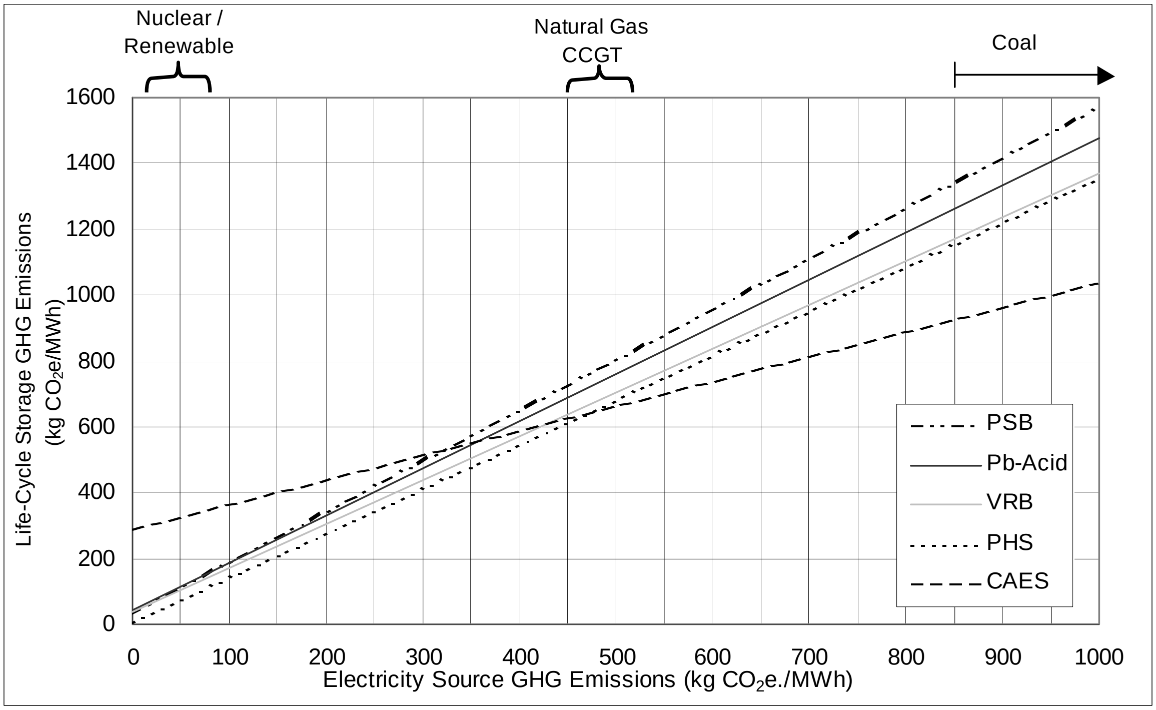

Figure 4.9: Life Cycle GHG Emissions from Electricity Storage Systems as a Function of Primary Electricity Source GHG Emissions

The three categories of generation are labeled on the top of the x-axis in Figure 4.9, based on emission rates provided in Table 3.1. The range of emission rates in Figure 4.9 reflects this large variation in primary electricity emissions. Due to natural gas combustion, CAES exhibits higher GHG emissions than PHS or BES when coupled to low GHG electricity generation. As emissions from the primary electricity generation increase, CAES becomes more favorable. The emissions rate from CAES equals the rate from non-combustion storage systems when the electricity source emissions rate is between 325 and 475 kg CO_2e/MWh. This value is equal to or less than the minimum emissions from currently available fossil generation technology. As a result, CAES is the lowest GHG emitting storage technology when coupled with gas, oil, and coal generation sources.

The unique features of CAES, including a low energy ratio (ER_s<1), and the use of natural gas for the "remainder" of the electricity generated results in a large difference of over 300 kg CO_2e./MWh between it and PHS or BES using current coal-derived electricity. The effect of "fuel switching" in the CAES system substantially reduces GHG emissions and makes CAES the preferred technology to store electricity derived from coal.

PHS and the VRB BES are generally similar in performance with regard to GHG emissions, with PHS having slightly lower overall GHG emissions due to lower construction related emissions. The low round-trip efficiency of the lead-acid and PSB batteries results in the highest level of emissions when coupled with fossil sources.

4.5.5 Future Developments

PHS is a very mature technology, with little forecast improvement for either energy input or efficiency. Improved turbines, along with other improvements in CAES technology are possible, although these improvements will be incremental in nature.[73] A number of improvements in BES systems could potentially improved their environmental performance. Improved electrolyte manufacturing techniques could decrease energy intensity, while increased efficiency of PCS may improve the round trip efficiency. Increased use of recycled materials would also dramatically reduce energy and emissions from BES systems. The VRB particularly could benefit from secondary material recovering from industrial processes.[74] The most significant improvement would likely result from the development of new electrolyte materials, with lithium based electrolytes currently being the most promising.[75]

4.6 Chapter References

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5. Analysis of Electricity Transmission and Distribution Systems

An analysis of electricity T&D increases the accuracy of an environmental assessment of electricity actually used by the consumer. Considering the effects of T&D provides a better basis to compare the environmental impact of different sources of electricity generation, as T&D losses vary among these different generation sources. As discussed in section 3, some intermittent renewable sources have unique T&D requirements that require inclusion of T&D effects for equal comparison to traditional sources. A life-cycle approach can be used to assess the effects of T&D losses, as well as effects related to construction and operation of T&D systems.

5.1 Introduction to Electricity Transmission and Distribution Systems

The T&D system consists of the various components required to deliver electricity from the generator to the consumer. The number of components required depends on both the type of generator and the type of customer.

5.1.1 Components of the T&D System

Transmission and distribution consists of several different levels of voltage and current, depending on proximity to generation or load. Power leaves a generator at high voltage and current, and voltages are reduced and current paths are split as the power flows towards the consumer. A general model of a typical T&D system is outlined below and illustrated in Figure 5.1. It consists of the following components:

a) Generation/Step-Up Transformer

Nearly all of the electricity used in the U.S. is generated at centralized power stations by rotating synchronous generators. These generators produce 60 Hz alternating current (AC) at voltages of 10-20 kV. This voltage is stepped up to the local transmission voltage, typically between 69-765 kV, depending on the generator's proximity to a load center.

b) Extra-High Voltage (EHV) Transmission Line (230, 345, 500 or 765 kV)

Large EHV transmission lines are designed to carry large amounts of power from very large distant power sources close to load centers. Large power generators, such as baseload coal and nuclear power plants, are typically located at some distance from population centers for environmental, safety, or aesthetic reasons. EHV lines typically carry 500-3000 MW.

c) Splitting/Switching Substation

These stations split the large EHV lines into multiple lines at a lower voltage, so that several large blocks of power can be brought closer to load centers.

d) High Voltage (HV) Transmission Line (115-230 kV)

HV Transmission lines bring large amounts of power, typically 100-1000 MW, to various points close to load centers. Intermediate load plants located close to load centers often tie in at this point.

e) Splitting/Switching Substation

Voltage is again lowered and split into multiple paths to better distribute the power within a load center. This lower voltage is often referred to as subtransmission.

f) Subtransmission Line (69-130 kV)

Subtransmission lines carry smaller blocks of power, typically 50-200 MW through load centers. Smaller peaking power plants that are located close to or within load centers often bypass the transmission level and tie in to the subtransmission system.

g) Distribution Substation

A distribution substation converts transmission or subtransmission voltage into distribution voltage, typically 5-35 kV. Substations are typically located within load centers, such as residential neighborhoods, or adjacent to end users, such as commercial or industrial facilities.

h) Distribution/Feeder Line (5-35 kV)

Distribution lines run through residential neighborhoods or commercial areas. Distribution lines in populated areas typically carry 5-50 MW each.

i) Service Transformer

The service transformer converts distribution voltage to end use voltage, typically 240/120 V for residential users. Service transformers are typically located within 100 meters of the end user. They are either mounted on poles and resemble large cans, or in areas with underground distribution, are placed in small above-ground structures.

j) Service Line (120/240 V)

These relatively short lines carry end-usable voltage to the consumer’s meter.

The voltage levels for transmission, subtransmission, and distribution are not strictly defined, and there may be some overlap in definition: 118 kV may be considered transmission in one system, and subtransmission in another.

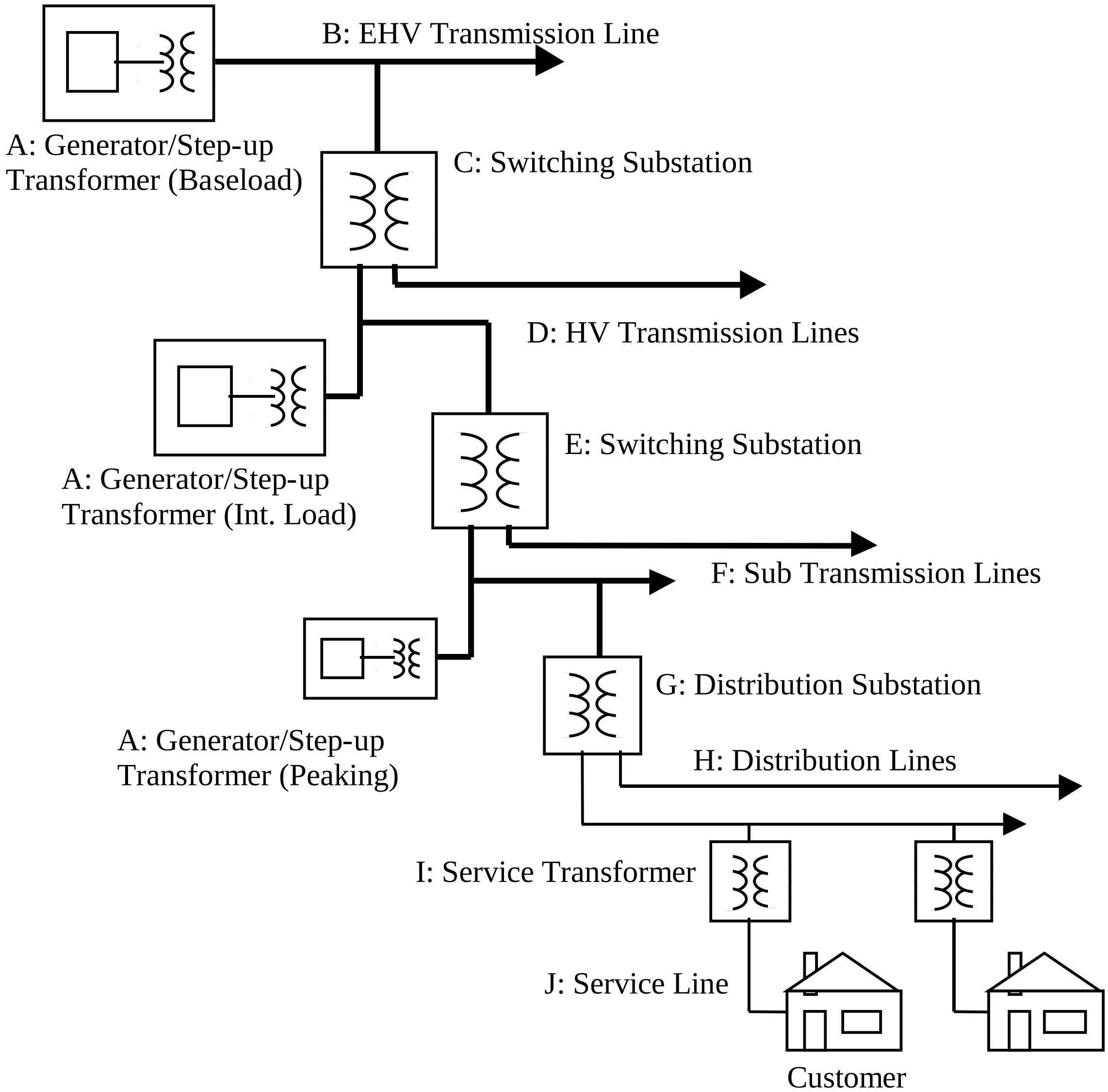

Figure 5.1: Typical Transmission and Distribution System

Electricity used by many residential and commercial facilities typically travels through five transformers and five sets of conductors, though there are many variations on this scenario. Many smaller generators are located within or close to load centers and bypass the transmission level, reducing the number of "paths" to 3 or 4. Industrial customers often receive power at higher voltages, and may bypass one or more sets of conductors and transformers. Distributed power sources such as solar PV systems may produce electricity at the same location it is used, and bypass the T&D system altogether.

Additional components in the T&D system are necessary for its safe and efficient operation, including meters, circuit breakers, switches, fuses, and electronic control systems. In addition, certain components are required to control the quality of electrical power. The voltage and current in AC power systems generally do not flow in step with one another. This quality, known as reactive power, can a have major impact on system operation, stability, and losses, and is discussed in more detail in section 5.3.

5.1.2 The Existing Transmission System in the U.S.

Bulk transfer of power between regions occurs mostly on EHV lines (230 kV and above.) There are approximately 254,000 km of EHV lines in the U.S.[1] Despite this extensive transmission network, the majority of electricity used in the U.S. is generated relatively close to its use. Traditional regulation has required utilities to be relatively self-sufficient in terms of meeting demand without depending on large amounts of external imports via transmission. In 2002, the net amount of electricity that flowed across state borders was less than 15%.[2]

5.2 Alternative Transmission Technologies

While the existing grid is dominated by overhead high voltage AC, there are a number of alternative technologies that are currently used, or may possibly be used in future transmission systems.

5.2.1 Underground Cables

Underground transmission is rarely used in the U.S., except in major urban centers. This is due to the relatively high cost of underground vs. overhead transmission lines. Both the cables themselves and installation are significantly more expensive, and underground cables typically have much lower thermal ratings since they are not naturally cooled by surrounding air.

5.2.2 High Voltage DC

Alternating Current (AC) is used almost exclusively in the transmission and distribution of electricity because AC voltage can be inexpensively changed using transformers. Despite this, high voltage direct current (HVDC) has a number of advantages over AC lines for transmission of power.[3] DC lines use only two conductors instead of three in conventional AC systems, reducing construction cost, right-of-way requirements, and visual impact. On equally sized systems, DC lines also have lower losses than AC lines. These two factors result in lower costs for DC systems for very long transmission distances. Over shorter distances however, the need for AC-DC and DC-AC converter systems results in higher costs for HVDC. Using current technology, the economic “break-even” distance is generally quoted as 500-800 km.[4] Reduced cost or increased efficiency of the converter stations would lower this break-even distance. There are a number of HVDC lines in the U.S. outlined in Table 5.1.[5]

Table 5.1: Major HVDC Transmission Lines in the U.S.

Project	Source/Load	Energy Source	Power (MW)	Length (km)
Pacific HVDC Intertie	Oregon/California	Hydro	3100	1361
Square Butte	North Dakota/ No. Minnesota	Coal (lignite)	500	749
CU	North Dakota /Minneapolis	Coal (lignite)	1000	701
James Bay	Quebec / New England	Hydro	2200	1500
Intermountain	Utah / California	Coal	1600	784

HVDC technology is a likely candidate for long distance transmission of wind power from the Midwest to distant load centers.[6]

5.2.3 Superconducting Transmission Systems

The use of superconducting materials has long been envisioned as an important component of future transmission systems. Superconductors conduct electricity without losses, and could greatly increase the amount of power flowing on a single line, reducing the need for large numbers of conductors to carry power.

Superconducting power cables are still in the development phase, with major use in this decade unlikely. [7] The largest planned project in the U.S. is a 2000-foot, 600 MW cable scheduled to be installed on Long Island, NY in 2005.[8] Superconducting transmission will not become a mainstream alternative until there are dramatic reductions in price.

5.2.4 Hydrogen

Hydrogen was not analyzed in this work for either its potential use as an energy storage or transmission mechanism because of its very high cost, low efficiency, and unlikely near-term application. The efficiency of long distance transmission of electricity via hydrogen is less than 50%, compared to at least 85% for transmission by wires due largely to the low efficiency of converting hydrogen into electricity. Even as a combined storage/transmission system it is far less efficient and cost effective than more conventional alternatives. Its only significant advantage is the potential ease of siting relative to long distance overhead lines.

Hydrogen is not currently competitive as an energy storage or transmission mechanism, but has been examined as an alternative energy “medium” to integrate renewable energy storage, transmission, and conversion to transportation fuel. The use of electric/hydrogen systems is often referred to as the “hydrogen economy” or “hydricity.” The development of such a system will probably depend on significant reductions (in excess of 90%) in the cost of fuel cells for vehicle applications.

Hydrogen could eventually be integrated with superconducting transmission technology. The proposed “continental supergrid” uses underground superconducting transmission cooled by liquid hydrogen.[9] These systems would carry both electricity and hydrogen from remote generation to major load centers. This very advanced technology will probably not be deployed before other renewable energy enabling technologies are needed.

5.3 Analysis of Transmission and Distribution Losses

Transmission losses occur in both conductors and transformers. A transmission loss factor for a delivered unit of energy requires understanding total losses in both the conductor paths and in the transformers between generator and load.

5.3.1 Conductor Losses

The power losses in a section of conductor are primarily a function of resistance and current, given by the relationship

$$P=I^2R \qquad (5.1)$$

Resistance is primarily a function of conductor type, size, line length, and temperature. Utilities choose conductor size and type by balancing the economic benefits of lower losses with the increased cost of more efficient conductors. Utilities also use the maximum possible voltage at each transmission stage, which keeps line current and system losses to a minimum.

Data on line resistance and voltage is easily obtainable, so an estimate of instantaneous losses can be calculated using equation 5.1 if line power flow is known. Determining average transmission line losses is more complex. Power flow through a conductor is seldom constant, and since transmission losses are proportional to the square of the current transmitted, it is not possible to simply multiply the total power transmitted by a constant loss factor. There are additional losses due to secondary effects, discussed in Appendix E.

In addition, reactive power effects can be substantial and must be considered. Reactive power results from the fact that the current and voltage in a conductor may not be in-phase. The result of reactive power is increased current flow for a given amount of power, resulting in higher losses. The amount of reactive power depends on system conditions, which vary over time.

Appendix E provides a sample loss calculation for a proposed Midwestern transmission line, and describes methods used by utilities to estimate conductor losses for planning purposes.

5.3.2 Transformer Losses

Transformers change voltage from one level to another to facilitate the transmission of electricity. Transformers pass current through coils of wire which creates a varying magnetic field which then passes through another coil of wire, inducing a current at higher or lower voltage. The voltage change is determined by the ratio of coils on the primary and secondary side. Losses in transformers are categorized as two types: load losses and no-load losses.[10]

Load losses are primarily a result of resistance in the transformer windings, and the losses vary with the amount of power being transmitted as described by equation 5.1. No-load losses result from magnetic inefficiencies in the transformer, and are independent of power consumption, similar in nature to “phantom loads” in appliances, which occur even when the device is turned off.

Due to the variation of load-losses, and other factors, average transformer efficiencies are easiest to determine by direct measurement. Typically, efficiencies for large transmission-level transformers are extremely high. Efficiencies for large utility transformers used at generators and substations are often above 99.8%. The total combined efficiency for the transformer sections associated with power transmission (items A,C, and E in Figure 5.1) can often exceed 99%.

Efficiencies for smaller distribution transformers and service transformers are much lower. Transformers are most efficient when operated at full load, and distribution and service transformers are typically used at much less than full load. Efficiencies of small distribution transformers are typically in the 98%-99% range, while service transformers are typically 96%-99% efficient. The high level of losses in service transformers puts an upper bound on the overall efficiency of the T&D system. At least 1% (and probably closer to 2%) of the electricity generated and delivered to low-voltage consumers in the U.S. is lost in the final transformer stage.

5.3.3 Transmission Loss Evaluation for Conventional Generation

In theory, deriving loss factors for a complete electric power system is possible, but would require a vast amount of data about the system. Data required would include:

- Composition and length of each transmission and distribution line.
- Total load on each transmission line at each moment, including power factor (a measure of reactive power.)
- Loss rate on each transformer.
- Total load on each transformer at each moment, including power factor.

Knowing the path of electricity flow is extremely difficult. Electricity may travel through many different paths at different times, so modeling the system requires knowledge of conditions throughout a region. Utilities and system operators use very powerful (and expensive) simulations to estimate losses for load forecasting and economic planning, and use vast amounts of often proprietary data to model regional T&D systems. Not only is certain data proprietary, previously available data is now restricted. FERC Form 715, which provides substantial details about transmission system loads, has been removed from the public domain since the Sept 11, 2001 terrorist attacks. In addition, many utilities, state agencies and system operators have also restricted public access to information about transmission systems. Without complete system data, estimating transmission losses from this “bottom-up” approach is unrealistic in anything but the simplest cases.

As an alternative to such calculations, publicly available loss data recorded by utilities and other electricity service providers can be used to reasonably estimate losses in T&D systems. Data from different electricity providers can be used to determine loss rates for various sections of the system, including local distribution, T&D within a region, or transmission of electricity between regions. Such methods are limited by the amount of data available, but can provide a reasonable estimate of T&D losses at the system level.

In general, transmission losses are a function of proximity of generator to load centers. Loss rates were evaluated for two general classes of generators: transmission level sources and subtransmission level sources.

Transmission level sources are plants generally located outside a load center, and feed into the EHV system. These are typically baseload sources such as coal and nuclear plants.

Subtransmission level sources are generally smaller power plants that provide intermediate load, or peaking service. A large fraction of these plants are natural gas and oil-fired turbines and reciprocating generators, although some smaller coal-fired plants operate partially as intermediate load and peaking facilities.

5.3.4 Transmission Loss Evaluation for Long Distance Transmission

Long distance transmission is used for a relatively small amount of the electricity used in the U.S. There are two general categories of long distance transmission. The first is transmission that occurs on multiple paths on the conventional EHV system. An example would be the flow of electricity from an existing generator in Minnesota to Chicago, where the electricity would flow along multiple lines, and be difficult to precisely identify. Average loss rates for long distance transmission must be quantified to facilitate deregulated market transactions. As a result, regional transmission organizations, such as the Midwest Independent System Operator, have developed estimates of average loss rates that occur between various systems, which can be applied to estimate losses between a specific generator and load area.

The second class of long distance transmission is the flow of electricity on a limited number of dedicated point to point lines, such as the two coal by wire HVDC lines running from North Dakota to eastern Minnesota. Loss rates for point-to-point transmission can be directly based on I^2R losses if the voltage, conductor properties, and load characteristics are known.

5.3.5 Distribution Loss Evaluation

While transmission losses are generally a function of distance, distribution losses are a function of both distance and customer type. Customer type may be categorized by the size and type of load. Distribution is a major component of power delivery to most residential and commercial customers, while industrial customers may bypass distribution completely.

Distribution losses were evaluated by examining loss rate records for utility systems that include only distribution. These systems include municipals, co-ops, and small local utilities, which meter their incoming electricity at a distribution substation. A total of 107 systems were examined. Utility and industry data can also be used to identify loss rate differences between customer classes.

5.3.6 Results

It is impossible to precisely determine the T&D losses for any particular class of generation technology or customer. However, analysis can provide a typical loss rate, as well as a typical loss range for a representative group. Given this limitation, Table 5.2 and 5.3 provides estimates for total transmission and distribution losses based on generator and customer class for utilities in the upper Midwestern U.S. The first data column in each table provides a typical or representative loss rate for each class. The second column provides the typical range of results

Table 5.2: Typical Transmission Loss Rates for Electricity Generated in the Upper Midwestern U.S.

Type	Typical Loss Rate (%)	Typical Loss Range (%)
Subtransmission-level Sources	0.5%	0.5-2%
Transmission-Level Sources (Urban)	1.8%	1-2%
Transmission-Level Sources (Rural)	3.6%	2-6%
Long Distance on EHV system	3.7%	2-10%
Long Distance on HVDC system	6.4%	5-9%

Table 5.3: Typical Distribution Loss Rates for Electricity Consumed in the Upper Midwestern U.S.

Type	Typical Loss Rate (%)	Typical Loss Range (%)
Urban Customers (Average of all types)	3.6%	2-8%
Urban Customer (Residential/Commercial)	4.1%	3-10%
Rural Customer (Average of all types)	6.3%	5-10%
Rural Customer (Residential/Commercial)	6.9%	5-12%

From Tables 5.2 and 5.3, a total T&D loss rate can be determined by summing the loss rates for the appropriate generator type and consumer. As an example, a typical urban residential customer receiving power from a baseload coal plant would incur a total T&D loss rate of about 5.9% (1.8% + 4.1%), while a typical loss rate for a rural residence would be about 10.5% (3.6% + 6.9%).

5.4 Analysis of T&D Operation and Maintenance

Operation and maintenance (O&M) of T&D systems results in emissions from two major sources. Fossil fuel combustion is associated with the periodic maintenance and replacement of T&D components such as lines, cables, poles and service transformers. In addition, certain transmission equipment releases sulfur hexafluoride, a potent greenhouse gas.

5.4.1 Energy Requirements and Emissions from System Maintenance

Emissions resulting from system maintenance can be estimated by applying economic input/output (EIO) emissions factors to annual maintenances costs reported by utilities. Expenditures for T&D related maintenance were compiled from 6 major utility systems, and 60 municipal electric systems in the upper Midwest for the years 2001 and 2002. EIO data was applied to this data to derive an effective emissions rate (kg CO_2e/MWh transmitted.)

Table 5.4 provides the results of the analysis, and includes a net T&D emissions rate for three customer types: urban/suburban, rural, and a weighted average of all types.

Table 5.4: GHG Emissions Rates for T&D System Maintenance in the Midwestern U.S.

Utility	T&D O&M Cost ($/MWh)	Energy Requirement (GJ_t/MWh)	GHG Emission Rate (kg CO_2e/MWh)
Urban/Suburban Utilities	3.12	1.5	1.5
Rural Utilities	7.03	3.5	3.5
Weighted Average	**3.45**	**1.7**	**1.7**

5.4.2 Sulfur Hexafluoride Emissions

Sulfur Hexafluoride (SF_6) is widely used as an insulating gas in large high-voltage circuit breakers and switchgear.[11] It has a number of useful properties, including chemical and thermal stability, and is non-flammable and non-toxic. Its primary disadvantage is its very high global warming potential, approximately 23,900 times that of CO_2 per unit mass. The SF_6 emissions associated with electricity T&D are primarily from leaks in older circuit breakers.

The U.S. EPA SF_6 Emissions Reduction Partnership program, tracks emissions of SF_6 from 65 electric utilities.[12] While emissions of SF_6 are not tracked by all utilities, emissions are generally proportional to transmission system size; estimates from reporting utilities can be applied to other utilities if transmission size is known. Total average SF_6 emissions were estimated based on various reporting utilities. [13,14]

Based on this data, GHG emissions associated with SF_6 emissions are roughly 1 kg CO_2e/MWh. A downward trend in SF_6 emissions has been reported by most utilities, due largely to replacement of older equipment and better handling practices, motivated by increasing costs of SF_6 supplies. Since most of the older leaking equipment has been upgraded, the EPA expects this downward trend to slow and future emission rates to remain roughly constant.

5.5 Construction Related Emissions

As with O&M, the emissions and energy consumption associated with T&D system construction produces "adders" that may be incorporated with other life-cycle aspects of electricity generation. This section provides the results of life-cycle analysis that estimates energy consumption and emissions related to construction of T&D components including transmission lines, and substations. Net GHG emissions that result from biomass losses in transmission line right-of-ways are also estimated. The results of this analysis may be used in several ways. Using data from individual components, a complete system may be “assembled” to determine the total GHG emission rate for a typical T&D system. This can be used to compare conventional generation to generation technologies that do not require T&D, such as off-grid renewable energy systems.

