Project Report

Energy Study

for

The South Dakota
Energy Infrastructure Authority

In fulfillment of
SDEIA Request for Proposal #2006-02

Schulte Associates LLC

January 16, 2007

ABSTRACT

The Governor and several key members of the South Dakota legislature have requested that the South Dakota Energy Infrastructure Authority (SDEIA) research the subject of electric generation options in South Dakota and prepare a detailed report summarizing those options. This Energy Study Report ("Report") responds to this request.

The objective of the Report is to present, as completely as possible, an assessment of the practicality and feasibility of electric generation from three major energy options--coal, nuclear, and wind power--as they would apply in South Dakota. Since South Dakota is already a net electricity exporter, the assumption used is that any new generating facility would be primarily used for exporting power.

The Report expands upon the information contained in an earlier report entitled "Joint Report of the South Dakota Energy Infrastructure Authority and South Dakota Energy Task Force" published December, 2005, and compliments the SDEIA report "Electric Industry Interviews Report" published December, 2006.

The Report describes the most important features of the generation alternatives and their probable costs. It summarizes the regulatory hurdles that would need to be crossed to secure sites, construction permits, and operating licenses for the installation of new coal, nuclear, and wind-powered generating facilities in South Dakota.

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EXECUTIVE SUMMARY

The South Dakota Energy Infrastructure Authority (the "Authority" or "SDEIA") was created by the South Dakota legislature in 2005 to *"…diversify and expand the state's economy by developing in this state the energy production facilities and the energy transmission facilities necessary to produce and transport energy to markets within the state and outside the state."*[1] In its initial effort, the Authority has elected to limit the scope of "energy production and transmission" to mean *electricity* production and transmission.

The Governor and several key members of the South Dakota legislature have requested the SDEIA research the subject of electric generation options in South Dakota and prepare a detailed report summarizing those options. This Report responds to this request.

The objective of the Report is to present, as completely as possible, an assessment of the practicality and feasibility of electric generation from three major energy options - coal, nuclear, and wind power - as they would apply in South Dakota. Since South Dakota is already a net electricity exporter, the assumption used is that any new generating facility would be primarily used for exporting power.

Schulte Associates LLC (SA) was retained by the Authority to conduct the research work and prepare this Report on behalf of the SDEIA.[2]

The Report describes two coal-based technologies and four nuclear plant options that would all be suitable for generating electric power in baseload service while operating at high annual capacity factors.[3] Developing technology for harvesting intermittent wind energy and converting it to electricity is also covered in a separate chapter.

The expected capital costs and levelized energy costs for the various technologies are presented in the Report, along with summaries of the regulatory and environmental permits that would probably be needed to build the respective technologies for power production and transfer in South Dakota. The Report also reviews the opportunities and challenges that utilities or merchant plant owners may encounter when planning the construction of new coal, nuclear or wind-based generating plants in the state.

The SDEIA published an Electric Industry Interviews Report in December 2006. That report observed that efforts by state government to promote greater exports of electric

[1] SDCL 1-16I, Section 2.
[2] Contact information for Schulte Associates is provided in Appendix F.
[3] See definitions for "baseload" and "capacity factor" in the Glossary of Terms provided at Appendix A of this Report.

power would require production plant additions, mitigation of transmission line constraints and the identification of customers willing to purchase the energy made in South Dakota. This new Report confirms the same findings; but gives greater visibility to the very large dollar investments that will be required of anyone seeking to license and construct new electric generating facilities – coal, nuclear or wind - anywhere on the Great Plains.

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CHAPTER 1.0

INTRODUCTION

1.1 South Dakota Energy Infrastructure Authority (SDEIA)

The South Dakota Energy Infrastructure Authority (SDEIA) was created by the South Dakota legislature in 2005 to *"…diversify and expand the state's economy by developing in this state the energy production facilities and the energy transmission facilities necessary to produce and transport energy to markets within the state and outside the state."*[4] In its initial efforts, the Authority has elected to limit the scope of "energy production and transmission" to mean *electricity* production and transmission.

The Authority joined with the South Dakota Energy Task Force in writing a Joint Report, dated December 2005, which examined both traditional and renewable energy resources available in the state.[5] The Joint Report also discussed constraints, primarily transmission limitations, on producers' ability to move electric power from South Dakota to distant load centers.

In August 2006, in response to its legislative mandate, the Authority retained Schulte Associates LLC (SA) to conduct interviews with entities that produce, transmit. distribute, regulate, control, and market electric power in South Dakota. The report, "Electric Industry Interviews Report", was published in December, 2006."

While the second study was being completed, SDEIA commissioned SA to undertake the Energy Study reported herein. Designed as a companion to the first two reports issued by the Authority, this document has been prepared to provide, in greater detail, descriptions of current and available technologies for power production that would probably be the centerpieces of any plan for expanding electric generating capacity in South Dakota. The technologies described herein are based on use of three alternative *primary* energy sources:

- Coal
- Nuclear
- Wind

This report describes the most important features of the generation alternatives, their probable power production costs, and the regulatory hurdles that would need to be crossed to secure sites, construction permits and operating licenses for their application in South Dakota.

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[4] SDCL 1-161, Section 2.
[5] Joint Report of the South Dakota Energy Infrastructure Authority and the South Dakota Energy Task Force", December 2005.

Like the two preceding SDEIA reports, this report is intended to assist South Dakota in identifying actions that the state could undertake in future years to diversify and expand the state's economy through the development of electric energy production and transmission.

1.2 Outline of the Study Process

SA used a four-step process to conduct the study and assemble the required information:

1. SA communicated with major companies and associations active in the design, installation, acquisition, permitting or operation of plants employing the target technologies. These organizations were interviewed to obtain the most recent public data on power generation options, product designs, installation methods and costs.

2. In order to present a clear picture of the regulatory processes applicable to the technologies, SA contacted a list of regulatory and permitting agencies, as well as licensing process experts, and solicited descriptions of the rules and regulations that would be encountered in the siting of new electric generating facilities in South Dakota.

3. Recently-published reports on related topics were consulted. SA focused on reports pertinent to facilities planned for installation in South Dakota and the immediate surrounding region to obtain a current picture of South Dakota's specific advantages and disadvantages as a site for each technology. For example, recent permitting efforts for wind energy projects in South Dakota, the proposed Big Stone Unit II coal-fired project in South Dakota, and the proposed Mesaba Energy Project [a coal-fueled integrated gasification combined cycle (IGCC) plant] in Minnesota have all resulted in regulatory filings that were collected and reviewed.

4. Finally, to round out the data, a wide-ranging Internet search was conducted to secure information from other national and international sources.

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CHAPTER 2.0

COAL TECHNOLOGIES

2.1 Coal Plant Summary

Electric generating plants built around steam boilers and fueled with pulverized coal are currently the standard for providing baseload power generation in much of the United States. The first part of this chapter is focused on the design features and performance characteristics of modern new coal-fired boiler-steam turbine-generator units that could be sited in South Dakota.

The second part of this chapter describes a relatively new technology for generating electricity from coal – integrated gasification combined cycle (IGCC). Current coal combustion technology requires the use of various types of emission control equipment. In an effort to meet increasingly restrictive emission standards, and to realize improvements in combustion efficiency, the electric utility industry is evaluating the IGCC technology at several demonstration plants. A description of the technology and the industry's efforts are detailed in Section 2.2.2.

2.2 Coal Facility Types

2.2.1 Coal–Fired Steam Boiler Steam Turbine Electric Generator Units

2.2.1.1 Major Components and General Process of Pulverized Coal (PC) Units

The major components of a typical modern coal fired power plant are: the coal handling facilities; the furnace where the coal is burned; the boiler section where the steam is produced; the steam turbine generator which generates the electricity; environmental control equipment including the chimney; cooling water facilities that condense the steam for reuse; and ash handling facilities. Figure 2.1 illustrates a typical pulverized coal-fired generating unit.

Coal is usually delivered to the site by conveyor from a near-by mine or by rail, barge, or truck from a more distant fuel supplier. The fuel inventory is usually stored in a coal yard[6] and then transferred to the coal hopper (15) which feeds a set of pulverized coal mills (16).

The coal, now in a finely ground form, is blown into the combustion chamber at the bottom of the multi-storied furnace and burned to produce a stream of hot gases. The gases pass through the boiler section and over an array of boiler tubes that are filled

[6] This storage can include long-term storage areas for addressing extended supply interruptions such as blizzards or labor strikes, and short-term, "active" storage for day-to-day operations.

with water. The water is heated by the hot gas stream producing steam in the boiler tubes.

The steam is piped to a multi-stage turbine (9 & 11) where it is directed at a series of blades on a shaft. The force of the steam on the blades causes the turbine shaft to rotate at high speed. The turbine shaft is connected to the generator rotor (5). The rotation of the generator rotor inside the generator stator coils produces electricity.

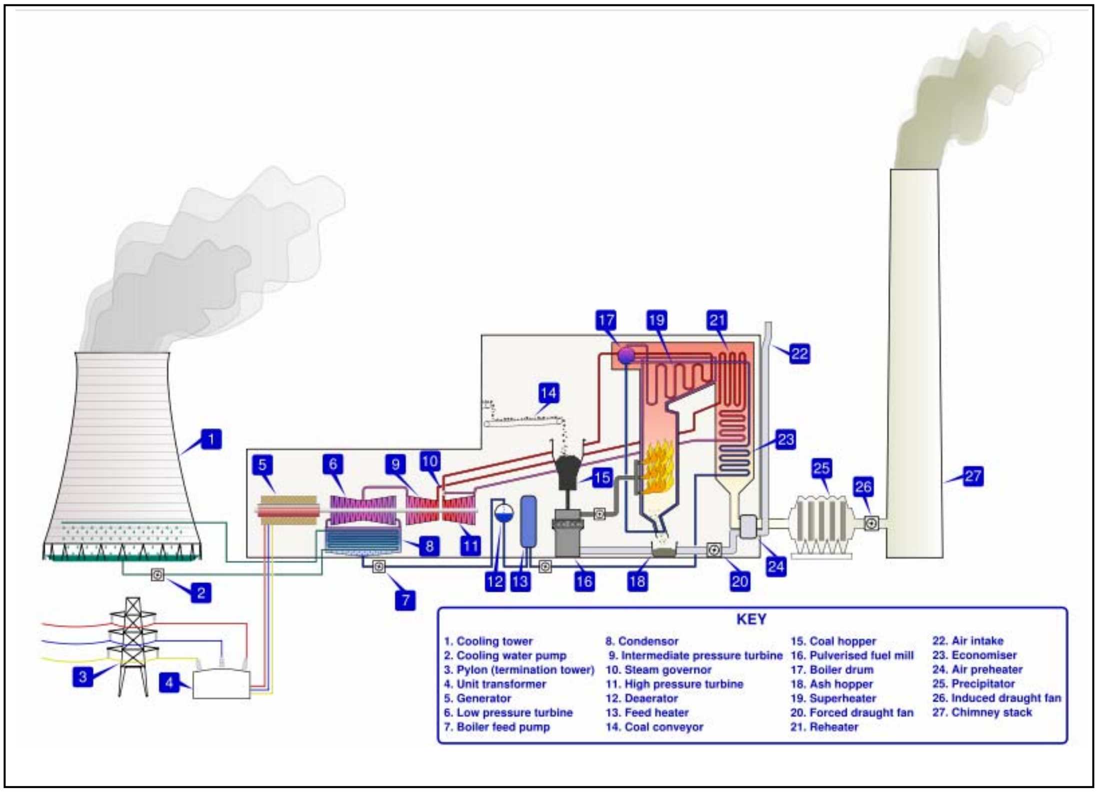
The electric current from the generator is passed to the unit transformer (4) where the electric driving force (voltage) is stepped up to transmission voltage and the current is sent out to customers over the connected transmission lines.

Steam leaving the turbine is cooled back to a liquid state in the condenser (8) and returned to the boiler. The flue gas stream leaving the boiler section passes through various emission control devices which remove particulate matter (5), sulfur dioxide (SO_2) and oxides of nitrogen (NO_x), as local environmental regulations may require, before being discharged to the atmosphere through the chimney (27). The large cooling tower (1), shown to the left in Figure 2.1, removes and discharges heat from the circulating water used to cool the steam in the condenser.[7] Other equipment in the plant is used to treat boiler feed water for corrosion prevention, handle ash and clinkers produced in the combustion process, and pre-heat air used to burn the coal.

[7] Other alternatives to the use of cooling towers include once-through cooling and dry cooling to accomplish the same function.

FIGURE 2.1

Layout of a Typical Coal-Fired Steam Boiler Generating Plant[8]



2.2.1.2 Sub-critical and Super-critical Pulverized Coal Steam Boiler Units

The cost of electric energy produced by a coal-fired, steam boiler unit is directly affected by the thermal efficiency of the steam production process. Thermal efficiency is measured in British Thermal Units (BTU) used per kilowatt-hour (KWh) of electric energy produced. The BTUs come from the coal burned.

High thermal efficiencies are achieved in a steam boiler unit by careful control of numerous parameters in the design and subsequent actual operation of the boiler. In the design stage, a choice is made to produce steam at temperature and pressure conditions that are below, above, or greatly above the “critical point” where the water in the last sections of the boiler tubes ceases to exist in a liquid state. A boiler operating at steam temperature and pressure conditions below the critical point is said to have a “sub-critical” design. A boiler operating with outlet steam conditions above the critical point is said to have a “super-critical” design. In theory and practice, the super-critical unit offers the higher thermal efficiency, and thus the lowest electric energy cost.

[8] Wikipedia, http://en.wikipedia.org/wiki/Image:PowerStation3.svg

Sub-critical plants can be used more easily than super-critical units in applications where the connected electric load is subject to change from hour-to-hour; i.e., where the electric load is cycling up and down. Sub-critical units, therefore, are adaptable for use in supplying cycling loads which may persist for only a few hours in each 24 hour operating day.

Super-critical boiler plants are less adaptable for meeting cycling or peaking loads. Plants operating under super-critical conditions need to be held at constant load to minimize the threat of corrosion problems in the boiler tubes and steam turbine. They are generally built for baseload applications in which the unit operates close to full, rated load virtually round the clock. And, because they have better fuel efficiency, they entail lower environmental emissions per unit of electric output.

Super-critical systems usually have capital costs that are 1 - 3% higher than those for sub-critical units; but operate at efficiencies of 35 - 43% versus 32 - 37%[9] for sub-critical plants. These figures describe the percentage of energy in the primary fuel, coal, that was successfully converted to electric energy at the outlet side of the unit transformer; i.e., at the busbar in the electric switchyard adjacent to the power plant. The remaining thermal energy in the coal, about 65% of the input energy, provides electricity to operate the auxiliary equipment (pumps, coal mills, fans, lighting, etc) in the plant, or is discharged from the plant with the flue gas up the chimney and the plume of hot air from the cooling tower.

Super-critical boiler units are currently the industry standard for new coal plants being ordered in the United States. Consequently, for the remainder of this report, SA will not discuss sub-critical plants. Any reference to a pulverized coal (PC) power plant should be understood as a reference to a super-critical facility.

2.2.1.3 Ultra-supercritical, Pulverized Coal, Steam Boiler Units

It should be noted that development efforts are underway on ultra-supercritical pulverized coal power plants to take advantage of even greater thermal efficiencies. These plants are expected to have capital costs 1-3% greater than super-critical plants. At the time of the writing of this report, however, the designers of ultra-supercritical boiler units are struggling to overcome material failures due to corrosion and other stresses resulting from the extreme temperature and pressure conditions required to achieve the "ultra" steam stage. Given the uncertainties about material applications in this boiler design, ultra-supercritical generating units will not be addressed further in this report.

[9] "Western Coal at the Crossroads" prepared by Western Resource Advocates April, 2006. Lower ends of the efficiency ranges shown are more reflective of the impact of adding modern emission control equipment.

2.2.1.4 Sub-critical, Fluidized Bed Units

Another example of a coal facility is a fluidized bed combustion (FBC) unit. These units float the fuel on upward-flowing jets of air while it is burning; causing it to resemble a boiling liquid. This turbulent mixing improves heat transfer and chemical reaction with the sorbent. The sorbent is usually limestone added to the fuel in order to reduce sulfur emissions. These units can be operated at atmospheric pressure in order to run a steam generator or be run at higher pressures to feed a combined cycle.

Some of the advantages of these systems are the flexibility of fuel feedstock, as well as reduced emissions. FBC units are able to meet sulfur dioxide and nitrogen dioxide emissions without expensive add-ons to the system. These units are commercially available up to 400 MW,[10] but are commonly sized smaller. FBC facilities are often used for burning of low-quality fuels such as waste streams from a paper mill or tire derived fuels. Were coal to be used, it must be conditioned, but does not have to be pulverized.

FBC plants are more expensive that super-critical PC and are not large enough to compete with super-critical PC units and IGCC.[11] Consequently, they will not be addressed further in this report.

2.2.2 Coal-Fueled, Integrated Gasification Combined Cycle (IGCC) Generating Units

2.2.2.1 IGCC Introduction

Integrated gasification combined cycle (IGCC) units are in development to be the next evolutionary step in electric power production using coal. Experience to-date is based on several demonstration facilities, and there are currently no plants operating with output ratings larger than 300 MW (net).[12] Confidence in the cost estimates for and performance characteristics of the IGCC units are expected to improve significantly as the first large versions of these plants are designed, built, and put into utility service; typically with financial support from private, federal and state sources.

Gasification units use of one of three technologies:

- Moving bed gasifiers (dry ash)
- Fluid bed gasifiers
- Entrained gasifiers

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[10] “Western Coal at the Crossroads” prepared by Western Resource Advocates, April, 2006.
[11] Michigan Electric Capacity Needs Forum, July 1, 2005 http://www.michigan.gov/documents/cnf_7-1-05_129763_7.pdf
[12] Source: Duke Power Company, http://www.duke-energy.com/about/plants/new_generation/coal/cliffside/qa/

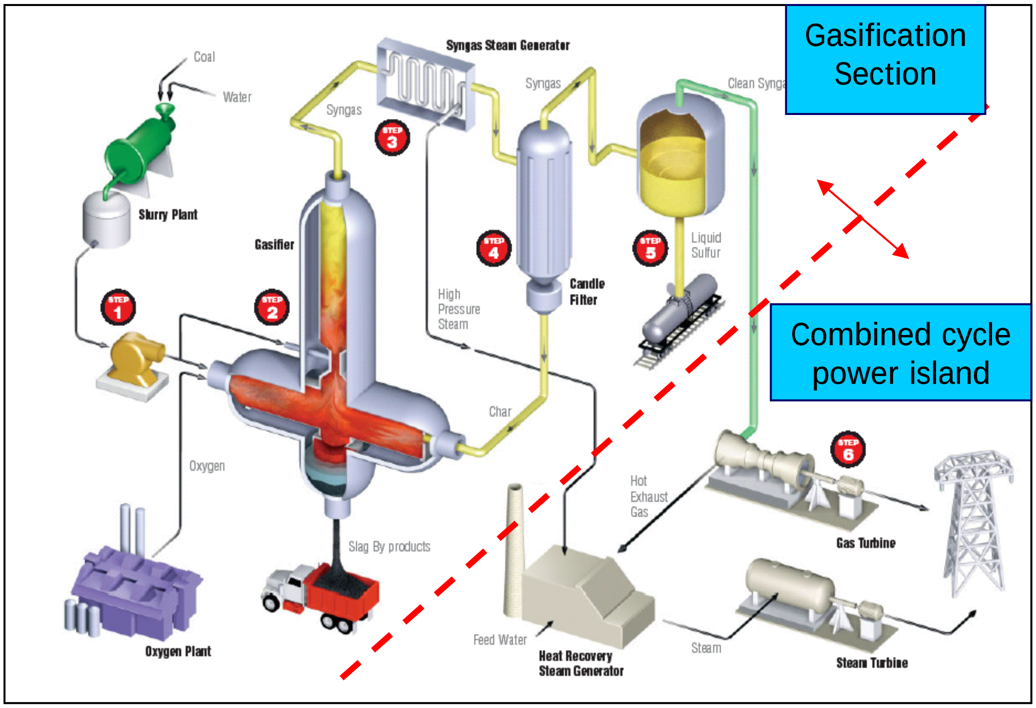
The electric industry's research arm, the Electric Power Research Institute (EPRI), has found that single-stage entrained gasifiers seem to have the best features related to potential carbon dioxide (CO_2) capture, ammonia control, water injection, slag removal, refractory life and maintenance cost. Consequently, in this report SA has chosen to focus on entrained gasifiers alone.

2.2.2.2 Major Component and General Process (IGCC)

The major components in a typical IGCC electric generating station are shown in Figure 2.2. Similar to a pulverized boiler-steam coal plant, coal is delivered to the plant site by conveyor, ship or railcar and temporarily stockpiled to provide a fuel inventory. The coal is ground continuously in a mechanical mill and blended with water (Step 1) to create a coal-water slurry. The slurry is then pumped into a large heated pressure vessel, the gasifier, which is the central piece of equipment in an IGCC plant.

In the gasifier, the feedstock is put under pressure in the presence of steam and partially burned. This part of the process is controlled by an air separation unit that supplies a carefully monitored mixture of oxygen and air to the gasifier. The carbon molecules in the coal break apart under the heat and pressure, and a chemical reaction occurs that produces the syngas. Unlike a pulverized coal plant, the gasification process occurs in primarily oxygen rather than air. Because air contains a large proportion of nitrogen, using oxygen instead helps an IGCC unit achieve lower nitrogen oxide (NOx) emissions than a PC unit.

FIGURE 2.2
Flow Diagram for a Coal-Fueled IGCC Electric Generating Plant[13]



The major useful components of syngas are hydrogen and carbon monoxide. The syngas includes other gaseous byproducts such as hydrogen sulfide and ammonia. The percentage of each of these constituent gases depends on the type and quality of the feedstock.

The minerals within the coal that are not oxidized separate and leave the gasifier as a glass-like inert slag or as marketable byproducts. Only a small amount of the coal leaves the gasifier as fly ash in the syngas stream, and it requires removal downstream from the gasifier.

The syngas is cooled and pollutants are stripped out of the hydrogen and carbon monoxide mixture before it is sent to a combustion turbine for power generation. This pre-combustion gas cleanup step avoids costly, post-combustion removal of sulfur, mercury and other combustion products. The process is said to be more efficient than the cleanup steps behind a pulverized coal, steam-boiler unit.

The IGCC process is intended to result in lower emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), and mercury (Hg) than is achievable in a pulverized coal steam

[13] Source: ConocoPhillips

boiler plant. The process also holds potential for capturing CO_2 from the syngas stream. The sulfur removed as elemental sulfur or sulfuric acid can be sold to chemical or fertilizer companies. In addition, the carbon capture potential of an IGCC unit would position IGCC owners to respond quickly to possible future regulatory calls for carbon emissions control in the name of environmental improvement. These topics will be discussed at a greater length in Chapter 6 of this report.

In an IGCC, the hot exhaust from the combustion turbine is directed to a waste heat recovery boiler where steam is produced to power a steam turbine generator, which produces additional electricity. The use of two different generating modes is the reason for calling this type of plant a “combined cycle” unit.