Another application of this analysis is to determine the additional energy and GHG burden that may result from the long distance transmission of distant energy sources such as wind, compared to conventional generation systems.

5.5.1 Analysis of T&D Lines

Overhead transmission systems consist primarily of conductors and support structures. Most conductors use aluminum reinforced with steel, referred to as “aluminum conductor, steel-reinforced” (ACSR). Transmission towers that support EHV lines above 345 kV are most commonly lattice-type structures constructed of steel and aluminum. A variety of structures are used to support lines at or below 345 kV and are made of materials such as wood, cement, and steel. There are many combinations of tower and conductor types. In this study, a representative sampling of tower and conductor types were chosen for each transmission voltage class and power level, with a total of 6 different overhead T&D line types.

Analysis primarily used PCA, based on material composition and mass, with EIO methods applied to construction and installation. Details of the analysis are provided in Appendix F.

5.5.2 Effects of Biomass Clearing

Development of transmission line corridors decreases the amount of vegetation present, and can produce a net increase in atmospheric carbon. To estimate the maximum increase in atmospheric carbon that results from T&D line installation, it was assumed that trees are cleared, but short grasses, brush and other vegetation remain. An average Midwestern forest, consisting of Pine, Spruce, Fir and Oak is estimated to contain 50-80 metric tons of carbon per hectare. This results in a CO_2 emissions factor of 18-29 kg/m^2 of forest cleared, if the forest is not allowed to regenerate.[15] Utility data for right-of-way (ROW) requirements were used to estimate total area required for typical transmission lines. Tree clearing for power line ROW can result in significant net GHG emissions. A new line that requires complete removal of trees can produce emission levels greatly exceeding those from line construction. As a result, GHG emissions from land use may be the most significant aspect of transmission line construction. However, the actual amount of emissions resulting from ROW development is generally much lower than the maximum value, since lines may follow roads, previously cleared land, or land with low density of trees. The majority of line distance in a T&D system is distribution, and most distribution lines follow roads and other cleared paths that would be developed regardless of the need for electrical transmission.

While underground lines are generally considered more environmentally friendly due to their reduced land use and visual impact, emissions from installation of underground lines may exceed those from overhead conductors, depending on the amount of biomass cleared for each type.

5.5.3 Results

Emissions related to the construction of transmission lines are potentially dominated by biomass losses. Table 5.5 provides the typical requirements for various overhead T&D lines, and the resulting *maximum* GHG emissions. In all cases, potentially more than 80% of the total GHG burden is due to the removal of trees in transmission line corridors. Details of the analysis are provided in Appendix F.

Table 5.5: Maximum GHG Emissions Resulting from the Development of Overhead Transmission and Distribution Lines

Line Voltage	Typical ROW Width (meters)	Typical Const. Energy (GJ_t/km)	Maximum GHG Emissions (tonne/km)	% of Emissions from Biomass (Maximum)
HVDC	50	1941	1,100	88%
500 kVAC	50	3059	1,100	81%
345 kVAC	37	1579	814	88%
230 kVAC	30	786	660	91%
69 kVAC	23	237	506	97%
Distribution	10	100-150	220	95%

A complete system analysis reveals a small GHG burden from T&D construction relative to other emission sources. To examine the total effect, the emissions associated with the construction of the T&D infrastructure for a large Midwestern utility (Wisconsin Electric Power, WEPCO) was examined. Data for the T&D system within the WEPCO service territory was obtained including total number of transmission lines and type, total length of distribution lines, and total number of service transformers and substations. Construction emissions factors were applied to each component. Complete information about the types of distribution lines was not available, so a range of estimates were used to account for the substantial difference between overhead and underground lines.

Three estimates were used to derive the emissions factors for T&D construction based on the system lifetime and amount of land consumed in transmission corridors. The worst case estimate, using a 20-year lifetime for all components and maximum land use for ROW found an emissions rate related to T&D construction of about 11 kg CO_2e/MWh. A more likely scenario found a rate of about 5 kg CO_2e/MWh, while a best case estimate produced a rate of about 2 kg CO_2e/MWh. While this range of results is large in percentage terms, the absolute burden from construction is quite small, especially compared to fossil generation and T&D losses.

5.6 Net T&D Effects for Conventional and Renewable Energy Systems

Using the results from sections 5.3 through 5.5, it is possible to estimate the impacts of T&D losses for different conventional and renewable energy systems.

Table 5.6 shows the life-cycle emissions associated with electricity used by a typical suburban or urban customer in the Midwestern U.S., including T&D effects, based on average losses associated with each generator class.

Table 5.6: GHG Emission Rates for Electricity Used by a Typical Residential Consumer in the Upper Midwestern U.S.

Local Generation Source/Type	Base (without T&D) Life-Cycle Emission Rate (kg CO_2e.MWh)	Estimated Typical Loss Rate (%)	Emissions resulting from T&D effects (kg CO_2e./MWh)
Coal	1049	5.9%	66
Nuclear	20	5.9%	4
Coal (Intermediate Load)	1180	4.6%	57
Gas Turbine (Intermediate Load)	562	4.6%	27
Gas Turbine (Peaking)	750	4.6%	36
Wind	20	5.9%	4
Distributed Solar PV	60	0%	0

The inclusion of T&D losses demonstrates a considerable increase over the base emission rates, particularly for fossil sources. The majority of the T&D effects are from losses, so the impact of T&D on non-combustion generation such as nuclear and wind is small.

5.7 Emissions Related to Electricity Sources Enabled by Long Distance Transmission

The ability of long distance transmission to export electricity from the upper Midwest may enable greater use of wind energy, but presents additional challenges to the goal of reduced air emissions. Of the four major HVDC lines located completely in the U.S., three of them were designed and built to deliver coal-derived electricity to major load centers. These “coal-by-wire” systems have a number of economic advantages over local coal generation. The price of transmission line construction and operation can be less than the cost of transporting large quantities of coal. This is particularly true for low energy content fuels such as lignite, which is available in large quantities in North Dakota. Power plants located near coal sources in Wyoming and North Dakota typically have variable electricity production costs at least 25% less than plants that receive coal via long distance rail. The two HVDC lines in North Dakota are fed by “mine mouth” generation facilities that have conveyor systems to carry coal directly from the mine to the power plant.

The most significant, largely exploitable wind energy resources in the U.S. include the low population areas of western North Dakota and eastern Wyoming. These areas also include much of the nation’s least expensive coal resources, including the Powder River Basin in Wyoming, and the rich lignite beds in North Dakota. The coincidence of these two resources presents a major challenge to the use of wind energy, both from a policy and economic standpoint. Current policy requires open access of transmission systems, which means that any transmission line built may not be restricted to any particular utility or fuel source.

There are several proposals to construct major coal by wire systems from Wyoming and North Dakota. These systems would employ HVDC technology to deliver electricity to major load centers in California and the Midwest. Some of these proposals include some wind energy, but only a relatively small fraction, compared to coal based generation. Without storage, wind is economically limited in terms of the fraction of energy it could produce in a combined coal/wind energy system, similar to the limits evaluated in Chapter 2.

The export of lignite-derived electricity is of particular interest for a number of reasons. Lignite is relatively cheap to extract through modern surface mining techniques, but is expensive to transport, due to its low energy density (energy/mass). This means that unlike Wyoming coal, lignite is particularly dependent on nearby transmission. The low energy content of the fuel also produces a higher GHG emission rate relative to other types of coal. Energy providers in North

Dakota have proposed the "Lignite 21" project which includes up to 2,000 MW of new transmission export capacity to be coupled to a new generation of lignite generation facilities.[16] The more ambitious TransAmerica Generation Grid (TAGG) proposes 18,000 MW of HVDC transmission coupled to 4,000 MW of wind, and 14,000 MW of coal, much of which is lignite.[17]

Table 5.7 reviews the properties of a new 1000 km, 1000MW HVDC power line. This type of line could provide electricity from lignite or wind energy from North Dakota to a major load center such as Milwaukee or Chicago. System parameters were based on similar long distance lines described in Table 5.1.

Table 5.7: Characteristics of a Hypothetical HVDC Line from North Dakota to Eastern Wisconsin or Northern Illinois

Voltage	+/- 450 kV DC
Power	1000 MW
Length	1000 km
Approximate Cost	$650 Million
Line + DC Converter Loss Rate	6.4%
Total Loss Rate (all T&D)	10.0%
Total Annual Losses (based on 85% system capacity factor)	745 GWh

Figure 5.2 illustrates the GHG emissions that would result from electricity delivered by a new HVDC line powered by a combination of lignite and wind.

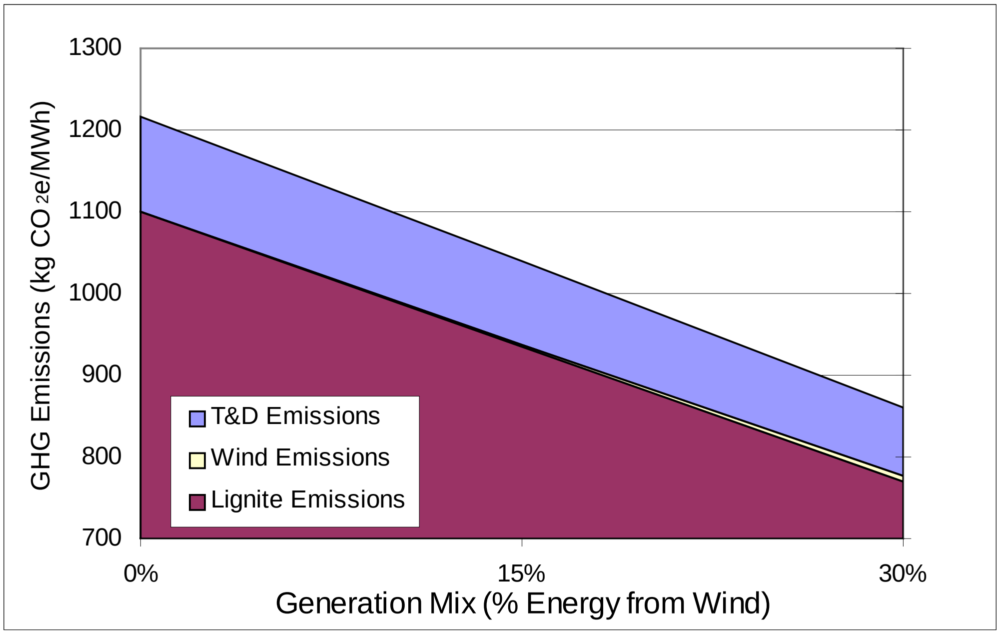

Figure 5.2: GHG Emissions from Electricity Exported from North Dakota

The combined lignite/wind system produces a relatively high GHG emission rate of over 850 kg/MWh, even when 30% of the energy is derived from the wind. (This proposed TAGG system derives only about 12% of its energy from wind.) The emissions related to T&D losses alone can exceed 100 kg/MWh.

If the construction of HVDC lines from areas rich in coal resources is not to produce such dramatically high GHG emissions, then wind must be competitive in terms of producing baseload quality power, directly comparable to coal based generation. The construction of baseload wind energy systems using storage is possible, and their energy usage and GHG emissions are evaluated in Chapter 6.

5.8 Chapter References

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6. Environmental Assessment of Integrated Renewable/Storage Systems

There are a number of likely combinations of intermittent renewable generation and energy storage, based on utility application and economics. Among the likely possible scenarios are wind/CAES, wind/PHS, and solar PV/BES.

Wind/CAES is the most likely possibility for near-term renewable storage systems in the U.S. The vast majority of the wind resources in the U.S. are located in the Midwest, which does not have the geologic features required for PHS, but does have many locations suitable for CAES.[1] There are currently two proposals for the development of CAES for wind energy storage in Iowa[2] and Texas.[3]

While wind/PHS is unlikely in the Midwestern U.S., there are sufficient wind resources and geologic features in the far western states for some wind/PHS development. The use of BES for wind storage is unlikely in the near future due to the high cost. The combination of solar PV and BES is possible for distributed and peaking power applications, although currently more expensive than many alternatives.

For these reasons, this analysis of renewable/storage systems focused primarily on wind/CAES, but provides an analysis of wind/PHS and PV/BES systems for comparison. The life-cycle energy efficiency and greenhouse gas emissions were evaluated for each of these three combinations of renewable generation and energy storage.

6.1 Environmental Analysis of a Wind/CAES System

Electric power systems in the midwestern U.S. are dominated by coal and nuclear systems. As previously discussed, these energy sources limit the operational flexibility of utilities and reduce the opportunity for intermittent wind energy to supply a large fraction of these region's energy supply. Wind energy generation, integrated with energy storage, can provide a source of power functionally equivalent to a baseload coal or nuclear plant, and may be considered as an alternative to these conventional sources. Baseload wind/CAES systems have been previously proposed, but not deployed due to the high cost of wind generation. The declining cost of electricity from wind turbines has now made such systems economically feasible,[4] and as a result, wind/CAES systems may become a significant part of future electric power systems in the midwestern U.S.

To evaluate the environmental performance of a baseload wind/CAES system, a simulation model was developed. (The combined wind/CAES system is referred to as a "baseload wind" system in the remainder of this section.)

The model develops a system that increases the capacity factor of a typical wind generator (25-40%) to a baseload level (greater than 70%),[5] and increases output stability, and predictability. The development of the model was strongly influenced by the constraints of electricity transmission. A high system capacity factor is required to maximize the use of expensive transmission assets. However, the transmission system also establishes the maximum output of the wind system. As a result, the model is designed to produce an amount of power that is equal to, but does not exceed a level established by the transmission capacity. The effects of losses in the transmission system were also considered in the model.

6.1.1 System Model

The Wind Energy Storage (WES) model uses a spreadsheet format (Microsoft Excel™) and simulates the hourly performance of a wind farm integrated with energy storage. Based on wind energy data and input parameters including storage efficiency and capacity, the WES model calculates the number of wind turbines and other infrastructure required to deliver performance similar to traditional baseload sources. The model compares the wind farm output to the target output on an hourly basis and attempts to provide constant power output by storing, or releasing from storage, the appropriate amount of energy. The objective of the WES model is to maximize the use of limited, capital-intensive transmission capacity to provide a constant amount of power equal to the size of the transmission system. Appendix G provides a logic diagram of the model, with sample input and output.

The performance of a wind energy system is dependent on a number of factors, including wind resource, turbine technology, and the size of the wind array. To consider these factors, a total of seven different cases were evaluated. Each case used at least one full year's worth of hourly wind data to consider seasonal variations in wind speed.

Two cases were created to evaluate the performance of modern, state-of-the-art baseload wind power plants. Case 1 simulates a medium size (in terms of traditional thermal generation) baseload power plant, with an output of 300 MW, located relatively close to a population center in the Midwestern U.S. Case 2 simulates a large baseload plant, with an output of 1000 MW, which could serve a significant fraction of the baseload energy demand of a large load center. The wind farm in Case 2 is located in a very remote, rural location, with excellent wind resources. Additional details about the two cases are provided in table 6.1.

Table 6.1: System Parameters for Simulated Wind Systems

System Parameter	**Case 1**	**Case 2**
System Size (Constant Power Output – MW)	300 MW	1000 MW
Hub Height (m)	80	100
Avg. wind speed at hub height (m/s)	8.2	8.7
Turbine Capacity Factor (%)	40.3	42.3
Distance to load center (km)	300 km	1200 km

Since very large wind farms using the latest turbine technology do not yet exist, hourly power data for these cases was simulated. Monthly average wind speed data from two likely wind farm locations was used to synthesize hourly wind speed data using a program created by the National Renewable Energy Laboratory.[6] This hourly wind speed data was then used to generate hourly power data based on the performance curve for a large modern turbine.[7]

Both simulated cases account for reduced system output due to periodic turbine maintenance, transmission losses within the wind farm, and array losses that occur in turbines situated downwind from neighboring turbines. (Transmission losses between the wind farm and the load center are considered separately). A total array loss rate of 12% was used, based on estimates from the U.S. Department of Energy.[8]

In addition to these two simulated cases, five cases were evaluated using data from existing wind farms. Three cases use data from existing midwestern U.S. wind power plants, provided by the National Renewable Energy Laboratory. Data from existing single wind turbines in North Dakota was modified (adding loss factors to simulate large arrays) to provide two additional cases.[9] The capacity factor for the existing wind turbine systems ranged from 33.1% to 37.3%. Since existing wind farms for which long term data is available use smaller, less efficient turbines than are currently being deployed, these cases likely represent the lower limit of system performance for new baseload wind systems located in the midwestern U.S.

CAES System

Performance of CAES is based on the analysis in Chapter 5. This analysis assumes that a kWh of electricity generated by the CAES turbine requires 4649 kJ of fuel plus 0.735 kWh of compressor electricity. CAES efficiency and heat rate are considered constant in all cases.

The size of the cavern in this study is measured in terms of the number of hours the CAES turbine can run at full output. Actual storage size would be dictated by economic and geological constraints. The results reported in this study assume a CAES system with a total storage time of 24 hours at full load.

Transmission Loss Effects

New transmission development will be required to deliver baseload wind energy to load centers. To evaluate the effect of transmission losses, two transmission systems were used. Case 1 assumed a 300 km, 345 kV AC system, while Case 2 used a 1200 km, +/- 500 kV HVDC system. Using data from chapter 5, the transmission loss rate, L_T, is estimated at 3% for the AC line and 10% for the HVDC line. Data from existing wind farms was modified to reflect a 3% transmission loss rate. These loss rates were incorporated using the transmission multiplier effect in equation 3.6.

System Optimization

Figures 6.1 and 6.2 provide sample profiles of a 2-week period for two possible wind-CAES operating scenarios, which demonstrate the need for system optimization. In each operating scenario, hourly wind energy data from a fixed wind turbine capacity is used to create a baseload source with a different target output level. The WES model then combines this target output level with other constraints such as storage size, to calculate the operational parameters including capacity factor and spill rate.

Short and long-term variations in wind speeds and limited storage capacity size cause overproduction and underproduction to frequently occur in both operating scenarios. Overproduction occurs when the storage cavern is full and when the wind output is greater than the maximum system output, resulting in unused, or “spilled” energy. It is assumed that transmission constraints prohibit this excess output from entering the grid. Underproduction occurs when storage cavern reserves have been depleted and extended periods of low wind conditions cause the total production to fall below the desired output level. It is assumed that an operating utility will avoid energy shortfalls by purchasing and storing inexpensive off-peak power as necessary.

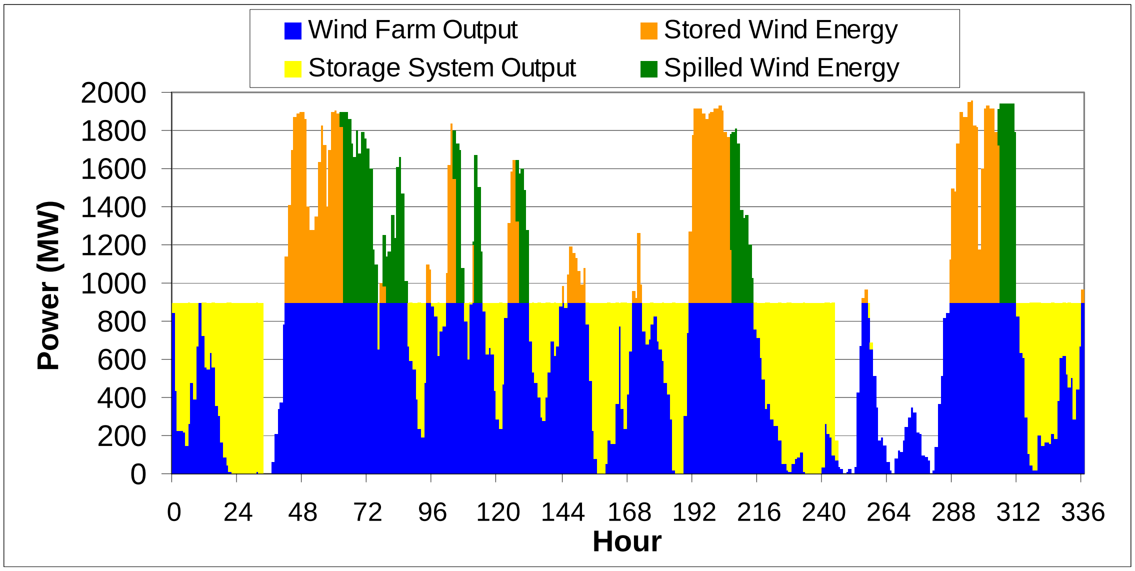

Figure 6.1: Sample Baseload Wind Generator Output (Target Output = 900 MW)

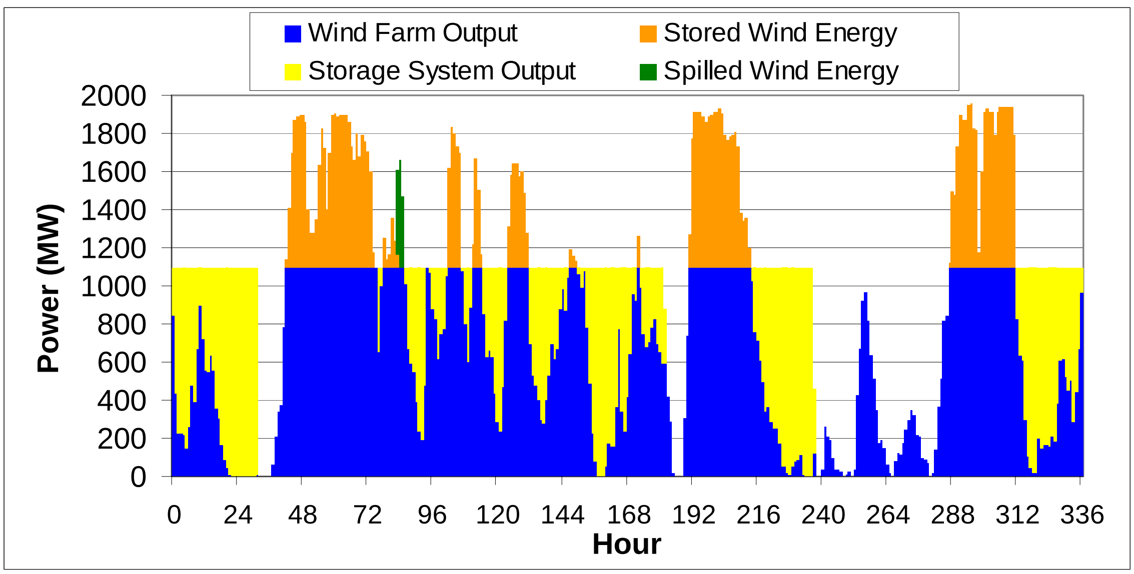

Figure 6.2: Sample Baseload Wind Generator Output (Target Output = 1100 MW)

Figure 6.1 illustrates a scenario where the constant output level is set to 900MW, resulting in an overall capacity factor of 90% for the two week period illustrated. To achieve this high capacity factor, a relatively large amount of wind energy is placed into storage. However, this also causes a greater amount of spilled energy, relative to Figure 6.2. In Figure 6.2, the constant output is set to 1100 MW, resulting in a lower spill rate, and a lower capacity factor (about 84% for the two week period illustrated.).

Energy storage systems allow utilities to take advantage of inexpensive off-peak power to fill depleted storage reservoirs and “ride-through” periods of low wind conditions. Thus, operating utilities will likely choose lower spill rates over higher capacity factors because the cost of off-peak energy from existing baseload plants is typically much less than the cost of building new wind energy.[10] The use of off-peak power for energy storage would be limited by availability of this resource, as well as the desire to avoid increasing emissions at existing fossil plants. The baseload wind systems analyzed in this study are not designed nor intended to serve as peaking power plants or energy price arbitrage systems. Rather, they are designed to produce new baseload capacity from a renewable source. The system impact of the use of energy storage for fossil-energy price arbitrage is addressed in Chapter 7.

Figure 6.3 shows the wind energy spill rate as a function of system operating capacity factor for the seven evaluated cases. The gray lines show performance of the five cases that use data from existing wind farms. The dark lines show results from the simulated cases. All of the existing wind farms can achieve capacity factors greater than 70% with spill rates under 10%, while the simulated cases achieve greater than an 80% capacity factor with a 10% spill rate.

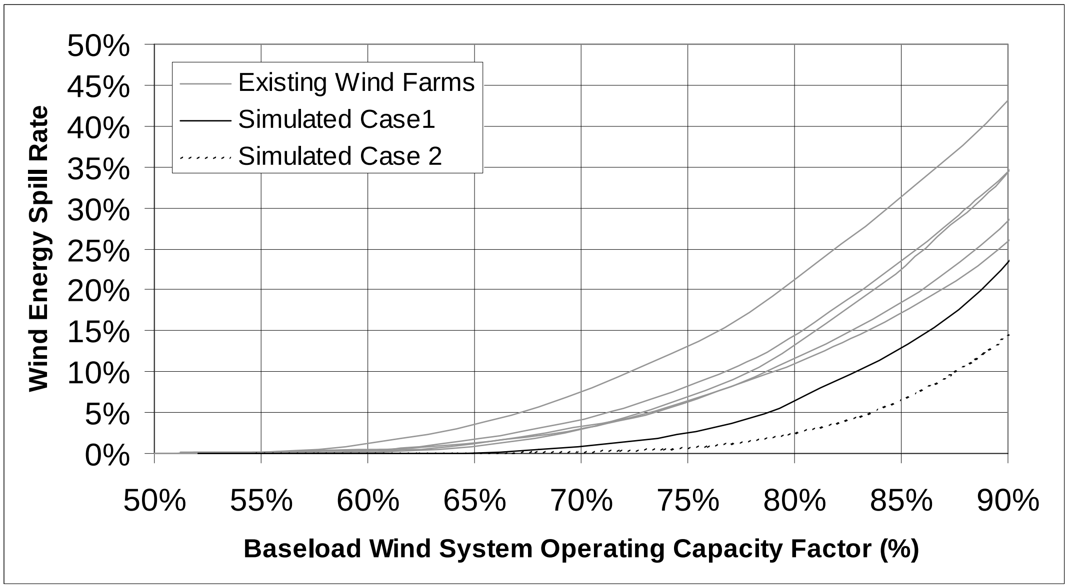

Figure 6.3: Spill Rate vs. Operating Capacity Factor for the Seven Baseload Wind Cases

While the evaluated cases used a fixed 24-hour storage time, economic or technical considerations may dictate a different storage time to optimize storage capital costs with the costs associated with different spill rates. Figure 6.4 illustrates the spill rate as a function of storage time for different capacity factors using data from Case 1. This figure illustrates that for any given storage size, spill rate and capacity factor are inversely related and shows that both high capacity factors and low spill rates are possible from baseload wind systems given sufficiently long storage times. Figure 6.4 assumes the storage and transmission system are 100% reliable. Assuming that very large storage times and high spill rates are uneconomic, this case appears to be limited to a capacity factor of about 90%. This limit is mostly a result of the significant seasonal variations in wind energy, and can be compared to conventional thermal generation. Given the appropriate level of demand, top performing coal or nuclear plants can achieve a 90-95% capacity factor, while lower values (80-85% for coal) are more common.[11]

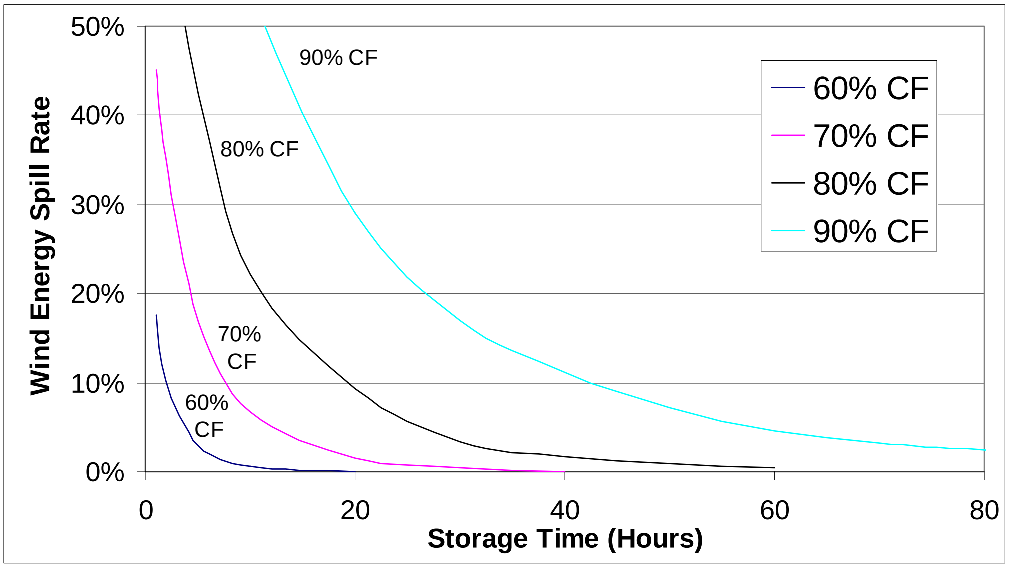

Figure 6.4: Wind Energy Spill Rate as a Function of Storage Time for Baseload Wind Case 1

Ultimately, capacity factor and spill rate are input parameters to the system model that in reality would be a function of economic rather than technical criteria. A real world system would use an economically "optimized" spill rate. The WES model evaluated systems with capacity factors ranging from 50%, where no energy was spilled, to 90%, where spill rates would likely be considered uneconomic. However, results are generally reported for the likely operating regime, which is considered to be operation with a capacity factor between 70%, which represents the approximate lower limit of what may be considered a baseload system, and 85%, which likely approaches the economic limit of most cases, in terms of spill rate.

6.1.2 Model Results

The WES model provides a number of technical performance indicators that may be used to evaluate each system's environmental performance. The two most important factors are the peak power ratio and the system fuel consumption rate.

The peak power ratio represents the number of units of wind turbine power capacity required to deliver 1 unit of constant power. A baseload wind energy system operating at a capacity factor of 100%, using an ideal storage system that is 100% efficient and has unlimited capacity, has a peak power ratio equal to the reciprocal of the wind farm capacity factor. For example, a wind farm with turbines operating at a CF of 33% requires 3 MW of turbines for an average output of 1 MW using an ideal storage system. A wind energy system using a pure storage system such as pumped hydro would require a greater peak power ratio to compensate for storage inefficiencies, which are reflected in a storage energy ratio (ER_S) greater than 1. Since the hybrid CAES system has a storage energy ratio less than 1, the peak power ratio for a wind/CAES system is substantially reduced, representing a tradeoff between increased wind turbine requirements and increased fossil fuel usage (and resulting greenhouse gas emissions.) Figure 6.5 illustrates the peak power ratio as a function of system capacity factor for the various cases. The two simulated cases show much lower peak power ratios than the results from existing wind turbines, a result of the projected increase in turbine capacity factor.

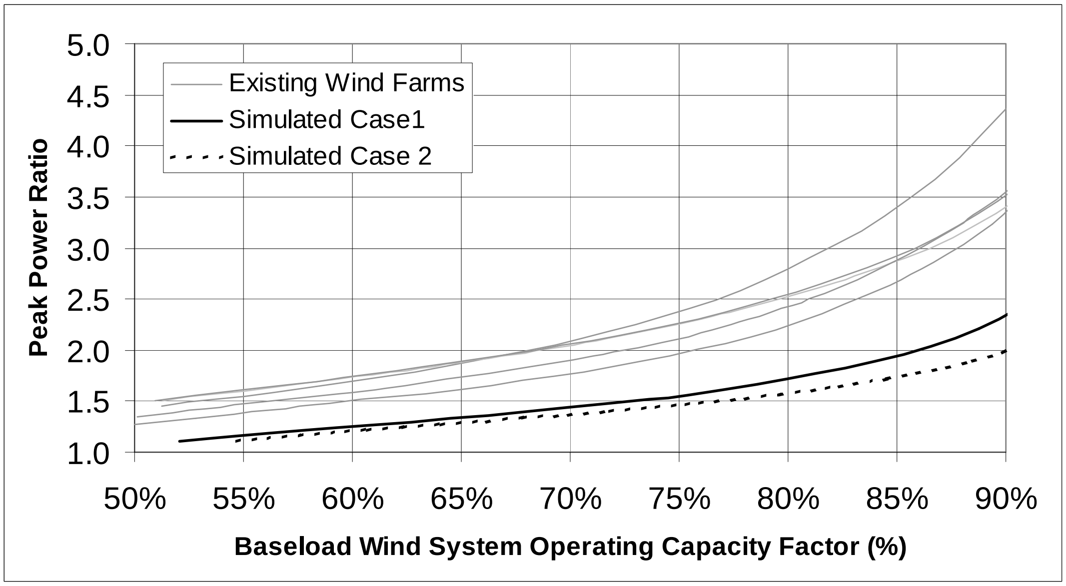

Figure 6.5: Peak Power Ratio vs. Operating Capacity Factor for the Seven Baseload Wind Cases

Figure 6.6 illustrates the system fuel consumption rate, or heat rate, defined as the CAES fuel energy input per unit of total system output, excluding transmission effects. For systems operating at a 70-85% capacity factor, the heat rate ranges from roughly 800- 1350 kJ/kWh, and can be compared to a traditional fossil plant heat rate, which is typically 7,000-12,000 kJ/kWh.[12] At higher capacity factors, the simulated cases demonstrate higher heat rates than most of the existing wind farms. This is due to the simulated cases' greater use of storage. For a given capacity factor, the simulated cases spill less energy, and instead store it and use it in the CAES turbine, resulting in higher fuel usage. Figure 6.6 provides additional information about system operation. The system heat rate, divided by the constant CAES heat rate (4649 kJ/kWh,) is the fraction of electricity ultimately provided by the storage system, which ranges from 17-29% for the cases operating at 70-85% capacity factor.

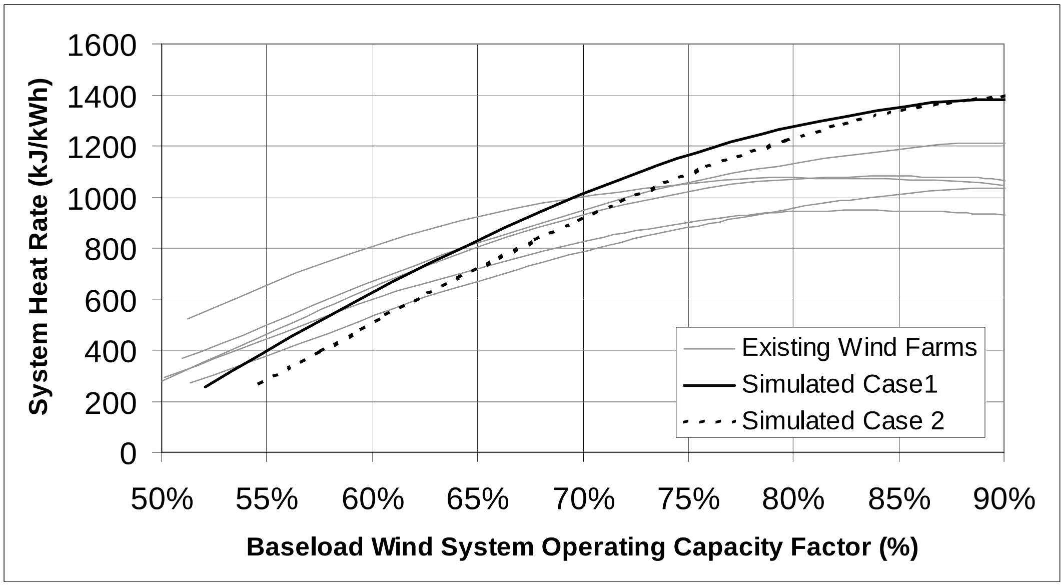

Figure 6.6: System Heat Rate vs. Operating Capacity Factor for the Seven Baseload Wind Cases

Table 6.2 summarizes the output parameters for various cases in their likely operating regimes (70-85% capacity factor, using 24 hours of storage).

Table 6.2: Operational Parameters for Baseload Wind Systems Operating with a Capacity Factor of 70-85%

Operational Parameter	**Case 1**	**Case 2**	**Range of Results for 5 Existing Wind Farms**
Wind Energy Spilled (%)	1.0-12.7	0.2-6.5	3.0-31.2
Peak Power Ratio	1.4-1.9	1.4-1.7	1.8-3.4
System fuel consumption (heat) rate (kJ/kWh)	1011-1356	915-1335	783-1187

6.1.3 Environmental Assessment

The life-cycle fossil energy efficiency and greenhouse gas emissions were assessed for each case using the operational data from table 6.2 and a component analysis of the wind and CAES subsystems.

Component Analysis

This study used existing life-cycle analyses of wind energy systems to derive the energy use and emissions associated with modern wind turbines.[13,14] Life-cycle energy requirements and emissions related to CAES and the transmission system were based on analysis performed in chapters 4 and 5. Case 1 and the existing wind farms are assumed to use the AC transmission line, while Case 2 uses the HVDC line. Details of the component analysis for construction and operation of the wind/CAES system are provided in Appendix G.

Emissions and energy requirements for recharging the CAES reservoir from external sources during low wind periods are not considered in this analysis. This is justified given the relatively high capacity factor of the system, which is comparable to a conventional baseload plant. The net emissions reported for most conventional systems include only emissions during operation. For example, the net emissions from nuclear and coal-fired power plants do not include emissions from other sources that replace their output during refueling or maintenance outages.

Fossil Fuel Efficiency

Fossil fuel efficiency is described in section 3.4.2. This measure of energy use is particularly relevant to wind/CAES systems, since natural gas fuel is a major system input.

Fossil energy is required to construct and operate baseload wind systems. The energy related to plant construction and decommissioning may be expressed as the total construction-related energy, EE_P (MJ_t), divided by the lifetime output of the storage plant E_L (MWh_e). The life of the plant is assumed to be 30 calendar years. Energy for CAES fuel (natural gas) is reflected by the effective fuel consumption rate, or heat rate (HR_{eff}), of the entire system (MJ_t/MWh_e). Other operation and maintenance (O&M) energy requirements are reflected in EE_{op} (MJ_t/MWh_e) and include requirements such as transportation fuel for site personnel, operation of CAES emissions control equipment, and the construction and installation of replacement parts.

The total life-cycle fossil fuel efficiency η_L (MWh/MJ), for the baseload wind/CAES system can be expressed as:

$$\eta_L = \frac{1}{HR_{eff} + EE_{op} + \frac{EE_P}{E_L}} \tag{6.1}$$

Greenhouse Gas Emissions

The life-cycle greenhouse gas emission rate is described in section 3.4.3. The construction emissions rate is expressed as the total construction-related emissions, EM (kg CO_2e) divided by the lifetime electrical output of the system, E_L (MWh). Emissions related to the CAES fuel consumption are a function of the system fuel consumption rate (HR_{eff}) and the emissions factor for the CAES fuel, EF_{gas} (kg CO_2e/MJ). Emissions related to wind and storage plant O&M are given by EF_{op} (kg CO_2e/MWh). The complete life-cycle emissions factor, EF_L (kg CO_2e/MWh), is then defined as:

$$EF_L = \left(HR_{eff} \bullet EF_{gas}\right) + EF_{op} + \left(\frac{EM}{E_L}\right) \tag{6.2}$$

6.1.4 Results

Details for the calculation η_L and EF_L are provided in Appendix G. Table 6.3 summarizes the results of the environmental analysis of the baseload wind systems for the likely operating regimes, defined as operating capacity factors between 70-85%.

Table 6.3: Life-Cycle Environmental Parameters for Baseload Wind Systems Operating at a 70-85% Capacity Factor (Including Transmission)

Environmental Parameter	Case 1	Case 2	Range of Results for 5 Existing Wind Farms
Life-Cycle Fossil Fuel Efficiency (%)	210-275	190-275	230-330
GHG Emission Rate (kg CO_2e/ MWh)	80-103	83-113	69-96

Figure 6.7 provides the range of results for the fossil-fuel efficiency analysis of the various cases. The evaluated cases demonstrate high levels of energy resource sustainability, indicated by fossil fuel efficiencies greater than 100%, which is superior to any fossil fuel-based system.

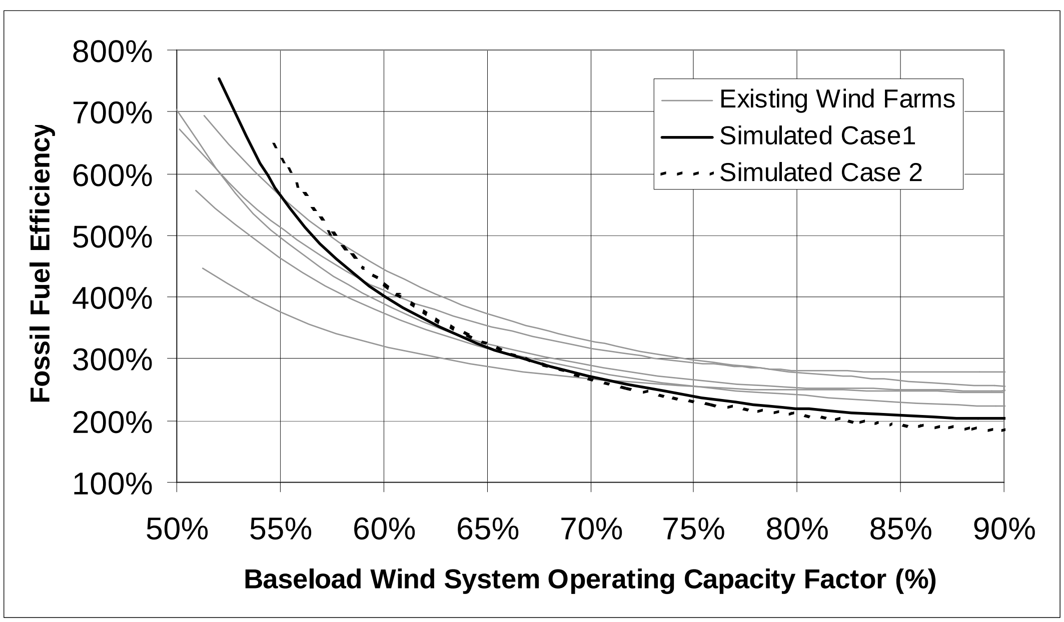

Figure 6.7: Life-Cycle Fossil Fuel Efficiency vs. Operating Capacity Factor for the Seven Baseload Wind Cases

Figure 6.8 illustrates the distribution of fossil energy inputs for a delivered unit of electrical energy from Case 2 when operating with an average capacity factor of 80%. Most of the energy input is the CAES fuel, which requires about 80% of total energy input requirements when considering both the fuel and fuel delivery.

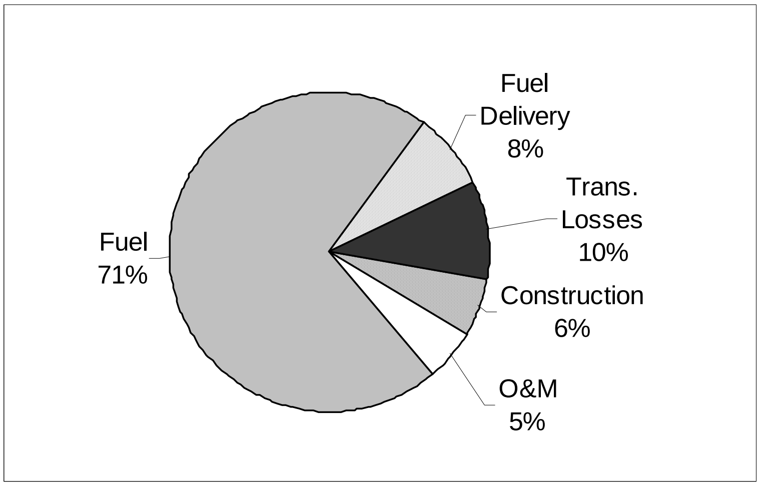

Figure 6.8: Distribution of Energy Sources for Baseload Wind Case 2 Operating at an 80% Average Capacity Factor

Figure 6.9 provides the range of greenhouse gas emission rates for the various baseload wind cases.

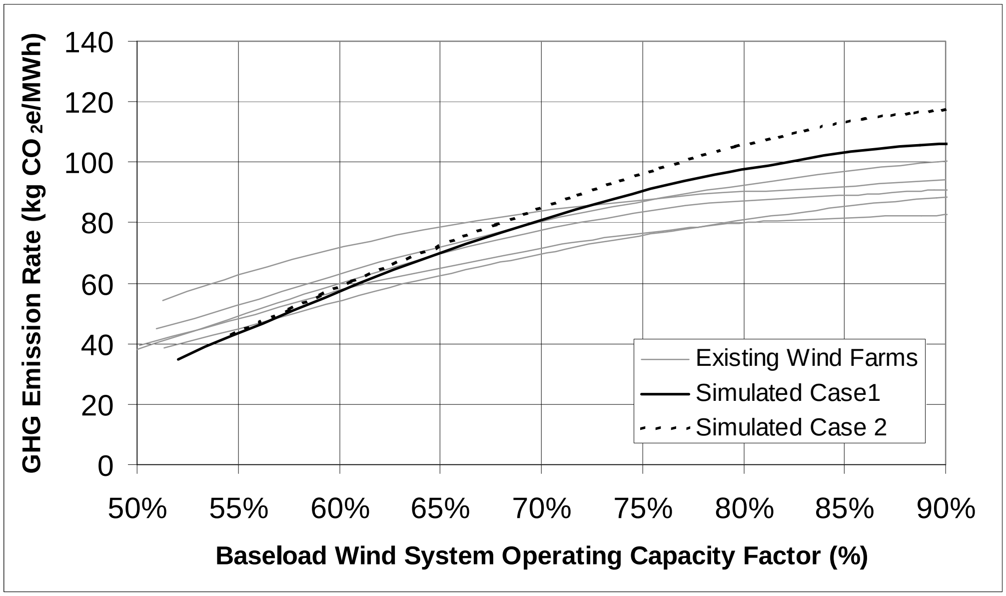

Figure 6.9: System GHG Emission Rate vs. Operating Capacity Factor for the Seven Baseload Wind Cases

The dominant source of air emissions from the wind/CAES system is natural gas combustion. This is illustrated in Figure 6.10, the distribution of GHG emissions from Case 2 when operating at a system capacity factor of 80%.

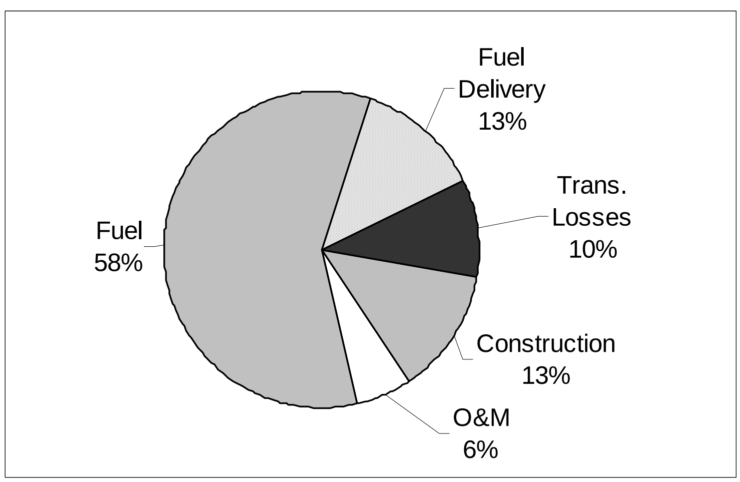

Figure 6.10: Distribution of GHG Emissions Sources for Baseload Wind Case 2 Operating at an 80% Average Capacity Factor

As can be expected, the distribution of sources is similar to Figure 6.9, since there is a general relationship between energy use and greenhouse gas emissions. The lower fraction of emissions from the CAES fuel shown in Figure 6.10 is due to the lower GHG emission rate of natural gas compared to the higher carbon content fuels used for construction and transportation. Emissions related to biomass clearing also increases the relative share of emissions from initial construction.

Figures 6.8 and 6.10 shows that system fossil fuel efficiency and GHG emissions are relatively insensitive to the parameters related to system construction and O&M. A 50% reduction in construction-related emissions results in a life cycle GHG emissions reduction of less than 7%. The most significant factor affecting the environmental performance of these baseload wind systems is the consumption of natural gas fuel reflected in the heat rate. As the system capacity factor increases, more energy is placed into storage, and consequently, more gas is burned in the CAES turbine. This results in an increase in the greenhouse gas emission rate, and a decrease in fossil fuel efficiency.

Substantial increases in environmental performance would require a change in the storage system, such as an increase in the CAES turbine efficiency. Use of a storage system that does not require fossil fuels could dramatically increase the fossil fuel efficiency and decrease the net GHG emissions. An alternative, wind/CAES system, independent of fossil fuels, could burn renewably-generated hydrogen, although this is probably uneconomic based on the current cost of electrolytic hydrogen.[15] Biofuels are another alternative to natural gas for the CAES system, if CAES remains economically superior to advanced batteries or other forms of electrical energy storage.

6.2 Environmental Analysis of Wind/PHS Systems

As previously discussed, large scale deployment of wind/PHS systems is unlikely due to the non-coincidence of wind resources, PHS geography, and land availability. However, some development of wind/PHS systems may occur, although on a smaller scale than wind/CAES systems. For example, the proposed Alta Mesa facility in southern California consists of about 28 MW of wind generation and a 70 MW, 420 MWh PHS plant.

The performance of a wind/PHS system is primarily a function of the amount of wind energy stored and the capacity factor of the wind system. Details of the Wind/PHS analysis are provided in Appendix H. Figure 6.11 provides a range of results for the fossil-fuel efficiency of wind/PHS systems with wind energy storage rates from 10-50%, and three different wind generator capacity factors.

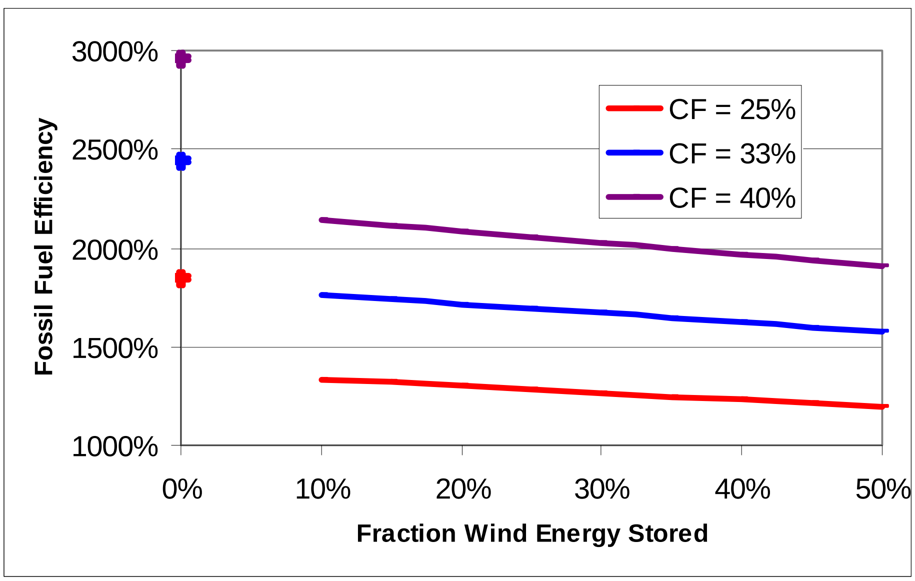

Figure 6.11: Fossil Fuel Efficiency of Wind/PHS Systems

The points on the far left of Figure 6.11 (0% wind energy stored) show the fossil-fuel efficiency of wind energy used without storage. The obvious discontinuity on the graph is due to the lack of energy required to construct the PHS system in the non-storage case. The worst case wind/PHS system produces more than 10 units of electrical energy per unit of fossil energy – and effective fossil fuel efficiency of more than 1000%.

Figure 6.12 provides the range of results for the life-cycle GHG emissions over the same range of operational parameters. It also demonstrates the substantial reduction in life-cycle emission rate when storage is not required.

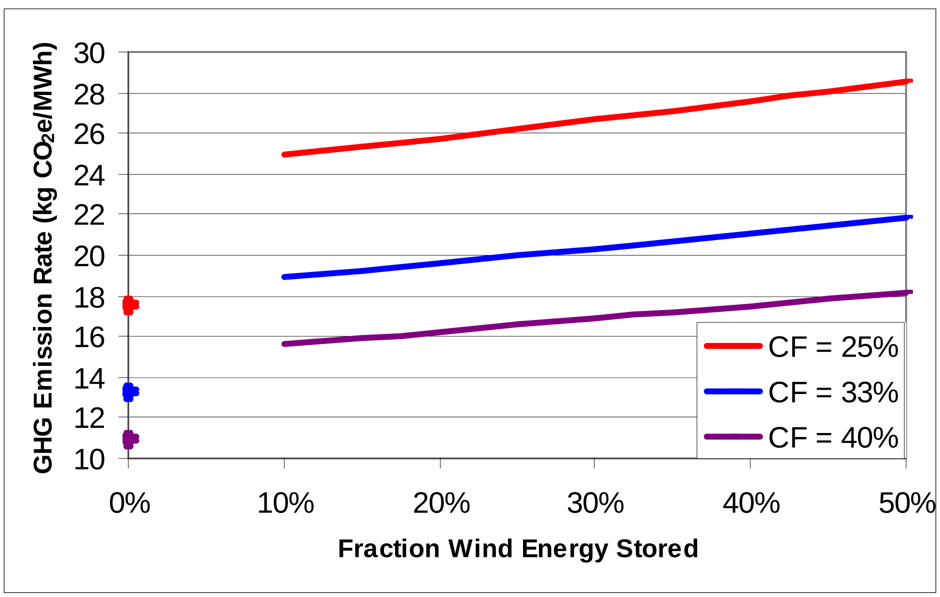

Figure 6.12: Life-Cycle Greenhouse Gas Emissions of Wind/PHS Systems

6.3 Environmental Analysis of PV/BES Systems

A common proposal for solar PV is to provide peak-load generation to offset peaking power and T&D requirements. The operation of a PV/BES system in this manner would be similar to the operation of wind/PHS system, with PV energy stored to maximize its value during peaking conditions. Both the amount of energy stored and the relative size of the PV/BES components will vary according to local conditions. Similar to the wind/PHS analysis, a range of operational conditions were evaluated, based on previous studies of PV/BES systems.[16] For this assessment, the PV storage fraction was varied from 10% to 50%. The energy and emissions data from an 8 kW solar PV system[17] is scaled to a 50 kW system, with a 25 kW, 200 kWh storage system. The system performance is heavily dependant on location and solar insolation. Effects of different locations and other system details are provided in Appendix H. Figures 6.13 and 6.14 provide the results of the analysis for fossil fuel efficiency and greenhouse gas emissions of a PV/BES system, based on the fraction of PV energy stored. As with the wind/PHS system, the results of a non-storage case, where no BES system is constructed, is shown for comparison in each graph.