IGCC is a unique system because it can use more than one type of fuel. Where a pulverized coal, steam-boiler unit is generally limited to using the type of coal for which the plant was designed, an IGCC unit can employ bituminous, sub-bituminous, and lignite coals by changing operating parameters. It can also employ biomass, waste, and petroleum coke. Often these materials are mixed to find the most economical fuel. An IGCC plant can also use higher sulfur coal while still maintaining low sulfur emissions. IGCC units can achieve efficiencies of 37 - 43% at present, but as the technology matures these are expected to rise above 50%[14].

2.2.2.3 IGCC History

IGCC technologies were first evaluated in the United States via three projects funded in part by the U.S. Department of Energy’s Clean Coal Demonstration Project. One unit, the Wabash River Coal Gasification Repowering Project in Indiana, has a rating of 262 MW. The demonstration ended in 2000, and after a period of non-operation due to commercial considerations, it is operating today. It employs the Dow Destec Gasification Process that is now offered on a commercial basis by ConocoPhillips as “E-GAS” technology.

A second demonstration project is Tampa Electric’s Integrated Gasification Combined-Cycle Project (a.k.a. the “Polk County Project”) in Tampa, Florida which went online in 1996. It uses the Texaco (now owned by General Electric) coal gasification process, and has a net electric output of 250 MW. It completed its demonstration stage, and continues today in baseload operation.

The third unit, (Pinon Pine) in Reno, Nevada, was rated at 107 MW and operated between 1999 and 2001; but encountered difficulties related to its high altitude location.

Other, larger IGCC units have operated for years at European chemical plants. New units are planned or under construction in Italy, Spain, Japan and the Netherlands.

[14] “Western Coal at the Crossroads”, prepared by Western Resource Advocates, April, 2006.

2.2.2.4 IGCC Pending Projects

In the U.S, public and private interests are proceeding with planning and development for a family of additional IGCC projects including those listed below:

- Projects
  - Mesaba Energy Project, Minnesota
  - Gilberton Coal-to-Clean Fuels and Power Project
  - Stanton Energy Center, Florida
  - FutureGen Project, U.S. Department of Energy (DOE)

- Sponsoring Companies
  - American Electric Power
  - Cinergy/PSI (being acquired by Duke Energy)
  - Northwest Energy
  - Tondu Corporation
  - Basin Electric Cooperative

2.3 Coal Industry Players

2.3.1 Pulverized Coal Plant Vendors

There are multiple potential sources in the U.S. for designing and constructing pulverized coal electric generating plants. Typically, a utility or independent power producer will employ an engineering firm such as Burns and McDonnell or Black & Veatch to design the facility, and combine those design services with a construction contractor such as Bechtel or Fluor Corporation for a complete design and build package. The utility itself may act as general contractor for the project, or they might buy the complete engineer-procurement-construction (EPC) process as a package, turn-key deal.

2.3.2 IGCC Vendors

The U.S. demonstration projects for IGCC technologies have led to the formation of three consortia offering design, engineer/construct, and technology services for commercial IGCC installations in the United States:

- GE Energy has aligned with Bechtel to deploy the former Texaco gasification technology,

- ConocoPhillips has aligned with Fluor Corporation to sell the E-Gas process, and

- Shell/Krupp Uhde has aligned with Black and Veatch to offer the Shell/Prenflo process.

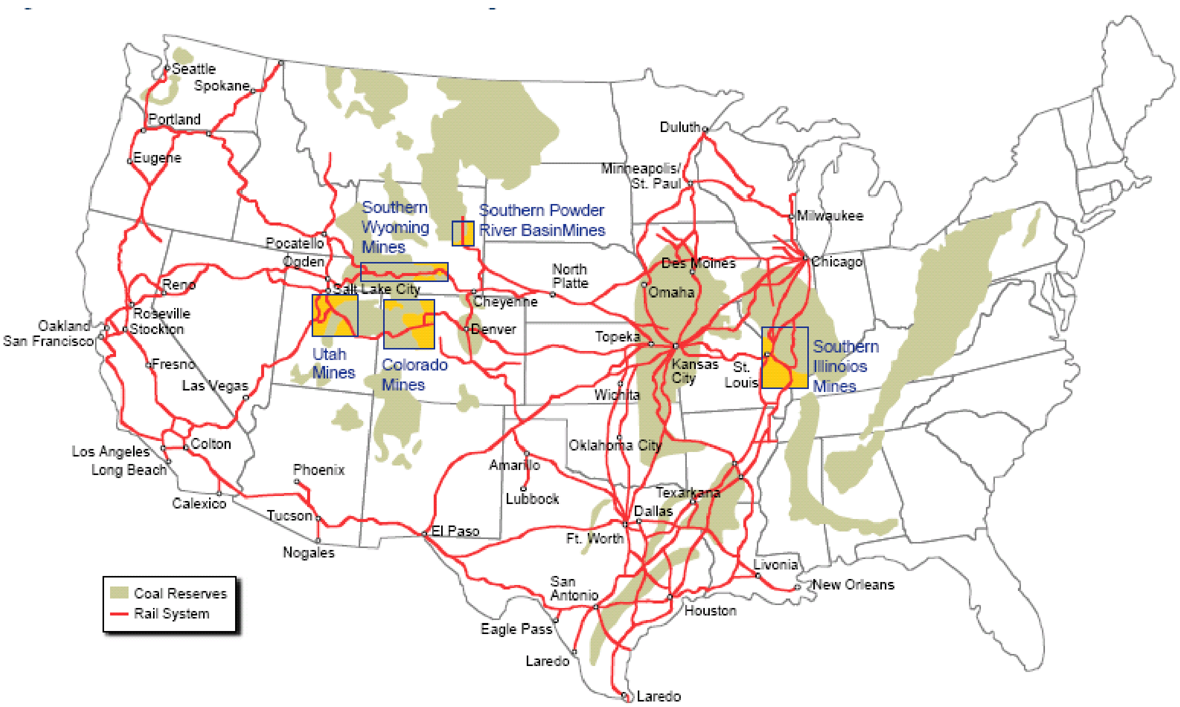
Utilities interested in making IGCC investments generally seek agreements with one of these consortia because IGCC units involve equipment and chemical processes that are unfamiliar to most utility planners and power plant operators. Also, as implied by the term IGCC, the integration of the gasification section and the combined cycle power island requires tight design and operating coordination from start to finish. So, this also argues for having a combined team that works closely together to ensure such integration.

2.4 Siting, Transmission & Fuel Requirements

Both pulverized coal and IGCC units need similar fuel supply transportation arrangements. Figure 2.3 shows the major coal fields and large railroad lines that serve existing coal-fired generating stations in the western United States. Not shown is the rail line providing coal service from Montana via North Dakota to the existing Big Stone I generating unit in the northeast corner of South Dakota.

FIGURE 2.3

Major Coal Mines and Western Rail Lines, 2003[15]



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[15] Southern California Edison, http://www.energy.ca.gov/2005_energypolicy/documents/2005-08-17+18_workshop/presentations-081805/Hemphill_EDISON.pdf.

Figure 2.3 leads to several observations about the availability of coal for any steam boiler or IGCC plant to be located in South Dakota:

1. It is likely that any new coal-based steam boiler plant sited in the state will use low-sulfur Western sub-bituminous coal from Wyoming or Montana, because South Dakota has no in-state mines and the state's proximity to Wyoming and Montana offers the shortest coal haul by rail. For example, Big Stone Unit II, planned for installation near Big Stone City by 2012, is being designed to use Western sub-bituminous coal.

2. The IGCC demonstration plants in the U.S. to-date have used either Eastern bituminous coals or petroleum coke as feedstocks.[16] There has been little experience with the performance of sub-bituminous (lower grade) coals in IGCC gasifiers in the U.S., although the ConocoPhillips E-GAS technology has some sub-bituminous coal testing in its lineage.[17] As a consequence, the siting of an IGCC unit in South Dakota may be complicated by the need to find and use a suitable coal or other fuel source not readily available from the closest mines in Wyoming and Montana. It should be noted that on July 15, 2006, the Wyoming Infrastructure Authority issued a Request for Proposal to have an IGCC built in Wyoming. It is to use Wyoming coals above 4,000 ft in elevation, as well as be capable of carbon sequestration for at least part of the emissions. There is no in-service date requirement.[18]

3. Figure 2.3 highlights the absence of major heavy load rail lines across South Dakota. The lack of heavy rail lines, and the resulting lack of competitive rail haul rates for coal, was mentioned by numerous interviewees in the SDEIA Electric Interviews Report – December, 2006. The absence of good rail service across the state should be seen as a serious impediment to siting coal-based generating plants in the state, and would likely contribute to high fuel costs for any plant that was successfully located near available water resources in the state.

2.5 Coal Licensing & Permitting

2.5.1 Pulverized Coal (PC), Steam Boiler Units

The Big Stone Unit II power plant project is a good example of the permitting process for a PC unit. Big Stone Unit II will be a super-critical PC unit that is scheduled for

[16] "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies" prepared by Nexant, Inc for the Environmental Protection Agency (EPA), July 2006.

[17] Sub-bituminous Western coal was tested at the Louisiana Gas Technology Institute (LGTI) gasification facility that was the foundation for later development of the Wabash River IGCC unit.

[18] Wyoming Infrastructure Authority, RFP Frequently Asked Questions, http://www.wyia.org/Docs/Announcements/Clarifying%20Questions%20Consolidated%20Response.pdf

commercial operation in the second quarter of 2012. The 630 MW project will be adjacent to the existing 430 MW Big Stone Unit I which is located near Big Stone City, SD.

In order to begin construction, Big Stone II needed to acquire six main and separate permits and government authorizations:

- Prevention of Significant Deterioration (PSD) Air Quality Permit
- Water Appropriations Permit
- Solid Waste Disposal Permit
- Federal Environmental Impact Statement (EIS)
- Energy Conversion Facility Siting Permit
- Certificate of Need and Routing Permit in Minnesota for electric transmission facilities to be located in that state.

There are a number of other permits and authorizations that were required, including the Corps of Engineers' Section 404 permit for dredging and filling in wetlands, as well as local zoning or other approvals.[19]

These other permits are summarized in the following chart from the Big Stone Unit II application for an energy conversion facility siting permit in South Dakota (Figure 2.4).[20]

Flow charts depicting the steps and timetables for applicable permits in South Dakota are provided in Appendix D.

In addition to permits required in South Dakota, additional permits may be required in other states as well. For example, certificates of need and/or routing permits may be required for transmission facilities necessary to accomplish the export of energy out of South Dakota.[21] Those requirements will vary, depending on the specific state involved.

2.5.2 Coal-Fueled IGCC Units

At present, the licensing process for a coal-fueled IGCC facility is similar to, but somewhat more complicated than, for pulverized coal plants. They are subject to the same permitting requirements described above for PC units. In addition, IGCC plants are subject to multiple state and federal regulations and need permits not for just

[19] Direct Testimony of Terry Graumann, Otter Tail Power Manager of Environmental Services, Big Stone Unit II Site Permit proceeding, SDPUC, March 15, 2006.
[20] Big Stone II Application for an Energy Conversion Facility Siting Permit, Otter Tail Power Company and Other Big Stone II Co-owners, South Dakota Public Utilities Commission, July, 2005
[21] The current Certificate of Need and route permit process in Minnesota for Big Stone Unit II transmission facilities are prime examples.

electrical generation and transmission facilities, but as a syngas facility and a co-production plant as well.[22]

FIGURE 2.4
Summary of Required Permits for a New Coal-Fired Generation Facility Located in South Dakota[23]

Timing	Gov't Level	Agency	Type of Permit/Approval
Prior to Construction	Federal	Western Area Power Administration	Environmental Impact Statement
		Corps of Engineers	404 Dredge and Fill
		FAA	Stack height and lighting approval
		Federal Land Managers	Class I Area Analysis
		FERC	(To Be Determined)
		USFWS	Threatened and Endangered Species
	State	SD Aeronautics Commission	Aeronautical Hazard Permit
		SD DENR	401 Certification
		SD DENR	PSD (Air) Permit
		SD PUC	Notification of Intent to file Energy Conversion Facility Permit application
		SD PUC	Plant Siting
		SD PUC	Transmission Facility Route Permit
		MN PUC	Certificate of Need for High Voltage Transmission Line
		MN EQB	MN Transmission Line Route Permit
		SD – Water Rights Program	Water Appropriation
		SD State Historic Preservation Office	Cultural and Historic Resources Review
		MN State Historic Preservation Office	Cultural and Historic Resources Review
	Local	Grant County Planning Commission	Zoning Approval
For Construction	State	SD DENR	NPDES Stormwater Permit for Construction
		MN DNR	Work in waterfowl or wildlife management areas?
		MN DNR	State-listed Endangered Species
		MN DNR	License to cross
		MPCA	NPDES Construction Stormwater
		MNDOT	Work in ROW
		Grant County	Erosion and Sediment Control
		Grant County or Big Stone Township	Driveway Permit for Construction Lay Down Area
		Multiple LGU's	Wetland filling or excavation for transmission line
		County Highways	Work in ROW
For Operation	Federal	DOE	Fuel Use Act Certification
		DOE	ORIS code number designation
		EPA	SPCC Plan
	State	SD DENR	Acid Rain Allowances
		SD DENR	AST certification
		SD DENR	Solid waste disposal permit.
		SD DENR	NPDES Storm Water Permit

[22] "An Analysis of the institutional Challenges to Commercialization and Deployment of IGCC Technology in the US Electric Industry" prepared by Global Change Associates, March 2004.
[23] Application for a South Dakota Energy Conversion Facility Siting Permit, Big Stone II, July, 2005.

2.6 Current Projects in the Region

2.6.1 Supercritical, Pulverized Coal, Steam Boilers, Pending Projects

Current projects in the region involving pulverized coal are:

- Big Stone II, South Dakota
- Westin 4, Wisconsin
- Nebraska City 2, Nebraska
- Whalen Energy Center, Nebraska
- Council Bluffs 4, Iowa

2.6.2 IGCC Pending Projects

Public and private interests are proceeding with planning and development of the following IGCC projects in the region:

- Mesaba Energy Project, Excelsior Energy, Minnesota
- Basin Electric Cooperative IGCC Project, North or South Dakota

The Mesaba Project is currently before the Minnesota Public Utilities Commission (MPUC) for approval. A decision is anticipated in Spring 2007. Also, it was announced in December 2006 that the federal government has decided not to provide financial incentives or loan guarantees for the Basin Electric IGCC project. The effects of this decision on Basin's plans for the development have not yet been determined.

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CHAPTER 3.0

NUCLEAR TECHNOLOGIES

3.1 Nuclear Technology Summary

A nuclear power plant uses the heat produced by a controlled nuclear reaction to generate steam, which powers a turbine-generator to produce electricity. Conceptually, this process is similar to a coal-fired generating plant, but with a nuclear reactor replacing the boiler.

The first nuclear reactors provided propulsion for nuclear submarines, and those naval designs were adapted to the construction of the first nuclear plant for electricity production that started service in 1957 at Shippingport, Pennsylvania.

South Dakota participated in the initial development of nuclear technology for utility use in the U.S. The Pathfinder nuclear plant, located on the site that currently hosts the Angus Anson peaking facility in Sioux Falls, was built in the 1960s as part of a federal government-sponsored demonstration program. This 60 MW (net) facility was constructed by a consortium of utilities including Northern States Power (NSP) which is now a part of Xcel Energy. Although the Pathfinder plant ran for a relatively short time, the experience and expertise gained there formed the start of the very successful NSP nuclear power program.[24]

Nuclear plant designs continued to evolve as utilities ordered new units into the 70's, and brought those plants on-line through the 70's and 80's. The oil crisis of the early 1970s helped to maintain interest in nuclear power as oil prices surged and availability declined. Then interest in nuclear power waned as oil prices stabilized and dropped, nuclear plant licensing reviews were dragged out in time, and nuclear plant construction costs surged upward. Generating plants using coal and natural gas were seen as being cheaper and less difficult to license. The nuclear reactor accidents at Three Mile Island in Pennsylvania and Chernobyl in the Ukraine cast a further dark pall over nuclear power planning, and U.S. orders for new plants had essentially ended by 1978. The last new nuclear plant built in the U.S. was placed in-service in 1990.

Over the past decade, however, interest in nuclear power has re-awakened due to rising oil prices, political instability in oil producing regions, and continuing increases in customer demands for electricity. Of particular recent interest are potential applications

[24] The Pathfinder turbine-generator was repowered using a fuel oil boiler. The reactor itself was mothballed in the 1960s, and then decommissioned and removed in 1990.

of nuclear power in response to concerns about global climate change.[25] The resurgence of interest in nuclear power has been abetted by the development of reactors with more attractive economics, and adoption of a revamped licensing process that should reduce time delays affecting station planning, design and construction.

Currently there are 103 operating reactors in the United States. In 2005, they accounted for 19.4% of total U.S. generation, or 782 BkWh.[26] The plants shown on Figure 3.1 below have become known for their reliability and low cost power production.

FIGURE 3.1
Commercial nuclear reactors with operating licenses[27]

3.2 Nuclear Facility Types

A nuclear fission reaction is the chain reaction where an atom is split into two smaller parts releasing energy and two or three neutrons. The neutrons collide with other atoms and continue the reaction. The fuel is Uranium-238 which has been enriched with 3% to 5% Uranium-235. The uranium is formed into pellets which are then inserted in tubes about 1 centimeter (0.4 in) in diameter. These are the fuel rods wherein the reaction occurs. The fuel rods are about 4 meters (~13ft) in length and are put into bundles called fuel assemblies. Also present in the system are control rods. The control rods absorb neutrons and control the rate of reaction depending on where they

[25] A nuclear plant emits no carbon dioxide (CO_2) during operation, and thereby does not contribute to global climate change effects.
[26] Nuclear Energy Institute, http://www.nei.org/index.asp?catnum=2&catid=342.
[27] *Ibid*.

are placed. Depending on the type of reactor, the process is initiated, controlled and stopped by raising or lowering control rods within the fuel rod bundles.

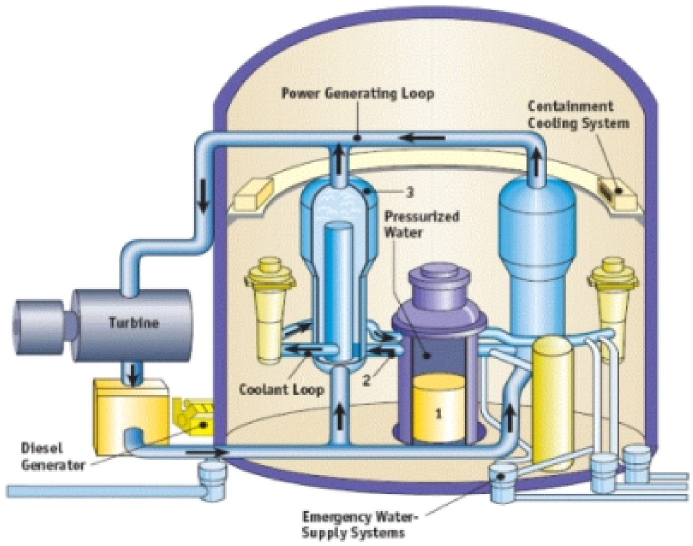
Commercial reactors differ mainly in how they produce steam to run the turbines. Commercial generating stations built in the U.S. to-date incorporate two different types of reactors: the Pressurized Water Reactor (PWR) and the Boiling Water Reactor (BWR). Both are considered Light Water Reactors (LWR), because they use water as coolant, in contrast to heavy water or gas-cooled reactors. LWRs generally have thermal efficiencies around 32% to 33%.

3.2.1 Pressurized Water Reactor (PWR)

PWRs are reactors which use two coolant streams to generate power. The first or primary coolant, a mixture of water and boric acid, circulates, under pressure, between the reactor vessel and a group of heat exchangers called steam generators. The primary coolant stream is kept under pressure in the piping system so that it will not boil, thus giving the PWR its name. For example, the Xcel Energy Prairie Island plant near Red Wing, Minnesota is a PWR facility.

The primary coolant, heated in the reactor, passes over heat exchanger tubes in the steam generators located in the reactor containment building. The primary coolant gives up heat to the secondary coolant flowing through the steam generator tubes. The second coolant boils and gives off steam that is then sent to the steam turbine to produce electricity. The steam turbine and generator set are located in a separate building outside the reactor containment structure. See Figure 3.2, below:

FIGURE 3.2
Major Components in a Typical PWR Nuclear Generating Station[28]



The presence of water and boric acid in the reactor is essential to sustain the fission reaction. Like all thermal reactors, PWRs require that the neutrons released from the nuclear fission be slowed down to sustain the chain reaction. The water molecules, because of their similar weight and size to the neutron, act as a neutron moderator to slow down the fast-fission neutrons. The boric acid readily absorbs neutrons, and increasing or decreasing its concentration in the reactor further controls the rate of reaction. In a PWR, the control rods are only used when initiating or shutting down the reactor.

In current plants, backup power is provided by emergency diesel generators in the event of power loss, to provide energy to the safety systems and other critical plant functions. This power would go to the emergency cooling water pumps and the containment cooling system.

An advantage of the PWR is that as the temperature of the primary reactor coolant increases, the primary coolant water expands and becomes less dense. This hinders its ability to be a neutron moderator and as a result the chain reaction will slow down, producing less heat. Keeping the primary coolant, which by necessity is radioactive, separate from the steam turbine is a second perceived advantage of the PWR design. It keeps the radioactivity within a closed loop, and thereby isolates it from the turbine-generator portion of the plant.

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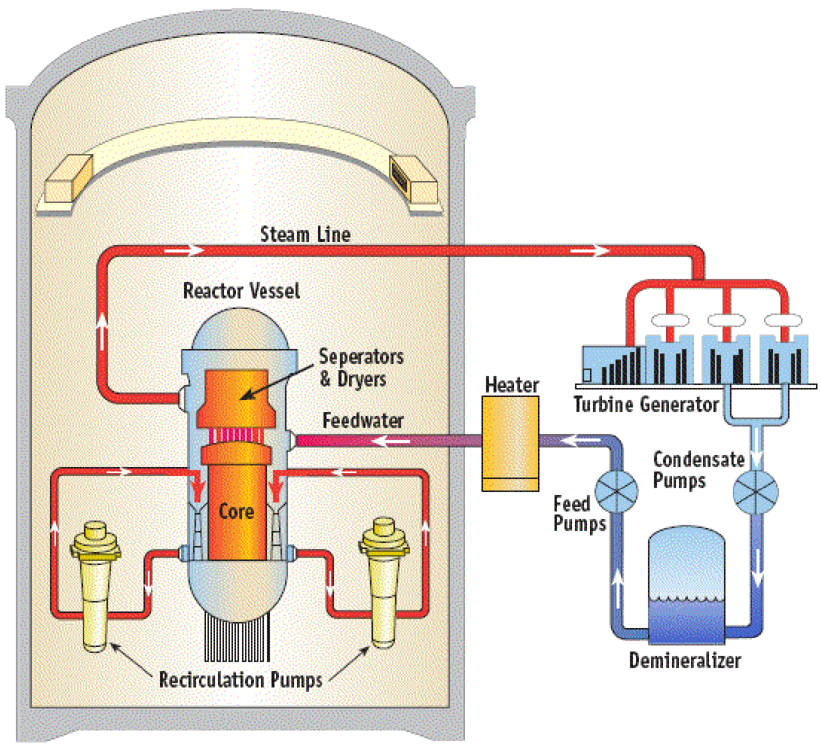
[28] Energy Information Administration, http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/pwr.html.