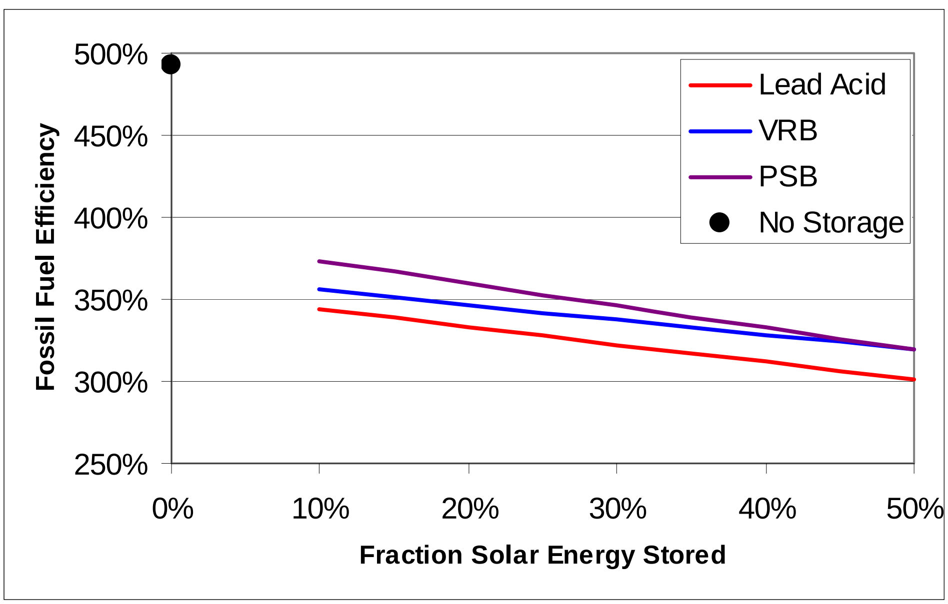

Figure 6.13: Fossil Fuel Efficiency of PV/BES Systems

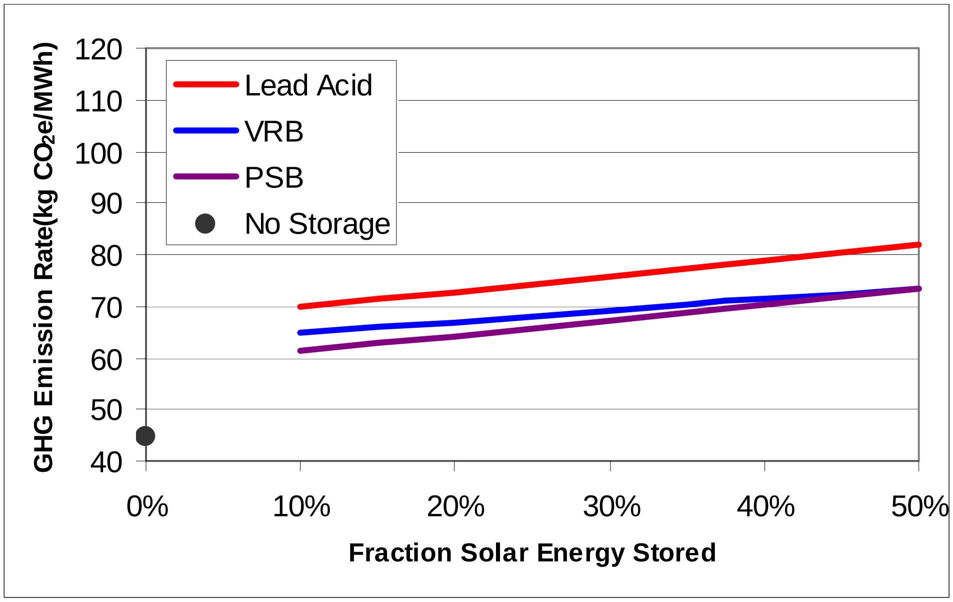

Figure 6.14: Life-Cycle Greenhouse Gas Emissions of PV/BES Systems

The addition of storage substantially reduces the fossil-fuel efficiency, and increases the emissions rate for the resulting dispatchable solar-energy system. The energy intensity of a PV-storage system is reflected in the high price of electricity from this system. For these technologies to be economically viable, the cost, and corresponding energy intensity, must decrease substantially.

6.4 Conclusions and Comparisons

The analysis of renewable energy systems combined with storage can be compared to the previous analysis provided in table 3.1. For a uniform comparison, T&D effects were included for all sources, with a 6.5% T&D loss factor added to fossil and nuclear generation. Figure 6.15 compares fossil fuel efficiency, while figure 6.16 compares life-cycle GHG emissions.

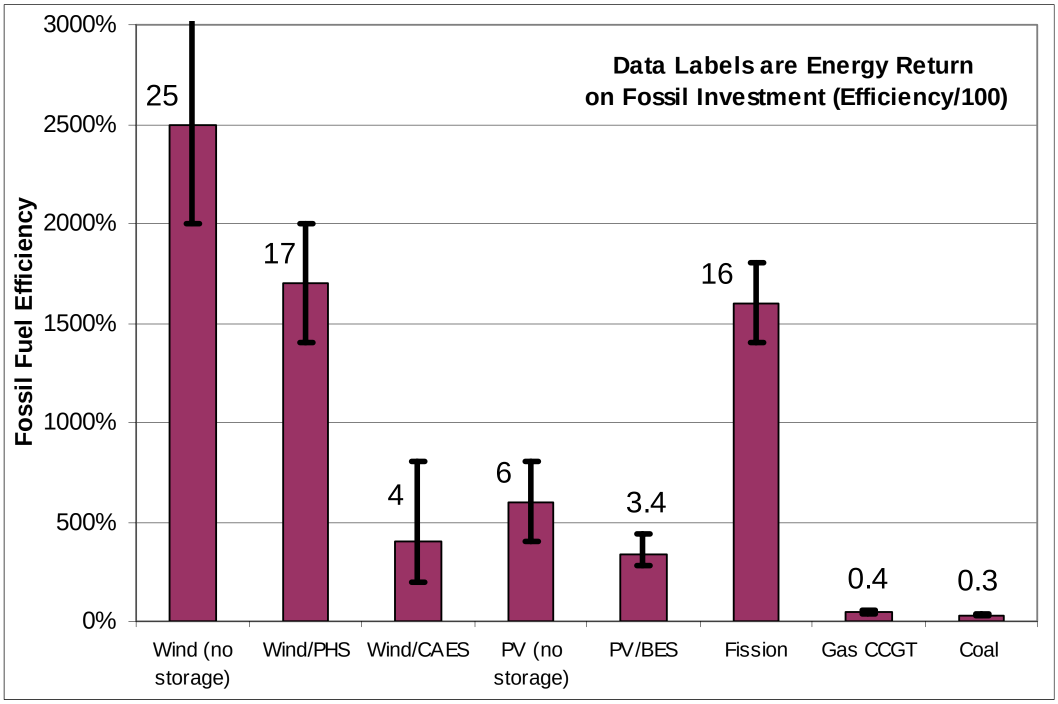

Figure 6.15: Life-Cycle Fossil-Fuel Efficiency for Electric Power Generation (Including T&D)

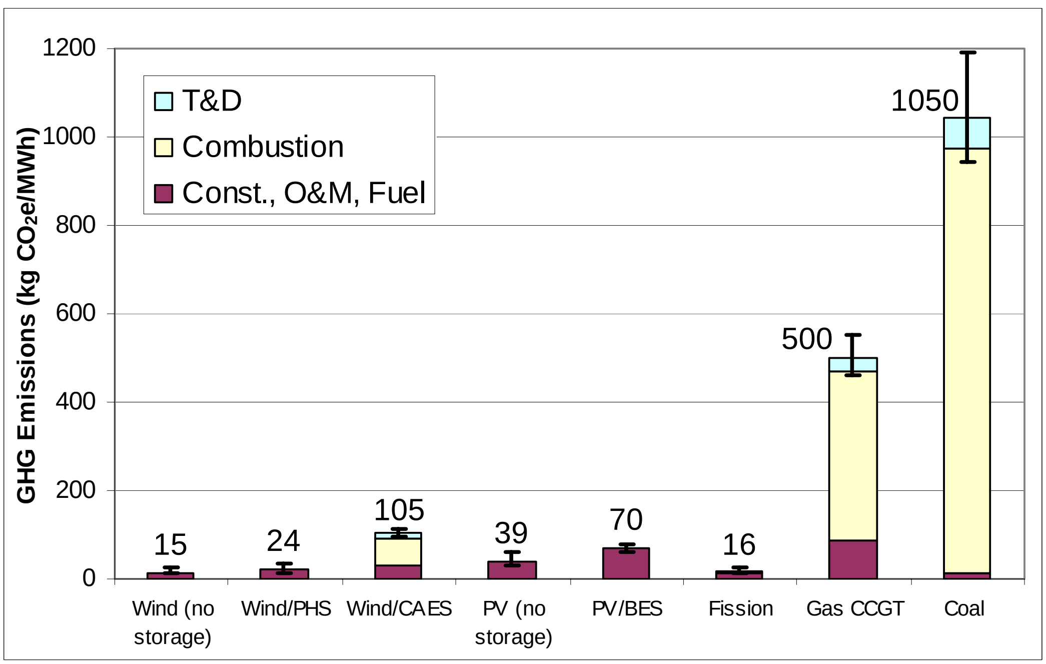

Figure 6.16: Life-Cycle GHG Emissions from Electric Power Generation (Including T&D)

The labels for each technology in Figures 6.15 and 6.16 represent a typical value, while the error bars represent the range of results from this study (for renewables) or from previous life-cycle studies for fossil and nuclear generation.[18]

Figure 6.17 provides a more detailed examination of GHG emissions from non-fossil based energy sources.

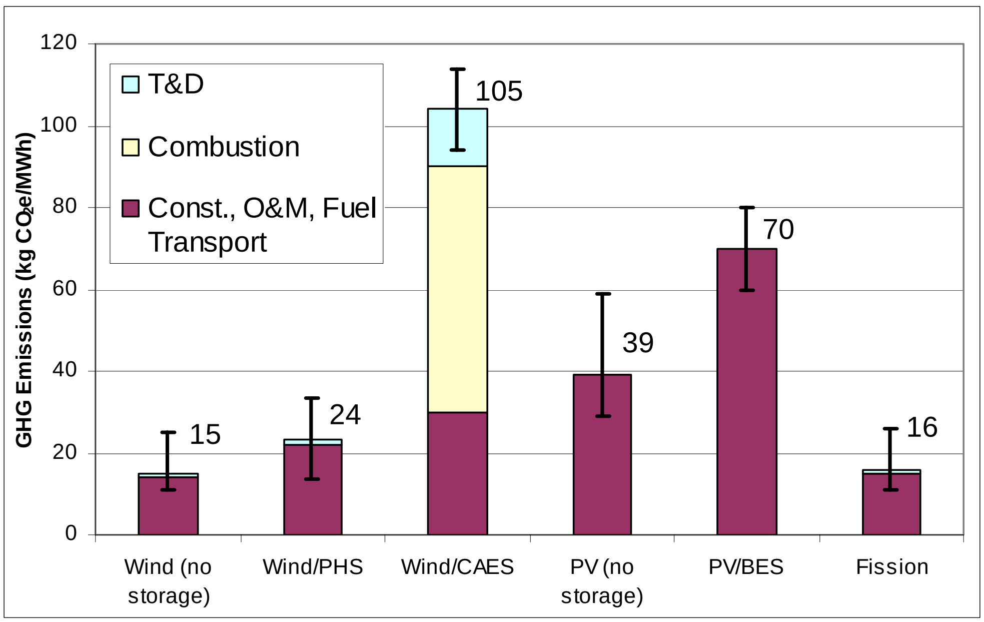

Figure 6.17: Life-Cycle GHG Emissions from Non-Fossil Based Electric Power Generation (Including T&D)

There is significant variation for each non-combustion technology, including nuclear energy. There are a number of reasons, but one of the more important reasons is the origin of energy to construct and operate each energy production technology. Emissions that result from the construction and operation of non-combustion energy sources result from the current dependence on fossil fuels, which varies by region. It is important to recognize that as the overall energy system is decarbonized, the life-cycle emissions from these sources will drop as well.

While the addition of storage substantially reduces the fossil fuel efficiency of all renewable energy systems, their life cycle efficiency remains substantially higher than any fossil based system. The use of natural gas fuel in CAES results in a significant difference between the two wind/storage systems. Wind/PHS shows a fossil fuel efficiency of over 1600%, producing more than 8 times more electricity from a unit of fossil energy than the wind/CAES system. Despite the decrease in performance resulting from CAES operation, the least efficient wind/storage system evaluated produces greater than 4 times more electricity per unit of fossil input than a highly efficient combined-cycle gas turbine.

The relatively poor fossil efficiency of the PV/BES system results from the combination of highly energy intensive generation and storage technologies.

The wind/PHS system shows emission levels that are not significantly higher (in absolute terms) than wind without storage. The wind/CAES net emission rate of 69-113 g CO_2e/kWh for the various analyzed cases is significantly higher than the life-cycle emission rate of wind without storage or nuclear-generated electricity. The PV/BES system's high energy intensity is reflected in its' relatively high GHG emission rate, relative to other non-combustion energy sources. The emission rate from all dispatchable renewable energy systems is substantially lower than any fossil technology.

The use of energy storage with renewable energy systems increases their value to electric power systems. As a result, even though their environmental performance decreases, this decrease is likely offset by their increased capacity credit and system-wide impacts. As the capacity credit of intermittent renewable energy systems is increased, they will likely displace a larger amount of fossil-generated electricity, and provide greater overall environmental benefits, since the life-cycle emissions rate and fuel efficiency of a renewable energy/storage system is significantly better than any fossil fuel generator.

6.5 Chapter References

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7. Environmental and Policy Assessment of Energy Storage used with Fossil Sources

The analysis in Chapter 4 found that electricity delivered from energy storage when coupled to low-carbon energy sources, such as nuclear and renewable energy, produces far less GHG emissions than fossil generation sources. Chapter 6 demonstrated that integrated renewable energy/storage systems also deliver relatively low levels of carbon emissions. While these results indicate that energy storage may be an effective tool in lowering carbon emissions from electricity generation, near term applications of energy storage may not have a net positive impact on carbon emissions, or emissions of harmful air pollutants.

The proposed Norton CAES plant is designed to use inexpensive, off peak coal generation, and resell this energy at times of higher demand. This application raises an interesting question of how the effective emissions from this plant should be measured and regulated. Any conventional generator must meet certain clean air standards which are different (generally more stringent) than those applied to existing plants. Energy storage appears to be able to take advantage of a loophole in federal regulation regarding the construction of new power plants.

This chapter provides an overview of the U.S. Clean Air Act, and examines the regulations that affect the use energy storage with existing power plants. It also provides an analysis of the actual emissions that will result from the construction and operation of energy storage facilities, compared to conventional alternatives. This chapter also proposes and evaluates policies that will encourage storage to be used to assist, rather than hinder the progress towards improved air quality.

7.1 Evaluation of the U.S. Clean Air Act Applied to Energy Storage

An energy storage facility can be regarded as an electric power plant with several unique characteristics, including its geographical and temporal displacement of air emissions. Most or all of their effective emissions are produced at another location, and there are no federal regulations that specifically address the interaction between energy storage and existing facilities. The emissions created by the use of energy storage originate from existing power plants with spare capacity. These plants are regulated by various provisions of the U.S. Clean Air Act, including the New Source Review program.

7.1.1 Basic Provisions of the Clean Air Act and New Source Review

The U.S. Congress has passed a number of laws designed to reduce air pollution and improve national air quality. The most important of these laws are embodied in the Clean Air Act (CAA), and its amendments. In 1970 the CAA established national ambient air quality standards (NAAQS), which establish upper limits for the ambient concentration of six “criteria” pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), lead (Pb), particulate matter (PM), and ground-level ozone (O_3).[1] Each state is responsible for establishing a State Implementation Plan to ensure that these air quality standards are met in each geographic area in the state.[2]

In 1977 the CAA was amended, to establish a two-track system for addressing air quality standards. The first set of rules addresses “non-attainment” areas, which do not meet NAAQS.[3]

The second set of rules establishes Prevention of Significant Deterioration (PSD) program, which addresses areas in attainment, where air quality does meet NAAQS.[4]

A major component of both tracks is the New Source Review (NSR) program that establishes specific rules regulating emissions from large stationary sources, such as electric power plants.[5] This program regulates the construction and operation of electric power facilities that have the potential to annually emit more than 100 tons of a regulated pollutant.[6]

When new major emission sources are proposed, pre-construction permits must first be obtained from the state permitting authority, which oversees the requirements of the federal CAA standards, including those of the NSR program.[7] Application for a permit must be accompanied by a technical evaluation of the projected emissions from the plant, including models of possible distribution of pollution concentration, and qualifications of other potential impacts on human health and the environment.[8]

The NSR program also contains technical standards referred to as New Source Performance Standards (NSPS) that establish emissions rates and emissions control equipment that must be installed on new plants. The NSPS depend on type and size of plant, and also on existing local air quality. If the area is in attainment, then the new source must conform to PSD rules.[9] In this case, the utility must install “best available control technology” (BACT) to control its emissions of each of the six criteria pollutants.

If the proposed plant is in an area not in attainment, then stricter rules are required for a new plant. Instead of BACT, the proposed facility must install technology that achieves “lowest achievable emission rate” (LAER.)[10] In addition, the facility’s emissions must be offset by emission reductions from other facilities in the area.[11]

It should be noted that NSPS are *input*-based emission standards as opposed to *output*-based standards. The standards establish the amount of emissions that are allowed per unit of fuel burned, not per unit of electricity produced. As a result, there is no defined standard for the amount of pollutants produced per unit of electricity generated. Input-based standards also provide little incentive for increased efficiency, nor substantial penalties for low efficiency.

Determining the actual “emission standard” for a new plant is complicated by the technology requirements. Technology requirements such as BACT generally create more stringent emission standards than NSPS. For example, current NSPS allows for up to 0.6 lb or 1.2 lb of SO_2 emissions for each MMBTU of fuel input, depending on fuel type.[12] The standards also require BACT for SO_2, which includes a number of flue-gas desulfurization technologies, generally referred to as scrubbers. The actual scrubber types that are allowed by the EPA must achieve specific SO_2 emission reduction rates of at least 70% or 90%, again depending on fuel type. The effective result of the current BACT standards is a maximum input emission rate generally between 0.06 and 0.32 lb SO_2/MMBTU, depending on fuel sulfur content. As a result, the technology standards render the NSPS emission standards irrelevant, and further complicate the process of attempting to precisely identify the legally required emission rates for electric generators affected by NSR. Some state and federal regulations for electric power plants include output-based standards, but the majority of CAA regulations continue to be based on fuel input.

When Congress was developing rules for new sources, they were faced with the issue of how to deal with existing plants, whose emissions often greatly exceeded NSR standards. In areas where local NAAQS are not met, states must develop plans that may include retrofits on existing facilities.[13] However, it was recognized that requiring immediate retrofit of all of the nation's generation facilities, especially those in areas that already meet NAAQS standards, would be economically disruptive.[14] It was decided that existing facilities in attainment areas would be allowed to continue to emit at their existing high level emission rates, until the facilities were upgraded or otherwise modified, at which point they would be considered new sources, and required to meet NSR rules. This decision, known as grandfathering, is probably the most controversial and contentious aspect of the New Source Review program.

While there is no "sunset" provision for these grandfathered power plants, it is generally concluded that Congress believed that power plants, like any technology, have limited lifetimes, and would eventually be replaced.[15] In addition, it is suggested that Congress viewed the generation of electric power like other industries – that improved technology would force the upgrade of existing plants to remain competitive. As a result, it is generally believed that Congress thought that older plants would eventually be retired or upgraded out of economic necessity. New construction or major upgrades provide the most economic opportunity for installation of new pollution equipment, so NSR is triggered for existing plants at the time of a major modification. This rule, referred to as the “change rule” in this chapter, states that NSR shall be triggered by:

> any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.[16]

Despite the fairly clear language, this terminology is insufficient to guide an operating utility. Terms such as “physical change” and “method of operation” must be sufficiently defined for a utility to follow the rules. Since enactment of the CAA, federal agencies have attempted to clarify the change rule to more precisely define these terms. These decisions have a significant impact on the use of energy storage with existing facilities.

7.1.2 The EPA’s Attempts to Clarify the New Source Review Provisions Regarding Existing Facilities

The Administrative Procedures Act (APA) of 1948 grants federal agencies certain powers to draft rules and regulations in order to accomplish the stated goals of Congressional legislation.[17] The Clean Air Act is an example of an “enabling act” which creates a new program, with specific goals. The APA establishes the authority of a designated agency (in this case the Environmental Protection Agency) to implement specific rules and regulations to effectively achieve legislative goals. This allows the necessary specific technical details of regulation to be developed by experts, as opposed to Congress, whose members may lack the necessary background to implement complicated technical programs.

The administering agency often has the responsibility of creating rules to achieve legislative goals for specific circumstances that have not been completely defined by the legislature. The specific, technical definition of “physical change” in the CAA is an example. The EPA must conform, as much as possible, to Congressional intent when defining this term. The “reasonableness” of agency rulemaking is often the subject of considerable scrutiny and litigation.

The responsibilities and constraints of the EPA with regard to this type of rulemaking were addressed by the Supreme Court in 1984.[18] The court decision in Chevron v. Natural Resources Defense Council, Inc established a two-step test (often referred to as the Chevron test) for determining the legality of agency rulemaking. First, Congressional intent must be established: “If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress.”[19] Second, if intent is unclear or not sufficiently defined, deference must be given to the agency, and a court is limited in its ability to create its own rules: "a court may not substitute its own construction of a statutory provision for a reasonable interpretation made by the administrator of an agency."[20]

The court explains its decision by stating that public policy, if unaddressed by Congress specifically, is better decided by an administering agency, which has both greater expertise and greater public accountability than the courts.

> Judges are not experts in the field, and are not part of either political branch of the Government. Courts must, in some cases, reconcile competing political interests, but not on the basis of the judges’ personal policy preferences. In contrast, an agency to which Congress has delegated policy-making responsibilities may, within the limits of that delegation, properly rely upon the incumbent administration’s view of wise policy to inform its judgments. While agencies are not directly accountable to the people, the Chief Executive is, and it is entirely appropriate for this political branch of the Government to make such policy choices – resolving competing interests

> which Congress itself either inadvertently did not resolve, or intentionally left to be resolved by the agency charged with the administration of the statute in the light of everyday realities.[21]

This rule, while simple in principle, does not necessarily simplify implementation of the CAA, or the change rule. Since initial passage of the CAA, the EPA has promulgated a number of rules attempting to define "physical change." Many have been challenged, because for NSR, both "tests" established by the Chevron ruling do not provide clear answers. In most challenges to EPA rule making, both sides have claimed fairly clear Congressional intent in their favor, and also have claimed that rules promulgated by the EPA have not provided a "reasonable interpretation" of Congressional intent.

The EPA's first attempt to provide a definition of "physical change" was a rule that defined a "change" as resulting in an annual increase of 100 or 250 tons per year of any regulated pollutant, depending on the source category.[22] The EPA also provided several categorical exemptions from the definition of physical change, including "routine maintenance and repair." In 1979 several of the EPA's rules were challenged, and the court in Alabama Power v. Costle rejected the "annual increase" definition of change, stating "EPA has extremely limited authority to exempt activities from the definition of 'modification'. . . . The Agency's authority is limited to circumstances of administrative necessity and circumstances having a '*de minimis*' or 'trivial impact on emissions."[23] The court also stated "[T]he term 'modification' is nowhere limited to physical changes exceeding a certain magnitude."[24]

The ruling did not address the various exemptions, nor did it help establish clear limitations on what modifications may occur, and it left industry with little additional guidance. Since this ruling, the EPA has made several attempts to clarify these rules, with limited success, and the change rule as of 2004 is still only defined by what it is *not*, established by a number of exemptions.[25] Major exemptions to the "change rule" include:

1) Routine maintenance, repair, and replacement
2) Increase in production rate, if unaccompanied by capital expenditure
3) An increase in the hours of operation
4) Use of alternate fuels
5) Installation of new pollution control equipment

The most important of these exemptions for energy storage is the "hours of operation" exemption, which establishes the legal use of energy storage without triggering new source review.

7.1.3 The Hours of Operation Exemption and Energy Storage

The hours of operation exemption has a clear impact on the use of electricity storage. An energy storage facility may store off-peak power from an older coal plant in an area currently in attainment, substantially increasing the hours of operation of this plant, and consequently, its air emissions. As long as NAAQS standards are not exceeded, the increase in emissions and potential decrease in air quality that result from the use of energy storage is allowed due to the hours of operation exemption.

It is important to consider, however, whether or not the hours of operation exemption was intended to allow for significant increases in emissions that are not the result of demand variations. In many ways the hours of operation exemption appears reasonable. Electric demand is highly variable, largely uncontrollable, and somewhat unpredictable. While utilities can roughly estimate the expected annual increases in electric demand, it would be impossible for them to predict exactly how much a plant will need to produce from year to year, especially considering the effects of weather-related demand. It is probably not reasonable for NSR to be triggered if a residence turns on an extra light bulb and increases the demand on a utility's intermediate load coal plant. Implementation of NSR is expensive and time consuming, and it is not practical for utilities to address small uncontrollable changes in demand through the NSR processs. The EPA recognized this limitation and justified the hours of operation exemption by stating "Congress could never have intended a company to have to obtain an NSR permit before it could lawfully change hours or rate of operation."[26]

The use of energy storage, however, is unlike daily, seasonal, and yearly variations in demand, many of which are fairly unpredictable. Use of energy storage is a planned business action that would likely require long term purchase contracts between the generator and the storage facility. In other words, the generator would know ahead of time that an increase in output (and emissions) was anticipated.

As a result, the use of energy storage would not necessarily be external to the operation of the generating plant – there must be a synergistic relationship between the ability of the plant to increase output, and the requirements of the energy storage facility. This difference could be deemed “controllable” vs. “uncontrollable” load growth.

This potential difference has been previously noted by legal scholars who have questioned the legality of the hours of operation exemption under certain circumstances similar to the use of energy storage (but not referring directly to its use).

> when a utility makes a long-term, strategic decision to increase the utilization of a power plant from 30 percent on average to 60 percent on average over an extended period, it is hard to understand why this is not an “operational change.” Such a change, if accompanied by a significant emissions increase, would appear to require the NSR under the statutory definition of “modification.” [27]

From another perspective, it is reasonable to ask why Congress would include the term “change in the method of operation**”** in the law if it did not intend to address long-term, strategic decisions such as the use of energy storage. It is reasonable then to consider that a planned business decision to increase output and turn an intermediate load plant into a baseload plant via the use of energy storage might be a “change in the method of operation” as defined by Congress. Furthermore, such a change clearly “increases the amount of any air pollutant emitted by such source**.”** As a result, it is possible that the hours of operation applied to the use of energy storage is outside the bounds of “administrative necessity and circumstances having a ‘*de minimis*’ or ‘trivial impact on emissions’” which is the intent of Congress, as interpreted by the court in Alabama Power v. Costle.

7.1.5 New Source Review and On-Site Energy Storage

The “reasonableness” of the hours of operation exemption applied to energy storage can be further examined by considering a hypothetical application: a large storage plant constructed on-site and physically attached to an existing fossil-based power plant. While such a plant has not been built since passage of the CAA, an examination of NSR interpretation and enforcement action by the EPA tends to reinforce the view that the use of energy storage is an unreasonable application of the “hours of operation” exemption.

The CAA change rule establishes that NSR is triggered by two “events” at a major facility: first, a physical change, or change in method of operation must occur, and second, there must be a significant increase in emissions.

As discussed in section 7.1.4, the only definition of physical change in EPA rules is what it is *not*, based on exemptions. It is unlikely that an energy storage facility could be interpreted in any of the three “physical” exemptions. Energy storage is not a replacement or repair, it does not allow for alternative fuels to be burned, and it is unlikely to be interpreted as a pollution control project.

A utility would likely claim that an energy storage facility is a “stand-alone” addition to a plant, which does not trigger NSR for the existing source. (For example, an addition of a second boiler to an existing plant does not result in the first boiler being subject to NSR.) A utility would likely claim that an on-site energy storage facility would be exempted. However, this exemption assumes that the new equipment does not somehow interact with the first, which is not the case for energy storage. The precedent is established by the second part of the test, a determination if there is an increase in emissions as a result of the physical change.

The EPA has proposed several rules to establish the measurement of post-change emissions, and this issue has been litigated a number of times. The EPA originally promoted an "actual to potential" test, which compares historical annual emissions to potential emissions that would result if the plant were to run constantly at full capacity. This test was struck down by the court in Wisconsin Electric Power (WEPCO) v. Reilly,[28] which is reasonable considering the actual to potential test will always result in a theoretical increase in emissions, since no plant can operate at full capacity at all times.

After the WEPCO ruling, the EPA promulgated the "actual to projected actual" test (referred to as part of the "WEPCO rule") that compares the actual annual emissions in the two years before the physical change, to the likely actual annual emissions after the physical change. An onsite energy storage facility would result in increased annual output, and based on the WEPCO rule, it appears likely that the use of on-site storage would trigger NSR.

This WEPCO rule has been the basis for recent EPA actions again power plant owners that have performed upgrades on coal-fired power plants. After the WEPCO rule was established, the EPA began investigation of suspected NSR violations. In 1999 and 2000, the Department of Justice filed eight actions on behalf of the EPA against utilities for CAA violations.[29] Recent court opinions in these cases provide additional insight into the potential legality of on-site energy storage, as they specifically address the hour of operation exemption rule, when accompanied by a physical change to the facility.

One of the EPA suits in 1999 was against Ohio Edison, claiming that eleven construction projects at its large Sammis coal-fired power plant were significant modifications that resulted in increased emissions. While the projects did not involve energy storage, a primary purpose of the Sammis projects was to “prevent or at least diminish the number and duration of outages, meaning unplanned periods of time when the unit was offline and unproductive.”[30] This means that the work was not intended to increase the rate of production, but to increase the number of hours of availability.

Ohio Edison’s defense included two major points: first, that the routine maintenance, repair, and replacement (RMRR) exclusion applied, and second, even if the modifications were major, they were still exempted because the emission *rate* did not increase. The increased hours of availability that resulted from the project resulted only in increased hours of operation, which is specifically exempted from NSR. This argument could be applied to the addition of energy storage, as it results in an increased number of hours per year that the plant produces saleable electricity.

The court rejected the RMRR exclusion, concluding that the projects were not routine. More importantly for energy storage, the court took a narrow view of the hours of operation exemption, stating that the exclusion in this case is not applicable under the new WEPCO rule:

> The language of this regulation clearly creates an exemption to the definition of "physical change" that applies when there is an increase in hours of operation unaccompanied by physical construction to the unit itself. For example, the exemption applies when there is a temporary increase in electricity demand which, without a physical change at a unit, results in an increased output of electricity. See WEPCO, 893 F.2d at 916, citing 45 Fed.Reg. 52676, 52704 (1980).[31]

Furthermore, the court specifically addresses modifications that allow increased annual output, which would directly be applicable in the case of on-site energy storage:

> [T]he [Ohio Edison] projects were all intended to result in increased hours of operation as a result of a reduction in the number and length of forced outages, or shutdown for repair or maintenance. A significant decrease in outages results in a significant increase in both production and emissions. Given the actual goals placed on the construction projects by Ohio Edison, and the substantial increase in emissions certain to follow, the company was required to project future emissions. If those projected increases were substantial, as defined by regulations noted below, preconstruction approval, which was never sought, was required by law.[32]

The basic conclusion of the Ohio court is fairly straightforward: a physical modification, accompanied by an increase in annual emission rate, is subject to NSR regulation, as established by the WEPCO rule.

It should be noted however, that the new WEPCO rule for determining post-modification emission rates has not been universally accepted by the courts. In an NSR case very similar to the Ohio Edison case, the court in United States v. Duke Energy Corp. ruled that the older hours of operation exemption cannot be invalidated by the newer WEPCO rule without sufficient justification, which according to the court, is not provided.[33] In this case, the court does not defer to the agency and claims that the intent of Congress has clearly allowed the hours of operation exemption to remain, since it did not address the issue in the 1977 or 1990 amendments to the CAA. The court essentially agrees with the defendant in the Ohio Edison case, that while a modification may not be exempted, if the result is only an increase in hours of operation, than this is exempted. (The court does, however, agree that an increase in emissions *rate* would trigger NSR.)

Both the Ohio Edison and Duke Energy courts quote various interpretations of the hours of operation exemption made by various EPA officials over the years, with opinions often a function of the political leanings of the current administration.

While the resolution of the applicability of the hours of operation exemption may lie with a higher court, it appears reasonable that the onsite use of energy storage would be interpreted as a physical change, resulting in increased emissions. This conclusion reinforces the idea that off-site energy storage, coupled with existing plants, is a loophole in NSR, since an energy storage device can be a physical modification to an existing plant, which is attached not with pipes and valves, but with electric wires. A utility considering energy storage would likely avoid constructing the facility on-site to avoid triggering NSR, but instead could locate the facility a short distance away, and couple the two facilities via transmission. These two applications, while having the exact same results from an engineering and emission standpoint are treated differently by existing policy.

7.1.6 Recent Administration Actions on New Source Review and Their Impact on Energy Storage

The EPA under the administration of President Bush has made several attempts to modify New Source Review that could have some impact on the use of energy storage.

On December 31, 2002, the EPA promulgated a new rule that revises the WEPCO "actual to potential actual" test.[34] Of most concern to environmentalists was the change in baseline for measuring pre-modification emissions levels. The older rule used emissions measured over the 24 months prior to the modification as the baseline, while the new rule allows the baseline measurement to occur over any 24 month period in the last 10 years. This weakens the previous rule by allowing a utility to use the "dirtiest" 24 month period as a baseline. The new rule did, however, continue the use of an annual emission rate, instead of an hourly emission rate, when considering the change. This tends to reinforce the notion that the EPA recognizes that annual emissions are a better measure of actual impact than hourly rates. In defending its decision to keep annual emissions in the new test, the EPA states:

> [The EPA] also expressed concern about the environmental consequences associated with the Exhibit B provisions [which measured only hourly rates, and not annual rates]. For one, you could modernize your aging facilities (restoring lost efficiency and reliability while lowering operating costs) without undergoing preconstruction review, while increasing annual pollution levels as long as hourly potential emissions did not change.[35]

This new rule would tend to reinforce the conclusion in the Ohio Edison case that considers annual emission rates the more important factor in measuring change.

Of far greater concern to environmentalists, and having potentially more impact on the actual use of energy storage is the rule promulgated on August 27, 2003.[36] This rule is a modification of the RMRR exclusion rule, and represents a significant change to the EPA's interpretation of NSR The rule allows any plant operator to perform any modification to the plant, as long as the cost of the modification does not exceed 20% of the value of the plant. More importantly, the rule places no restriction on the number of modifications that may be performed over an extended time period. This rule would appear to allow the complete reconstruction of a plant, one 20% at a time, without ever triggering new source review.

While neither of these new rules directly addresses the legality of energy storage, they do make energy storage easier to implement in practice. Before these rules were proposed, a plant operator may have been unable to increase annual plant output due to the need for plant upgrades that may have triggered NSR. The new 20% rule now allows for extensive upgrades, which could be performed for the express purpose of increasing plant availability in order to sell to a new merchant storage facility. These upgrades can be performed without triggering new source review and the storage facility can sell energy that produces emissions that greatly exceed NSPS, while any competitive new source of generation must meet NSPS.

The modification rules were perceived by many environmentalists as a complete “rollback” of NSR, and quickly challenged in court by several states.[37] On December 24, 2003, the D.C. Circuit Court of Appeals halted implementation of the rules.[38] The de minimus ruling in Alabama Power v. Costle appears to challenge the ability of the EPA to create such categorical exemptions such as the greatly expanded RMRR rule, but the new rules have certainly set the stage for another round of courtroom challenges that will likely take many years to resolve.

7.1.6 Conclusions

Some interpretations of NSR make a compelling case that the use of energy storage is an unjustified application of the hours of operation exemption. Alternately, a strict interpretation of the hours of operation exemption would allow the use of energy storage with existing power plants, even if constructed on-site, and resulting in considerable increases in emissions. The disparate viewpoints taken in recent litigation involving existing and proposed EPA rules have led some observers to suggest that the definition of “**any physical change in, or change in the method of operation…. which increases the amount of any air pollutant”** may ultimately lie with the Supreme Court’s interpretation of Congressional intent.

While a complete analysis of Congressional intent regarding NSR is beyond the scope of this work, a few observations can be made about the use of energy storage and new source review:

1) The nature of electricity means that a “physical change” to a power plant may occur at a location some distance from the plant.
2) The long term contracts associated with the planned use of energy storage could reasonably be interpreted as a “change in the method of operation”
3) While the hours of operation exemption seems reasonable for unplanned and uncontrollable demand growth, it is less reasonable when applied to the planned use of energy storage.
4) Many of the rules established in the CAA specifically address emissions in yearly amounts *and* hourly emission rates. Congress recognized that both measurements of emissions are important to protect human health and the environment. Allowing large annual increases of emissions through the hours of operation exclusion is incompatible with this viewpoint.
5) The “de minimus” ruling of Alabama v. Costle implies that the court considers an annual increase of 100 or 250 tons to be greater than an acceptable value, and beyond the intent

of Congress. This ruling appears to be incompatible with the hours of operation exemption, especially considering this exemption may produce an annual increase at a plant that is much higher than this value.

6) The hours of operation exclusion does little to protect the health and welfare of the citizens of the U.S., while at the same time it provides substantial distortion of the marketplace. It allows incumbent utilities to use low cost, high emissions electricity with storage to compete with new sources that must bear the costs of NSR.

The potential effects of the energy storage loophole can be evaluated by measuring the emission rates and annual emissions that may result from the use of energy storage systems with existing coal-fired power plants.

7.2 Emissions Resulting from the Use of Storage Systems with Coal Fired Power Plants

This chapter suggests that energy storage systems should be viewed as a new source of peaking and load following electricity, and that net air emission impacts should be analyzed from that perspective. To perform this analysis, it is necessary to understand in detail the sources of stored energy, as well as the interaction between energy storage and fossil energy sources.

7.2.1 Availability Generation for Energy Storage Systems

The suggestion that the use of energy storage represents a loophole in the CAA implies that there is a great deal of unused capacity from existing grandfathered power plants. If this is not true, this “loophole” will be of little consequence to actual increases in air emissions. A power plant survey was performed to identify the availability of off-peak coal-based generation. This was performed by comparing the actual production of the nation's coal plants to their potential output if used at maximum capacity.

Since the bulk of the existing coal generation capacity is in near the industrial Midwest, and since the largest proposed CAES plant is located in Ohio, coal plants in the six state region around Ohio, including Michigan, Indiana, Kentucky, West Virginia, and Pennsylvania, were evaluated. Actual annual production data was derived from the EPA's E-Grid database[39] for the year 2000 for each plant. The actual production data was then compared to their maximum potential output, based on average availability for plants in each class (size) of plants, derived from the National Electric Reliability Council (NERC) Generating Availability Data System (GADS) database.[40] The total difference provides an approximate idea of how much spare capacity exists in the coal-fired power plants in this region.

The facilities evaluated were dedicated electric generation facilities, and excluded cogeneration facilities, small plants (under 25 MW), and plants with very low (<5%) capacity factors.

Overall, there are a total of 111 plants meeting these criteria, with a total capacity of about 104 GW. In 2000, these plants generated with an average capacity factor of 61%, while the average availability of these plants was 82-86%, with a capacity weighted average of about 84%, according to the GADS database. The difference between actual and potential generation is a potential increase of roughly 205,000 GWh, equivalent to about 28 GW (28 large plants) of "new" baseload generation operating at 84% CF. There is clearly significant capacity available for energy storage in this region.

7.2.2 Emission Rates of Existing Coal-Fired Generators

The EPA E-Grid database was used to evaluate emissions from existing sources that may provide electricity to energy storage facilities. There is considerable variation in the emission rates of CO_2, SO_2, and NO_x, among these older plants. The CO_2 emission rate is a direct function of the overall thermal efficiency (heat rate) of the plant. The emissions of SO_2 are a function of both heat rate and coal sulfur content, which varies from about 0.3-1.5% for “low sulfur” western coal, to 3-4% for high sulfur eastern coal.[41] Most grandfathered plants do not use SO_2 scrubbers, which are currently required by NSR regulations. NO_x emissions are a function of heat rate and the combustion characteristics of the power plant. Most existing plants use “low NO_x” burners, but do not employ post-combustion controls, such as selective catalytic reduction (SCR), which is required by NSR for new plants. Modern plants meeting NSPS have several additional environmental benefits due to increased thermal efficiency, including lower thermal pollution, reduced fine particulate emissions, and lower mercury emissions. Prior to 2004 mercury was unregulated, but in 2004 the EPA proposed a cap-and-trade system to control mercury emissions.[42]

Appendix I provides additional details of availability and emissions rates of representative plants that can be used to provide off-peak electricity for the use of energy storage. Table 7.1 provides a summary of typical rates for high, low and average emission rates for existing grandfathered plants, as well as rates for more contemporary plants. Emission rates are based on fuel inputs and are expressed in English units (lbs. and BTU) since these are the units used by reporting agencies and codifed in federal law.

Table 7.1 Emissions Characteristics of U.S. Coal-Fired Power Plants

Plant Type	Heat Rate (BTU/kWh)	Representative *Input* Emissions Rate		
		CO_2 (lb/MMBTU)	SO_2 (lb/MMBTU)	NO_x (lb/MMBTU)
High Emissions (grandfathered)	11,000-13,000	205	2-3	0.6
Low Emissions (grandfathered)	9,500-11,000	205	0.4-.8	0.4
Weighted Average (existing)	10,500	205	1.38	0.5
Post 1977 NSR	9500-10,000	205	.05-.12	.3-.4
Modern (2004)	9,000-9,500	205	.05-.12	.08

The "high emissions" plant has poor performance due to age and the use of high-sulfur coal. The "low emissions" plant is newer (but constructed before 1977 NSPS) and more efficient, and uses lower sulfur coal. The third data set is a weighted average of all coal-fired power plants in the six-state region described in this section, and includes a few plants built or modified after the 1977 NSR standards. The fourth data set is for plants built after the 1977 NSR rules, which required SO_2 scrubbers, but did not require post-combustion controls for NO_x.[43] The final data set is for a likely plant built in 2004, a supercritical coal plant with post-combustion controls for both SO_2 and NO_x.[44]

7.2.3 Air Emissions Associated with Fossil-Energy Storage Systems

For the power plants identified in section 7.2.1, each plant was evaluated in terms of emissions rate that would be produced if generating electricity for storage. The net emissions resulting from energy storage can be calculated using equation 3.12, and must consider the generator efficiency increases that result from the use of storage. This efficiency increase is measured by the *marginal* emission rate of the power plant, as well as dynamic benefits of storage, such as provision of spinning reserves.

A power plant that runs at optimal load all times may consume about 10,000 BTU of heat input for each kWh generated. This "heat rate" will increase as the plant is used to follow load. As it ramps up and down, it will operate at different efficiencies. In addition, start-up and shut down results in lost heat energy. The same plant used to follow load may average 11,000 BTU/kWh. The issue for energy storage is the heat rate of the next, or additional, unit of energy produced for energy storage. This will typically be much lower than the average heat rate. This is illustrated in Figure 7.1, an idealized average and marginal heat rate curve for a coal-fired power plant. Each point on the marginal heat rate curve represents the average heat rate of an incremental additional load of 5 percent.

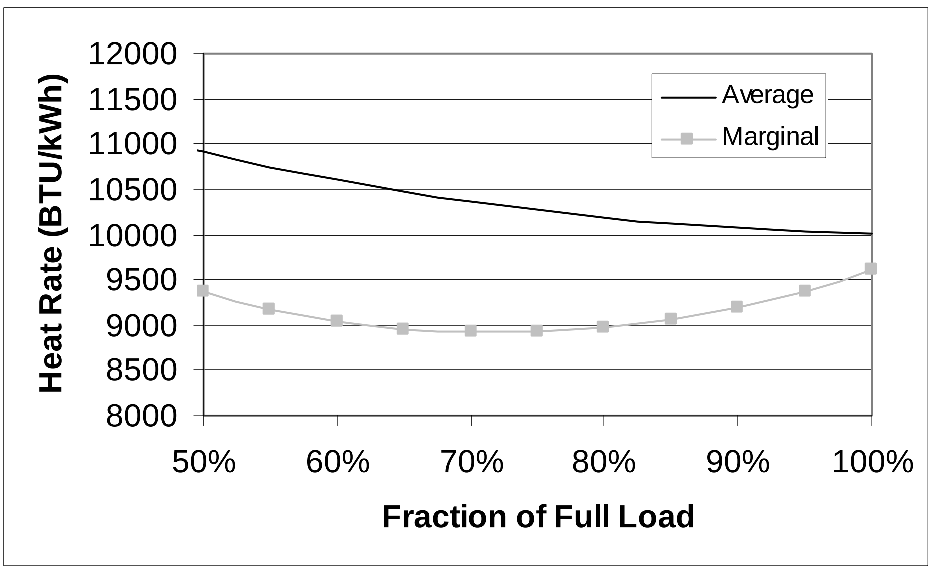

Figure 7.1: Average and Marginal Heat Rates as a Function of Load for a Coal-Fired Power Plant

If a load following plant with an 11,000 BTU/kWh heat rate can be fully loaded using storage, the average heat rate may fall to 10,000 BTU. The additional generation, which is attributed to the use of energy storage, has a marginal heat rate of only 9,100 BTU. (This number actually represents the average marginal heat rate, which is the average heat rate of all electricity produced raising the power plant from partial to full load.) This efficiency gain is realized only because of the decreased cycling that results from the use of energy storage and can potentially produce lower emission rates from existing sources, particularly compared to relatively inefficient load-following alternatives.

The heat rate curves for individual power plants are generally not available. In addition, published heat rate curves do not include the efficiency losses associated with shutdowns. The average marginal heat rate for Midwestern coal plants was estimated by using theoretical heat rate curves[45], and also by comparing heat rates of various plants under different operating conditions. The marginal heat rate will vary substantially between plants, with a typical range of 8000-10,000 BTU/kWh. A 5% reduction in heat rate was added to account for dynamic benefits, including reduced spinning reserve requirements.

Using the power plant marginal heat rates and the input emission rates from Table 7.1, the average emission rates for energy storage systems coupled with existing coal plants can be calculated. The net emissions from energy storage systems coupled with existing coal plants for CO_2, SO_2, and NO_x are shown in Figures 7.2-7.4. Results are shown for CAES, PHS, and the PSB-BES. Results for the VRB-BES would be nearly equal to PHS, and Pb-Acid BES would be about midway between PHS and the PSB. Also shown are two non-storage alternatives that could be constructed as an alternative to provide load-following and peaking power. In addition, the results for CAES are provided if the use of CAES triggered NSR for the coal plant providing electricity for storage. In all cases, only point-source emissions are included, ignoring construction, O&M, etc.

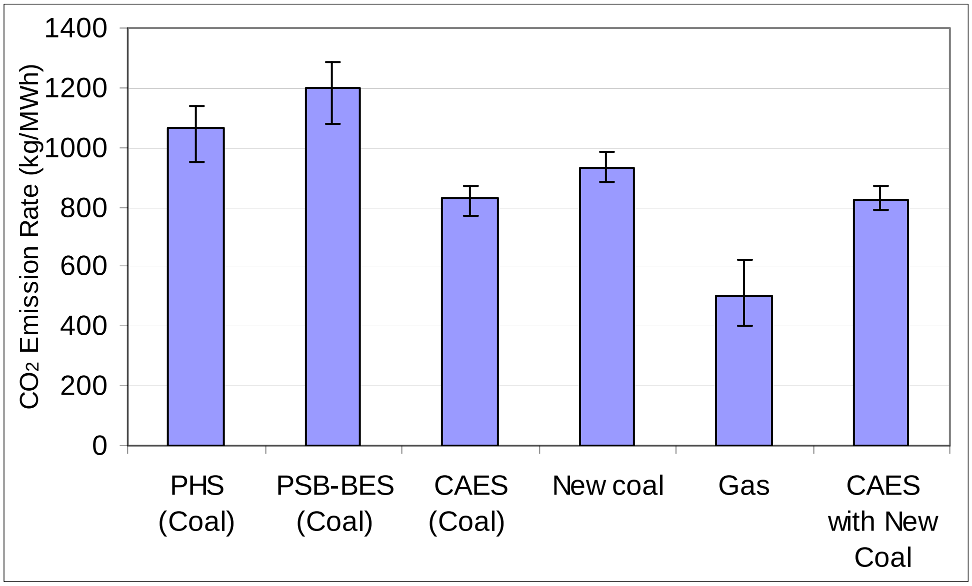

Figure 7.2: Point Source CO_2 Emission Rates from New Sources of Load-Following Electricity

The variation in CO_2 emission rates for each source in Figure 7.2 result primarily from the different operational heat rates. For each storage technology, a generator marginal heat rates range of 8500 to 9500 BTU is considered. Additional details are provided in Appendix I.

Due to the "fuel-switching effect" of the hybrid storage-generation CAES system, this storage technology produces significantly lower net GHG emissions than PHS or BES when coupled to existing fossil generation. Despite the inefficiencies associated with storage, GHG emissions from coal-powered CAES can be lower than a coal plant operating without storage. Emissions from BES and PHS coupled with coal are generally higher than most other sources, including load-following coal. PSB-BES has particularly unfavorable results due to its low storage efficiency. From a greenhouse gas perspective, the use of PHS and BES with coal is undesirable, unless substantial thermal plant efficiency gains can be achieved.

Figures 7.3 and 7.4 provide SO_2 and NO_x emissions rates for the various load-following sources.

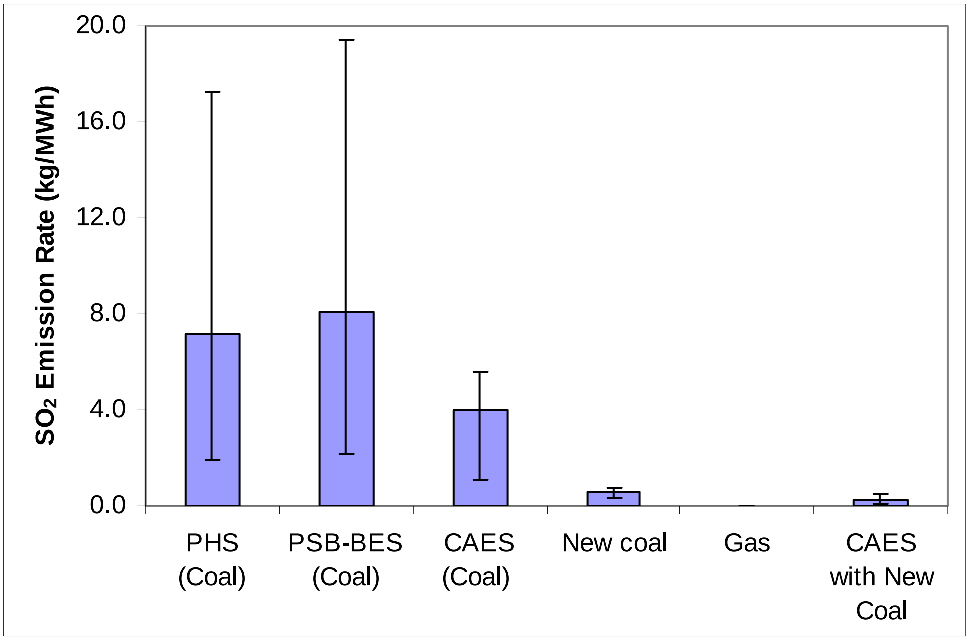

Figure 7.3: Point Source SO_2 Emission Rates from New Sources of Load-Following Electricity

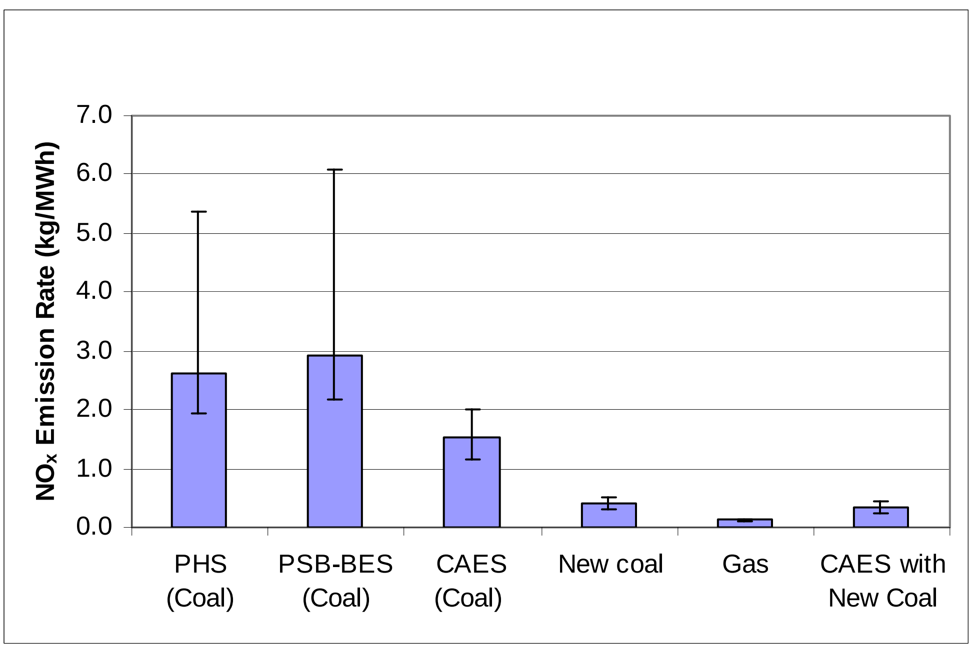

Figure 7.4: Point Source NO_X Emission Rates from New Sources of Load-Following Electricity

The impacts of NSR are dramatic in terms of SO_x and NO_x emission rates. While there is a large variation in emission rates for the storage systems coupled to older coal plants, their emissions rates are typically much higher than any new source that could be legally constructed for the generation of load-following or peaking power.