The disadvantages of the PWR are that the heat, pressure and potentially corrosive boric acid can be hard on the materials used in the reactor vessel, piping system and steam generators. These major components in a PWR reactor thus require more maintenance. Also, reactors of the PWR design cannot be refueled while operating, thus requiring them to go off-line periodically while fuel assemblies are replaced in the reactor vessel.

3.2.2 Boiling Water Reactor (BWR)

The BWR contains only one coolant loop (See Figure 3.3). The water flowing through that loop is kept at a lower pressure than in a PWR. It is allowed to boil at elevated temperatures and that steam is delivered directly to the steam turbine to produce electricity.

FIGURE 3.3:
Major Components in a BWR Nuclear Generating Station[29]



For example, the Xcel Energy Monticello nuclear plant near Monticello, Minnesota is a BWR facility.

[29] Energy Information Administration, http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/bwr.html.

The rate of reaction is controlled through two methods in a BWR. The level of the control rods within the fuel rod assemblies accounts for the control up to around 70% of rated power. The remaining 30% is controlled through the flow rate of the primary coolant. An increased water flow rate increases neutron moderation and speeds the reaction. On the other hand, slower reaction rates are brought about by decreased coolant flow.

The simpler design and increased thermal efficiency in a BWR should lead to lower power costs for the BWR vis-à-vis a PWR plant. However, because of the radiation present in the coolant loop, the steam turbine must be shielded and personnel protection must be employed during maintenance. The increased costs of operating and maintenance usually balance out the savings from the simpler design and greater thermal efficiencies. Just like the PWR, as the coolant temperature increases in a BWR, the nuclear fission slows providing a passive safety system.

3.3 Nuclear Industry Players

3.3.1 Reactor Design Options

For the purposes of this report, SA has investigated four (4) reactor design options. They are as follows:

- AP1000 (Westinghouse)
- Evolutionary Power Reactor (Unistar)
- Advanced Boiling Water Reactor (GE)
- Economic Simplified Boiling Water Reactor (GE)

These are the most current reactor designs for electric power production, and the most likely options to be built in the next 10 years. None of these current technologies have been employed in the United States, because no reactor has been put into service in the USA since 1996, and a new one has not been ordered since 1977. Meanwhile, much of the new construction and concurrent technological advancement in reactor design has occurred overseas.

The four reactor options listed above have significant differences from the PWR and BWR reactors that are currently in use. Power output has been increased and the industry is working to make accidents, such as the Three Mile Island and Chernobyl events, a statistical near-impossibility in these new reactors.[30]

[30] It is generally recognized that the Chernobyl reactor design had less-extensive safety features than reactors in the U.S. Nevertheless, the accident there remains a public image driver for continued safety improvements in all reactors.

The difficult aspect of discussing any attributes of the aforementioned reactor options is that none have been built on U.S. soil. The only one to have been built at all is the Advanced Boiling Water Reactor (ABWR), and that design will possibly be phased out in favor of the next generation Economic Simplified Boiling Water Reactor (ESBWR) that the General Electric (GE) is now promoting.

Information about the new reactor designs that SA has used in this report was derived from two sources, company brochures that are written as sales documents, and conjecture by industry analysts that may be unreliable. This is an important point to understand when examining the reactor options that follow.

3.3.2 Westinghouse AP1000

The AP1000 is Westinghouse's most recent addition to their family of reactors designed and built for electric power production. (Westinghouse technology is already in use in almost 50% of the nuclear reactors worldwide.)[31] The AP1000 will provide around 1150 MW and is an update of the AP600. The AP600 was certified in 1999 during the period when no nuclear plants were being built. Westinghouse, understanding that the AP600 was undersized to compete in today's market, increased the power output through the addition of two steam turbines along with updates to the reactor.

The AP1000 is a pressurized water reactor (PWR). Westinghouse is particularly proud of the passive safety systems that they have designed for the AP1000. "The AP1000 passive safety systems require no operator actions to mitigate design-basis accidents. These systems use only natural forces such as gravity, natural circulation, and compressed gas to achieve their safety function. No pumps, fans, diesels, chillers, or other active machinery are used, except for a few simple valves that automatically align and actuate the passive safety systems."[32]

These methods give the AP1000 the ability to control reactor events in the short term even with complete loss of power and without operator intervention following design basis events. With this technology, Westinghouse advertises that the plant will need about one-third less staff for operations and maintenance compared to an existing PWR plant with a similar rated output. Another advantage of this system is a significant reduction in valves, pumps, piping, etc compared to a similarly sized, existing plant, thus contributing to decreased capital costs and construction time.

The AP1000 is designed to be manufactured off-site in modules that can be shipped to the plant site for final assembly. Westinghouse claims that, using this method, construction of different portions of the plant can proceed in parallel; and the owner-builder can arrive at a finished product much faster. Westinghouse has indicated that its AP1000 design will need but 18 months for site preparation, 36 months from first

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[31] Westinghouse AP1000 brochure.
[32] *Ibid*.

concrete pour to fuel loading, and, finally, 6 months for startup and testing. It has a smaller footprint than an existing plant with the same generating capacity. The AP1000 is designed to have a refueling cycle of 16-20 months and require a refueling outage of but 17 days. A 93% availability over its 60 year design lifetime is expected.

3.3.3 Evolutionary Power Reactor

Areva's Evolutionary Power Reactor (EPR) is also a PWR and is rated at 1600 MW. Areva is a company based out of France and the world's leading reactor supplier. It is involved in all levels of production and distribution for reactor plant components that might be used in the United States.

The first EPR is currently being built in Finland and is scheduled to be connected to the grid in 2009.

The EPR "features four separate redundant safety systems, each capable of performing the entire safety function for the reactor independently. The reactor containment building has two cylindrical walls with two separate domes and a steel liner. The inner and outer walls are made of reinforced concrete more than four feet thick, designed to withstand postulated external hazards."[33]

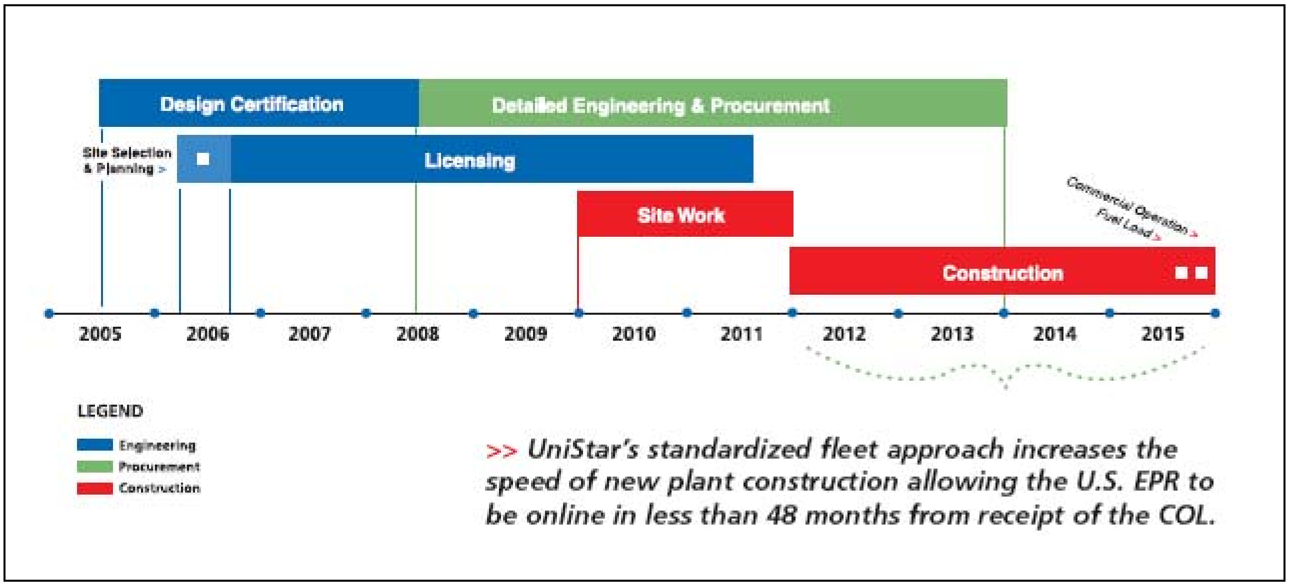
Areva advertises an overnight capital cost[34] of $2000/kW (2005 dollars) and an on-line maintenance capability that should make the EPR more than 94% available on average during its lifetime. The refueling outages are projected to take the plant offline for 16 days at a time. The EPR offers a flexible refueling cycle of 12-24 months.[35] A unique feature of the EPR is that it can accommodate use of recycled fuel (MOX).

In the United States, Areva has entered into a partnership with Constellation Energy, a holding company whose subsidiaries include Baltimore Gas and Electric and Constellation Energy Generation Group that owns and operates a diversified fleet of coal, nuclear and hydroelectric generating plants totaling 12,000 MW. The Areva-Constellation partnership is named Unistar. Unistar is set up to handle all phases of a nuclear plant project from permit application to construction to operation of the completed plant. A potential plant purchaser can arrange for Unistar, as experts in the field, to manage everything involved in a nuclear power plant acquisition. Similar design and construction management agreements are available with GE and Westinghouse on a case-by-case basis.

Unistar's proposed operational schedule is shown in Figure 3.4:

[33] *Ibid*.
[34] See Appendix A for a glossary of terms, including "Capital Cost, Overnight".
[35] Unistar EPR brochure.

Figure 3.4
UniStar U.S. EPR Roadmap to Commercial Operation[35]



3.3.4 Advanced Boiling Water Reactor

GE's Advanced Boiling Water Reactor (ABWR) is the only one of the four new reactor options that has been demonstrated in operation to-date. There are currently five operating plants in Japan, with another reactor under construction in Japan and two more being built in Taiwan. The ABWR can be designed to deliver from 1350 to 1600 MW (net). GE is also able to claim a 39 month construction timetable for this model based on its demonstrated experience in Japan.

GE's ABWR boasts improved safety, performance and seismic response, along with a smaller reactor footprint, than previously built BWR plants. Optimized modular components, proven in actual construction, as well as sophisticated control systems are advantages of this plant type. GE's available literature also mentions reduced radioactive waste production and reduced occupational exposure to radiation hazards as advantages to be found in their ABWR design.

3.3.5 Economic Simplified Boiling Water Reactor

The Economic Simplified Boiling Water Reactor (ESBWR) is the next generation of GE reactors. It will deliver approximately 1600 MW (net). It takes lessons learned from the BWR and ABWR to improve performance and reduce cost. Like the AP1000, the ESBWR's safety systems are largely passive. It is short of a Generation IV reactor as discussed below, but it is a step toward full passive safety. This reduction in active systems is achieved through employing natural forces. It contains six safety-related passive, low-pressure loops and the system is designed to control any event for 72 hours without any operator action.

As a consequence, GE was able to eliminate 25% of the usual pumps, valves, and motors from the product design; and thus achieve a reduction in expected construction time down to 36 months[36].

3.3.6 Other reactor designs

There are other plant designs all in the pre-application review by the U.S. Nuclear Regulatory Commission (NRC); but their certification is not anticipated in the near future. These additional alternative reactor options are mentioned here for the sake of completeness:

- Atomic Energy of Canada Limited (AECL) - Advanced CANDU Reactor (ACR) 700
- South Africa - Pebble Bed Modular Reactor (PBMR)
- General Atomics - Gas Turbine-Modular Helium Reactor (GT-MHR)
- Westinghouse - International Reactor Innovative and Secure (IRIS)

3.3.7 Generation IV

The U.S. nuclear industry has developed a shorthand terminology for referring to past, current and likely future generations of nuclear plant designs. Early nuclear units are referred to as Generation I. Units ordered in the 70's and completed in the 80's and 90's are referred to as Generation II. Current nuclear plants under consideration for construction in the U.S. are either part of Generation III (ABWR) or Generation III+ (AP1000, EPR, ESBWR).

Current Generation III and III+ plants, with nameplate ratings of 1500 MW+, require singular large financial commitments, and represent large operating risks (i.e., lots of eggs in one basket) should such a large plant become inoperable due to a forced outage or scheduled refueling cycle and maintenance. Large-scale utility systems are more capable of absorbing and managing these risks than small systems. Large-scale plants also generally require large transmission line upgrades for power transfer to distant load centers, and the lines then represent additional operating risks attributable to adverse weather or equipment breakdown. This is a consideration that South Dakota must address when considering exporting power.

Generation IV plants, if built, would enter service 10 to 20 years from now but are near enough on utility calendars to at least be mentioned here. The Generation IV reactors will incorporate designs that continue down the path of greater safety, enhanced modular construction, and improved economics. They will be inherently safe and operator proof, with unexpected excursions in pressure and temperature conditions

[36] GE Energy, ESBWR fact sheet.

managed by passive safety systems. Generation IV units will have higher efficiencies as well as be flexible enough for other uses such as producing hydrogen. They will also be smaller, produce less radioactive waste and spent fuel, and represent a *step-down* in power output. As a result, Generation IV plants will be suitable for siting close to load centers thus reducing transmission line requirements.

3.4 Siting, Transmission & Fuel Requirements

An electric generating plant incorporating a nuclear reactor requires an industrial site with a substantial array of supporting features including:

- A location with underlying sound geology; i.e., no earthquake fault lines, stable soil conditions, minimum chemical contamination and low exposure to bad weather and flooding.

- Enough acreage to provide room for the reactor containment, turbine-generator hall, administrative building and numerous auxiliary structures. The site also needs to be sufficiently large to provide isolation for the plant facilities from neighboring industrial, commercial, residential and recreational activity. The isolation is required to provide for plant security, development of evacuation plans, and storage of spent fuel assemblies pending a national solution for spent fuel disposal.

- Proximity or pathways to the regional electric transmission network for export of the energy produced in the plant, and receipt of start-up and back-up power for the generating station.

- Proximity to a sturdy rail, road or marine network for importing construction materials, modular assemblies, fuel, construction labor, and operating staff.

- Access to a reasonably large source of water for process cooling, emergency flooding, potable water supplies, and construction needs.

Although total site acreage requirements will vary in accordance with site-specific considerations,[37] in general a total land area of about one section (640 acres) would be adequate to support construction purposes for a 1,200 MW site. Ongoing operating requirements after construction would require a smaller area.[38] Locations satisfying all of these conditions are increasingly hard to find because of environmental restrictions, expansion of residential centers, public concerns with safety, and competing demands on resources of clean water and air. A list of new nuclear plants now under consideration is provided later in this Chapter 3.

[37] Site size requirements are primarily driven by needs for the plant owner to control the site property and potential radiation exposure at the plant boundaries.

[38] For example, the Prairie Island nuclear plant site near Red Wing, Minnesota supports about 1,100 MW of generation and consists of about 520 acres.

It is noteworthy that of the 17 current sites being discussed for new reactors, *only one is a "greenfield" (new) site*. This is of particular interest to the consideration of possible new nuclear facilities in South Dakota. All remaining new plants have proposed sites adjacent to currently-existing and working nuclear facilities. The preference for old ("brownfield") versus new ("greenfield") plant sites is thought to be a consequence of planning to:

- Avoid some of the costs associated with securing air, soil, water and other permits for a new site,
- Make use of security and evacuation arrangements already in-place at existing sites,
- Avoid some acquisition costs for land and easements that would be needed to build outlet transmission lines away from a new site,
- Make use of water supplies and treatment facilities already available on the existing site.

It also deserves mention that identification of a suitable new site entails substantial financial risk on the part of the developer. As noted later, it costs almost $100 million to $300 million to complete initial site identification processes and certification; with no guarantee of success of the process. *This is a big financial risk barrier* for any developer of a nuclear plant project on a new greenfield site.

In addition, potential plant owner-builders have realized that nuclear units may not need to be located near a major railroad, because the fuel tonnage required to run a nuclear unit is relatively small compared to a coal-fired plant. A typical nuclear unit, for example requires about 20 metric tons (22 tons) of fuel per year and the whole industry in the United State requires about 2,000 metric tons (2200 tons) per year.[39] This compares to a similarly-sized coal plant that may need 2 million tons of coal per year.[40]

Similar to the fuel input, a typical nuclear plant and the nuclear industry as a whole produce about the same amounts of spent fuel each year, respectively. This amount of fuel can easily be transported by truck, and the fuel cladding makes sure that anyone passed by a truck receives a negligible amount of radiation. The Nuclear Energy Institute (NEI) reports that a person can receive more radiation from the naturally-occurring radioactive potassium in one, daily banana than from watching a year's worth of nuclear spent fuel pass by.[41] The shipments are carefully monitored throughout their journey by the NRC and the Department of Transportation to ensure the public's safety.

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[39] Nuclear Energy Institute, http://www.nei.org/index.asp?catnum=2&catid=349
[40] 22 MBtu/ton, 630 MW plant at 88% annual capacity factor and a heat rate of 9000 Btu/kWh.
[41] Nuclear Energy Institute, http://www.nei.org/index.asp?catnum=2&catid=243

Also, the largest components in the current generation of nuclear plants may be supplied as modular units. Westinghouse has stated the AP1000 modules can be sized to be transported on truck, barge or rail depending on the particular site.[42]

The price of uranium has gone from around $10/lb in 2003 to $60/lb in October, 2006. If this trend continues, reprocessing spent fuel will become a viable option. Reprocessed fuel was outlawed during the President Carter administration over fears of nuclear proliferation. The ban was later lifted under President Reagan. However, it has not been pursued because it is cheaper to mine the uranium or buy the Highly Enriched Uranium (HEU) from old Russian nuclear warheads that have been blended down. The future of that HEU purchase agreement is in doubt and, if prices for newly-mined uranium continue to escalate, reprocessing may again become a priority.

3.5 Nuclear Plant Licensing & Permitting

3.5.1 History

Nuclear regulation and licensing has gone through many changes in the past 20 years. Before 1989, the process was not standardized and "design as you build" was the norm, which further complicated and delayed licensing procedures. It was a difficult and lengthy process, often with reviews overlapping and regulations changing during plant construction. This process was governed by 10 CFR Part 50.

In 1989, the Nuclear Regulatory Commission established a new licensing process: 10 CFR Part 52. The Energy Policy Act of 1992 then established the framework for how the new process would be used. Part 52 references numerous technical specifications in Part 50; and it is still possible to certify a plant under the old Part 50 regulations, but none of the current plants under review are using the old process. The new federal process and framework are expected to produce substantial improvements in both the speed and cost of licensing for new nuclear facilities.

There are four hurdles in the new licensing regime:

- Reactor Design Certification
- Early Site Permitting (ESP)
- Construction and Operating License (COL)
- Passing the Inspections, Test, Analyses, Acceptance Criteria (ITAAC)

3.5.2 Reactor Design Certification

The more recent reactor design certification process was put in place to end the historical "design as you build" method, which caused delays and increased cost. As

[42] Westinghouse Electric Company, http://www.dti.gov.uk/files/file35440.pdf

described by the Nuclear Regulatory Commission (NRC)[43], the NRC will bestow a reactor design certification independent of a specific site. The application must contain sufficient detail for the NRC to be able to address all of their safety concerns and questions about the proposed reactor. In effect, the design must contain everything except for site-specific requirements such as intake structures and the ultimate heat sink. The applicant must also have a proposed ITAAC for the completed plant as well as meet all of the Commission's relevant regulations. Next, the Advisory Committee on Reactor Safeguards (ACRS), along with NRC personnel, reviews the proposed plant in a public meeting.

Once all of these criteria have been passed and the reactor design has been certified, the NRC is unable to require a modification of the design unless certain stringent requirements are met. These include if "the design [did] not meet the applicable regulations in effect at the time of the design certification, or if it is necessary to modify the design to assure adequate protection of the public health and safety."

The NRC takes between 36 and 60-plus months to perform a review once the application is submitted by a reactor vendor.[44] Once approved, a reactor design certification is valid for 15 years. This process takes place well before and separate from the sale of a reactor to a customer. A potential purchaser of a nuclear power plant need only concern themselves with the next three steps in the licensing process.

3.5.3 Early Site Permitting (ESP)

Early Site Permitting allows companies to obtain a permit on a specific site for a nuclear power plant. The ESP is completed before deciding to build a plant and is independent of the reactor design. A site safety analysis, an environmental report, and emergency planning information are the three facets of this review. At various stages during this process, the public, as well as federal, state, and local officials have an opportunity to participate in the NRC review.

The application contains the following information:

- Site boundaries;
- Seismic, meteorological, hydraulic, and geologic data;
- Location and description of any industrial, military, or transportation facilities and routes;
- Existing and projected future population statistics for the surrounding area;
- Evaluation of alternative sites;
- Proposed general location of each unit planned to be on the site;

[43] Nuclear Regulatory Commission, http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/licensing-process-bg.html.
[44] Nuclear Energy Institute, http://www.nei.org/index.asp?catnum=3&catid=1362.

- Number, type and power level of the unit planned for the site;
- Maximum discharges from the plant to water, air and soil
- Type of plant cooling system to be used;
- Radiation dose consequences of hypothetical accidents; and
- Plans for coping with emergencies.[45] (50)

"An ESP review process that encompasses a range of reactor designs enables companies to select the best design when they proceed with a decision to build."[46] So upon completion of the licensing, the NRC is able to give the potential customer a set of parameters that are acceptable on their particular site. An appropriate reactor design can be selected with these in mind.

Assembling an ESP application takes between 12 and 24 months. The length depends on whether the site is next to an existing facility or is a "greenfield". After the application is submitted, the approval process involves a NRC review and a public hearing. That second step takes approximately 33 months; but the NRC is currently looking for ways to streamline it. The ESP is then valid for 10-20 years and can be renewed for another 10-20 years.

3.5.4 Construction and Operating License/ ITAAC

The Construction and Operating License (COL) is a combined license. The COL may refer to an ESP, a certified reactor design, or both. Any issues that were addressed and resolved in receiving those first two permits are considered resolved for the purposes of the COL. This is part of the steps that have been implemented to streamline the new process. It allows the committee to focus only on new problems and not rehash old ones. Companies have an option to forgo the ESP and wrap that license into the COL application.

The receipt of a COL signifies that the NRC has resolved all of their safety concerns before any concrete is poured. The COL, like the ESP, can be treated as an asset. It may be used upon issue or at some later date.

To ensure that the construction is going as planned, at certain intervals the NRC investigates to make sure the plant complies with a family of Inspections, Test, Analyses, and Acceptance Criteria (ITAAC) set up earlier. As the facility passes each test, notice is published in the *Federal Register*.