7.2.4 Analysis of the Emissions from a Proposed Energy Storage Facility – The Norton CAES Project

As discussed previously, energy storage facilities are not required to consider their net emissions under NSR, and therefore are not required to report these emissions when applying for pre-construction permits. As a result, the public and regulators are left unaware of the actual impacts on air quality that may result from the use of storage. This situation can be examined in detail by estimating the annual emissions that will result from the operation of an actual proposed plant – the Norton CAES facility.

As a major stationary source, the preconstruction permit application for the Norton CAES facility was required to include an emissions and air quality analysis.[46] This analysis, and the other documents filed in support of the Norton CAES facility, provide no indication of the actual emissions that will result from operation.[47] In fact, there is very little mention of the fact that this plant will be coupled primarily to power plants whose emissions greatly exceed NSPS. Section 7.2.3 demonstrates that even with the dramatically reduced marginal heat rate and the “fuel switching effect” of coal-powered CAES, this new source of load-following and peaking power will produce significantly higher levels of emissions than any other generation source that could be legally constructed.

Using the analysis in section 7.2.3, it is possible to estimate the emission rates and annual emissions that will result from the operation of the Norton CAES facility. The net emissions from this new source can then be compared to the emissions from alternatives that meet NSPS. Alternatives include CAES coupled to a coal plant that meets NSPS, and two non-storage alternatives: the combination of an intermediate load NSPS coal plant and a simple cycle gas turbine, and the combination of combined cycle and simple cycle gas turbines.

According to the Norton CAES application, the completed plant will operate at a capacity factor of 23-48%, with a maximum output of 2700 MW. The higher capacity factor is probably optimistic, since PHS facilities in the U.S. seldom exceed 25% capacity factor, and are often under 20%.[48] This assessment assumes an annual capacity factor of 25%, producing annual electric generation of 5913 GWh. Table 7.2 provides the total emissions that would result from each of four systems that provide this amount of electricity. The two CAES/coal cases are based on emission rates calculated in section 7.2.3, with the CAES ER_{net} reduced to 0.72, since the CAES plant is located relatively close to load centers. The non-storage case with a NSPS coal plant assumes an intermediate load coal plant with an average heat rate of 10,000 BTU, producing 3000 GWh annually, and a simple-cycle gas turbine producing the remaining 2914 GWh at a heat rate of 10,500 BTU/kWh. The natural gas case assumes that 3000 GWh is produced by a combined-cycle gas turbine operating at a heat rate of 8,500 BTU/kWh, with the remainder produced by a single-cycle gas turbine.

Table 7.2: Point Source Emissions from New Load-Following Electricity Generators Providing 5913 GWh Annually

	Annual Fuel Consumption and Emissions for a 2700 MW Plant Operating at a 25% CF			
	Fuel Consumed (Billion BTU)	CO_2 (tonnes)	SO_2 (tonnes)	NO_x (tonnes)
CAES with Typical Existing Coal Plant				
CAES	24,834,600	1,806,153	7	339
Coal	36,613,296	3,411,693	22,967	8,321
Total	**61,447,896**	**5,217,846**	**22,974**	**8,660**
CAES with Coal Plant Meeting NSPS				
CAES	24,834,600	1,806,153	7	339
Coal	36,187,560	3,372,023	1,645	1,316
Total	**61,022,160**	**5,178,175**	**1,652**	**1,655**
NSR Coal and GT				
Coal	30,000,000	2,795,455	1,636	1,091
Gas Turbine	32,043,000	2,330,400	9	583
Total	**62,043,000**	**5,125,855**	**1,645**	**1,674**
NSR Gas				
CCGT	25,500,000	1,854,545	7	348
GT	32,043,000	2,330,400	9	583
Total	**57,543,000**	**4,184,945**	**16**	**930**

CAES coupled to existing coal generation produces much higher levels of SO_2 and NO_x than competing new sources of load-following power. The CAES plant will effectively produce at least 13 times more SO_2 and 5 times more NO_x than the alternative plants that can legally be constructed. These new sources must perform air modeling and conform to BACT standards. The CAES plant must only consider the CAES turbines in its air modeling, and can completely ignore the significant emissions that result from the coal combustion component of the CAES facility.

Operating at a 25% capacity factor, the CAES plant coupled to an existing coal-fired plant will annually “burn” in excess of 24 trillion BTU, roughly equivalent to the annual consumption of a 350 MW baseload coal power plant. **In other words, the construction and use of the CAES**

facility in this manner is equivalent to constructing and operating a baseload 350 MW coal-burning power plant without meeting any of the requirements of NSR.

While CAES coupled to pre-NSR plants produce high levels of SO_2 and NO_x, CAES coupled to a new coal plant performs roughly equivalent to the new coal/gas combination, and would clearly be superior to an all new coal scenario. In addition, the new coal/CAES system uses less natural gas than the non-storage alternatives, so would be more fuel sustainable, have lower fuel costs, and provide additional system benefits unique to energy storage.

This analysis demonstrates that for an accurate comparison of the emissions from CAES to an alternative load following facility, emissions from the CAES electricity source should be evaluated. Without such an analysis, there is tremendous bias towards the storage facility that is potentially far more polluting than a new plant.

7.3 Policy Options for Addressing the Energy Storage Loophole

The analysis in section 7.2.3 demonstrates considerable emissions from the use of the Norton CAES facility, or any facility coupled to an older coal generation facility. Any new conventional source of electricity generation must meet NSR, which includes both providing an analysis of emissions, and meeting certain emission standards. It is worth evaluating how an energy storage system might meet the standards of NSR.

7.3.1 Accounting for Emissions from Energy Storage System

An examination of the various application documents from the Norton CAES project and as the TVA Regenesys project provides no indications of the air emissions that will result from storage plant operations, beyond storage plant point source emissions. This omission limits the ability of the public and policymaker to reasonably evaluate the emissions from different load-following and peaking energy sources.

Application materials, testimony, and supporting information for the Norton Energy Storage (NES) CAES facility give no indication of the fact that large amounts of emissions will result from the use of CAES. During hearings on the proposed Norton CAES facility, testimony from a NES official implies that off peak nuclear power may be used for the CAES compression cycle, despite the clear lack of significant off-peak nuclear capacity. [49] In addition, the stated "demonstrable environmental benefits associated with this CAES project" include "the use of off-peak electric energy, and a [low] natural gas heat rate [that] combine to create a point source emissions profile lower than any other available fossil-fired generation technology."[50]

While this statement is technically correct, nowhere in the testimony or filings is any estimate of total emissions that will result from CAES operation, even under hypothetical scenarios that must have been generated for such a facility to be proposed as an IPP project.

Another example of incomplete information regarding the actual emissions resulting from energy storage is a statement in an article promoting CAES published by another CAES developer, Ridge Energy Storage:

> CAES is an environmentally friendly technology….Per-megawatt emissions from CAES are about one-third of conventional fossil fuel generation plants… The low thermal heat rate of a CAES plant (less than 4,500 Btu/kWh) enables it to produce power with about 60% fewer emissions than a comparably sized simple cycle plant or 30% fewer emissions than a similarly sized combined-cycle plant.[51]

This statement is demonstrably untrue, unless all compressor electricity is derived from nuclear or renewable sources, which is highly unlikely for any of the proposed CAES facilities.

To provide the public and regulators with sufficient information to evaluate energy storage as a source of load-following and peaking power, full accounting of emissions resulting from energy storage should be required. Required documents, such as environmental impact statements, should provide estimates of the emissions that will result from expected power purchases. Such disclosures should, of course, estimate and report the substantial environmental benefits of storage, including increased plant efficiency, reduced spinning reserve requirements, and any other advantages unique to energy storage. Full accounting would be a first step in acknowledging and addressing the energy storage loophole.

7.3.2 Closing the Energy Storage Loophole

If the energy storage loophole is to be considered significant enough to be specifically addressed, there are two possible general remedies. If the net emissions from the use of energy storage are to meet NSPS, either the storage system operator or the electricity provider must be responsible for ensuring that the standards are met. Each of these options can be examined critically.

Option 1) Consider storage as a new source, whose effective emissions must meet NSPS

One possible solution would be to require the storage plant to be responsible for its net emissions. The storage plant would be responsible for tracking its net emissions by summing the emissions that result from increased power plant output, and dividing this by its production rate. To encourage the beneficial use of energy storage, the facility would be able to deduct offsets that result from efficiency increases, as well as reduced emissions resulting from spinning reserve provisions and other gains. To enable maximum economic efficiency, the emissions rate would be measured as an average. Such a method would allow for flexible purchase agreements, to meet a net output-based emissions standard.

Unfortunately, closing the loophole in this method would likely face significant opposition, and has some significant practical limitations. Tracking emissions reductions due to efficiency increases is difficult, and complicated by current input-based emissions standards. Measuring energy storage emissions using an output-based standard would require a fundamental shift in the manner in which emissions are monitored and recorded. Potentially more significant is the amount of regulatory oversight that would be necessary to enforce provisions, and avoid deceptive emissions accounting practices. As an example, the energy storage facility could arrange to purchase power from a regulated utility that operates two power plants, a nuclear plant which always runs at full capacity, and a grandfathered coal plant with spare off-peak capacity. The operating utility could potentially increase the existing coal plant output (using the hours of operation exemption) to meet the baseload, which would free up the nuclear plant to sell its "spare" capacity to the storage facility. Careful oversight would be necessary to monitor such transactions. The significant technical and regulatory limitations of this approach makes this solution unlikely. This solution also violates the basic "polluter pays" principle which is the general standard for emissions responsibility. Any realistic solution will likely address emissions at the source.

Option 2) Require the electricity sales to energy storage to meet NSR

Electricity sales to energy storage facilities could be required to meet NSR by altering the hours of operation exemption. The EPA could promulgate a rule that limits the hours of operation exemption in cases that consist of fundamental changes in method of operation. Long term, planned, and utility-initiated increases in hours of operation that are accompanied by the use of enabling technologies such as energy storage would fall outside the hours of operation exemption. This rule would appear to be consistent with the language of the CAA. This solution would also remove a market inconsistency for competing sources for new peaking power.

This solution is less complicated to administer, and is more transparent than the first option. It is also more consistent with the general "polluter pays" principle, where the generator of emissions is the responsible party for tracking and compliance. While this method does not account for the potential emission reduction benefits of energy storage, it does not require any new accounting methods that would be required with output-based standards.

7.4 Conclusions

Energy storage provides unique opportunities to electric power systems to increase the overall flexibility of low emission sources such as nuclear and wind generation. However, in the near term, the likely sources of electricity for energy storage are older coal-fired power plants with high rates of emissions. The combination of energy storage and an older coal-fired plant creates a new source of peaking power with emissions that typically greatly exceed the maximum allowable emissions for a source that could be legally constructed. Since NSR allows for increased output at older plants due to increased demand, NSR will not be triggered if a power plant increases its output due to the use of energy storage. As a result, energy storage is a new source of power that, while legal, appears to violate the *intention* of New Source Review. As long as the hours of operation exemption remains in place, energy storage will be able to take advantage of these older grandfathered plants, and energy storage will have an economic advantage over sources of energy that produce lower amounts of environmentally harmful air emissions.

7.5 Chapter References

[1] 40 C.F.R. Part 50.

[2] 42 U.S.C §7410.

[3] 42 U.S.C §7501-7515.

[4] 42 U.S.C §7470-7492.

[5] 42 U.S.C §7411.

[6] 42 U.S.C §7602(j).

[7] 42 U.S.C §7661.

[8] 40 C.F.R §52.21.

[9] 42 U.S.C §7475.

[10] 42 U.S.C §7501(3) and 7503(a)(2).

[11] 42 U.S.C §7501(a)(1)(A).

[12] 40 C.F.R §60.43(a).

[13] 42 U.S.C §7502(c).

[14] H.R. Rept. 95-284, 145; 1977 CRS Legislative History, 2652.

[15] National Academy of Public Administration. (April 2003) *Breath of Fresh Air: Reviving the New Source Review Program* Washington, D.C.

[16] 42 U.S.C §§7411(a)(4),7475(a),7479(2)(C),7501,7503 .

[17] 5 U.S.C §§551-559.

[18] Chevron U.S.A., Inc. v. Natural Res. Def. Council, Inc., 467 U.S. 837, 104 S.Ct. 2778, 81 L.Ed.2d 694 (1984).

[19] Id. at 862.

[20] Id. at 865-866.

[21] Id. at 865-66.

[22] 43 Federal Register 26830 (June 19, 1978).

[23] *Alabama Power v. Costle,* 636 F.2d 323 (D.C. Cir. 1979) 636 F.2d at 358-361.

[24] Id at 400.

[25] 40 C.F.R §60.14(e).

[26] 45 Fed Reg 52,676, 52,704 Aug 7, 1980.

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[28] Wisconsin Electric Power Co. V. Reilly, 893 F.2d 901, (7th Cir. 1990).

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[30] United States v. Ohio Edison Company, Case No. 2:99-CV-1181 (S.D. Ohio, August 2003).

[31] Id. At 83.

[32] Id. At 6.

[33] United States v. Duke Energy Corp., 278 F.Supp.2d 619 (M.D.N.C. 2003).

[34] 67 Federal Register 80,205 **(**December 31, 2002).

[35] Ibid.

[36] 68 Federal Register 61,248 **(**October 27, 2003).

[37] *State of New York v. United States Environmental Protection Agency*, No. 03-1380 (D.C. Cir. filed Oct. 27, 2003).

[38] State and Territorial Air Pollution Program Administrators Via http://www.4cleanair.org/members/010204wklyupdateshell.pdf

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[44] Wisconsin Public Service Corporation. (2003). Certificate of Public Convenience and Necessity Application. Supercritical Pulverized Coal Electric Generating Facility Weston Unit 4 Project.

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[47] Ohio Power Siting Board. (2001). In the Matter of the Application of Norton Energy Storage, LLC for a Certificate of Environmental Compatibility and Public Need for an Electric Power Generating Facility In Norton, Ohio. Case 99-1626-EL-BGN (Summit County, Ohio).

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8. Conclusions and Recommendations for Further Study

8.1 Conclusions

1) Intermittent electricity generation sources such as wind and solar energy impose burdens on electric power systems that result in added costs. As the fraction of electrical energy provided by intermittent increases, the delivered cost of this energy can increase dramatically. At some point, energy storage becomes an economic necessity to allow an increase in the use of intermittent sources. This amount is dependant on many factors, including renewable resource characteristics, existing generation capabilities, and available energy storage technology. While much more research is required to determine this economic break-even point, certainly 10-30% is reasonable bound for the amount of wind energy that can be economically deployed in coal-based systems where CAES geology is available.

2) The location of economic intermittent renewable resources such as wind will require a large expansion of long distance transmission capacity. If intermittent wind energy is to provide a large share (>20%) of the nation’s electrical energy supply, both transmission and energy storage will need to be deployed on a large scale.

3) The number of storage technologies available for use with intermittent renewables is quite small. Since pumped hydro is unlikely to be expanded due to environmental considerations and geographic constraints, compressed air energy storage is the most likely technology for large-scale storage of wind energy. Batteries may play an increased role for distributed energy systems such as solar PV.

4) In terms of environmental impact, energy storage systems are mostly “pass through” technologies. The “life-cycle” components of energy storage systems, such as construction and O&M are a relatively small fraction of net environmental impact for most technologies. Only the fuel delivery component of CAES produces a large amount of energy use and emissions, especially compared to emissions and energy use from fossil energy production.

5) Since the energy use and CO_2 emissions from energy storage systems are largely a function of the primary generation source, the lowest efficiency technologies such as PSB-BES will result in the greatest energy use and emissions, particularly when coupled to highly polluting sources. The net GHG emission rate from PSB-BES is about 15% higher than the VRB-BES or PHS. The unique hybrid-CAES system has lower GHG emissions than any other storage technologies when coupled to fossil source. When coupled to coal, GHG emissions from CAES are at least 25% lower than any other storage technology.

6) Considering both transmission and distribution provides additional insights into the actual environmental impact of electricity generation technologies. While the impact of T&D construction and O&M is relatively small, T&D losses can significantly increase the impact from fossil sources. This issue is of particular concern when considering large-scale development of the nations extensive lignite resources in the upper Midwest. Emissions related only to the T&D of lignite derived electricity will typically exceed 100 kg/MWh.

7) Integrated renewable/storage/transmission systems can be an alternative to conventional generation systems. Wind/CAES can be deployed on a large scale, and demonstrates high levels

of fossil energy sustainability, delivering more 5 times the amount of electrical energy from a unit of fossil fuel than the most efficient combustion system available. The GHG emissions from a wind/CAES system are about 20% of the lowest emission fossil system in existence. Both wind/PHS and Solar PV/BES also demonstrate superior performance to fossil energy systems in terms of energy sustainability and GHG emissions for intermediate and peaking generation.

8) Since the environmental impact of energy storage systems reflect the primary generation source, their use is not necessarily positive in terms of air emissions. The unique "grandfathering" provisions of the U.S. clean air act allow for increased output from existing coal plants that produce high levels of emissions. Energy storage provides a loophole that could be used to increase output from these plants, instead of building cleaner alternatives. A proposed CAES plant that has been permitted will effectively produce SO_2 at a rate more than 10 times the amount allowed by law for a new power plant. Its effective NO_x emission rate could be as high as 5 times greater than legally permitted for a new plant. This loophole has been largely overlooked, and should be examined critically if new technologies for generation of peaking and load-following power are to be compared equally to the use of energy storage with existing coal fired power plants.

8.2 Recommendations for Further Study

1) Significant work remains in understanding the economic limits of intermittent sources in existing electric power networks. Potentially the most significant benefits would be a better quantification of the incremental cost of wind energy integration at higher capacity and energy penetration. Furthermore, this quantification should be able to account for the changing nature of

the electric power grid, including the use of different generation technologies, but also considering the effects of deregulation.

2) A more advanced model of national wind energy penetration should be developed. This has significant policy implications. If wind energy is only able to provide a fairly small percentage of the U.S. electric demand without significant transmission developments, long-term transmission planning policies in the U.S. must be developed appropriately. The interaction between wind energy and future low-carbon sources should also be examined. The use of large amounts of wind energy in a system without the use of storage is dependent on overall system flexibility. Two possible low-carbon power sources, nuclear energy and integrated gasification combined-cycle (IGCC) with carbon capture are far less flexible than current gas and coal generation technologies. In a sense, nuclear energy and wind are, to a certain extent, mutually exclusive technologies. It is conceivable that large scale deployment of wind energy could limit the use of these technologies (or the opposite may alternatively be true.)

3) The metrics of energy analysis and environmental impact related to electric power systems can be improved with additional research. As suggested in Chapter 3, energy discounting would provide more meaningful results in terms of net energy production. Discounting of carbon emissions would provide a better assessment of GHG emission rates. In additional, appropriate "weighting" of energy sources should be addressed.

4) The large scale use of intermittent renewables will require new metrics for understanding their social and environmental impacts. Significant areas of research must consider relative land use, aesthetics, and risk perception.

The large scale deployment of renewable energy systems will require the construction of new technologies that will have a fundamentally different set of visual impacts and perceived risks compared to existing technologies. New development is potentially challenged by increased concerns regarding the environmental impacts of electric power systems, concerns that did not exist when much of the existing electric power infrastructure was developed. Much work remains to understand the social acceptability of large scale renewable energy systems.

Appendix A: Regional Wind Energy Requirements

Table A.1: Sales by State	
STATE	**Total Sales (MWh)**
AL	79,233,768
AR	41,732,449
AZ	62,281,754
CA	235,438,767
CO	44,236,038
CT	30,530,550
DC	9,409,760
DE	10,664,879
FL	199,698,300
GA	117,790,473
IA	39,213,229
ID	21,096,017
IL	135,685,219
IN	97,733,968
KS	35,846,951
KY	79,975,499
LA	74,681,020
MA	52,662,741
MD	59,799,687
ME	11,835,722
MI	101,954,781
MN	60,287,771
MO	73,213,157
MS	44,286,865
MT	11,165,218
NC	117,622,866
ND	9,809,757
NE	24,722,640
NH	10,316,372
NJ	72,339,691
NM	18,726,594
NV	28,167,293
NY	141,398,705
OH	154,458,595
OK	49,666,725
OR	45,884,830
PA	137,893,545
RI	7,846,557
SC	74,832,367
SD	8,626,999
TN	95,320,199
TX	316,061,963
UT	23,217,308
VA	96,122,996
VT	5,617,438
WA	79,666,210
WI	65,183,501
WV	27,669,432
WY	12,949,505

Table A.2 Sales by Region		
Region	Total Sales (MWh)	Fraction of Total U.S.
1	758,060,118	22.60%
2	369,005,451	11.00%
3	315,814,326	9.41%
4	515,690,426	15.37%
5	1,396,006,350	41.61%
Total U.S.	3,354,576,671	100.00%

Table A.3: Wind Generation Requirements in Region 1			
	Low (2%)	Medium (8%)	High (15%)
Generation (MWh)	15,161,202	60,644,809	113,709,018
Inst. MW (.33 CF)	5,245	20,979	39,335

Table A.4: Wind Generation Requirements in Region 3			
	Low (2%)	Medium (8%)	High (15%)
Generation (MWh)	6,316,287	25,265,146	47,372,149
Inst. MW (.33 CF)	2,185	8,740	16,387

Table A.5 Wind Generation Requirement in Region 5			
	Low (0%)	Medium (2%)	High (5%)
Generation (MWh)	0	27,920,127	69,800,318
Inst. MW (.30 CF)	0	10,624	26,560

Table A.6 Parameters for New Export Capacity for Scenario 2	
System Size (GW)	30
Capcity Factor	0.75
Annual Energy Production (GWh)	197,100,000

Consumption Data from U.S. DOE "Electric Power Annual 2001"
DOE/EIA-0348(2001) Available at:
http://tonto.eia.doe.gov/FTPROOT/electricity/034801.pdf

Table A.5 Wind Energy Requirements in Region 2 with Transmission Constraints								
National Wind Energy Goal	**Total Required Wind Energy (MWh)**	**Total Required Wind Capacity (Approx. MW)***	**Required Wind Generation in Region 2 (MWh)**			**Fraction of sales in Region 2**		
			Low	Medium	High	Low	Medium	High
0%	0	0	-15,161,202	-88,564,936	-183,509,335	-4%	-24%	-50%
2%	67,091,533	21,882	51,930,331	-21,473,403	-116,417,802	14%	-6%	-32%
5%	167,728,834	54,706	152,567,631	79,163,897	-15,780,502	41%	21%	-4%
10%	335,457,667	109,412	320,296,465	246,892,731	151,948,332	87%	67%	41%
15%	503,186,501	164,118	488,025,298	414,621,564	319,677,165	132%	112%	87%
20%	670,915,334	218,824	655,754,132	582,350,398	487,405,999	178%	158%	132%
25%	838,644,168	273,530	823,482,965	750,079,231	655,134,833	223%	203%	178%
30%	1,006,373,001	328,236	991,211,799	917,808,065	822,863,666	269%	249%	223%
35%	1,174,101,835	382,943	1,158,940,632	1,085,536,898	990,592,500	314%	294%	268%
40%	1,341,830,668	437,649	1,326,669,466	1,253,265,732	1,158,321,333	360%	340%	314%

Table A.6 Wind Energy Requirements in Region 2 with New 30 GW Transmission Capacity and Storage								
National Wind Energy Goal	**Total Required Wind Energy (MWh)****	**Total Required Wind Capacity (Approx. MW)***	**Required Wind Generation in Region 2 (MWh)**			**Fraction of sales in Region 2**		
			Low	Medium	High	Low	Medium	High
0%	-197,100,000	-64,286	-212,261,202	-285,664,936	-380,609,335	-58%	-77%	-103%
2%	-130,008,467	-42,403	-145,169,669	-218,573,403	-313,517,802	-39%	-59%	-85%
5%	-29,371,166	-9,580	-44,532,369	-117,936,103	-212,880,502	-12%	-32%	-58%
10%	138,357,667	45,126	123,196,465	49,792,731	-45,151,668	33%	13%	-12%
15%	306,086,501	99,833	290,925,298	217,521,564	122,577,165	79%	59%	33%
20%	473,815,334	154,539	458,654,132	385,250,398	290,305,999	124%	104%	79%
25%	641,544,168	209,245	626,382,965	552,979,231	458,034,833	170%	150%	124%
30%	809,273,001	263,951	794,111,799	720,708,065	625,763,666	215%	195%	170%
35%	977,001,835	318,657	961,840,632	888,436,898	793,492,500	261%	241%	215%
40%	1,144,730,668	373,363	1,129,569,466	1,056,165,732	961,221,333	306%	286%	260%

*Assumes a national average capacity factor of 35%

** This amount is the amount in addition to the 197,100,00 MWh produced annually by a "baseload wind" system, aggregated into Regions 1,3,4, and 5. This energy is produced by 30 GW of new export capacity and a system a capacity factor of 75%, enabled by energy storage. See chapter 6 for additional details. This amount of energy exported from Region 2 does not affect the amount of energy that can be produced by wind in the other regions. These regions can produce additional amounts of wind energy determined by the constraints established in the three scenarios.

Appendix B: Pumped Hydro Storage Data

Table B.1: Basic Data Related to PHS Systems Analyzed						
Project Name	Location	First Power Date	Power (MW)	Storage Time (hours)	Storage Energy (MWh)	References
Bad Creek	SC	1991	1000	24	24000	a,b
Balsam Meadow	CA	1987	200	8	1600	a,
Bath County	VA	1985	2100	11	23700	a,c,d,e
Clarence Cannon	MO	1984	31	9	265	a,
Fairfield	SC	1978	512	8	4096	a,
Helms	CA	1984	1206	15*	18090	a,f,g
Mt. Elbert	CO	1981	200	12	2410	a,
Racoon Mtn.	TN	1978	1530	21	31400	a,
Rocky Mtn.	GA	1995	760	8	6080	a,h,I

*Storage time for Helms based on weighted average on remaining plants due to inconsistencies in reported data.

All Data for the Basic Data, Dams, Underground Components, Power House, Excavation, and Land Use is derived from the following references:

a) Task Committee on Pumped Storage of the Hydropower Committee of the Energy Division of the American Society of Civil Engineers. (1993.) Compendium of Pumped Storage Plants in the United States, American Society of Civil Engineers, New York.
b) McLaren, D. G., et al. (1989). Design features of the Bad Creek pumped storage project generators motors. IEEE Transactions on Energy Conversion 4(2): pp. 191-6.
c) Anon. (1985). Bath county pumped storage. Civil Engineering (American Society of Civil Engineers) 55: pp. 55.
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e) Zagars, A. and J. M. Hagood (1977). Bath County, a 2100 MW Development in the USA. International Water Power and Dam Construction Oct.
f) Anon. (1985). Helms pumped storage project. Civil Engineering (American Society of Civil Engineers) 55: pp. 50
g) Paul, K. (1989). Design features of the Helms pumped storage project. IEEE Transactions on Energy Conversion 4(1): pp. 9-14.
h) Konstantellos, C., et al. (1997). Rocky Mountain Pumped-Storage Project in Operation since the Summer of 1995. Waterpower '97
i) Murphy, D. R. and W. R. Ivarson (1991). Rocky Mountain Project Will Provide Peak Power for Georgia. International Water Power and Dam Construction Feb.: pp. 22-24.

Table B.2 Energy Requirements and Emissions Resulting from Construction of Dams											
Project Name	**Earth Volume (m3)**	**Earth Moving Energy (GJ)**	**Earth Moving GHG Emissions (tonnes)**	**Concrete volume (m3)**	**Concrete Energy (GJ)**	**Concrete GHG Emissions (tonnes)**	**Steel Energy (GJ)**	**Steel GHG Emissions (tonnes)**	**Total Energy (GJ)**	**Total GHG Emissions (tonnes)**	**Notes**
Bad Creek	10,295,218	417,986	29,969	205,904	706,458	79,170	318,740	20,352	1,443,184	129,491	a
Balsam Meadow	170,653	6,929	497	3,413	11,710	1,312	5,283	337	23,922	2,146	a,c
Bath County	16,060,000	652,036	46,751	400,000	1,372,400	153,800	619,200	39,536	2,643,636	240,087	a
Clarence Cannon	1,709,085	69,389	4,975	34,182	117,277	13,143	52,913	3,379	239,580	21,497	a,b
Fairfield	7,642,563	310,288	22,248	200,351	687,405	77,035	310,144	19,803	1,307,837	119,085	a
Helms	4,021,270	163,264	11,706	80,425	275,940	30,924	124,499	7,949	563,702	50,579	a
Mt. Elbert	1,123,722	45,623	3,271	22,474	77,110	8,641	34,790	2,221	157,523	14,134	a
Racoon Mtn.	7,349,000	298,369	21,393	716,980	2,459,958	275,679	1,109,885	70,866	3,868,213	367,938	a,b
Rocky Mtn.	9,109,100	369,829	26,517	201,500	691,347	77,477	311,922	19,916	1,373,098	123,910	a

Notes:

a) Volume of materials is based on the volume and composition of dams in references provided in Table B.1. All materials, including concrete grouting is included. Energy and emissions is based on volume times the per volume energy and per volume emissions in the Materials Data Spreadsheet.

b) Volume of Lower dam materials was based on dimensions due to incomplete volumetric data.information:

c) Balsam Meadow dam at Shaver Lake is existing, so no energy and emissions are allocated to PHS

Table B.3 Energy Requirements and Emissions Resulting from Construction of Underground Components (Includes upper and lower tunnels, penstocks, surge chambers and powerhouse										
Project Name	**Underground volume (m3)**	**Concrete volume (m3)**	**Total Excavation Energy (GJ)**	**Total Excavation GHG Emissions (tonnes)**	**Total Concrete Energy (GJ)**	**Total Concrete GHG Emissions (tonnes)**	**Total Steel Energy (GJ)**	**Total Steel GHG Emissions (tonnes)**	**Total Energy (GJ)**	**Total GHG Emissions (tonnes)**
Bad Creek	381,378	36,375	72,262	5,023	124,803	13,986	10,042	619	207,107	19,628
Balsam Meadow	127,188	3,890	24,099	1,675	13,347	1,496	111,302	6,865	148,748	10,035
Bath County	575,421	345,987	109,029	7,578	1,187,081	133,032	388,548	24,809	1,684,658	165,419
Clarence Cannon	1,052	0	199	14	0	0	6,695	413	6,894	427
Fairfield	64,819	3,290	12,282	854	11,288	1,265	601,699	37,110	625,269	39,229
Helms	414,101	37,125	78,462	5,454	127,376	14,275	0	0	205,838	19,728
Mt. Elbert	33,546	0	6,356	442	0	0	281,602	17,368	287,958	17,810
Racoon Mtn.	279,571	12,726	52,972	3,682	43,663	4,893	32,637	2,013	129,272	10,588
Rocky Mtn.	93,756	160,015	17,765	1,235	549,011	61,526	356,875	22,499	923,651	85,260

Note: Underground volume is the sum of the volumes of upper and lower tunnels, shafts, surge tanks, penstocks, and tailrace. Data from in references provided in Table B.1.Energy and emissions calculated on excavation volume times excavation energy and emissions in material data. Concrete and steel volumes is based on the liner thickness.

Table B.4 Energy Requirements and Emissions Resulting from Excavation						
Project Name	Total Underground Excavation in Table B.3 m3	Total Fill Required m3	Total Excavation Required to provide Fill (m3)	Additional Fill Required (m3)	Energy For Additional Fill (GJ)	GHG Emissions For Additional Fill (tonnes)
Bad Creek	381,378	10,295,218	2,573,805	2,192,427	251,766	17,548
Balsam Meadow	118,716	170,653	42,663	-76,053	-8,733	-609
Bath County	575,421	16,060,000	4,015,000	3,439,579	394,982	27,530
Clarence Cannon	1,052	1,709,085	427,271	426,219	48,945	3,411
Fairfield	64,819	7,642,563	1,910,641	1,845,822	211,964	14,774
Helms	414,101	4,021,270	1,005,318	591,217	67,892	4,732
Mt. Elbert	33,546	1,123,722	280,931	247,385	28,408	1,980
Racoon Mtn.	266,067	7,349,000	1,837,250	1,571,183	180,426	12,576
Rocky Mtn.	93,756	9,109,100	2,277,275	2,183,519	250,743	17,477

This table calculates the energy required to quarry rock fill for dams. Much of the material is derived from required underground excavation. This chart calculates additional fill materials to be quarried. Assumes all fill materials require 25% rock composition. Any material not derived from tunneling is quarried on site and requires normal fill moving operation.

Table B.5 Energy Requirements and Emissions Resulting from Land Clearing and Biomass Removal					
Project Name	Total Land Area Cleared or Flooded (m2)	Total Land Intensity M2/MWh	Total energy	Emissions	Notes
Bad Creek	1,490,000	62	1,323	46,047	
Balsam Meadow	240,000	150	213	7,417	
Bath County	3,310,000	140	2,939	102,292	c
Clarence Cannon	48,862	184	43	1,510	
Fairfield	807,010	197	717	24,940	
Helms	1,900,886	105	1,688	58,745	
Mt. Elbert	1,140,000	473	1,012	35,230	b
Racoon Mtn.	2,411,571	77	2,141	74,527	
Rocky Mtn.	4,505,000	741	4,000	139,222	a

Notes

a. Rocky mountain auxillary pools "primarily for recreation" but also provide make-up water, allocated 50% to PHS

b. Lower reservoir partially existing, so only upper area used.

c. Balsam Meadow dam at Shaver Lake is existing, so no energy and emissions are allocated to PHS

Table B.6 Calculation of Energy and Emissions Related to Electrical System and Balance of Plant					
Item	**Typical Cost (1997 $/kW)**	**EIO Energy Factor (MJ/ 1997 $)**	**EIO Emissions Factor (grams/ 1997 $)**	**Energy Factor (GJ/MW)**	**Emissions Factor (kg/MW)**
Turbine/Generator	195	7.19	520.39	1,403	101,476
Other Electrical	40.5	8.00	575.00	324	23,288
Misc Equipment	15	5.911613	429.987506	89	6,450
Other Civil Works	45	9.93	844.36	447	37,996
Total	NA	NA	NA	2,262	169,210

The cost of each component was based on the weighted average costs (based on power) of components at Bad Creek, Bath County, Helms, and Rocky Mountain, derived from FERC Form 1 financial data. All EIO factors derived from Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001.

Table B.7 Energy Requirements and Emissions Related to PHS Electrical System and Balance of Plant			
Project Name	**Power (MW)**	**Energy (GJ)**	**GHG Emissions (tonnes)**
Bad Creek	1000	2,262,306	169,210
Balsam Meadow	200	452,461	33,842
Bath County	2100	4,750,843	355,340
Clarence Cannon	31	70,131	5,245
Fairfield	512	1,158,301	86,635
Helms	1206	2,728,341	204,067
Mt. Elbert	200	452,461	33,842
Raccoon Mtn.	1530	3,461,329	258,891
Rocky Mtn.	760	1,719,353	128,599

Energy and emission factors in Table B.6 were multiplied by the size of each facility.

Table B.8 Energy Requirements and Emissions Resulting from Decommisioning			
Project Name	Cost (k$)	Total Energy (GJ)	GHG Emissions (tonnes)
Bad Creek	9,078	44,409	3,273
Balsam Meadow	1,579	7,723	569
Bath County	53,017	259,354	19,114
Clarence Cannon	245	1,197	88
Fairfield	4,041	19,770	1,457
Helms	9,520	46,569	3,432
Mt. Elbert	1,579	7,723	569
Racoon Mtn.	12,077	59,079	4,354
Rocky Mtn.	5,999	29,347	2,163

Decommissioning costs estimated at 10% of capital equipment costs. Frank R. Walker Company, (1999) The Building Estimator's Reference Book (26th ed.) Chicago, IL.

EIO factor for general construction derived from Green Design Initiative. (2001) EIOLCA.net - Economic Input-Output Life Cycle Assessment. Carnegie Mellon University. Via http://www.eiolca.net. Accessed November 24, 2001.

Table B.9 Total Energy Requirements and Emissions Resulting from the Construction of PHS Systems								
Project Name	Total Construction Energy (GJ)	Total Construction GHG Emissions (tonnes)	EE_S (GJ/MWh storage time)	EM_S (tonnes CO_2e/MWh storage time)	Life-Cycle Energy Rate (GJ/MWh)	Life Cycle Emissions Rate (kg CO_2e/MWh)	Weighted EE_S	Weighted EM_S
Bad Creek	4,210,095	385,197	175	16	40	4	175,421	16,050
Balsam Meadow	624,333	53,401	390	33	30	3	78,042	6,675
Bath County	9,736,412	909,782	411	38	44	4	862,720	80,614
Clarence Cannon	366,790	32,178	1,384	121	113	10	42,908	3,764
Fairfield	3,323,858	286,120	811	70	62	5	415,482	35,765
Helms	3,614,030	341,282	200	19	29	3	240,935	22,752
Mt. Elbert	935,086	103,565	388	43	44	5	77,601	8,595
Raccoon Mtn.	7,700,460	728,873	245	23	48	5	375,214	35,515
Rocky Mtn.	4,300,192	496,630	707	82	54	6	537,524	62,079

Weighted Average Results:
EE_S = 372 GJ/MWh Storage Time
EMS = 36 tonnes CO_2e/MWh Storage Time

Appendix C: Compressed Air Energy Storage Data

Table C.1 Results: Energy Requirements and GHG Emissions from Operation				
Component	**Electrical Energy Input (kWh_{in}/kWh_{out})**	**Thermal Energy Input (kJ/kWh_{out})**	**GHG Emission Rate (kg CO2e/MWh)**	**Source Table**
Primary Electricity	0.735			C.3
Delivered Natural Gas Fuel		4,649.40	233.96	C.3
Natural Gas Delivery		518.01	52.01	C.7
Other Variable (O&M + SCR)		27.08	2.00	C.7
Total Plant (without gas infrastructure)		26.31	1.98	C.4 & C.5
Natural Gas Infrastructure		29.78	2.11	C.4
Total	**0.735**	**5,251**	**292**	

Table C.2 Summary of CAES System Performance Specifications				
Item	**Value**	**Units**	**Ref**	**Notes**
CAES Heat Rate	4536	kJ/kWh	1pg5	A
Net Heat Rate	4649.4	kJ/kWh		B
CAES Energy Ratio	0.7	kWh_{in}/kWh_{out}	1pg5	
Storage Loss Factor	1	None		No cavern losses (see text)
Transmission Loss Factor	1.025	None		2.5% each way (see text)
Net Energy Ratio	0.735	kWh_{in}/kWh_{out}		C
Natural Gas Capacity Req.	3402	MJ/sec		D
Maximum Power Output	2700	MW	1pg5	
Storage Capacity	43200	MWh	1	
Minimum CF	0.23	None	1pg19	This assesment does
Maximum CF	0.48	None	1pg19	not use these CFS
Annual Plant Output (min)	5,439,960	MWh		
Annual Plant Output (max)	11,352,960	MWh		
Annual O&M Cost (min)	20	$Million	1 pg 62	
Annual O&M Cost (max)	30	$Million	1 pg 62	
Assumed Plant Lifetime	40	Years		
Assumed Annual Plant Output	4,730,400	MWh		Assumes .20 CF
Assumed Total Plant Output	189,216	GWh		
Natural Gas Emission Factor	0.0503	tonnes co2e/gj	2	
Point Source GHG Emissions	233.96	kg CO2e/MWh		

References
1. Norton Energy Storage L.L.C. (2000). Application to the Ohio Power Siting Board for a Certificate of Environmental Compatibility and Public Need. Summit County, Ohio.
2. Spath, P. L. and M. K. Mann (2000). Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System. National Renewable Energy Laboratory. Golden, CO. NREL/TP-570-27715.

Notes:
A) The quoted heat rate of 3884 btu/kwh uses a lower heating value (LHV) of natural gas. This is equivalent to 4303.4 BTU/kWh using the higher heating value (HHV) which has a ratio 1.108 (22985 btu/lb hhv and 20745 btu/lb lhv from ref 2 which is equivalent to 4535.6 kJ/kWh
B) Equals heat rate times output transmission loss factor
C) Equals ER * output TL factor * input TL factor (both of which are = in this calculation)
D) Equals power*heat rate (NOT net heat rate)

Table C.3: Plant Construction and Decommissioning (gas plant components)

Component	Std. Plant Energy (GJ)	Std Plant Emissions (tonnes CO2e)	CAES adjustment Factor (multiplier)	CAES Construction Energy (GJ)	CAES Construction Emissions (tonnes CO2e)
Combustion Turbines	570,073	41,273.21	1.70	968,205	70,098
Recuperator (Roughly equiv. to CCGT HRSG)	35,187	2,566.00	1.70	59,761	4,358
Transformers	65,158	4,725.48	4.35	283,751	20,579
Pumps	38,067	2,714.79	1.00	38,067	2,715
Electrical Equipment	83,048	5,893.54	4.35	361,659	25,665
Noise Attenuation	1,780	125.94	1.00	1,780	126
Road upgrades	4,638	300.54	1.00	4,638	301
Pipeline & Header Interconnect	42,064	2,926.06	4.35	183,182	12,743
construction	695,305	48,582.08	1.70	1,180,898	82,511
building materials	125,891	20,736.95	1.70	213,811	35,219
Decommissioning	59,221	3,959.72	1.70	100,581	6,725
Natural Gas Infrastructure	2,140,248	151,426.82	2.70	5,777,924	408,800

Scaling Factors:	
Proportional	4.35
Turbines	1.70
Gas Infrastructure	2.70

Notes on Calculations:

Since there are many common components between a CAES plant, and a gas turbine plant, the results for each CAES component was calculated by scaling the results from a previous study of a gas-turbine power plant. The previous study was an evaluation of a 620 MW combined cycle plant. This study is a 2700MW CAES plant. Each component was scaled based on the relative size. Four scaling factors were used:

Scaling factor = 1 for the few components that would be nearly identical in both cases.
Scaling factor = 2700/630 or 4.35 was used for certain power components, such as electrical equipment that are directly proportional to plant size.
Scaling factor = 1.7 was used for several other components. This scaling factor is a result of the effective power output of a CAES turbine, which is equal to about 300/117 that of a conventional gas turbine (see text) So this scaling factor is actually 2700/630 times 117/300.
Scaling factor = 2.7 was used for the natural gas infrastructure required by CAES. This factor is a the result of upscaling the natural gas fuel consumption rate for the gas plant (equal to the product of capcity and heat rate) to the CAES consumption rate. This is equal to 2700/630 times (4649*7500) where 7500 is the heat rate of the gas plant.

Source of gas turbine data:

Meier, P. J. (2002). Life-Cycle Assessment of Electricity Generation Systems and Applications for Climate Change Policy Analysis, Ph.D. Dissertation, University of Wisconsin - Madison.

Table C.4 Plant Construction and Decommissioning (CAES specific components)								
Component	**Cost (M$)**	**cpi adj**	**Total CAES Cost in 1997M$**	**EIO Factor (GJ/M$ 1997)**	**EIO Factor (tonnes CO2e/ M$ 1997)**	**Total Energy (GJ)**	**Total Emissions (tonnes CO2e)**	**Notes**
Compressors/related	76.50	1.2	93.57	6,301.35	454.41	589,648	42,521	A
Cavern Development	94.35	1.2	115.40	3,858.36	277.25	445,267	31,996	B
Additional T&D	45.00	1.0	45.00	9,000.84	642.79	405,038	28,926	C

Notes:
A: Cost derived from EPRI (1994), scaled to reflect a total of 9 compressors. EIO Factor is for "Pumps and Compressors" at EIOLCA.net
B: Cost derived from EPRI (1994), scaled to reflect total cavern size of 43200 MWh. EIO Factor is for "Well Drilling" at EIOLCA.net
C: Cost derived from NES (2002). EIO Factor is for
were derived from the Green Design Initiative at EIOLCA.net

References:
Electric Power Research Institute. (1994). Standard compressed-air energy storage plant: design andcost. EPRI. Palo Alto, Calif. TR-103209.
Norton Energy Storage L.L.C. (2000). Application to the Ohio Power Siting Board for a Certificate ofEnvironmental Compatibility and Public Need. Summit County, Ohio.
EIOLCA.net is the Economic Input/Output LCA Database maintained by the Green Design Initiative. Website at www.eiolca.net. All data is from the 1997 data set.

Table C.5 Total Energy Input and Emissions for Construction (EE_S and EM_S)			
Total CAES Const. Energy (GJ)	**Total CAES Const. Emissions (tonnes CO2e)**	**EE_S (GJt/MWh Storage Capacity)**	**EM_S (tonnes CO2e/MWh Storage Capacity)**
10,614,209	773,282	246	18

These are the totals of all fixed components from tables C.3 and C.4. The EES and EMS values are the totals divided by the CAES storage capacity (43200 MWh)

Table C.6 Operation and Maintenance, and Fuel Delivery						
Natural Gas Delivery		**Energy Requirements (GJt/GJ gas delivered)**	**Emissions (tonnes CO2e/GJ Gas Delivered)**	**Energy (GJt/GWh)**	**Emissions (kg CO2e/MWh)**	**Notes/ Source**
		0.1114	0.0112	518.01	52.01	A
Non Fuel O&M	**Cost ($/MWh)**	**Energy Intensity of Maint (GJ/$)**	**co2 Intensity of Maint (tonnes/GJ)**	**Energy (GJt/GWh)**	**Emissions (kg CO2e/MWh)**	**Notes/ Source**
	5.5	0.0049	362.8	27.08	2.00	B
SCR	**Gas Plant Heat Rate (GJ/GWHe)**	**Gas Plant SCR Energy Rate (GJ/GWHe)**	**Gas Plant SCR Emission Rate (kg CO2e/MWh)**	**Energy (GJt/GWh)**	**Emissions (kg CO2e/MWh)**	**Notes/ Source**
	7378	8.5	0.44	5.23	0.28	C

Notes:
A: Natural Gas energy requirement is based on Meier (2002) where 136,151,287 GJ of Gas is required to deliver 1,222,020,000 GJ of Gas. Emissions to deliver this amount of gas is equal to 13,671,272 tonnes CO2e. These energy and emissions factor were then scaled to the CAES heat rate
B: O&M cost data from Table C.3. EIO factor is for "Other Repair and Maintenance Construction" at EIOLCA.net.
C: SCR data derived from Spath and Mann (2000) These values scaled to CAES plant heat rate.

Refs:
Meier, P. J. (2002). Life-Cycle Assessment of Electricity Generation Systems and Applications for Climate Change Policy Analysis, Ph.D. Dissertation, University of Wisconsin - Madison.
Spath, P. L. and M. K. Mann (2000). Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System. National Renewable Energy Laboratory. Golden, CO. NREL/TP-570-27715.

Appendix D: Battery Energy Storage Data

Table D.1 Energy and Emissions related to VRB Electrolytes				
	Mass (kg/MWh)	Cost ($/MWh)	Energy (GJ/MWh)	Emissions (tonnes/MWh)
Electrolyte Components				
Water	25002.22		0.75	0.00
Sulphuric Acid	13562.22		7.05	0.73
Vanadium as (V2O5)	5264.44		352.37	25.29
Total Materials			360.17	26.02
Production		4320	92.93	5.98
Total Electrolyte			453.10	32.00

Table D.2 Energy and Emissions related to VRB Stack				
VRB Power Stack Components	**Material**	**Mass (kg/MW)**	**Energy (GJ/MW)**	**Emissions (tonnes/MW)**
Stack structural	Steel	50320	1731.0	124.3
Stack structural	Various Plastic	6560	307.0	23.9
Connectors	Copper	3680	482.1	27.4
Membranes	High Energy Plastic	2080	97.3	7.6
Electrodes	Carbon	1200	48.0	3.6
Others	Assumed Metal/Plastic	1720	120.4	8.6
Total		65560	2785.8	195.5
Manufacturing			5103.6	370.0
Total Stack per MWh (E/P = 8 hrs)			986.2	70.7

All materials data for VRB based on:
1: Rydh, C. J. Environmental assessment of vanadium redox and lead-acid batteries for stationary energy storage. Journal of Power Sources 80, 21-29 (1999)
Production cost from:
2: Skyllas-Kazacos, M. & Menictas, C. The Vanadium Redox Battery for Emergency Back-Up Applications", Proceedings, Intelec 97, Melbourne, 19-23 October 1997. (1997).(5): p. 825-831.

Table D.3 Energy and Emissions related to VRB Transport					
Components	**Mass (kg/MW)**	**Mode**	**Distance (km)**	**Energy (GJ/MWh)**	**Emissions (tonnes/ MWh)**
Electrolyte (Sulfuric Acid)	13562	Rail	1000	3.61	0.28
Battery Components	13459	Ship	4000	15.88	1.24
Battery Components	13459	Rail	1000	3.58	0.28
BOS	9000	Truck	2000	56.25	4.39
Total for 1 MWh (E/P = 8 hours)				79.3	6.2

Table D.4 Energy and Emissions related to VRB PCS and BOS				
	Cost (M$)	Per Unit	Energy (GJ/unit)	Emissions (tonnes/unit)
PCS	4	15 MW	1884.89	134.61
Building	3.20	15 MW	1024.43	0.00
Cooling System	2.73	15 MW	1040.52	0.73
Transformer	0.50	15 MW	524.95	25.29
Storage Tanks	0.9	6 M liter	230.50	26.02
Engineering, Site Misc	4.5	15 MW	658.49	44.30
Decommissioning		15 MW	64.03	4.72
Total		1 MWh	670.5	47.8

PCS and BOS Data from

Lee Hoffmeier (2002) Personal Conversation (Cost of storage Tanks)
Lotspeich, C. (2002). A Comparative Assessment of Flow Battery Technologies. Electrical Energy Storage - Applications and Technology Conference, San Francisco, CA
TVA. (2001). Environmental Assessment: The Regenesys Energy Storage System. Tennessee Valley Authority. Muscle Shoals, Alabama.

Table D.5 Energy and Emissions related to PSB Battery Components				
	Mass (kg/MWh)	Cost ($/MWh)	Energy (GJ/MWh)	Emissions (tonnes/MWh)
Electrolyte Components*				
Sodium Bromide	8305	5814	91.562603	6.217237421
Sodium Sulfide	3183.00	1592	25.07	1.70
Sodium Hydroxide	958.00	322	5.07	0.34
Sulfur	2225.00	160	2.52	0.17
Total Materials			124.23	8.44
Production		5000	78.74	5.35
Module			739.64	53.02
Total Electrolyte			202.97	13.78

Table D.6 Energy and Emissions related to PSB Transport					
Components	**Mass (kg/MW)**	**Mode**	**Distance (km)**	**Energy (GJ/MWh)**	**Emissions (tonnes/ MWh)**
Battery Components	20641	Ship	4000	24.36	1.90
Battery Components	20641	Rail	1000	5.49	0.43
Sulfur	2225	Rail	1000	0.59	0.05
BOS	9000	Truck	2000	56.25	4.39
Total for 1 MWh (E/P = 8 hours)				86.7	6.8

Table D.7 Energy and Emissions related to VRB PCS and BOS				
	Cost (M$)	Per Unit	Energy (GJ/unit)	Emissions (tonnes/unit)
PCS	4	15 MW	1884.89	134.61
Building	3.20	15 MW	1024.43	0.00
Cooling System	2.73	15 MW	1040.52	0.73
Transformer	0.50	15 MW	524.95	25.29
Storage Tanks	0.6	4 M liter	153.66	11.32
Engineering, Site Misc	4.5	15 MW	658.49	44.30
Decommissioning		15 MW	64.03	4.72
Total		1 MWh	670.5	47.8

All materials data for PSB based on:
Fairley, P. (2003). Recharging the Power Grid. MIT Technology Review 106(2): pp. 50-57.
Toby Edmonds (2002) Personal Conversation (Cost of Electrolytes)

PCS and BOS Data from
Lee Hoffmeier (2002) Personal Conversation (Cost of storage Tanks)
Lotspeich, C. (2002). A Comparative Assessment of Flow Battery Technologies. Electrical Energy Storage - Applications and Technology Conference, San Francisco, CA
TVA. (2001). Environmental Assessment: The Regenesys Energy Storage System. Tennessee Valley Authority. Muscle Shoals, Alabama.

Table D.8 Energy and Emissions related to Lead-Acid Battery Components				
	Mass (kg/MWh)	**Cost ($/MWh)**	**Energy (GJ/MWh)**	**Emissions (tonnes/MWh)**
Electrolyte Components*				
Water	14222		0.4	0.0
Sulphuric Acid (primary)	2556		1.3	0.1
Lead (primary)	16333		443.6	31.7
Polypropylene (prim)	2160		101.1	7.9
Polyethylene or fiberglass	533		6.9	0.4
copper (primary)	72		9.5	0.5
Tin, Arsenic, Antimony (pm)	562		1.7	0.1
Manufacturing			**396.9**	28.3
Total (1st unit)			**961.4**	**69.1**
Total (20 year functional unit)			**2017**	**144.9**

Table D.9 Energy and Emissions related to Lead-Acid Battery Transport					
Components	**Mass (kg/MWh)**	**Mode**	**Distance (km)**	**Energy (GJ/MWh)**	**Emissions (tonnes/ MWh)**
Battery Components	88867	Rail	3000	73.28	5.16
Sulfuric Acid	2556	Rail	1000	2.54	0.20
BOS	9000	Truck	2000	56.25	4.39
Total for 1 MWh (E/P = 8 hours)				132.1	9.7

Table D.10 Energy and Emissions related to Lead-Acid PCS and BOS				
	Cost (M$)	**Per Unit**	**Energy (GJ/unit)**	**Emissions (tonnes/unit)**
PCS	4	15 MW	1884.9	134.6
Building	3.20	15 MW	1024.4	0.0
Cooling System	2.73	15 MW	1040.5	0.7
Transformer	0.50	15 MW	525.0	25.3
Engineering, Site Misc	4.5	15 MW	658.5	44.3
Decommissioning		1MWh	98.0	9.7
Total		1 MWh	670.5	47.8

All materials data for based on:

Rydh, C. J. (1999). Environmental assessment of vanadium redox and lead-acid batteries for stationary energy storage. Journal of Power Sources 80: pp. 21-29.

Rantik, M., Life Cycle Assessment of Five Batteries for Electric Vehicles Under Different Charging Regimes. 1999, Chalmers University of Technology

PCS and BOS Data from

Rodriguez, G. D., et al. (1990). Operating the world's largest lead/acid battery energy storage system. Journal of Power Sources 31(1-4): pp. 311-320.

TVA. (2001). Environmental Assessment: The Regenesys Energy Storage System. Tennessee Valley Authority. Muscle Shoals, Alabama.