Not less than 180 days before the facility is loaded with fuel, a notice of operation is printed in the *Federal Register*. A public hearing is held at this time only if a petitioner can prove beforehand that one or more of the ITAACs have not been met.

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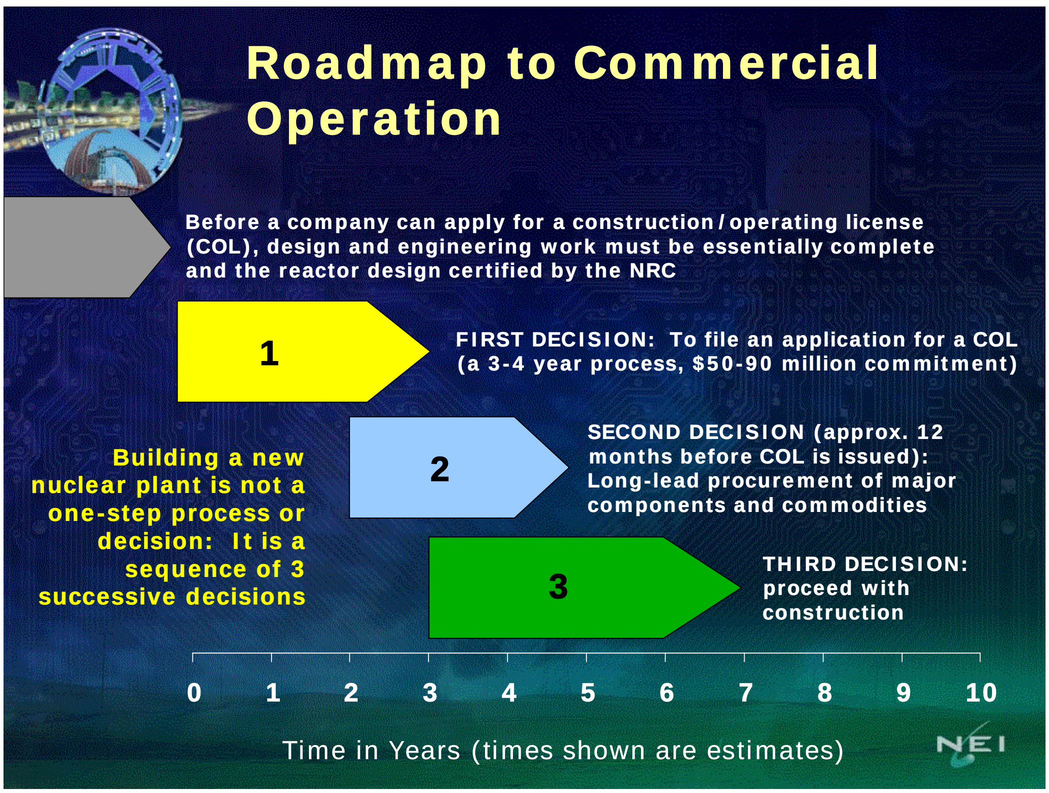
[45] NRC, http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/licensing-process-bg.html.
[46] http://www.nei.org/index.asp?catnum=3&catid=1362.

No nuclear power plant has yet gone through the entire COL process, but it is estimated to take as long as 42 months. The Nuclear Regulatory Commission (NRC) envisions reducing the COL process down to as short as 18 months, once the initial bugs have been worked out of the process.

The whole certification process for one plant with one reactor is estimated to cost around $100 to $300 million dollars to get a site certified under the COL.[47] What these decisions would look like for a prospective customer is illustrated in the following graphic (Figure 3.5) from the NEI:

FIGURE 3.5
NEI Roadmap to Commercial Operation License (COL)



Of the four reactor options being considered, only the GE ABWR and the Westinghouse AP1000 have completed design certification. The GE ESBWR should be certified by

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[47] Schulte Associates LLC meeting with Nuclear Management Company, Hudson, WI, November 30, 2006.

2009, allowing potential plants to be operational by 2015.[48] Unistar is expected to submit an application in 2007 for the design certification of its EPR.[49]

3.6 Current Nuclear Projects

There are a number of new nuclear plants being considered by various companies throughout the United States; but no one has yet completed their COL. The seventeen sites under consideration are listed below on Figure 3.6.

FIGURE 3.6
Status of New Nuclear Plant Developments[50]

Company	Site	Early Site Permit	Design # of Units	Construction/ Operating License Submittal
Dominion	North Anna, VA	Under review, approval expected 2007	ESBWR (1)	November 2007
TVA (*NuStart)*	Bellefonte, AL	Will go straight to COL	AP1000 (2)	October 2007
Entergy (*NuStart*)	Grand Gulf, MS	Under review, approval expected early 2007	ESBWR (1)	November 2007
Entergy	River Bend, LA	Will go straight to COL	ESBWR (1)	May 2008
Southern Company	Vogtle, GA	Under review approval expected early 2009	AP1000 (2)	March 2008
Progress Energy	Harris, NC Florida to be determined	Will go straight to COL	AP1000 (2) Not yet determined (2)	Harris – October 2007 Florida – July 2008
South Carolina Electric & Gas	Summer, SC	Will go straight to COL	AP 1000 (2)	October 2007
Duke	William States Lee, *Cherokee County*, SC	Will go straight to COL	AP1000 (2)	October 2007
Exelon	Clinton, IL	Under review, approval expected 2007	No decision	No decision on COL
Exelon	Texas to be determined, TX	Will go straight to COL	Not Yet determined	2008

48 GE ESBWR fact sheet.
49 Russ Bell, Nuclear Energy Institute, Director of New Plan Licensing, October 6, 2006.
50 GE Energy, ABWR fact sheet, http://www.gepower.com/prod_serv/products/nuclear_energy/en/downloads/abwr_fs.pdf

FIGURE 3.6 (continued)
Status of New Nuclear Plant Developments

Company	Site	Early Site Permit	Design # of Units	Construction/ Operating License Submittal
Constellation *(UniStar)*	Calvert Cliffs, MD or Nine Mile Point, NY plus three other sites	Will go to COL but submit siting information early	EPR (5)	First submittal 4Q – 2007
Duke	Oconee, SC	Considering ESP	No decision	No decision on COL
Duke	Davie, NC	Considering ESP	No decision	No decision on COL
NRG/STPNOC	Bay City, TX	Will go straight to COL	ABWR(2)	Latter part of 2007
Florida Power & Light	Not yet determined	Not yet determined	Not yet determined	Not yet determined
Amarillo Power	Amarillo, TX vicinity	To be submitted in 4Q - 2007	ABWR(2)	As soon as practicable after 2007
TXU	Glen Rose, TX Other sites yet to be determined	Will go straight to COL	Not yet determined (2-5)	2008

Areva's first EPR, which is currently being erected in Finland, has encountered trouble with its construction schedule and, as of the writing of this report, was 18 months behind schedule. A spokesman for Areva is on record saying that, "The initial calendar was perhaps too ambitious." As a result, Areva is expected to face increased costs of 500 million Euros (or about $625 million US$).[51] This should be taken as a warning for the first few plants to be built here in the United States.

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[51] Assumes US$-to-Euro exchange rate is 0.8 U.S. dollars per Euro.

CHAPTER 4.0

WIND ENERGY TECHNOLOGIES

4.1 Wind Energy Introduction

Wind technologies for electric power production have matured very rapidly in the past twenty years. From 1980 through 2005, the expected cost of energy from a wind turbine farm decreased approximately 80%.[52] Further cost reductions were expected as the technology continued to evolve. In 2006, however, the downward trend in wind energy costs may have reversed due to rapidly rising material and labor costs for all new electric plants which are presently in great demand, worldwide. We will say more about wind turbine cost characteristics in Chapter 5.

FIGURE 4.1

Typical Wind Resource on the Buffalo Ridge[53]

[52] http://www.awea.org/pubs/factsheets/BuyingWindRetail.pdf.

[53] “Buffalo Ridge Wind Towers”, Hendricks, MN website, www.hendricksmn.com/wind_towers.html.

4.2 Wind Technology Discussion

Today, the various competitors' utility-sized wind turbines for electric generation have all evolved to generally the same configuration. They incorporate a turbine-generator and a three-bladed rotor (propeller) that are mounted on a tall steel tower set over a heavy concrete foundation. The control mechanisms for the rotor blades and the types of generators are the main features that typically vary from model-to-model and manufacturer to manufacture.

Towers stand anywhere from 50 to 120 meters (165-400 ft) tall. These are usually of tubular steel construction and bolted to a reinforced foundation. Twenty to 100 separate towers are generally grouped together in one area creating a wind "farm." To avoid disruption of the air flow over adjacent towers, each tower sits on about one acre of open land; however, the actual footprint of one tower uses only about 2 to 5% of the available acreage[54] or about ¼ acre per turbine.[55] The required land is usually leased from an owner under a long-term agreement. Access rights for the operator for purposes of construction and ongoing maintenance activities also need to be established. The lessee may pay on the order of $2,000 to $4,000/MW[56] per year to the lessor to secure one acre of farmland for a typical single wind machine installation.

Rotor diameters can range anywhere from 70 to 100 meters (230-330 ft) for machines in the 1 to 2 MW class. The blades are manufactured with different lengths compatible with the wind regime to be harvested. The blades are positioned in front of the tower toward the wind. The turbine generator set and the rotor blades revolve at the top of the tower as the wind direction changes. As the rotor turns, the tips of the blades travel well above the ground surface; therefore, cattle grazing and farming can continue underneath the towers as the generator operates.

Two alternative types of control systems are used for the blades and rotor on a tower to (a) protect them from damage in high wind and (b) control the electric power output. The first control system detects wind direction and turns the rotor towards the wind. It also operates to position the blades in the wind stream according to the wind velocity that is present. The blade angle with respect to the wind stream is changed in order to maintain as constant a power output as possible. This is called pitch control. In high winds, the blades are turned parallel with the wind ("feathered") in order to protect the turbine from over-speed conditions.

The second type of control system on a wind energy tower uses the principles of stall control. The blades are fixed to the rotor and the absence of a complicated control mechanism saves investment dollars and maintenance expense. The blades are

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[54] AWEA, http://www.awea.org/newsroom/pdf/Wind_Energy_Basics.pdf

[55] United States Government Accountability Office, "Wind Power's Contribution to Electric Power Generation and Impact on Farms and Rural Communities" September, 2004

[56] AWEA, http://www.awea.org/newsroom/pdf/Wind_Energy_Basics.pdf

aerodynamically designed so that at high winds, turbulence is generated at the back side of the blades which reduces the force on the blades and slows their rotational speed. Another version of stall control is called active stall control where the blades have certain fixed positions that maximize performance for different wind speeds. The difference between this and pitch control is that, with active stall control, at high winds the blades turn into the wind to cause the stall and slow the rotor.

The shaft that is attached to the rotor hub rotates with the rotor blades and delivers the energy of rotation into the nacelle, the rounded cylinder at the top of the tower. The nacelle contains the significant components of the wind turbine including the gearbox and the generator. These can be accessed by a ladder that is placed inside the hollow tower, and serviced in the nacelle without exposure to the elements.

Because the energy produced by a wind turbine fluctuates with wind speed and duration, special types of generators must be used. The two types are called synchronous and asynchronous. A synchronous generator produces power at a frequency related to the rotation of the rotor, and requires an indirect grid connection to function. On the other hand, an asynchronous' generator is specially designed so it can be connected directly to the electric grid.

The availability of modern wind turbines hovers around 98%. That is, they are ready and waiting or ready and turning to produce electricity most of the time.[57] But the number that is more important for wind turbines is their annual capacity factor, which is usually somewhere between 27%[58] and 48%[59]. The capacity factor is calculated as the ratio of the actual energy output from a wind turbine over a stated period of time (usually one year) divided by the theoretical wind energy output that would have been produced had the turbine generator been operating a full rated output over the same period. The relatively low capacity factor for a wind turbine is due to the fact that though the turbines in the Midwest may be turning 65-90%[60] of the time, they are not always running at full power output because of the variability of the wind resource.

Modern wind turbine generators are expected to have operating lives of 20-30 years, assuming appropriate maintenance is performed.

[57] American Wind Energy Association (AWEA), http://www.awea.org/faq/wwt_basics.html.
[58] NEI, http://www.nei.org/documents/U.S._Capacity_Factors_by_Fuel_Type.pdf.
[59] Energy Information Administration, Assumptions of Annual Energy Outlook 2006, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2006).pdf.
[60] American Wind Energy Association (AWEA), http://www.awea.org/faq/wwt_basics.html.

4.3 Wind Industry Players

The major manufacturers of wind turbines used in the United States are currently (all capacity values shown are nameplate output at rated wind speed):

- GE Energy, with 1,433 MW installed in the U.S. in 2005. They offer two lines of turbines for on-shore use, rated 1.5 MW and 2.X (2.5-3.0 MW).

- Vestas, with 700 MW installed in the U.S. in 2005. This company is the leading wind turbine manufacturer worldwide. They offer turbines sized at 850 kW, 1.65 MW, 1.8-2.0 MW, and 3.0 MW. Another manufacturer, NEG Micon, has recently merged with Vestas.

- Mitsubishi, with 190 MW installed in the U.S. in 2005. They currently offer turbines sized 1 MW or smaller, and are developing a 2 MW series.

- Suzlon, with 55 MW installed in the U.S. in 2005. They offer turbines sized 950 kW; and 1, 1.5, and 2 MW.

- Gamesa, with 50 MW installed in the U.S. in 2005. Their line has power ratings of 850 kW and 2 MW.

- Clipper Windpower is a recent start-up company with but one unit installed in Wyoming in 2006 and offering a turbine sized at 2.5 MW. [61]

Suzlon, Gamesa, and Clipper Windpower have recently established manufacturing facilities in the U.S. As new entrants come into the U.S. market, turbine production is expected to become less concentrated in both location and numbers of vendors.

The leading *owners* of wind installations in the United States as of 2005, in decreasing order of owned capacity, were:

1. FPL Energy: 3,192 MW
2. PPM Energy: 518 MW
3. MidAmerican Energy: 360.5 MW
4. Caithness Energy : 346 MW
5. Babcock & Brown: 319 MW[61]

In 2005, the leaders in *purchasing* wind-derived energy from other producers, in decreasing order of purchased capacity, were:

[61] AWEA, http://www.awea.org/news/Annual_Industry_Rankings_Continued_Growth_031506.html.

1. Xcel Energy : 1,048 MW
2. Southern California Edison: 1,021 MW
3. Pacific Gas & Electric Co.: 680 MW
4. PPM Energy: 606 MW (for resale)
5. TXU: 580 MW[61]

The largest wind farm operating in South Dakota in 2006 was the 41 MW collection of wind machines at Highmore, SD owned by Florida Power Group, with the output being sold to Basin Electric Power Cooperative.

The most recent announcement of a large new committed wind farm installation in South Dakota was made by Xcel Energy with PPM Energy in September 2006. It will involve 50 MW of wind turbine capacity installed east of Brookings, SD. These generating units will be part of a larger investment including another 100 MW of wind machines sited further east along the Buffalo Ridge in Minnesota.

Other potential wind farm developments in South Dakota were reported earlier by the South Dakota Energy Infrastructure Authority in its Electric Industry Interviews Report dated December 2006. The listing of potential new wind farms reported in that document is restated at the end of this Chapter 4.

4.4 Siting & Transmission Requirements

4.4.1 The Wind Resource in South Dakota

The choices made during siting of a wind farm determine its ability to produce power and therefore its level of profitability. There are a number of factors to take into consideration when choosing an area to harvest the wind. First, one must find an area that has historically good wind speeds. The American Wind Energy Association (AWEA) ranks SD fourth for the states with the most wind potential.[62]

That ranking was accomplished largely through computer models built upon sparse actual data. The South Dakota Wind Resource Assessment Network (WRAN) was initiated to change that. The WRAN is managed and directed by South Dakota State University (SDSU).[63] They have set up eleven sites throughout South Dakota in order to obtain relevant and accurate data, with more sites to come. Each site measures wind direction and speed. Some obtain wind data at multiple heights, and measure solar irradiance as well.

Meanwhile, wind potential maps like Figure 4.2, below, from the Department of Energy are readily found, and can be used for locating promising wind regimes on a macro level.

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[62] American Wind Energy Association (AWEA), http://www.awea.org/faq/wwt_potential.html.
[63] Wind Resource Assessment Network, http://www.sdwind.com/

FIGURE 4.2

South Dakota Wind Energy Resource Map[64]

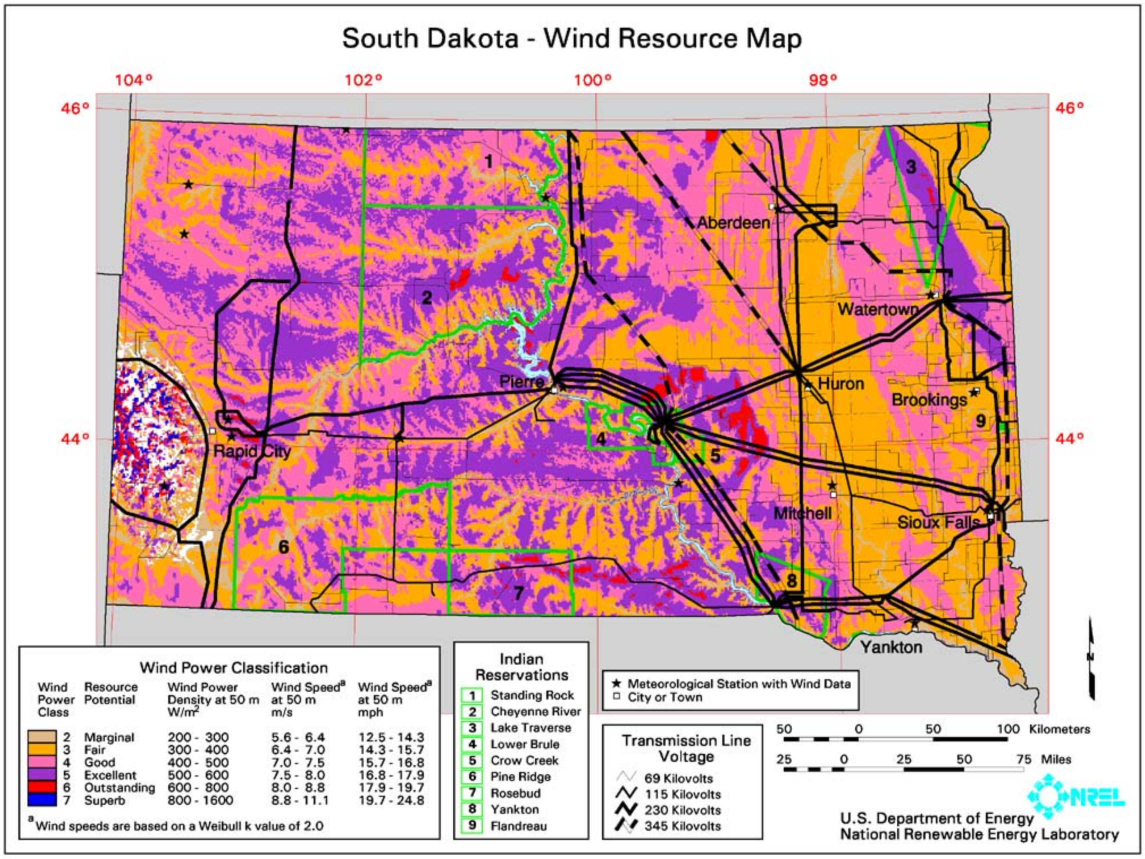

Figure 4.2 is color-coded according to the Wind Power Class found at a specific site. The Wind Power Class is directly related to the capacity factor that can be achieved by a large wind turbine located at the specific site and altitude. An average Class 6 site has the potential for providing an annual capacity factor of 48% if a wind machine is located there.[65] A Class 5 location offers an annual capacity factor of about 40%, a Class 4 site about 30% capacity factor, and a Class 3 site around 20%.[66]

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[64] U.S. Department of Energy National Renewable Energy Laboratory, http://www.eere.energy.gov/windandhydro/windpoweringamerica/images/windmaps/sd_50m_800.jpg. Data shown for 50 meter height

[65] http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2006).pdf#page=77.

[66] http://www.awea.org/policy/regulatory_policy/transmission_documents/Expansion/Midwest%20Wind%20Development%20Plan.pdf.

4.4.2 Site-Specific Considerations

Differences in wind speed change the output of a wind turbine significantly. The power output of a turbine varies with the cube of the wind speed. Therefore, locating a wind regime with only slightly better wind characteristics will result in large improvements in power output. This is the great advantage of the work being done by the WRAN.

Potential sites for locating a wind machine, therefore, must be studied in detail to estimate how a wind turbine might perform. Beyond wind speed and duration, sites must be investigated for their wind turbulence characteristics. Turbulent air going through the rotor blades decreases power output while also increasing wear on the machine. A turbine's performance is also influenced by the surrounding terrain. Obviously, the tower needs to be placed away from trees and buildings, but it can also be affected negatively by long grass and shrubs. While these smaller obstacles are along the surface, they can still affect the performance of the turbine at the hub height 50-120 meters (165-400 ft) up.

Intelligent siting can also maximize the power output of a wind regime, for just as there are things that slow wind down, there are others that speed it up. One method is to use the tunnel effect, where a turbine is placed between two smooth hills and the wind speeds up to go between them. (The same phenomenon, called the Venturi Effect, is experienced when walking between two tall buildings on a windy day.) Another example is to put the turbine near the top of a hill on the side of the prevailing wind direction. The air approaching the hill is compressed and speeds up. It is important in both instances that the hill profile be smooth. Otherwise turbulence may develop and the gains made from careful siting can be lost due to erratic air movement.

To keep the wind turbines in a certain regime from interfering with one another, they are arranged according to the direction of the prevailing wind. As a rule of thumb, the towers are located 5 to 9 rotor diameters apart in the prevailing wind direction and 3 to 5 diameters apart and perpendicular to the wind.[67]

The economics of siting are complex. Often the best wind sites, offering the best power densities, are difficult to access with the heavy machinery needed for construction, and the transmission lines needed as power outlets. In addition, while larger towers and turbines are more efficient, sometimes it is a better choice to install smaller units that can be transported on existing roads without having to install new bridges or repair damaged asphalt.

Another important factor in siting a wind farm is its proximity to and the availability of adequate transmission lines. Individual turbines can often be directly connected to local, lower voltage distribution circuits. However, a larger utility scale wind farm will usually require its own line, and one or more substations of substantial size and cost.

[67] http://www.windpower.org/en/tour/wres/park.htm.

4.4.3 Connecting to the Grid

4.4.3.1 Transmission

Electric interconnection of individual wind machines and small groups of machines to the grid can usually be accommodated by connection to the local electric distribution system at distribution-level voltages. However, larger wind farms entail connection to higher voltage bulk transmission facilities; particularly where long-range export of their energy output is involved. As discussed in the previous SDEIA report,[68] the availability of adequate transmission facilities is recognized as a significant challenge to large-scale wind development; particularly in South Dakota.

4.4.3.2 Operational Considerations

From an operational perspective, connecting a wind farm to the electrical grid is a different task than for plants that have a constant MW output.

First of all, individual turbines have varying outputs due to wind gusting and minute variations in wind speed over short periods of time (less than 5 minutes). These small output changes are commonly averaged out by the installing multiple turbines that experience these small changes, all at different times.

On a macro scale, the output variations from a wind farm over the course of a day, hour-to-hour, are a continuing concern when adding wind power to any utility's electric system. A rough guideline for addressing the macro issues has been put forth by the American Wind Energy Association:

- Up to the point where wind generates about 10% of the electricity that the utility system is delivering in a given hour of the day, fluctuations in wind farm output are not an issue. There is enough flexibility built into the utility system for reserve backup, varying loads, etc., that there is effectively little difference between such a system and a system with 0% wind. Variations introduced by wind are much smaller than routine variations in load (customer demand).

- At the point where wind is generating 10% to 20% of the electricity that the system is delivering in a given hour, it is an issue that needs to be addressed, but that can probably be resolved with wind forecasting (which is fairly accurate in the time frame of interest to utility system operators), system software adjustments, and other changes.

- Once wind is generating more than about 20% of the electricity that the system is delivering in a given hour, the system operator begins to incur significant additional

[68] "Electric Industry Interviews Report", at Page 39.

expense because of the need to procure additional equipment that is solely related to the system's increased variability.[69]

According to the American Wind Energy Association (AWEA), utility systems that have greater than 20% wind in their portfolio will probably experience increased costs for system regulation on the order of 0.3 – 0.6 cents/kWh.[70]

These topics were also investigated and reported in the 2006 Minnesota Wind Integration Study that was completed in December, 2006.[71]

- The Study found that wind-derived energy could reliably supply 20% of Minnesota's retail electric energy sales in 2020 if sufficient transmission system improvements are made to move the power from wind farms to load centers. *(Approximately 4500 MW (nameplate) of wind generation would be needed to produce the required electric energy in that year. Minnesota utilities currently use, or have plans to acquire, the output from about 900 MW of wind turbines located in Minnesota and nearby states.[72] These figures imply that Minnesota represents a possible market for another 3600 MW of new wind turbines that might be installed over the next 13 years to serve customers of Minnesota utilities. However, as described in the previous SDEIA report,[73] other competitors for that market abound.)*

- The Study also explored application of additional wind energy up to 25% of Minnesota's retail electric energy sales in 2020. This level of wind energy utilization was also deemed feasible provided customers would need to pay about $4.41/MWh (or 0.41 cents/kWh) of wind-derived generation to offset incremental ancillary costs for added operating reserves, resource variability and day-ahead forecasting errors in the market area managed by the Midwest Independent Transmission Operator (MISO). Lower levels of incremental ancillary costs were projected for lower levels of wind energy integration.

- The Study found that installing large numbers of wind turbines over a large geographic footprint would help reduce the variability in output from the combined collection of wind resources on a minute-to-minute and hour-to-hour basis. However, the effective load carrying capability of the combined wind resource could vary substantially from year-to-year due to region-wide weather patterns. If 4500 MW of wind generation is available to Minnesota utilities in 2020, these wind farms

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69 AWEA, http://www.awea.org/faq/wwt_potential.html.
70 AWEA, http://www.awea.org/faq/wwt_basics.html.
71 Final Report – 2006 Minnesota Wind Integration Study, Volume I, EnerNex Corporation in collaboration with the Midwest Independent Transmission System Operator (MISO) for the Minnesota Public Utilities Commission, November 30, 2006.
72 According to AWEA, Minnesota currently has 812 MW (nameplate) of installed wind capacity, as of September 2006.
73 "Electric Industry Interviews Report", SDEIA, December 2006.

might only contribute about 900 MW to the effective load carrying capability of the connected generating units in the region; and this capability might fall as low as 225 MW during a year with adverse weather conditions.

The current Renewable Energy Objective for Minnesota utilities is 10% of retail sales to be supplied by renewables by 2015. Minnesota Governor Pawlenty recently announced a goal of 25% of all Minnesota energy resources (electricity, transportation and heating) to be supplied from renewable resources by 2025.[74] This initiative is subject to legislative review and approval.

For comparison to values determined in the Minnesota Wind Integration Study, Xcel Energy has developed corresponding information for its Colorado service territory. According to Xcel[75], increased dependence on wind energy in Colorado will trigger the need to keep more generators on standby, and such generators are usually low-efficiency natural gas plants.

Xcel planners in Colorado estimate that if wind technology can attain 20% of total generating capacity in that state, the cost of standby generators will climb to $8/MWh of wind in addition to an overall generating cost of $50 or $60/MWh after including a federal tax credit of $18/MWh. Xcel says there are many reasons for the difference between this $8/MWh value and the $4.41/MWh value from the Minnesota study including differing study methods, but the most important is the limitations in the transmission system. Relatively speaking, compared to Minnesota, Colorado is more of a transmission interconnection "island" as a result of being situated in the mountains. Consequently, existing regional backup generation is less able to support the intermittent wind source there. Minnesota's closer inter-ties and the MISO market may allow tighter integration and reserve sharing, and lower costs compared to areas such as Colorado. This assumes ongoing future transmission system development in Minnesota where necessary.

From the above discussion it is important to be aware that many factors will affect the ancillary costs of wind. The specific characteristics of the South Dakota resource and transmission will determine what costs would be. It will best to use the range of ancillary costs from $4.41/MWh to $8/MWh, until a value specifically determined for South Dakota is available.

4.5 Licensing & Permitting

Licensing a wind generating facility is a different procedure than for coal and nuclear-based power stations. The regulations are fewer in number because there are no fuels being consumed, and therefore no waste being produced during the energy production. However there is still a significant number of necessary permits.

[74] "Pawlenty: Think ahead on energy", Minneapolis Star Tribune article, December 13, 2006, Page A1.
[75] Frank Prager, Xcel Energy Managing Director of Environmental Policy, January 15, 2007.

The actual turbine machinery is approved before a customer becomes involved, much like with nuclear. The certification assures the customer that the technology has been:

- Tested and evaluated by an accredited certification test organization.

- Examined by a registered certification agent to ensure compliance with internationally approved standards for identification and labeling, power performance, structural integrity, acoustic emissions, loads, power quality, safety and other characteristics.

- Demonstrated to have safe operating characteristics, including control systems that reflect sound engineering practice[76]

FPL Energy has a good discussion on its website about the process for siting a wind farm.[77] First, having chosen a location, the landowners and others in the area are contacted. More often than not, the siting requirements involve renting land from farmers. Any concerns that they might have are addressed and design changes can be made to deal with those issues.

Next, environmental impacts will be examined. Potential landscape alterations and changes in water run-off are included. Possible effects on animals and other living organisms are investigated, especially in sensitive areas like wetlands. In particular, bird and bat flight patterns will need to be studied in relation to turbine siting. Finally, a turbine will produce light flickering on anything that happens to fall in its shadow path. Wind machines are located so that shadows thrown by the turbines and rotors do not fall cross anyone's home, and thereby adversely affect their quality of life.

Navitas Energy submitted an application for an energy conversion facility permit on July 11, 2006. It is for a 200 MW wind site in Brookings County, SD at the White Wind Farm. Navitas anticipates that the following permits will be required:

- National Environmental Policy Act (NEPA) compliance
- U.S. Army Corps of Engineers (USACE): Section 404 compliance
- U.S. Fish and Wildlife Service (USFWS): Section 7 consultation
- Section 106 review with Native American Tribes and South Dakota State Historical Society
- Federal Aviation Administration (FAA): Determination of No Hazard to Air Navigations, and minimum lighting requirements.
- South Dakota Public Utilities Commission (PUC): South Dakota Codified Law Chapter 49-41B

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[76] National Wind Technology Website, http://www.nrel.gov/wind/working_cert_what.html.
[77] FPL Energy Website, http://www.fplenergy.com/portfolio/wind/siting_develop.shtml.

- South Dakota Department of Environment & Natural Resources: 401 Water Quality Certification and National Pollution Discharge Elimination System (NPDES) Storm Water Permit for Construction Activities.
- South Dakota Department of Transportation: Highway Access Permit and Utility Permit.
- Brookings County: Conditional Use Permit, Soil Erosion & Sediment Control Plan, Building Permit, Driveway Application and Construction Permit.[78]

The requisite steps for developing a wind resource in South Dakota are shown in Appendix E.

4.6 Proposed Wind Projects

Figure 4.3 shows the substantial list of wind power projects that have been discussed with or reported to the South Dakota Public Utilities Commission as of August 2006. The Western Area Power Authority (WAPA) has indicated to SA that it has received applications for transmission interconnections by wind farms that together might incorporate 4000 MW of wind machines to be installed over the next decade. The Midwest Independent System Operator (MISO) reports that 2000 to 3000 MW of proposed wind developments are currently in their queue for requested connection to the transmission grid on the Minnesota side of the Buffalo Ridge alone.[79]

[78] "White Wind Farm LLC Application to the South Dakota Public Utilities Commission for a Facility Permit", prepared by HDR Engineering, July 2006.
[79] MISO discussion at Big Stone Unit II transmission certificate of need public hearings, Morris, MN, October 10, 2006.

FIGURE 4.3
Potential South Dakota Wind Energy Projects[80]

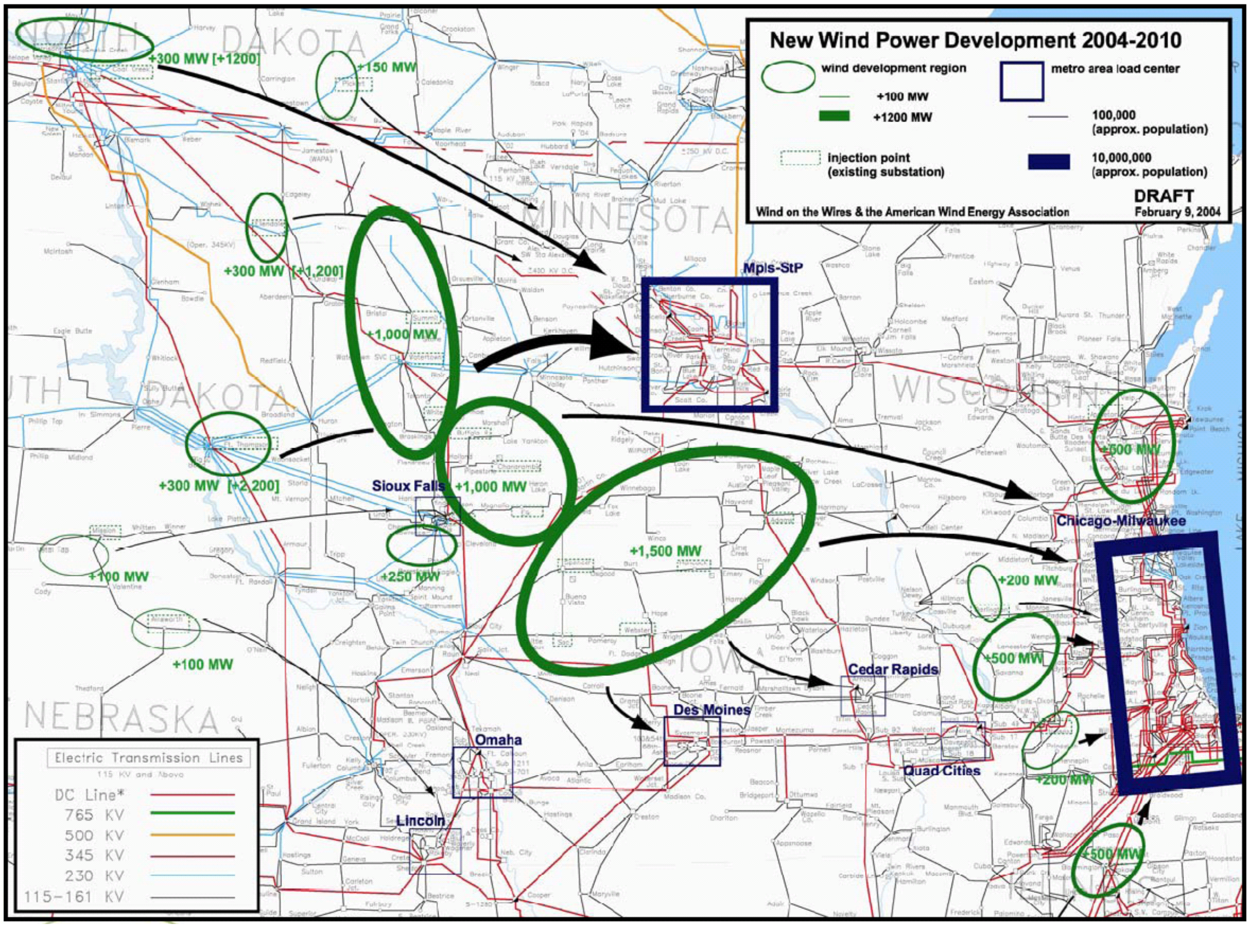
Project Name	Developer	MW	Location	Utility
Minn-Dakota Wind	PPM	100	Brookings	Xcel
Java Wind	Superior Renewable	39	Walworth	MDU
White Wind Farm	Navitas Energy	200	Brookings	Merchant Plant
Tatanka Wind Power	Tatanka Wind Power	90	McPherson	Merchant Plant
Northern Lights Wind Farm	Northern Lights Wind	100	Roberts	Merchant Plant
Sisseton-Wahpeton Tribe	Sisseton-Wahpeton Tribe	40	Roberts	Tribe
Lower Brule Tribe	Lower Brule Tribe	40	Lyman	Merchant Plant
Andover	Andover Wind Project	30	Roberts	Merchant Plant
Missouri River Wind	MRES	70	Codington	MRES
Rolling Thunder	Clipper and BP	100	Hand/Hyde	Merchant Plant
Turkey Ridge	Clipper and BP	100	Hutchinson/Turner	Merchant Plant
Wessington Springs Hills	Superior Renewable	40	Jerauld/Buffalo	Merchant Plant
Bad River	Ted Turner	100	Haakon/Stanley	Unknown
Fox Ridge	Faith School District	140	Central SD	Merchant Plant
Confidential	Confidential	90	Central SD	Confidential
Gregory County	Shell Oil	100	Gregory	Merchant Plant
Yankton Sioux	Talon LLC	40	Charles Mix	Merchant Plant
Rosebud	Disgen	65	Todd	Confidential
Pine Ridge	Unknown	40	Shannon	Merchant Plant
Total		**1,524**		

4.7 Likely Pattern of Wind Development in South Dakota

Wind on the Wires, an organization dedicated to the expansion of wind resources in the Upper Midwest, has a development plan updated in 2004 that is shown below on Figure 4.4 below.

[80] Source: Steve Wegman, South Dakota Public Utilities Commission, October 2006.

FIGURE 4.4
New Wind Energy Development Plan in Upper Midwest, 2004-2010[81]



The ovals shown in green on Figure 4.4 provide an indication as to the general location of wind energy developments that might be experienced between Chicago, Illinois, on the east, and Pierre, South Dakota, on the west, during the decade ending in 2015.

Note that the largest planned developments in South Dakota are identified in the eastern part of the state, which is nearest the expected load centers to the east in the Twin Cities of Minneapolis/St. Paul, Milwaukee and Chicago.

81 Wind on the Wires and the American Wind Energy Association, "Midwest Wind Power Development" February, 2004.

4.8 The South Dakota Advantage

As discussed in the previous SDEIA project report,[82] the in-state "opportunity" for using South Dakota-produced wind power is relatively small compared to the 12,000 MW of wind energy production potential estimated for the state. This demonstrates that the wind industry can only fully blossom in South Dakota if it finds electric markets *outside* the state, and develops the transmission paths to reach those markets.

Fortunately, the opportunity for an attractive South Dakota value proposition for wind energy development is potentially large. Industry interviews conducted as part of the previous SDEIA project identified that South Dakota's best wind regimes may offer wind generator output that is significantly better than regimes in other states. Thus, for the same wind machine, more valuable energy could be produced every year if it is located in South Dakota compared to elsewhere. This additional energy output has value that can be used to pay for additional transmission necessary to deliver it to markets, and to produce economic value to the state.

For example, the interviews indicated that a wind machine located in the best areas in South Dakota may achieve an annual capacity factor of 40% to 45% or more. This compares with nominal 35% for the same machine if it were located on the Buffalo Ridge in Minnesota. SA estimates that this five to 10 percentage point difference in annual output would justify 150 to 300 miles of additional 345 kV transmission line, compared to the same machine located on the Buffalo Ridge and operating at a 35% capacity factor.[83]

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[82] SDEIA "Electric Industry Interviews Project Report", December 2006.
[83] Assumes a double-circuit 345 kV line can carry 1400 to 1600 MW, and costs $1.4 million per mile.

CHAPTER 5.0

ECONOMICS

5.1 Economics Introduction

For purposes of illustrating approximate magnitudes of costs for the technologies in this Study, SA consulted various industry sources.

The reader is advised that obtaining consistent cost figures from publicly-available industry data in a manner that enables a useful, "apples-to-apples" comparison across different projects, different project owners and technology types is a difficult procedure. Different industry entities define their costs in different ways, with some including some factors in the costs and others leaving them out. Typically, published costs do not specify all of the assumptions used in developing the costs stated thereby frustrating efforts to ensure consistency between sources. Finally, industry sources in general are not particularly exacting or consistent in the terminology they use when describing costs. Business considerations, including competitive concerns, contribute further to the vagueness of published data.

Accordingly, SA has developed a glossary of cost terminology that is included at Appendix A of this Report for the Authority's convenience and use. This glossary provides definitions of the terms used in this Chapter and elsewhere in the Report. Meanwhile, the reader is cautioned that similarly-titled resource costs taken from different source documents may not provide an accurate, "apples-to-apples" comparison without additional research and adjustments.

5.2 Relative Costs Comparison

5.2.1 Coal and Wind: September 2005

The engineering consulting firm of Burns and McDonnell prepared a cost comparison of coal and wind technologies for the Big Stone Unit II project Co-Owner utilities. This report, entitled "Baseload Generation Alternatives" and dated September 2005, was first filed with the South Dakota Public Utilities Commission as part of the Big Stone Unit II Site Permit proceedings in 2006. This report was later updated as described later in this Chapter.

The Burns and McDonnell study compared the capital, operating and ownership costs of pulverized coal (both sub-critical and super-critical) units, IGCC units, natural gas-fired combined cycle (NGCC) units, and wind energy as they would be applied to fulfill the Co-Owners' baseload capacity and energy needs starting in the year 2011. Because wind energy is intermittent, the study examined combinations of wind and NGCC technologies to determine the costs of wind energy with similar reliability parameters as a baseload coal-fired plant would provide. The study did not include nuclear units, which will be described later.

The various detailed costs examined in the study are provided at Appendix C, on Figure C.1. In summary of Figure C.1, the following Figure 5.1 provides an overview of the September 2005 Burns and McDonnell results:

FIGURE 5.1
Cost Comparison of Various Generation Technologies[84]
September 2005

Alternative	Installed Capacity (MW)	Fuel	Capital Cost ($/kW) (2011 COD)	Capacity Factor (%)	Prod Tax Credit?	Levelized Busbar Cost ($/MWh, 2011 COD) IOU	Public Power
Sub-critical PC	600	PRB	1,765	88		**58.41**	**47.21**
SCPC	600	PRB	1,800	88		**58.81**	**47.37**
NGCC	600	Nat gas	601	88		**77.94**	**75.51**
IGCC	535	IL Bitum	2126	88		**83.84**	**71.05**
Wind							
w/o backup	600	NA		40	No	**50**	**50**
Wind/Gas combo	1200	Nat gas		88	No	**72.89**	**65.12**
Wind/Gas combo	1200	Nat gas		88	Yes	**67.43**	**65.12**

These results were calculated for both investor-owned utilities (IOU), and public power entities. The wind/natural gas combination alternatives were examined both with and without the federal Production Tax Credit (PTC), which reduces the apparent cost of wind energy. Future continuation of the PTC by Congress is often a subject of debate in wind energy assessments.[85] Wind without a reliability backup was assumed to operate at a 40% annual capacity factor, while the other alternatives including the wind/gas combination alternative were assumed to operate at a baseload capacity factor of 88%. Figure 5.1 also assumes no carbon taxes, which will be discussed later.

The costs were calculated to produce a levelized busbar cost over the plant life,[86] assuming a 2011 commercial operation date (COD) for all alternatives. The results on Figure 5.1 show that wind without a reliability backup has the apparent lowest levelized lifetime busbar cost of $50/MWh. However, this cost does not include consideration of the fact that the wind resource is intermittent, and thus needs to be backed up by other, reliable capacity sources to ensure reliable supply during peak load times and thereby be truly comparable to the other alternatives on Figure 5.1.

[84] See Appendix C, Figure C-1 for details.
[85] Congress did extend the PTC during December 2006; but only for one additional year.
[86] See Appendix A for a glossary of terms including busbar and levelized costs.

As shown on Figure 5.1, when the wind alternative is combined with NGCC units to achieve a baseload-equivalent reliability level, the resulting wind/gas combinations show significantly higher busbar costs than the pulverized coal options for such baseload applications.[87] The NGCC and IGCC options showed higher costs as well. Public power entities show lower costs than IOUs for all alternatives, because their cost of financing is lower. This is particularly important on baseload coal and nuclear units because they tend to have higher capital costs.

5.2.2 Nuclear: September 2005

Determining corresponding costs for new nuclear units is even more challenging. First, no new nuclear plants have been commissioned in the U.S. for decades, and the new technologies currently under consideration have no actual track record in operation (except for the ABWR). So, any comparisons at this point are at risk of being conjecture. The Burns and McDonnell study summarized on Figure 5.1 above did not examine nuclear alternatives.

As an approximation, SA discussions with nuclear industry sources indicates the industry hopes that cost incentives and guarantees for nuclear power contained in the federal Energy Policy Act of 2005 will make new nuclear units competitive with coal units. So, including those impacts would mean that a new nuclear unit with Energy Act impacts would have a levelized busbar cost between $50 to $60/MWh for units theoretically installed in 2011, using the September 2005 Burns and McDonnell study results. As discussed earlier, the initial new nuclear plants will likely be constructed on existing brownfield sites, so costs on new greenfield sites will likely be higher.

Costs for nuclear plants are likely being affected by a recent run-up in capital costs for all construction projects, as described later in this Chapter 5. On the flip side, nuclear plants are also less susceptible to costs associated with possible future carbon regulation, which is also described later.

5.3 Potential Effects of Carbon Regulation

5.3.1 Introduction

The preceding cost discussion does not include possible future impacts of carbon (CO_2) regulation on the busbar costs of the technologies. At the current time, many utility industry managers and executives anticipate that Congress may enact some form of carbon regulation. However, what form the regulation may take and what cost it may level on CO_2-emitting sources remains to be determined.

[87] The Burns & McDonnell analysis was designed to examine wind/gas combinations as alternatives to a baseload plant. Wind or natural gas facilities may, together or individually, be more cost-effective than coal plants for other applications.