Appendix E: Calculation of Transmission Line Losses

1: Instantaneous Losses on an AC Line

The following example demonstrates estimation of losses that will occur on a proposed transmission line under various operating conditions.

Line Details:[1]

Voltage: 345 kV AC, three-phase
Maximum Power Transfer: roughly 1000 MW (typical transfer rates will be lower)
Line Length: 370 km
Conductor Type: 954 kcmil ACSR "Cardinal", two conductors/bundle
Conductor resistance:[2] 0.108 ohms/mile at 25C
0.117 ohms/mile at 50C
0.120 ohms/mile at 75C

From this information, it is possible to calculate the instantaneous losses. The majority of line losses are due to conductor resistance. Instantaneous power losses in a conductor are given by.

$$P=I^2R_T \tag{E.1}$$

where R_T is resistance as a function of temperature.

Manufacturers data can be used to supply resistance information. Total resistance of a complete line section is calculated by:

$$R_{total} = \frac{\text{ohms}}{\text{length}} \times \text{total length} \times \frac{3\,(\text{for 3-phase AC})}{\text{no. conductors /bundle}} \tag{E.2}$$

Current in a three-phase power system is calculated from the relationship:

$$I = \frac{P}{V \times \sqrt{3} \times pf} \tag{E.3}$$

where pf is the power factor, assumed to be a constant 0.9 for this estimate.

Table E-1 provides instantaneous losses for the line for 3 power transfer cases.

[1] Public Service Commission of Wisconsin. Final Environmental Impact Statement Arrowhead – Weston Electric Transmission Line Project – Volume 1 Docket 05-CE-113, October 2000
[2] Southwire Corporation. Via http://www.mysouthwire.com/ Accessed July 18, 2003

Table E.1 Instantaneous Loss Rates for a Proposed Transmission Line

Power (MW)	Line Resistance (ohms)	Current (Amps)	Losses (MW)	**Loss Rate (%)**
250	37.26	418	6.5	**2.61**
500	40.37	837	28.3	**5.65**
1000	41.54	1,674	113.1	**11.31**

2: Average Annual Losses

Utilities use a variety of methods to calculate average losses on a line for planning purposes. One method is to calculate instantaneous losses for a number of projected loads and use a weighted average of loss rates based on expected load duration. A hypothetical loading for this line might be: 65% at 250MW, 30% at 500 MW, and 5% at 1000 MW.

In addition to resistance, additional loss mechanisms must be considered. These include leakage through line insulators, and corona losses. Corona losses are due to breakdown of the electrical insulation properties of air, and occur primarily in very humid air, or during rainstorms. These additional losses on a 345 kV line in Wisconsin with an average load of 400 MW would be approximately 3 kW/mile, adding a total average loss of 0.69 MW.[3]

Using these estimates for loads and load duration, annual average losses would 20.2 MW, or an average loss rate of 5.37%.

3: Transmission Losses on a DC Line

Losses on a DC line are the sum of resistance losses and converter station losses.

Resistance losses are calculated using equation E.1 and E.2, where the number 3 is replaced by 2 in the numerator of the last term of equation E.2. Instantaneous current on a DC line is calculated by P=IV, since there is no power factor.

For example, the CU DC line runs from the Coal Creek coal plant in North Dakota to the Dickenson substation near Minneapolis, MN, a distance of 701 km.[4] The line typically delivers about 950 MW at a voltage of +/- 450 kV. If the line delivers constant power, this results in a current of about 1188 amps. The total resistance of the line is about 24.85 ohms, resulting in a total average power loss of 35 MW, or a loss rate of 3.7%.

Converter station losses are the sum of semiconductor and other internal losses, plus electricity required to operate the station. The sum of these values is about 0.8-1% on each converter station.

The total loss rate for the entire line is estimated at about 5.5%.

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[3] Electric Power Research Institute. Transmission line reference book, 345 KV and Above. 1983

[4] CIGRE (1996). Compendium of HVDC Schemes Throughout the World. Version C. CE/SC:14.

Appendix F: Transmission Line Construction Data

Table F.1 Results Energy and Emissions Associated with Utility Transmission Line Construction (without Biomass Effects)

Voltage/Peak Power	Tower Energy (MJ/km)	Tower Emissions (kg CO2e/km)	Conductor Energy (MJ/km)	Conductor Emissions (kg CO2e/km)	Total Line Energy (MJ/km)	Total Line Emissions (kg CO2e/km)
HVDC	949,200	68,329	992,017	60,059	1,941,217	128,387
500 kVAC (3000 MW)	1,274,640	91,756	1,784,776	108,063	3,059,416	199,818
345 kVAC (1000 MW)	634,156	45,650	944,574	58,483	1,578,730	104,133
230 kVAC (400 MW)	482,768	29,982	483,444	29,272	966,212	59,253
69 kVAC (50 MW)	65,800	5,132	171,546	10,739	237,346	15,872
35 kV Distribution	60,480	4,717	91,080	6,964	149,760	11,681
15 kV Distribution	51,120	3,987	37,800	3,398	94,680	7,385
240 V Distribution	51,120	3,987	36,000	3,117	91,080	7,104

Table F.2 GHG Emissions Associated with Biomass Losses in Transmission Line Corridors

Voltage Class	Tower Type	ROW Width (meters)	Area (m2/km)	Max GHG Emissions (tonnes CO2e)	Const. Emissions (tonnes CO2e)	Max Ratio Biomass/Const.
HVDC	Lattice	50	50000	1,100,000	128,387	8.6
500kVAC	Lattice	50	50000	1,100,000	199,818	5.5
345 kVAC	Lattice	37	37000	814,000	104,133	7.8
115-230 kVAC	Pole	30	30000	660,000	59,253	11.1
69 kVAC	Pole	23	23000	506,000	15,872	31.9
Distribution	Pole	10	10000	220,000	11,681	18.8

Notes:
Data for Row width from:
Public Service Commission of Wisconsin. Final Environmental Impact Statement Arrowhead – Weston Electric Transmission Line Project – Volume 1. Docket 05-CE-113. (2000).

Schmidt, G. F., B.; Kolbeck, S.; (1996). HVDC transmission and the environment. Power Engineering Journal 10(5): pp. 204 -210.

Nantahala Power at http://www.nantahalapower.com/customerservice/rightofway/whatis/transmission.asp

Transmission Line Reference Book, 345 KV and Above / Second Edition, Copyright 1982 by the Electric Power Research Institute Inc., Prepared by Project UHV.

Power Technologies Inc (1978). Transmission Line Reference Book, 115-1389 kV Compact Line Design. Palo Alto, CA, Electric Power Research Institute Inc.

Table F.3 Energy and Emissions Associated with Utility Pole and Tower Construction									
Voltage Class	**Type**	**Weight (kg)**	**Number/km**	**Tower Energy (MJ/tower)**	**Tower Emissions (kg CO2e/tower)**	**Install Cost ($)**	**Install Energy (MJ/tower)**	**Install Emissions (kg CO2e/tower)**	**Notes**
HVDC	Steel Lattice	10500	2.5	361,200	25,946	4,620	18,480	1,386	a
500 kv	Steel Lattice	14100	2.5	485,040	34,841	6,204	24,816	1,861	a
345 kV (single circuit)	Steel Lattice	6100	2.875	209,840	15,073	2,684	10,736	805	a
230 kV	Steel Pole	1100	8	58,410	3,603	484	1,936	145	a
69 kv	Wood Pole			65,800	5,132				b
35 kV Distribution	Wood Pole			60,480	4,717				b
15 kV Distribution	Wood Pole			51,120	3,987				b

Notes:
a) Data for Weight, composition and other tower data is Transmission Line Reference Book, 345 KV and Above / Second Edition, Copyright 1982 by the Electric Power Research Institute Inc., Prepared by Project UHV.
Install cost based on Ghannoum, E. Y., S.J.; (1989). Optimization of transmission towers and foundations based on their minimum cost. IEEE Transactions on Power Delivery 4(1): pp. 614 -62.

b) Data is for 1 km section of wood poles. Data includes entire life-cycle of construction and installation, including 2 poles for wood due to aging Sources: Data is taken from:
Kunniger, T. a. K. R. Life Cycle Analysis of Utility Poles, A Swiss Case Study. Proceedings of the 3rd International Wood Preservation Symposium: The Challenge – Safety and Environment (1995).
Sedjo, R. Wood materials used as a means to reduce greenhouse gases (GHG): An examination of wooden utility poles.” in Mitigation and Adaptation Strategies for Global Change, Vol. 7, No. 2, 2002, pp191-200, Kluwer Academic Publishers.

Table F.4 Energy and Emissions Associated with Line Conductors									
Voltage	**Peak MVA (approx.)**	**Conductor Name and number per phase**	**Size (MCM)**	**Alum. Weight (kg/km)**	**Steel Weight (kg/km)**	**Alum. Energy (MJ/km)**	**Alum. Emissions (kg CO2e/km)**	**Steel. Energy (MJ/km)**	**Steel Emissions (kg CO2e/km)**
69 kv	50	linnet	336	472	217	49,088	2,885	8,094	694
230 kv	400	Ortolan	1033	1448	283	150,592	8,852	10,556	906
345kv	1000	Cardinal use 2/phase	954	1338	490	139,152	8,179	18,277	1,568
500 kv	3000	bittern use 3/phase	1272	1782	348	185,328	10,893	12,980	1,114
HVDC 900kv	1000	Lapwing use 2/phase	1590	2229	434	231,816	13,626	16,188	1,389

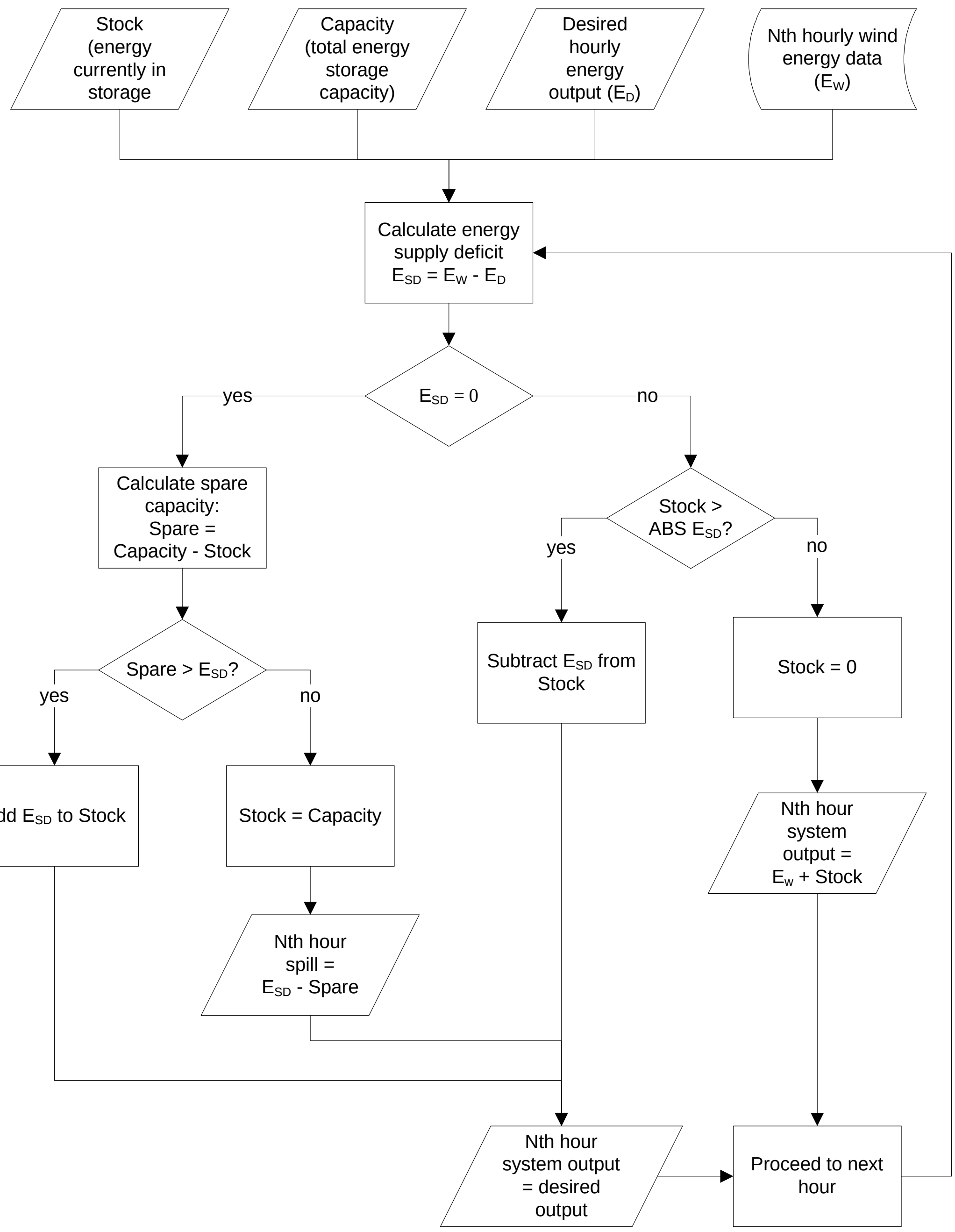
Notes:
Energy and emissions data is for a single conductor! Multiply by number of phases and #of conductors per phase

Conductor Data from
Walker, M., Ed. (1982). Aluminum Electrical Conductor Handbook, The Aluminum Association.

Line Details from
Transmission Line Reference Book, 345 KV and Above / Second Edition, Copyright 1982 by the Electric Power Research Institute Inc., Prepared by Project UHV.

Power Technologies Inc (1978). Transmission Line Reference Book, 115-1389 kV Compact Line Design. Palo Alto, CA, Electric Power Research Institute Inc.

Appendix G: WES Model Flow Diagram



WES Model Flow Diagram. This diagram describes the basic flow of the WES model. In each hour, actual wind output is compared to desired output, and the energy surplus or deficit is met by storage. The amount of energy actually placed into or withdrawn from storage is determined by the storage system energy ratio (ER).

Appendix H: Calculation of Life-Cycle Efficiency and GHG Emissions from Wind/PHS and PV/BES Systems

Table H.1 Energy and Emissions Associated with Wind and PHS Subsystems					
	Const. Energy Input (GJ/MW)	**Const. Emissions (tonnes/ MW)**	**O&M Energy (MJ/MWh)**	**O&M Emissions (kg CO2e/ MWh)**	**ER**
Wind	8510	769.8	NA	NA	NA
PHS	2984	285.6	25.8	1.8	1.35

Wind Data Includes O&M over lifetime. From White, S. W., and G. L. Kulcinski (2000). Birth to Death Analysis of the Energy Payback Ratio and CO2 Gas Emission Rates from Coal, Fission, Wind, and DT Fusion Electrical Power Plants,. Fusion Engineering and Design **48**(248): pp. 473-481.

Table H.2 Life-Cycle Fossil Fuel Efficiency and GHG Emissions Associated with Wind/PHS Systems									
	Total Annual Energy Produced (MWh)			**Fossil Fuel Efficiency (x100)**			**Life-Cycle GHG Emissions (kg CO_2e/MWh)**		
	CF = 0.25	**CF = 0.33**	**CF = 0.40**	**CF = 0.25**	**CF = 0.33**	**CF = 0.40**	**CF = 0.25**	**CF = 0.33**	**CF = 0.40**
Fraction Wind Stored									
0	2190	2891	3504	18.5	24.5	29.6	17.6	13.3	11.0
0.10	2133	2816	3413	13.4	17.6	21.4	24.9	18.9	15.6
0.15	2105	2778	3368	13.2	17.4	21.1	25.3	19.3	15.9
0.20	2076	2741	3322	13.0	17.2	20.8	25.8	19.6	16.2
0.25	2048	2703	3277	12.8	16.9	20.5	26.2	20.0	16.6
0.30	2020	2666	3231	12.7	16.7	20.2	26.7	20.3	16.9
0.35	1991	2628	3186	12.5	16.5	20.0	27.1	20.7	17.2
0.40	1963	2591	3141	12.3	16.2	19.7	27.6	21.1	17.5
0.45	1935	2554	3095	12.1	16.0	19.4	28.1	21.5	17.9
0.50	1906	2516	3050	11.9	15.8	19.1	28.6	21.9	18.2

Table H.3 Energy and Emissions Associated with PV and BES Subsystems					
	Const. Energy Input (GJ/MW)	**Const. Emissions (tonnes/ MW)**	**O&M Energy (MJ/MWh)**	**O&M Emissions (kg CO2e/ MWh)**	**ER**
PV	25587	1564	NA	NA	NA
Lead-Acid	10680	800	62	5	1.43
VRB	9012	644	54	3.3	1.33
PSB	7020	500	45	4	1.54

PV Data includes O&M over lifetime. From Meier, P. J. and G. L. Kulcinski (2002). *Life-Cycle Energy Requirements and Greenhouse Gas Emissions for Building-Integrated Photovoltaics*. Energy Center of Wisconsin Research Report 210-1.

Table H.4 Life-Cycle Fossil Fuel Efficiency and GHG Emissions Associated with PV/BES Systems									
	Total Annual Energy Produced (MWh)			**Fossil Fuel Efficiency (x100)**			**Life-Cycle GHG Emissions (kg CO_2e/MWh)**		
Fraction Energy stored	**Lead-Acid**	**VRB**	**PSB**	**Lead-Acid**	**VRB**	**PSB**	**Lead-Acid**	**VRB**	**PSB**
0	1752	1752	1752	4.9	4.9	4.9	44.6	44.6	44.6
0.10	1699	1709	1691	3.4	3.6	3.7	70.1	64.9	61.4
0.15	1673	1687	1660	3.3	3.5	3.7	71.4	65.9	62.8
0.20	1647	1665	1629	3.3	3.5	3.6	72.8	67.0	64.1
0.25	1620	1643	1598	3.2	3.4	3.5	74.2	68.0	65.6
0.30	1594	1622	1568	3.2	3.4	3.5	75.7	69.1	67.0
0.35	1568	1600	1537	3.1	3.3	3.4	77.2	70.2	68.5
0.40	1541	1578	1506	3.1	3.3	3.3	78.7	71.3	70.1
0.45	1515	1556	1476	3.0	3.2	3.3	80.3	72.4	71.7
0.50	1489	1535	1445	3.0	3.2	3.2	81.9	73.6	73.4

Appendix I: Performance of Existing Coal Plants in the Midwestern U.S. Used in this Study

EPA eGRID2002 Version 2.01 Plant File (Year 2000 Data)						
State	**Plant name**	**Plant capacity factor**	**Plant generator capacity (MW)**	**Plant 2000 annual NOx input emission rate (lbs/MMBtu)**	**Plant 2000 annual SO2 input emission rate (lbs/MMBtu)**	**Plant 2000 nominal heat rate (Btu/kWh)**
OH	O H HUTCHINGS	0.2260	447	0.588	1.258	11,967
PA	CROMBY	0.2422	420	0.343	0.800	13,819
PA	EDDYSTONE	0.2469	1569	0.264	0.404	13,181
KY	TYRONE	0.2477	138	0.654	1.250	13,981
MI	HARBOR BEACH	0.2601	125	0.921	1.344	11,740
MI	DAN E KARN	0.2930	1761	0.326	0.896	11,690
IN	LOGANSPORT	0.2990	61	0.871	2.380	14,543
KY	E W BROWN	0.3212	1606	0.389	1.991	11,205
WV	NORTH BRANCH	0.3212	80	0.356	0.311	14,676
OH	PAINESVILLE	0.3351	54	0.866	3.006	15,205
PA	PORTLAND	0.3410	620	0.271	2.173	10,080
PA	SEWARD	0.3850	218	0.440	2.551	11,605
IN	DEAN H MITCHELL	0.3917	547	0.272	0.551	12,317
IN	NOBLESVILLE	0.4009	100	0.972	3.116	12,563
IN	ELMER W STOUT	0.4039	1000	0.333	2.085	10,928
OH	R E BURGER	0.4128	538	0.679	4.605	10,560
OH	ORRVILLE	0.4155	85	0.956	6.642	15,462
IN	EDWARDSPORT	0.4176	144	0.696	2.630	15,552
IN	H T PRITCHARD	0.4242	396	0.515	2.045	11,727
PA	MITCHELL POWER STATION	0.4337	449	0.370	0.141	11,085
PA	NEW CASTLE PLANT	0.4343	431	0.378	2.547	11,819
MI	ST CLAIR	0.4354	1929	0.478	1.256	10,896
PA	SUNBURY GENERATION LLC	0.4443	498	0.565	2.439	11,875
OH	PICWAY	0.4504	106	0.483	4.484	11,238
KY	GREEN RIVER	0.4518	264	0.578	3.380	13,246
MI	ECKERT STATION	0.4557	375	0.381	0.646	13,805
IN	MICHIGAN CITY	0.4610	680	0.512	0.739	11,139
OH	NILES	0.4647	293	0.929	2.991	11,136
OH	EASTLAKE	0.4657	1289	0.562	2.252	10,571
KY	HMP&L STATION TWO	0.4682	405	0.472	0.460	15,442
IN	BAILLY	0.4933	653	1.308	0.323	11,282
IN	WABASH RIVER	0.4942	1173	0.439	2.115	10,906
MI	J B SIMS	0.4975	85	0.388	0.324	10,438

State	Plant name	Plant capacity factor	Plant generator capacity (MW)	Plant 2000 annual NOx input emission rate (lbs/MMBtu)	Plant 2000 annual SO2 input emission rate (lbs/MMBtu)	Plant 2000 nominal heat rate (Btu/kWh)
PA	ELRAMA POWER PLANT	0.4997	510	0.482	0.308	13,470
MI	B C COBB	0.4999	511	0.348	1.275	11,286
IN	R M SCHAHFER	0.5063	2201	0.384	0.635	11,275
OH	BAY SHORE	0.5159	655	0.734	0.580	10,552
WV	RIVESVILLE	0.5389	110	0.783	1.711	13,249
KY	SHAWNEE	0.5506	1750	0.380	0.658	12,280
IN	A B BROWN	0.5516	619	0.435	0.435	10,547
KY	CANE RUN	0.5552	661	0.411	0.929	11,676
PA	TITUS	0.5616	261	0.315	2.246	10,624
MI	ENDICOTT GENERATING	0.5622	55	0.399	0.376	14,831
OH	CONESVILLE	0.5685	2175	0.529	2.525	10,088
OH	W H SAMMIS	0.5855	2468	0.503	1.847	10,320
KY	PARADISE	0.5870	2558	0.867	2.039	10,815
PA	SHAWVILLE	0.5951	631	0.425	2.863	10,246
WV	JOHN E AMOS	0.5990	2933	0.590	1.223	9,683
KY	MILL CREEK	0.6005	1717	0.379	0.640	11,942
PA	HOMER CITY STATION	0.6043	2194	0.442	2.188	10,333
IN	TANNERS CREEK	0.6054	1100	1.121	2.315	9,989
PA	G F WEATON POWER STATION	0.6065	120	0.561	0.390	11,626
OH	WALTER C BECKJORD	0.6100	1376	0.547	1.798	10,825
MI	J H CAMPBELL	0.6151	1542	0.499	0.956	10,262
KY	GREEN STATION	0.6158	586	0.424	0.196	10,935
OH	W H ZIMMER	0.6173	1426	0.472	0.491	10,266
WV	MITCHELL	0.6175	1633	0.581	1.268	9,641
KY	COOPER	0.6182	321	0.427	1.976	10,546
MI	JAMES DE YOUNG	0.6187	63	0.648	1.270	14,001
WV	ALBRIGHT	0.6221	278	0.507	2.475	12,139
MI	BELLE RIVER	0.6231	1709	0.268	0.554	11,371
WV	PLEASANTS	0.6240	1368	0.358	1.110	9,891
OH	MUSKINGUM RIVER	0.6274	1530	0.706	3.876	9,578
MI	MONROE	0.6362	3293	0.534	1.220	9,606
IN	R GALLAGHER	0.6365	600	0.432	3.393	10,397
WV	KANAWHA RIVER	0.6369	439	0.615	1.210	9,967
KY	GHENT	0.6378	2226	0.356	0.882	10,791
WV	MOUNTAINEER (1301)	0.6449	1300	0.505	1.087	9,604
PA	CHESWICK POWER PLANT	0.6454	565	0.366	2.575	10,919
PA	HATFIELD'S FERRY POWER STATION	0.6474	1728	0.473	3.375	10,019

State	Plant name	Plant capacity factor	Plant generator capacity (MW)	Plant 2000 annual NOx input emission rate (lbs/MMBtu)	Plant 2000 annual SO2 input emission rate (lbs/MMBtu)	Plant 2000 nominal heat rate (Btu/kWh)
IN	WHITEWATER VALLEY	0.6495	94	0.434	3.611	12,514
PA	ST NICHOLAS COGENERATION PROJECT	0.6514	117	2.069	0.718	12,421
MI	ERICKSON	0.6534	155	0.419	1.379	10,650
MI	J R WHITING	0.6622	346	0.309	0.887	11,668
OH	CARDINAL	0.6632	1880	0.564	2.346	9,316
KY	ELMER SMITH	0.6772	445	0.759	0.410	12,646
PA	BRUCE MANSFIELD	0.6831	2741	0.370	0.372	9,535
OH	J M STUART	0.6845	2452	0.591	1.443	9,963
WV	KAMMER	0.6891	713	0.769	2.149	9,283
IN	STATE LINE ENERGY	0.6899	532	0.595	0.559	10,014
OH	MIAMI FORT	0.7021	1358	0.563	1.795	10,874
KY	TRIMBLE COUNTY	0.7031	566	0.393	0.415	10,494
WV	PHIL SPORN	0.7039	1106	0.622	1.696	9,367
IN	MEROM	0.7244	1080	0.386	0.401	12,252
OH	GEN J M GAVIN	0.7268	2600	0.483	0.281	10,625
IN	PETERSBURG	0.7271	1881	0.335	0.626	11,214
KY	KENNETH C COLEMAN STATION	0.7273	521	0.431	2.516	10,816
WV	ALLOY STEAM STATION	0.7285	40	0.906	0.438	12,597
IN	GIBSON	0.7297	3340	0.446	1.599	10,045
PA	KEYSTONE	0.7309	1883	0.327	2.755	9,242
PA	CONEMAUGH	0.7324	1883	0.342	0.118	9,954
IN	CLIFTY CREEK	0.7328	1304	0.753	1.008	10,117
KY	BIG SANDY	0.7410	1097	0.540	1.550	9,388
IN	F B CULLEY	0.7506	411	0.461	0.733	11,860
KY	DALE	0.7528	176	0.491	1.249	11,399
WV	HARRISON	0.7534	2052	0.469	0.088	10,585
MI	J C WEADOCK	0.7534	333	0.306	0.814	10,744
OH	KILLEN STATION	0.7636	687	0.454	1.059	10,126
KY	EAST BEND	0.7670	648	0.381	0.653	10,446
WV	FORT MARTIN	0.7767	1152	0.715	2.445	9,400
IN	ROCKPORT	0.7874	2600	0.406	0.696	10,154
WV	MT STORM	0.7900	1681	0.624	1.825	10,652
WV	WILLOW ISLAND	0.7956	213	1.076	2.097	11,774
WV	GRANT TOWN POWER PLANT	0.8107	96	1.004	0.348	12,465
IN	FRANK E RATTS	0.8169	233	0.491	2.505	11,028
KY	D B WILSON STATION	0.8270	440	0.435	0.504	12,580
OH	KYGER CREEK	0.8413	1086	0.781	3.303	9,546