5.3.2 Effects on Coal Plants

Coal plants emit CO_2 as a product of the combustion process. Because of their higher efficiency, supercritical pulverized coal plants emit lower CO_2 per unit of electric output than subcritical units do. For coal plants, their busbar cost will tend to increase linearly (proportionally) with the cost of CO_2 that is applied to them, as illustrated on Figure 5.3. Future opportunities and costs for CO_2 capture and storage (sequestration) are also a topic of discussion when considering possible future carbon regulation. IGCC technology has been viewed as potentially more amenable to carbon capture than pulverized coal.[88] However, recent research by EPRI indicates that pulverized coal units may be retrofitted with advanced carbon capture technology in the future, making it more cost-effective than IGCC, both with or without carbon capture.[89] These debates are certain to continue until actual experience is gained with both technologies. This too will be driven by the type and magnitude of carbon regulation in the future.

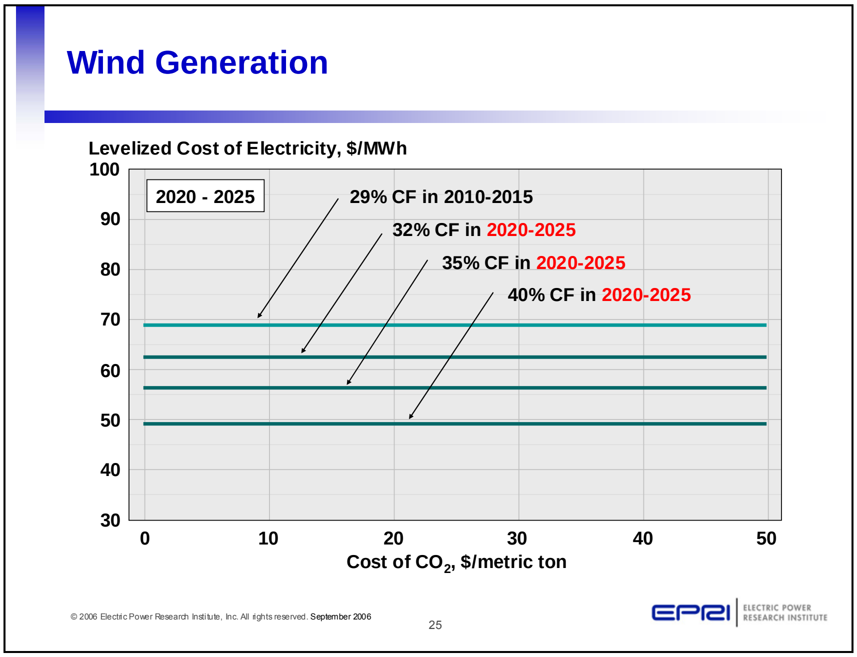
5.3.3 Effects on Cost of Wind Energy

The levelized cost of electricity for wind energy can be seen in the following graph (Figure 5.2) as it relates to capacity factor and various levels of CO_2 costs. As wind's technology continues to improve, so will the performance characteristics of its turbines. The data here does not include the Production Tax Credit. In addition, note that the cost of wind energy is flat across all values of future CO_2 costs. This occurs because a wind machine does not produce CO_2.

[88] AEP chose to pursue IGCC technology for their next generation of coal plants based on IGCC's superiority to accomplish carbon capture.

[89] DOE, EPA and EPRI are working on these developments and estimate that chemical absorption processes will become a commercially viable, post-combustion carbon capture alternative at supercritical pulverized coal plants by the 2010 timeframe. Rebuttal testimony of Thomas Hewson, Big Stone Unit II certificate of need proceedings, MPUC, December 1, 2006.

FIGURE 5.2
Cost of Wind Energy as Functions of
Capacity Factor and Cost of Carbon (CO2)[90]



5.3.4 Effects on Nuclear Plant Costs

Similar to the considerations described above for wind energy, nuclear plants also do not emit CO_2. So, their costs as a function of CO2 values would be flat like that shown for wind on Figure 5.2, above, although the nuclear units would typically run at a much higher capacity factor than wind machines do.

5.3.5 Overall Effects on Costs: Summary

The potential effects of CO_2 costs on various generation technologies is summarized on Figure 5.3, below, based on information compiled by EPRI. Pulverized coal and IGCC units using coal show lower levelized busbar costs ($/MWh) for lower values of CO^2 costs. This assumes that the CO_2 cost applies to all MWh of output of the various generation alternatives shown. If a different CO_2 cost protocol is used (for example, if a cap and trade approach results in less than the entire output of a coal unit is subject to the CO_2 cost), then the breakeven CO_2 costs between various technologies shown on Figure 5.3 would move upward toward higher CO_2 cost values.

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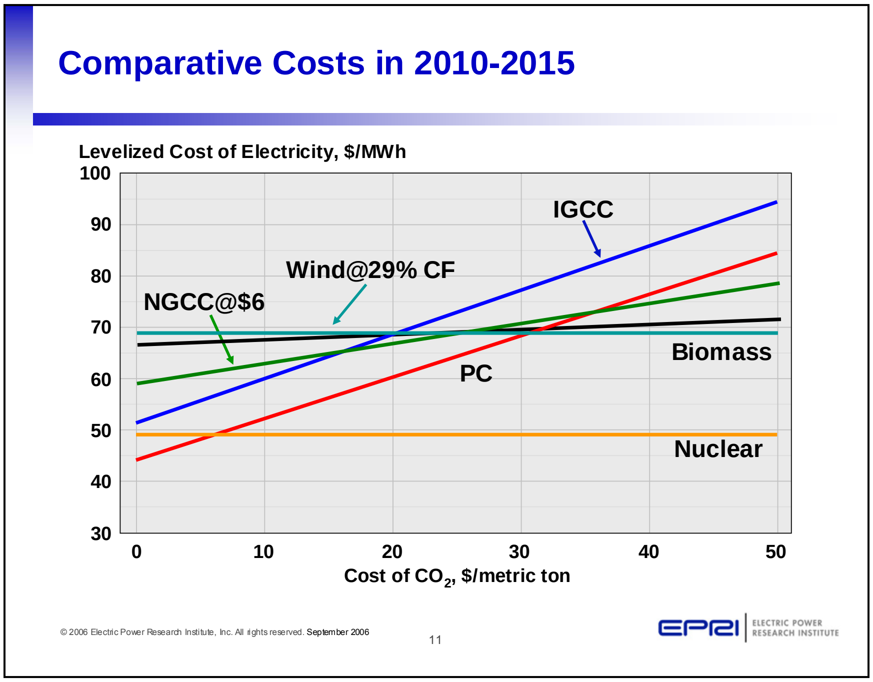
[90] Electric Power Research Institute (EPRI), September 2006. Costs shown represent wind machines operating in intermittent mode due to variability of the wind resource. Does not include the cost of providing firm capacity for reliability purposes.

FIGURE 5.3
Cost of Wind, Coal and Nuclear as Functions of
Capacity Factor and Cost of Carbon (CO_2)[91]



As shown in Figure 5.3, the busbar costs of nuclear and wind alternatives do not change with increasing CO_2 costs, because those technologies do not emit CO_2. Also, the wind energy line shown on the Figure corresponds to an annual capacity factor of 29%. To the extent the wind machines operate at higher capacity factors (See Figure 5.2), their costs will be lower than that shown in Figure 5.3. However, as noted earlier, this does not include additional costs for backup capacity for the sake of reliability.

Regardless, it is clear from Figure 5.3 that future CO_2 regulation costs could have a significant impact on relative costs between generation technologies, and thus future choices between them. As a result, the appropriate and reasonable future value to be used for future carbon regulatory costs, if any, is currently the subject of heated debate nationwide.

[91] Electric Power Research Institute (EPRI), September 2006.

5.4 Recent Market Effects on Costs

The earlier discussion of costs was based on cost assumptions as of September 2005. More recently, the industry is realizing that the current build-up in baseload generating plants and other construction projects worldwide is creating a supply/demand imbalance that is driving the costs of such projects upward.[92] Increases in commodity prices such as steel, concrete and labor are universal trends affecting construction projects worldwide.

For example, as a result of these market forces, the projected capital cost of Big Stone Unit II was increased 33% in June 2006, compared to previous estimates. Duke Energy reports a 50% capital cost increase in their planned baseload unit. Combined with various improvements including increased unit capacity and an improved fuel efficiency (heat rate), the levelized busbar cost of Big Stone Unit II is projected to be 23% higher than before.

Accordingly, Burns and McDonnell revised their comparison of busbar costs for several of the alternatives shown on Figure 5.1. The revised costs are summarized on Figure 5.4. More details are provided in Appendix C on Figure C.2.

Because of the general escalation affecting all generation projects for the same reasons, the costs of all alternatives are shown to be higher on Figure 5.4. Just as a rising tide lifts all boats, market forces are raising the costs of all electric generation options. As a result, any cost estimates that predate 2006 *are probably understating the current trends* in generating plant costs. A depression in the world economy could deflate these trends, but the trends appear to be very strong at the current time.

FIGURE 5.4

UPDATED COST COMPARISON OF VARIOUS GENERATION TECHNOLOGIES[93]

October 2006

Alternative	Installed Capacity (MW)	Fuel	Capital Cost ($/kW) (2012 COD)	Capacity Factor (%)	Prod Tax Credit?	Levelized Busbar Cost ($/MWh, 2012 COD) IOU	Levelized Busbar Cost ($/MWh, 2012 COD) Public Power
Sub-critical PC	600	PRB					
SCPC	630	PRB	2,168	88	NA	**69.62**	**56.38**
NGCC	500	Nat gas					
IGCC	535	IL Bitum					
Wind							
w/o backup	600	NA		40	No	**60**	**60**
Wind/Gas combo	1200	Nat gas		88	No	**80.78**	**77.77**
Wind/Gas combo	1200	Nat gas					

[92] For example, the engineering consulting firm of Black & Veatch estimates that the current volume of baseload coal generating plant development will soon exceed the record levels seen in the 1960s.
[93] See Appendix C, Figure C.1 for details.

Even wind energy is not immune to these market forces. GE Energy envisions a time in the future when wind costs will drop back down to as low as $1500/kW, with technological advancement and a long-term extension to the PTC. But the days of $1200-1300/kW are gone for wind.[94] Recent Requests for Proposals for wind developments have indicated that the capital cost of wind machines has increased 40% to 70% during the past two years, and may be approaching $2,000/kW.[95] The current popularity of wind in particular is also adding to the market pressures affecting costs for this technology.

5.5 Economic Subsidies and Incentives

5.5.1 Coal

Other power generation industries, such as nuclear and wind, consistently add a caveat to any cost discussion about coal receiving de facto subsidies in that it does not have to pay for its wastes that are sizeable and not benign. The actual cost of the effect that coal plants' byproduct exact on the environment is something that has been debated but never effectively quantified. Were carbon capture and sequestration to be required, or a tax put on carbon dioxide released to the atmosphere, the coal facilities' current economic advantage would be affected.

Approximately $1.65 billion in federal support was designated for IGCC projects in Energy Policy Act of 2005. The first $1 billion was allocated to nine utilities throughout the United States in December, 2006 and sub-bituminous coal was left out due in large part to a technical oversight by the writers of the legislation.[96] Consequently, understanding the performance of coals that South Dakota would most likely use will not be developed until after the remaining $650 million is distributed in June, 2007.

5.5.2 Nuclear

Nuclear power must factor in the cost of decommissioning. That cost is around $300-500 million dollars per plant,[97] or 9-15% of initial plant cost.[98] This will add 0.1-0.2 cents/kWh of cost over the lifetime of the plant.[98]

The Energy Policy Act of 2005 has certain provisions in it that benefit nuclear power. First, the federal government will provide loan guarantees of up to 80% of the total project cost. The resulting improved debt rates will end up saving hundreds of millions of dollars per project. Also, the first 6000 MW of new nuclear capacity will receive an

[94] Beth Soholt, Director, Wind on the Wires.
[95] Prefiled rebuttal testimony of Bryan Morlock, Otter Tail Power Company, Big Stone Unit II transmission certificate of need hearings, MPUC, December 8, 2006.
[96] The exception being federal loan guarantees for the Mesaba Energy Project in Minnesota that is proposed to use sub-bituminous coal.
[97] NEI, http://www.nei.org/index.asp?catnum=2&catid=351.
[98] Uranium Information Center, http://www.uic.com.au/nip08.htm.

$18/MWh production tax credit. The Price-Anderson Act was also renewed as a part of this legislation. It provides insurance for the public in the event of a nuclear accident. There is also money set aside for the first six new reactors to offset any costs from unexpected delays.

The combination of the loan guarantees and the production tax credit are estimated by Constellation Energy to save a nuclear plant about $25/MWh in busbar costs. These incentives, and possibly carbon taxes, are necessary to make new nuclear plants more competitive with coal-fueled alternatives, as noted earlier. However, potential roadblocks remain. The Energy Policy Act has been passed, but the money has yet to be appropriated.

The Nuclear Power 2010 program is a cost-share program with industry to reduce the uncertainty in the decision-making process for building new nuclear power plants. The program includes testing new licensing processes for nuclear.

Both of these bills had support bipartisan support when they were both passed and that should continue. The issue of the storage of spent fuel is still the main issue to be resolved.

5.5.3 Wind

Currently wind power receives production tax credit (PTC) that was first set up in the Energy Policy Act of 1992. The PTC is adjusted for inflation and currently stands at 1.9 cents per kWh. The industry has suffered because the credit has to be renewed every couple years. The utility is only able to move ahead in fits and starts as shown by its installed MW per year when the PTC lapsed in 2002 and 2004.

- 2005 – 2431 MW
- 2004 – 372 MW
- 2003 – 1667 MW
- 2002 – 411 MW
- 2001 – 1697 MW[99]

Six months before the credit expires, it becomes very difficult to get capital loans. The rush to get projects completed before the credit lapses raises costs. The PTC was recently extended at the beginning of December, 2006. The current law will apply only to utility-scale wind turbines put in place before the end of 2008. Cost had been escalating as the old PTC was set to expire at the end of 2007, and companies were rushing to get projects finished. What the costs will be now, having just released the time pressure, is difficult to predict.

[99] AWEA, http://www.awea.org/news/Annual_Industry_Rankings_Continued_Growth_031506.html.

Because of the rush to get projects completed, GE, which has accounts for 60% of the new added capacity, is sold out through 2007 at least. Clipper, a new turbine company, is committed well into the future as well.

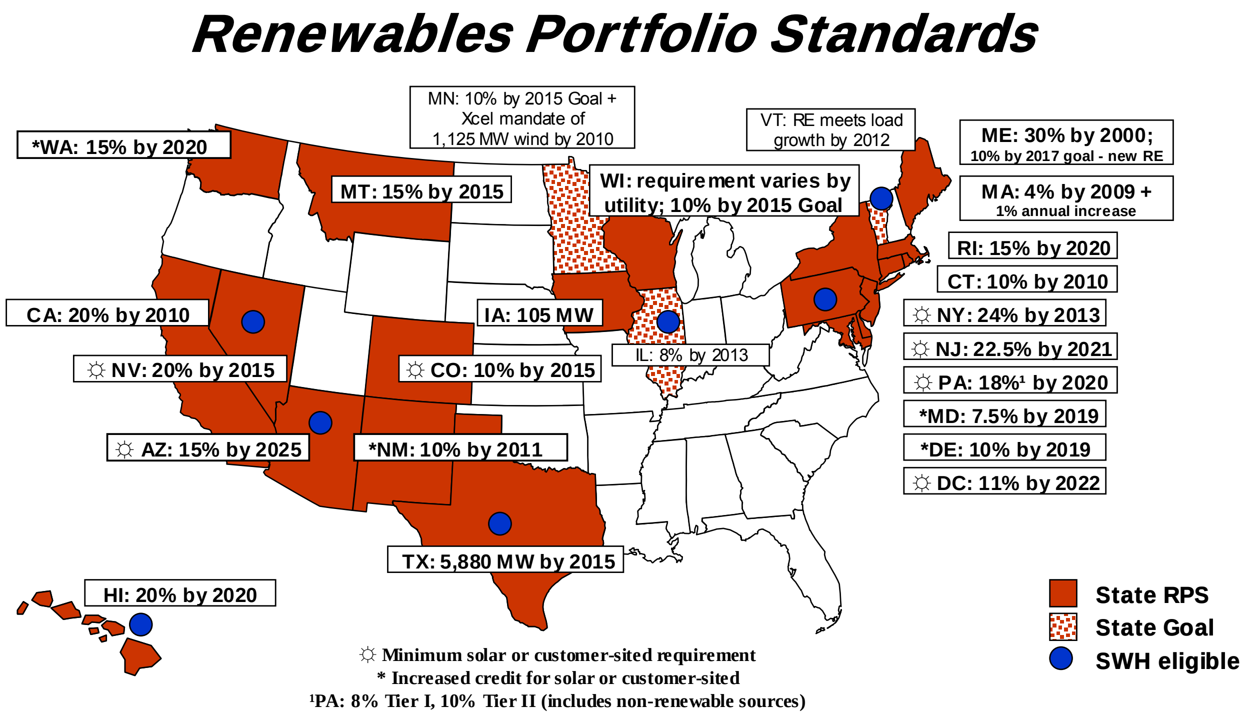
Increased concern over the environment raises the possibility of a federal Renewable Energy Standard (RES) in the future. A RES would set a certain minimum limit of renewable energy sources within a state's energy portfolio. This is something to be aware of because, were it to be passed, a Federal RES would drive a lot of wind industry business forward nationwide.

At the state level, Minnesota currently has legislation that establishes an objective of 10% of retail electric energy to be supplied by renewable energy sources by 2015. Such sources may be located outside of the state. The governor of Minnesota in December 2006 announced a plan to increase this objective to 25% renewables by 2025, for all energy sectors (electricity, transportation and heating). This proposal is subject to review by the Minnesota legislature.

The current state-by-state Renewable Portfolio Standards are shown below on Figure 5.5.[100] A blue dot signifies states where Solar Water Heating (SWH) is included within the standards. Although the specific definition of these portfolio standards varies by state, a "Standard" tends to be a proscriptive measure. A Renewable Energy Objective, or goal, often requires a good-faith effort to achieve the specified level of renewables, but is not a requirement with associated penalties for failure to meet the objective.[101]

[100] Database of State Incentives for Renewable Energy, November 2006, http://www.dsireusa.org/library/includes/topic.cfm?TopicCategoryID=6&CurrentPageID=10&EE=1&RE=1
[101] As shown on Figure 5.5, the current Minnesota Renewable Energy Objective (REO) is such a goal.

FIGURE 5.5
CURRENT RENEWABLES PORTFOLIO STANDARDS BY STATE



5.6 Job and Economic Benefits to South Dakota

5.6.1 Benefits Overview

New electric generation facilities provide additional new jobs during the construction process, both in direct jobs involved at the plant site and indirect jobs in the local communities supporting the project. Once the facility is constructed and goes in-service, ongoing operations and maintenance (O&M) jobs continue, as well as supporting jobs and resources in the local communities.

5.6.2 Coal

The Big Stone Unit II super-critical pulverized coal power plant is currently under regulatory review, and provides an excellent example of what a new coal facility has to offer a region. The Big Stone II owners state that the plant will add to community:

- Local Job Growth:
  - o 2,550 Full Time Equivalent (FTE) positions during construction (4 jobs/MW)
  - o 1,844 Full and part-time jobs in the communities (2.9 jobs/MW)
  - o An average of 1,098 jobs per year for four years (1.7 jobs/MW)

- State Benefit During Construction (Four year construction period)
    - 2,550 FTE positions during construction (4 jobs/MW)
    - 2,291 FTE and part time jobs in the communities (3.6 jobs/MW)
    - An average of 1,210 per year for four years (1.9 jobs/MW)

- Long-term local job growth:
    - 35 FTE employed in operations (0.06 jobs/MW)
    - 29 FTE and part-time positions in the communities (0.05 jobs/MW)[102]

There will also be $627.8 million that will impact the local community specifically and the State of South Dakota as a whole benefiting from $745.1 million in expenditures.[103]

These impacts are for an additional unit being built at a "brownfield" site that already has a generating facility. For a greenfield site, it is likely that the construction period impacts would be similar. For a greenfield site, the long-term local job growth impacts would be somewhat higher than those shown above, because a single new unit on a greenfield site would require more operations employees than an incremental unit added to a brownfield site.[104] However, as shown above, the construction period impacts are much larger than the ongoing operations impacts.

5.6.3 Nuclear

The Diablo Canyon Power Plant in San Luis Obispo County, California is held up by the nuclear industry as an example of what a nuclear facility can add to the surrounding community. It has two reactors sized at 1,100 MW each. They were completed in 1985 and 1986.[105] Their capacity factors for 2005 were 87.3% and 99.2%.

The facility's impact at the county, state, and national level in 2002 was $641.9 million, $723.7 million, and $1 billion respectively. The plant directly employed 1,707 people and through its activity in the marketplace claimed responsibility for adding another 580 jobs to the community. Through combining direct and indirect taxes, Diablo Canyon accounted for an estimated $38 million annually in state and local taxes in 2002.[106]

On average, each current nuclear plant generates 500 jobs within the plant and another 500 out in the community. The new wave of plants will employ 1,300-2,000 people

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[102] Testimony of Randall M. Steuffen, University of South Dakota, Big Stone Unit II Site Permit proceeding, SDPUC, March 15, 2006.
[103] Economic Impact Highlights of Big Stone II Power Plant Construction, February 15, 2006.
[104] For example, the current operating staff at Big Stone Unit I alone is about 125 people, compared to the incremental operating staff additions of 35 FTEs for Unit II.
[105] As a example of the old regulatory process, these two took 17 and 16 years, respectively, to build.
[106] "Economic Benefits of Diablo Canyon Power Plant" by NEI, PG&E February 2004.

during construction, and add 300-500 jobs to the surrounding communities to support operations.[107]

5.6.4 Wind

Wind energy, when properly added to the grid, displaces production by higher cost fossil fuels. It provides a steady income to the farmers and ranchers who are able to continue working under its shadow largely unhindered. A typical land owner receives $2,000 - $4,000/MW per year for having wind turbines sited on their land and the installations only take up 2-5% of the land.[108]

In addition, wind turbines add to the property tax base for rural counties. The levied tax usually amount to 1-3% of the total project cost. Assuming the lower value of 1%, that would mean about $10,000/MW-yr for the rural communities.[109]

During construction of a wind farm, each MW will require 2.5 to 3 job-yrs of employment. Upon completion of construction, the turbines will require about one skilled O&M job for every 10 turbines installed.[108]

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[107] CASEnergy Coalition, http://www.cleansafeenergy.org/WhyNuclear/EconomicBenefits/tabid/120/Default.aspx
[108] AWEA, http://www.awea.org/newsroom/pdf/Wind_Energy_Basics.pdf
[109] U.S. Department of Energy, Wind Powering America program, http://www.neo.state.ne.us/neq_online/april2004/apr2004.01.htm

CHAPTER 6.0

ENVIRONMENTAL

6.1 Introduction

Environmental impacts are an important consideration in the selection of the appropriate generation technologies to be used. Often, a combination of generation technologies are selected to achieve a robust mix (portfolio) of energy types, costs, operating characteristics and environmental performance.

6.2 Coal

Coal-based generating plants today use advanced emissions control equipment. Nevertheless, they still emit amounts of sulfur dioxide (SO_2), nitrogen oxides (NOx), particulate matter (PM) and mercury (Hg). They also produce amounts of solid waste in the form of fly ash, bottom ash and scrubber solids that are usually landfilled but in some applications are sold as a byproduct.

Coal plants also consume water for cooling and other plant processes. An IGCC unit will require much less water than a PC plant, often as much as 50% less when using a cooling tower. This is an important consideration for SD because of the arid climate.

Where economically and environmentally possible, electric companies prefer to use cooling water from the ocean, a lake or river, or a cooling pond instead of a cooling tower. This type of cooling can save the cost of a cooling tower and may have lower energy costs for pumping cooling water through the plant's heat exchangers. However, the waste heat can cause the temperature of the water to rise detectably. Power plants using natural bodies of water for cooling must be designed to prevent intake of organisms into the cooling cycle. A further environmental impact would be organisms that adapt to the warmer temperature of water when the plant is operating that may be injured if the plant shuts down in cold weather.

Some byproducts of coal power plant processes are in fact beneficial. For example, fly ash from PC boilers is useful as a substitute for aggregate in concrete. Surplus steam or heated water from the cooling systems of PC or IGCC units can be used to facilitate co-located industrial processes or greenhouses. An IGCC unit can produce sulfur in near-elemental form, which is marketable for production of agricultural fertilizers. An IGCC unit can also produce synthetic natural gas or a wide variety of other chemicals for use at co-located or remote industrial facilities.

6.3 Nuclear

There is always much discussion surrounding the waste products of nuclear fission and what can be done with it. Up to now, the nuclear plants in the United States have produced about 54,000 metric tons (60,000 tons) of waste in the nuclear industry's history.[110] This radioactive material is currently being stored at 65 plant sites in 31 states.

The solution was originally seen to be the Yucca Mountain storage facility in Nevada that was to open in 1998. However, lawsuits, money shortages, and scientific and political debate have continually pushed this timing back.

The concept for a repository at Yucca Mountain is to seal the waste in extremely durable containers called waste packages, and then place the containers in deep underground tunnels. Drip shields made of another corrosion-resistant metal will be placed over the waste packages. Were the facility to be eventually opened, much of its 77,000 ton capacity would be taken up by the spent fuel quantities that have already been produced and are now in temporary storage at the plants.

If the price of uranium continues to rise, spent fuel rods will turn into a valuable commodity. The waste produced from the reprocessing cycle is smaller and is less radioactive. It gives off less heat and therefore Yucca Mountain would be able to hold a greater volume. In addition, the remaining radioactivity would decay over the next 600 years as opposed to 10,000 years for our current waste.

Unlike coal plants, nuclear plants produce no carbon dioxide (CO_2) emissions. Accordingly, the increase in concern regarding global climate change is part of the reason why nuclear technology is again starting to be considered for additional new power production applications in the U.S.

6.4 Wind

Wind is a renewable and clean resource. Unlike coal, it produces no air emissions or solid wastes. Unlike coal and nuclear, it requires no water supplies. And, unlike nuclear, it produces no radioactive spent fuel waste.

The primary environmental impacts of wind energy include possible adverse impacts on avian populations due to bird strikes on the turning blades, and visual impacts associated with large quantities of wind machines. Although not much of a consideration at current installed capacity levels, large extended fields of wind machines as the technology is used in massive quantities represent a visual disruption of the natural prairie and country vistas enjoyed by residents of these lands in the past.

Noise used to be a big problem within the wind industry. The early, primitive turbines built in the 1980s had problems with noise and were irritating up to a mile away. They would often create a tonal hum. Current designs have all but eliminated that concern

[110] Nuclear Energy Institute, http://www.nei.org/index.asp?catnum=2&catid=349.

through three major changes. First, the aerodynamics of the turbines have been improved to prevent any vibrational noise. Second, the nacelles, where all the moving parts are located, have increased sound proofing. Lastly, the gearboxes are designed for quiet operation.

All of these aid the wind turbines in only adding a low-level swooshing sound to the environment. A wind farm at a distance of 750-1000 ft is no louder than a kitchen refrigerator. And often, because of how it is situated within a wind environment, it is impossible to separate with turbine generated sounds from the background noise. The only problems might arise where a turbine is situated on a hill with the housing below it, shielded from the wind and therefore the wind background noise. In those cases, the wind noise would carry farther.[111]

6.5 Summary of Environmental Parameters

Figure 6.1 provides a tabular comparison of various emissions per MWh for the various generation technologies discussed in this Report while Figure 6.2 provides some representative amounts for example plants:

[111] American Wind Energy Association, Facts about Wind Energy and Noise, http://www.awea.org/pubs/factsheets/WE_Noise.pdf

FIGURE 6.1
Comparison of Environmental Emission Rates, by Generation Technology[112, 113]

	Supercritical Pulverized Coal	IGCC	Advanced Nuclear Plants	Wind
Capacity Factor	85%	85%	90%+	30-48%
Availability	90%+ (55)	80-85%	93%	98%
Construction Period (yrs)	4	4	5 to 8	1 to 3
Operating Life (yrs)	40	40	60	20-30
Heat Rate (Btu/kWh)	9,000	8,520	10,400	Not applicable
NOx (lb/MWh)	0.50	0.326	0	0
SO2 (lb/MWh)	0.541	0.089	0	0
CO (lb/MWh	0.83	0.22	0	0
PM (lb/MWh)	0.100	0.052	0	0
CO2 (lb/MWh)	1739	1541	0	0
Hg (lb/MWh)	3.49E-6	3.11E-6	0	0
Volatile Organic Compounds (lb/MWh)	0.023	0.013	0	0
Solid Waste (lb/MWh)	67	45	0	0
SO2 Removal Basis (%)	87	97.5	NA	NA
NOx Removal Basis	0.06 lb/MMBtu	15 ppmvd at 15% O2	NA	NA
Radwaste (metric ton/yr)	0	0	20	0

Notes for Figure 6.1:

1. The performance characteristics for coal plants represent a plant using sub-bituminous coal.
2. Particulate removal is 99.9% or greater for the IGCC cases and 99.7% for sub-bituminous. Particulate matter emission rates shown include the overall filterable particulate matter only.

112 "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies" prepared by Nexant, Inc for the Environmental Protection Agency, July 2006.

113 "Clearing California's Coal Shadow from the American West", prepared for Western Resource Advocates, 2005.

3. A percent removal for NO_x cannot be calculated without a basis, i.e. an uncontrolled unit, for the comparison. Also, the PC and IGCC technologies use multiple technologies (e.g., combustion controls, SCR). The NO_x emission comparisons are based on emission levels expressed in ppmvd at 15% oxygen for IGCC and lb/MMBtu for PC cases.
4. Solid waste includes slag (not the sulfur product) from the gasifier and coal ash plus the gypsum or lime wastes from the PC system.
5. The relatively low SO_2 removal efficiency of 87% shown represents relatively low sub-bituminous coal sulfur content of only 0.22%. Higher removal efficiencies are possible with increased coal sulfur content.
6. These numbers are for a general plant. Actual performance will depend on siting and the technology employed.

Figure 6.2 provides corresponding information for nominally-sized example facilities on an annual basis.

FIGURE 6.2

Comparison of Environmental Emissions by Generation Technology

(lbs/year)

	PC 600 MW	IGCC 600MW	Nuclear
NOx	2,233,800	1,456,438	0
SO_2	2,416,972	397,616	0
CO	3,717,043	991,807	0
PM	446,760	232,315	0
CO_2	7,769,156,400	6,884,571,600	0
Hg	16	14	0
VOC	102,755	58,079	0
Solid Waste	299,329,200	201,042,000	0
Radwaste	0	0	44,000

All of the technologies being discussed have some sort of water requirement. Wind turbines even require a small amount for washing in arid climates to clear the blades of dust and insects. Unless removed, that buildup over time degrades performance. Water Consumption is defined as water that is not returned to the source from which it was withdrawn. That usually means that it is lost to evaporation. Figures 6.3 and 6.4 summarizes these numbers for the various types of cooling on a per MWh and acre-ft/yr basis.

FIGURE 6.3
Water Usage Rates by Generation Technology[114, 115]
(gallon/MWh)

Generation type	Water Withdrawal	Water Consumption
PC, once-through cooling	20,000 to 50,000	~300
PC, pond cooling	300 to 600	300-480
PC, cooling tower	500-600	~480
Nuclear, once-through	25,000 to 60,000	~400
Nuclear, pond cooling	500 to 1100	400-720
Nuclear, cooling tower	800 to 1100	~720
IGCC, cooling tower	~380	~200
Wind	~1	~1

Figure 6.4 provides a comparison of annual water use for nominal plant sizes of the various technologies.

FIGURE 6.4
Nominal Annual Water Use by Generation Technology Type[116]
(acre-feet/year)

Generation type	Water Withdrawal	Water Consumption
PC 600MW, once-through cooling	274,211 – 685,527	4,113
PC 600MW, pond cooling	4,113 – 8,226	4,113 - 6,581
PC 600MW, cooling tower	6,855 – 8226	6,581 – 20,034

114 EPRI, "Water & Sustainability (Volume 3): U.S. Water Consumption for Power Production - The Next Half Century", March 2002.
115 American Wind Energy Association, http://www.awea.org/faq/water.html.
116 Assuming 85%, 90%, and 35% capacity factor for coal, nuclear, and wind, respectively. Coal Plant size of 600MW chosen because comparable to Big Stone II. Nuclear plant size of 1150 MW was chosen because it is the smallest of the four reactor options and therefore has the smallest water requirement for the fairest comparison with the smaller rated coal plants.

Nuclear 1150MW, once-through	695,608 – 1,669,460	11,130
Nuclear 1150MW, pond cooling	13,912 – 30,607	11,130
Nuclear 1150MW, cooling tower	22,259 – 30,607	20,034
IGCC 600MW, cooling tower	5,210	2,742
Wind 100MW	~1	~1

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CHAPTER 7.0

SOUTH DAKOTA OPPORTUNITIES AND CHALLENGES

7.1 Introduction

For the reader's convenience, the most important opportunities and challenges from previous chapters are reiterated in this Chapter 7.

7.2 General Opportunities in South Dakota for Power Plant Siting

The basic opportunities to be found in South Dakota for siting electric generating plants using coal, nuclear or wind energy include the following:

- Land for plant siting is available in South Dakota at reasonable cost. Land can be found that is distant from population centers and characterized by good, underlying geology.

- Water is probably available for cooling, flue gas scrubbing and boiler water makeup purposes from the Missouri River, the James River or Big Stone Lake.[117]

- The business and labor climate in South Dakota is favorable. Citizens understand the complex tradeoffs involved in conducting business and building facilities. The workforce is productive and skilled.

- Governmental policy is supportive, the regulatory environment is generally favorable, and local planning and zoning are not impediments when it comes to developing, permitting, constructing and operating electric facilities.

7.3 General Challenges in South Dakota for Power Plant Siting

The general challenges that business interests anticipate encountering when planning to site new generating facilities in South Dakota are summarized below:

- South Dakota itself provides only a small market, and anticipates slow growth rates in that market for electric power. The 2005 non-coincident peak electric load in the state was only about 2,000 MW, growing at only 1.0 - 1.5% per year. Power generated at new facilities in South Dakota will have to be moved long distances to load centers in Minnesota, Wisconsin, Illinois, Iowa, or Colorado.

[117] There are many competing interests using these three sources of water, and securing permits to make large scale water withdrawals from the Missouri River, the James River or Big Stone Lake may not be an easy task.

- South Dakota may not have sufficient numbers of skilled laborers in-state to provide the 1000 or more workers required for the construction of a large power plant project. Laborers for large projects may need to be recruited and paid to relocate from distant states.

- Contractors on a large, remote, power plant project may encounter difficulty in finding adequate lodging, meal, medical, school, and transportation services for a large, temporary workforce.

- Assembling consortia of utilities in South Dakota to finance and construct power plants and transmission facilities for power export purposes may be a complicated exercise. Many of the major electricity producers in the state are either investor-owned utilities with defined service territories, or some form of public power entity with not-for-profit business models that are not compatible with promotion and financing of facilities for an export power business.

- Organizations and individuals opposed to power plants for environmental, conservation or other reasons are mobile. South Dakota offers no unique shelter from law suits, injunctions or demonstrations that can delay the licensing and construction of major power plant facilities and related transmission lines, including transmission facilities need in neighboring states necessary for experts of energy from South Dakota.

7.4 Opportunities and Challenges for Coal Technologies

7.4.1 Opportunities for Coal Plants

- The atmospheric air quality in South Dakota is generally good, and the air sheds at potential power plant locations can probably absorb controlled levels of emissions from new coal-based facilities.

- Land is probably available for the safe disposal of coal ash and byproducts from flue gas cleanup.

7.4.2 Challenges for Coal Plants

- Concerns about global warming and CO_2 discharges from fossil-fueled plants are sparking a national discussion about continuing reliance on coal for electric power production – especially in new facilities. South Dakota offers no apparent advantage over other states when it comes to CO_2 control, capture or sequestration, although its proximity to depleted oil fields in western North Dakota may offer an alternative for carbon sequestration via CO2 injection into those fields.

- Coal-fired generating facilities require a large and reliable supply of fuel. South Dakota has no in-state coal mines. Coal for power plant use will need to be brought into South Dakota from Wyoming or Montana. Coal, once loaded on rail cars, can be moved to power plants close to load centers as an alternative to moving electricity across South Dakota by transmission lines.

- A 600 MW power plant, for example, might use about 5,200 tons of coal a day and thus require the arrival and departure of a 100 car, 10,000 ton coal unit train every 46 hours. At this time, South Dakota has no heavy-duty, competitively-priced rail service for delivering coal in these volumes to future new generating plant sites. The proposed DM&E rail line from Wyoming across South Dakota into Minnesota has been delayed by routing and financing issues.

- Mine-mouth, coal-fired, generating plants in Wyoming, Montana and North Dakota may be better positioned than new coal plants sited in South Dakota to provide electricity at competitive rates to customers in Minnesota, Colorado and the South West.

7.5 Opportunities and Challenges for Nuclear Technologies

7.5.1 Opportunities for Nuclear Plants

- South Dakota's citizens may be more amenable than citizens in other states to accepting nuclear plant installations because they hosted the pioneering, nuclear, Pathfinder Project near Sioux Falls as nuclear power technology was being developed in the 60's and 70's. South Dakota has also been the long time home for several squadrons of aircraft and ballistic missiles carrying nuclear weapons for the nation's strategic defense. South Dakotans have learned to live with nuclear technologies.

- In South Dakota, a nuclear generating station could be located at substantial distances from population centers thus simplifying planning for emergency evacuation, plant security and spent fuel storage.

7.5.2 Challenges for Nuclear Plants

- Utilities planning new nuclear facilities are generally choosing to locate them at existing nuclear generating sites to take advantage of licenses, permits, water supplies, trained personnel, security systems and evacuation plans that are already in-place. South Dakota has no existing operating nuclear generating stations.

- The nation has not yet adopted a plan and a site for permanent disposal of nuclear waste including spent fuel from power reactors. While the national disposal solution remains a work-in-progress, utilities must provide on-site storage for spent fuel at existing nuclear plants; and waste disposal remains a technical, financial and political problem overhanging the industry. South Dakota offers no unique solution to this long term problem vis-à-vis the situation in other states.

7.6 Opportunities and Challenges for Wind Technologies

The sum of commitments, plans and hopes for installation of wind-based generating facilities in South Dakota indicates that the state could become home for more than 12,000 MW of wind turbines.

7.6.1 Opportunities for Wind

- South Dakota is thought to have the fourth best wind resource for power production considering all the states in the continental U.S. The wind resource in the state has been thoroughly mapped at a macro level by federal agencies, and both public and private organizations are refining knowledge of the wind potential.

- South Dakota citizens are enthusiastic about hosting wind energy developments, and looking forward to realizing income from leasing land, constructing towers, servicing turbines and, ultimately, manufacturing tower and turbine components in-state.

- Large hydroelectric stations on the Missouri River in South Dakota offer un-tapped opportunities for converting some part of the intermittent, wind resource in the state to firm power supplies. Planning for and coordination of hydroelectric pumped storage and wind energy sources has not traditionally been undertaken; apparently because there are already many competing uses for the water in the Missouri. This concept deserves a re-look, based on the burgeoning wind opportunity in the state, and the quest for a way to make intermittent wind energy a firm reliable capacity source to address concerns regarding global climate change.

7.6.2 Challenges for Wind

- South Dakota lacks native electric loads sufficient to provide a market for all of the wind-derived energy that could be produced in the state. In particular, it lacks industrial and commercial loads that could be shaped to use wind energy with its intermittent availability.

- Other states, notably Wyoming, North Dakota, Nebraska, Minnesota and Iowa, have wind resources that are similar to or less robust than those available in South Dakota; but their resources are located between South Dakota and potential customers for wind energy located to the east and west. Wind developers in other states, due to their proximity to big electric markets, represent formidable competitors to wind developers hoping to build additional wind facilities in South Dakota.

- Mine-mouth coal-fired power plants in Wyoming, Montana and North Dakota represent additional, strong competition for wind-based generating units that might be located in South Dakota.

- Wind developers claim that South Dakota's sales, property tax and excise tax structures provide a disincentive for building wind turbines in South Dakota vis-à-vis nearby states.[118]

7.7 Opportunities and Challenges Related to Transmission

Because South Dakota has a relatively small, in-state market for electric energy, all proposals for new power plant construction ultimately lead to consideration of the potential export market for electricity. Moreover, they also lead to discussion of the interconnected transmission network needed to serve in-state and export customers. The transmission network in and around South Dakota is characterized by yet another list of opportunities and challenges.

7.7.1 Opportunities in Transmission

- Electric utilities serving residential, commercial and industrial customers in South Dakota hold the view that the existing in-state electric transmission grid is sufficiently robust to provide reliable, safe and flexible service to their in-state customers, and to existing, out-of-state customers who already receive allocations of preference power from the federal facilities on the Missouri River.

- Transmission studies by federal agencies and others have identified locations in South Dakota where modest additions of new generating capacity can be interconnected with the existing transmission grid without causing grid failures or requirements for major new transmission investments. Some wind developers are considering turbine installations at those available locations.

- Existing utilities in South Dakota have also indicated to SA that they are both willing and able, technically and financially, to design and build any additional transmission facilities required to serve the likely needs of their existing customers. They also stand ready to plan and undertake transmission line and substation improvements for power export purposes when and where new *customers* appear to pay for the associated added transmission service.

- Investor-owned, independent transmission companies stand ready to acquire or build transmission facilities inside and beyond South Dakota to address transmission bottlenecks that utilities are unwilling or unable to solve. This again assumes that that willing customers can be found to pay for the improvements.

7.7.2 Challenges in Transmission

- Wind developers, owner-operators of transmission facilities in South Dakota, and the Midwest Independent Transmission System Operator (MISO) acknowledge that the existing transmission system in South Dakota is not adequate to move very large

[118] "Electric Industry Interviews Report", SDEIA, December 2006 at Page 39.

blocks of electric energy from South Dakota to distant export markets in Minneapolis, Milwaukee, Chicago, Kansas City, Denver or other points outside the immediate Plains Region.

- South Dakota government and utilities alone cannot overcome all of the transmission bottlenecks between South Dakota and potential customers for electric energy exported from the state. South Dakota's aspirations to increase power exports for economic development will require joint action with other states and utilities to find rights-of-way, smooth permitting processes, and demonstrate benefits for everyone who is likely to be affected by new or upgraded transmission lines.

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CHAPTER 8.0

TECHNOLOGY SELECTION

8.1 Introduction

This report has summarized the characteristics of various selected electric generation technologies. The actual choice of technology is not within the purview of the State of South Dakota alone. Instead, such technology selections occur through a complex process that entails many considerations, assumptions and involved parties.

8.2 Identification of Need

The process typically begins with the identification that a particular group of customers needs or will need additional electric supply resources. Simply stated, the need is the difference between forecasted energy requirements and the forecasted ability of existing resources to fulfill those requirements in a particular year. Traditionally, initial determination of need has been done by public power entities or investor-owned utilities that have designated service areas in which they serve retail customers. The identification of need occurs within their efforts to plan for reliable energy supplies for those retail customers.

Additional need can occur in various ways. It can be the result of ongoing economic growth causing associated growth in customers' electric demand. Anticipated future retirement of existing facilities or expiration of current supply contracts can also be factors. The cost of continuing to operate existing facilities and their fuel supplies together with associated environmental considerations must also be considered. For South Dakota's purposes, these factors and others as they exist in other states will affect the future need for additional energy exports from South Dakota.[119]

8.3 Alternatives Development

When a future need has been identified, a list of feasible resource alternatives is also identified as potential candidates to meet the future need. This list can include demand-side management (DSM) program options to help customers reduce their peak demand and energy requirements. The alternatives list may also include wind, coal, nuclear, hydro, natural gas-fired and other supply options.

In order to be viable options, the alternatives must be technically and politically feasible. They must be available in the needed time frames and, taken individually or together, offer a total resource of a magnitude sufficient to meet the forecasted need. They must

[119] The previous SDEIA, "Electric Industry Interviews Report" dated December 2006 encourages the State to get involved in the resource planning processes of various regional entities to help identify ways where the state can be successful in securing these export markets for the benefit of South Dakota.

have an acceptable environmental profile. They must be financeable. And, they also must be capable of being permitted in all regulatory jurisdictions where such permits will be required.

8.4 Choice of Alternatives

The actual selection of various resource alternatives depends on the type, size and timing of the identified need, the characteristics of existing facilities the utility already has, and the characteristics of the available alternatives. As a simple example, if a utility forecasts that its annual peak demand will be growing due to additional air conditioning load from new homes to be built during the planning period, it would be more inclined to consider additional peaking DSM programs or new peaking generating facilities to serve that need, rather than new baseload facilities. As another example, a utility with sufficient existing capacity may consider adding additional wind energy facilities to help offset production from its existing facilities to save fuel costs or improve its environmental profile.

Today, utilities typically use complex computer planning models to assist them in resource selection. These models match forecasted needs with numerous combinations of available resources to identify those combinations that would result in the best outcomes of low cost, risk management and environmental impacts. Because the output of these models are driven by a multitude of input assumptions the actual future values of which are unknowable, the modeling process is only a tool in the resource decision process. Such selections also require expert experience and judgment to determine the best technology options to actually pursue. The utility may solicit the input from outside entities to help them make these selections before proceeding.

Instead of a single technology, the utility will typically identify a portfolio of various diverse and complimentary options to pursue, comprising an overall resource plan for the future.

8.5 Permitting and Other Approvals

Finally, the chosen technologies are submitted to various regulatory agencies for permits and other necessary approvals within the laws and rules of each jurisdiction. Approval of these important items is necessary to enable financing, construction and operation of the selected technologies. Permits necessary for approvals of the technologies addressed in this Energy Study are discussed elsewhere in this Report.

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APPENDIX A

GLOSSARY OF TERMS
WITH APPLICATION TO ELECTRIC UTILITY SYSTEM PLANNING

Availability
A power plant's availability, expressed in percent (%), is a measure of the number of hours in a stated period that the plant was ready or available to operate compared to the total number of clock hours in the same period. The base period used in the calculation may simply be a calendar month or year. The base period, however, may also be defined as the number of hours that the plant was *scheduled* to be in-service during the stated period. For example, a nuclear plant may have been scheduled in-service for 17 days in August and out-of-service for 14 days for re-fueling during the same month. Assume the plant actually operated at full load for 16 days. If the 31 days in August are used for the base period in the calculation of availability, the plant was available 52% of the time. If, instead, the *scheduled* in-service hours are used in the calculation of plant availability, the plant was "available" 94% of the time.

When comparing generation options using availability as a measure of value, it is important to understand what definition is being used for the base period; i.e., the denominator, when calculating the availability ratio.

Allowance for Funds Used During Construction (AFUDC)
Cash is the lifeblood of every large utility construction project. Planners, designers, engineers, contractors, laborers, consultants and lawyers all expect to be paid regularly while the project is underway and before the power plant or transmission line is put into service. Similarly, the project vendors providing steel, concrete, transformers, turbines, wire, boilers and piping also require payment upon delivery of materials and equipment during the construction period.

In large projects, the owner or sponsor usually meets these cash requirements by borrowing funds from sources outside the utility company. The borrowed funds may come from consortia of banks in the form of temporary construction loans; or from investors who agree to purchase long term bonds or common stock (equity) issued by the project owner.

Utilities typically do not charge their customers for costs associated with large projects until those projects are completed and place in services. As a result, the use of borrowed funds during the construction period typically results in (a) interest expense that can reduce net income, or (b) an increase in the number of outstanding shares of stock thus diluting earnings per share. The construction project, therefore, can have an adverse effect on corporate earnings before the plant or transmission line goes into service and produces revenue.

To mitigate the possible adverse effects of using borrowed funds, the project owner may elect to recognize the cost of borrowed money as part of the capital cost for the project. In practice, the cost of debt or equity is “capitalized,” made part of the project costs, and effectively removed from the owner’s income statements published during the construction period.

For a regulated utility, the nominal interest rate that is used in computing the cost-of-money to be capitalized is established by the federal or state regulator. The nominal rate usually bears a close relationship to the actual cost of money being incurred by the owner for loans, debt and equity; but the regulator can elect to approve a nominal rate that is different from the actual cost. The accounting entry appears in the owner’s income statement as the Allowance for Funds Used During Construction (AFUDC).

It is important to note here that the AFUDC is an accounting entry that can improve the appearance of the owner’s income statement; but the owner still has to find the cash to pay labor, vendors and contractors on-time during the construction period. This is referred to as the need to maintain “liquidity” in the owner’s company during the construction period in addition to maintaining earnings or positive net income.

Over large, multi-year, construction projects, the AFUDC can accumulate to be a substantial part of the project capital cost. Therefore, when comparing project alternatives, it is always important to know if the estimated capital costs for alternative plans include or exclude AFUDC; i.e., the capitalized cost of money.

Busbar Cost

Busbar cost is the cost of electricity at the output port of the power plant. This port is typically the high voltage bushing of the step-up unit transformer at the location in the power plant substation where the electricity leaves the plant. By definition, busbar cost does not include downstream transmission, distribution or administrative costs that also appear in monthly bills sent to electricity customers. Busbar cost is one measure used by engineers to compare generation plant options.

Busbar costs for an electric generating plant include:

- All capital-related or ownership charges related to the capital cost of the plant. (See “Capital Cost,” “Fixed Charges” and “Levelized Annual Fixed Charges” in this Glossary.)
- All fixed operating and maintenance costs – principally labor and supervision
- All variable operating and maintenance costs - principally fuel, fuel transportation, lubricants, chemicals, outside services for repairs, and station power expenses.

All the annual ownership and operating/maintenance costs are added up for one period, usually one year, and divided by the MWh output of the plant for that same period. The result is the busbar cost for the period expressed in $/MWH.

Busbar Cost, Levelized

Busbar costs for a power plant vary from year-to-year because the underlying cost components change from year-to-year. For example, annual fixed charges tend to decline over time while annual operating and maintenance (O&M) costs tend to increase due to economic inflation. Consequently, while busbar cost can be stated as a single year value; it is frequently expressed as a levelized annual cost over the lifetime of the facility.

The busbar cost, levelized, can be found by computing the present worth of the time-varying stream of annual fixed charges and O&M expenses estimated over the expected operating life of the power plant. The total present worth figure at the in-service date of the plant can then be converted to a constant or uniform annual cost by applying a capital recovery factor. The factor is computed using the owner's expected cost of money. The uniform annual cost figure, divided by the expected annual power output from the plant, results in a uniform annual busbar cost in dollars. This figure is defined as the levelized busbar cost for the plant and stated in $/MWh.

Capacity Credit, Planned

A wind turbine generator has value as both a source of energy (MWh) and a source of capacity or power (MW). In an electric utility system, the value for capacity assigned for planning purposes to a wind machine or wind farm is typically less than the rated or nameplate capacity of the installed wind machine(s). This value can be calculated by deriving the Effective Load Carrying Capability (ELCC) for the wind machine, or collection of machines, in the utility system to which the wind turbine(s) is connected.

The ELCC for a collection of wind machines is a complicated function of expected wind conditions, customer electric demands, and other generator capabilities in the utility system under study. The 2006 Minnesota Wind Integration Study reported that the estimated ELCC for large collections of wind machines, that could be in-service by 2020, range from 5% to 20% of the installed wind generating capacity. If, for example, 5000 MW of wind turbines are in-service in 2020, Minnesota utilities might assign these machines a combined capacity credit or value between 250 MW and 1000 MW for planning purposes. The machines rated 5000 MW could provide 20% or more of the retail electric energy sold in Minnesota in 2020; but they would not be relied on to provide more than about 1000 MW of the customers' demands for capacity.

Capacity Factor

The capacity factor (CF) for an electric generating station measures the amount of energy that the station has produced or is expected to produce over a stated period of time compared to the theoretical amount of energy that the same station could produce if operating at full, rated output over the same period of time. Capacity factors are usually measured or stated for 12 month periods. They are usually expressed in percent (%). For example, the reported annual capacity factor for a 500 MW, coal-fired, generating station might be 75% in a given year. That means that the station actually produced about 3.285 million MWh versus the 4.38 million MWh that it would have produced if operated at full load throughout the year.

Capital Cost

Total amount paid to acquire a utility asset by purchase or construction. If the asset is a generating station acquired by construction, the capital cost usually refers to all of the labor, material and incidental costs incurred in planning the station, acquiring the site, securing permits and licenses, performing the construction, acquiring a fuel supply and testing the equipment up through the date that the station is put in-service and starts providing electricity to customers. The incidental costs may involve legal and consultants' fees, interest charges and fees paid on construction loans and part of the CEO's salary and benefits allocated (capitalized) to the project.

Capital Cost, Actual

The total amount recorded in the owner's books-of-account for all costs *actually incurred* in acquiring or constructing an asset or facility through the facility's in-service date. The amount will include all material, labor and incidental charges *actually incurred* by the owner. This amount cannot be known with certainty until the facility is in-service and all of the outstanding invoices have been received from vendors who provided design, construction and testing services, and after all expenses actually incurred by the owner's employees are collected and properly allocated to the project.

The actual capital cost becomes the basis for the owner's calculation of how much revenue will be needed, year-by-year, from customers during the operating life of the facility to recoup all of the annual fixed charges and operating/maintenance expenses associated with use of the facility until it is retired from service – maybe 30 years hence.

If the owner is subject to revenue and rate regulation by federal, state or municipal authorities, the actual capital cost becomes the starting point for calculating the amount of rate base that the regulatory authorities will recognize as attributed to the new asset for rate making purposes. The amount recognized in rate base may be equal to or less than the actual capital cost.

Capital Cost, Estimated

The total capital cost of a facility or asset *estimated* today as of the date the facility will be in-service; i.e., providing service to customers. This is an estimate made *today* for the actual total cost of a facility that may not be acquired or completely constructed until many years into the future. During this acquisition or construction period, the estimate may be updated many times. The actual total capital cost of the asset or facility recorded in the owner's books of account on the in-service date may be substantially different than the initial estimate made today.

To go from overnight cost to estimated or forecast total capital cost, an engineer will:

- Assume a month-by-month distribution of the overnight cost from current day to the in-service date for the facility,
- Apply one or more escalation rates to the distributed, overnight costs. Expenditures in the later months and years of the distribution will be more affected by the escalation factors, of course. Different escalation rates may be used for labor and materials, respectively; and the escalation rates used may vary from year-to-year in the work papers of the engineer.
- Estimate month-by-month or year-by-year interest charges on monies (escalated dollars) borrowed to build the facility,
- Sum all the resulting escalated costs, including the interest charges, to get the estimated, total capital cost of the facility. This is the capital cost that goes into the estimated busbar cost calculation for electricity (MWH) generated by a new power plant, for example.

The capital cost, estimated, is the sum of escalated dollars from different years; however, this capital cost is sometimes referred to as the total capital cost in dollars as of the in-service year for the facility. This practice provides a crude basis for comparing costs of alternative plans in outlying years but it is an inaccurate and sloppy way of defining capital costs for large projects with multi-year construction schedules.

Capital Cost, Overnight

Overnight cost usually refers to the hypothetical, estimated, capital (construction) cost of a facility, either a power plant or a transmission line, in current-year dollars (say, 2006$) assuming the facility could be built overnight. This is usually the starting point for developing a facility cost estimate, because the engineer estimates how much material and how many man-hours would be required to fabricate and build the facility, all in current-year dollars. BUT, because the power plant the engineer is designing may take several years to get permits and other required approvals, and may take another four years to construct, escalation/inflation, interest on borrowed funds and other factors working on the overnight cost cause the final capital cost of the plant to actually be more than the overnight cost. Engineers talk in terms of overnight costs, so they can compare various generic plant types to others on a common basis.

Cost of Money

Utility companies borrow money for major projects and to meet normal cash requirements for paying employees and vendors before accounts receivable are collected from customers. Borrowed funds may come from bank loans, or from issuing long term bonds (debt), preferred stock or common stock (equity). Companies have to pay interest charges on monies borrowed through loans and the issuance of bonds. Companies have to produce net income to pay dividends on preferred stock and report earnings for common stock. Stockholders have in-mind a return that they expect to realize on the shares they are holding. Cost of money refers to the interest rate and/or the return for equity that a company expects to pay, or is paying, on borrowed funds being used in the business.

Cost of Money, Weighted

Assume a company is going to borrow funds to construct a transmission line. Further assume that the one-half of the monies are expected to come from issuing long term bonds bearing an interest rate of 8% per year. The other half of the monies will be raised by issuing common stock to shareholders who expect an annual return of 15% on equity. The company's planning engineers will calculate and use a weighted cost of money in their economic studies. The weighted cost of money can be found using the mathematical procedure modeled below:

Cost of debt component:	0.50 x 0.08 =	0.040
Cost of equity component:	0.50 x 0.15 =	0.075
Weighted cost of money:		0.115, or 11.5 % per year

Effective Load Carrying Capability (ELCC)

Effective Load Carrying Capability (ELCC) is the amount of new or additional electric load (call it "L"), that can be added to an electric system after adding a new generating unit with rated capacity ("C") to the same system. The calculation of ELCC is typically made under the assumption that the system shall continue to operate with a Loss of Load Expectation (LOLE) that is unchanged from the LOLE calculated before adding Load L and Capacity C.

Assume, as a simple example, that a new, 500 MW generating unit is added to Utility System A. If the new unit is perfectly reliable, it should be possible to add 600 MW of additional customer load to Utility System A while retaining the same level of reliability in the System. We would say, in this case, that the ELCC for the 600 MW generating unit is 500 MW. If the 500 MW unit has a reliability index of 70%, we might say that is ELCC is 350MW.

In practice, it is not possible to calculate ELCC values by multiplying a simple reliability index times a unit's rated capacity value. The calculation must be made hour-by-hour using system demand curves, plant capacity ratings and reliability values.

Fixed Charges

The amounts that will be booked year-by-year in a company's books of account (in the Operating or Income Statement) as costs that are associated with the *ownership* of an asset or facility whether or not it is actually being fully used. Fixed charges represent amounts that must be collected as revenue from customers during any period to pay the ownership costs of the facility whether or not it is operating. Fixed charges are costs that are incurred and recorded *after* an asset or facility is in-service. They are intimately related to the actual capital cost for an asset; but are used to calculate busbar energy costs in the operating period for a facility after the construction period is ended.

It is customary to define fixed charges as having five (5) components:

1. Book Depreciation
2. Property Insurance
3. Property Taxes
4. Cost of Money
   - Interest on Long Term Debt
   - Return for Equity (Common Stock)
   - Dividends on Preferred Stock
5. Corporate Income Taxes on Net Income (on Return for Equity)
   - Federal
   - State
   - Other

Actual fixed charges appear in a company's books as dollar amounts, and those dollar amounts change from month-to-month and year to year. The changes are principally driven by depreciation which causes the net amount invested in any facility to decline from year to year. Actual, annual, fixed charges can also change, however, due to changes in corporate tax rates, property tax rates, and insurance premiums. Typically, total fixed charges decline annually over the operating life of an asset.

Fixed Charge, Levelized Annual

When planning the acquisition or construction of a new facility or transmission line, it is useful to have an estimate for the "average" annual fixed charges that will arise from the planned investment. This "average" is typically computed as a *levelized* annual fixed charge. The steps used in computing this single number for a planned new generating station follow:

1. The estimated annual fixed charges associated with the planned investment are estimated year-by-year over the expected 30 year operating life of the station. Planning engineers expect that the annual fixed charges will vary from year to year, and generally decline over the life of the property.

2. The 30-year stream of time-varying fixed charges are then brought back to the expected in-service date for the station (Year End 0) using present worth methods and a discount rate set equal to the owner's estimated, weighted cost-of-money for the dollars invested in the station. The total present worth of the fixed charge stream, a large number, is calculated at Year End 0.

3. Using the same 30-year period and the same weighted cost of money, a compound amount factor is found and used to calculate the value of a constant or uniform annual fixed charge which, if booked every year for 30 years, would have the same present worth value as the amount computed in Step 2, above. This uniform fixed charge, stated in dollars, is defined as the *levelized annual fixed charge* applicable to the planned asset.

4. If the levelized annual fixed charge, in dollars, is divided by the expected annual power output from the station, the fixed charge or ownership cost component for energy at the station busbar can be found and expressed in $/MWh.

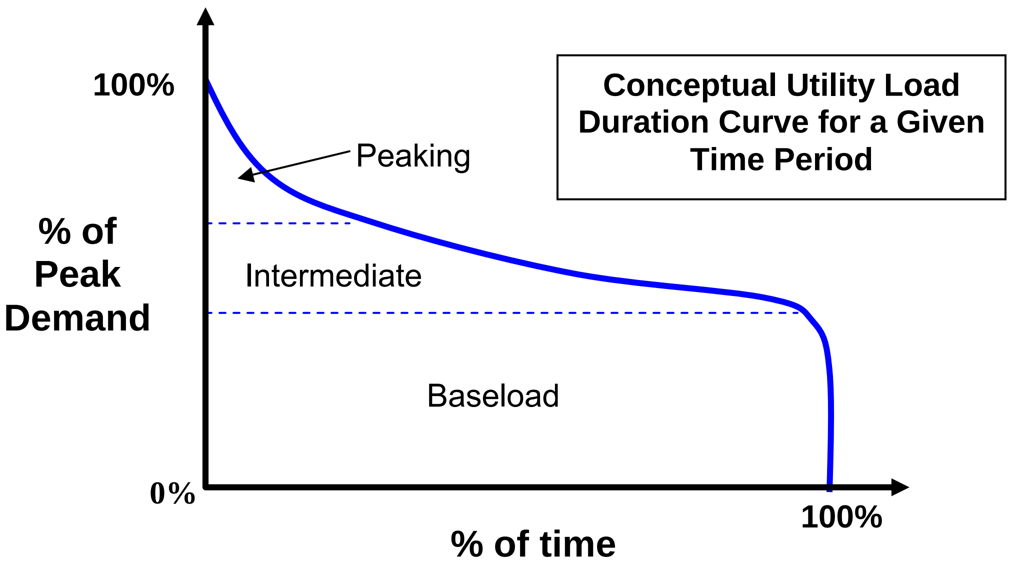
5. Engineers usually find it convenient to re-state the levelized annual fixed charge as a percent of the estimated capital cost for the asset – in this case a generating station. For long lived assets and weighted costs of money like 10-15%, the levelized annual fixed charge rate is frequently found to be a number like 15 -20% of the estimated capital cost for the project.

Engineers have devised algorithms and computer software to calculate levelized annual fixed charges using quick and easy methods.

Load Duration Curve, Annual

The total demand or load on an electric utility system is measured in MW and varies from hour-to-hour. (The load actually varies from second-to-second; but these fine-grain load changes will be ignored here.) The load changes as customer-owned lights, motors, heating elements, cooling units and other equipment are turned on and off across the supply network. Across every clock hour in one year, some minimum collection of the connected loads is always in-use and their combined demands establish the minimum load served by the utility. At other times, 3:00 p.m. on a hot day in July for example, a large collection of the connected loads are in use and their combined demands create the annual peak load seen by the utility. During the 8,760 hours in a year, the load being served typically varies somewhere between the minimum and peak load values.

Planning engineers have found it useful to meter the total load on an electric utility system hour-by-hour, and then count the number of hours that the total load served is at or above stated demand values between the minimum and peak loads. This data, plotted on graph paper, provides a ski-jump shaped curve known as the utility's annual load duration curve.



A load duration curve is constructed by ordering the hourly system MW loads of the time period under consideration in decreasing rank order of their magnitude. When the curve is then normalized in per-unit of the period peak hourly demand, the resulting curve as shown above represents, for each % of total time on the X-axis, the probability that the load will be at the corresponding % of peak demand on the Y-axis, or greater. For example, the graph shown above illustrates that there is a near-zero probability (% of time) that load will be 100% of the peak demand or greater. Conversely, there is a 100% probability (% of time) that the load will be about 50% of the peak demand, or greater.

Planning engineers expect the right side of the curve to be low and generally flat confirming that the minimum load persists across all 8760 hours in the year. The rectangular area under the bottom part of the load curve, extending from zero to 8760 hours, is usually referred to as the "baseload" region. The utility must provide generating plants that will operate economically over most of the hours in the year to serve electric equipment producing the electric demands under this region of the curve. Said units typically have high installation or capital costs.

At the upper left side of the curve, planning engineers expect to find that the highest load persists for only one or two hours in a year. This triangular area of the curve, at the top of the "ski-jump", is called the "peaking" region. Utilities usually prepare to serve this region with generating units that may have high operating costs but low capital costs. The high operating costs are acceptable because the supply equipment used here operates over only a few hours each month.

The broad, triangular area under the load duration curve between the baseload and peaking regions is called the "intermediate" region. Equipment designed to operate over the hours bridged by this load region is usually characterized by both medium operating costs and medium capital costs.

Loss of Load Expectation (LOLE), Annual
One measure of reliability in an electric utility system is the Loss of Load Expectation (LOLE). This is a theoretical or planning number that measures the likelihood that the installed generation will be *insufficient* to meet the connected electric load at any time during some stated period in the future. A common practice is to try to maintain the LOLE, the probability of a generation deficit, at not more than one day in ten years. This probability is calculated by combining estimated customer demands, generator capacity ratings and generator reliability values on an hour-by-hour basis over one year.

Operation and Maintenance Expense, Fixed
Fixed operation and maintenance (O&M) expenses are those necessary to have and maintain an asset, a power plant for example, ready for use even if it is not operating. Fixed O&M expenses are principally comprised of salaries and benefits for operating and maintenance laborers, guards, supervisors and plant administrators. It may include inventory costs for lubricants, water treatment chemicals, spare parts and tools.

Operation and Maintenance Expense, Variable
Variable operation and maintenance (O&M) expenses are those caused by actual operation of an asset, a power plant for example. Variable costs for a power plant will be principally fuel expenses, fuel transportation charges, waste disposal costs and out-of-pocket costs for consumables such as lubricants, chemicals and water used.

Production Cost
Production cost, in $/MWh, for a power generating facility is defined as the *variable* operating and maintenance cost over any period divided by the facility power output during the same period.

Production cost, or variable operating and maintenance cost per unit, is the sum of costs arising from use of the plant; i.e., the sum of expenses for fuel, fuel transportation, water treatment chemicals, outside services for maintenance, lubricants, and station power consumption.

Production cost does not include fixed charges (ownership costs) or fixed operation and maintenance expenses.

Production cost describes the expenses incurred while actually operating the plant after the plant equipment is in-place and staffed to serve customers.

Water, Consumption
Water consumption at an electric power plant commonly refers to the portion of water withdrawals that are not returned to the same source or not able to be reused in the local area. This includes water used as a chemical ingredient, water lost to evaporation and seepage, water incorporated in and carried off the site in ash or other by-product materials and by humans, or water that is otherwise transformed into its constituent gases or contaminated.

Water consumption usually does not include all water used for cooling spent process steam or lubricants. Typically, most of this water is returned to the source from which it was withdrawn. If, for example, water is withdrawn from a river to fill a power plant cooling pond, and water is drawn from the pond to cool process steam flows in the plant condenser and then returned to the pond, the water consumed for cooling is only that water lost from the pond due to evaporation and seepage. This amount of consumption can be found by measuring the amount of make-up water that is withdrawn from the river from time-to-time to restore the design water level in the pond.

Water, Uses
In an electric power plant, water may be used for boiler feed and make-up water, slurry transport of solid fuels, chemical processing, cooling spent steam in a condenser, lubricant cooling, emergency cooling, chemical injection in a wet flue gas scrubber, dust control, waste removal, fire protection, sanitation and cleaning, drinking and cooking, and construction. Some of these uses result in water being consumed. Other uses are followed by return of the water to the source.

Water, Withdrawal
Water withdrawal typically refers to all the water that is removed from a source and used for power plant needs. The source may be a river, stream, lake, dam impoundment, aquifer, or other underground deposit. It is occasionally termed *water throughput*. This term includes water that may be returned to the source. All withdrawn water may not be actually consumed in the power plant.

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APPENDIX B

SUMMARY COST COMPARISON FOR VARIOUS GENERATION TECHNOLOGIES

The table below gives an idea of the relative cost numbers used by the Energy Information Administration (EIA), a government agency that predicts economic trends for the coming years. This is the set of assumptions from which the EIA's Annual Energy Outlook 2006 was made. The costs shown here are overnight costs, which are the initial building blocks for estimating, but are not the same as, capital costs. See Appendix A for a glossary of terms including overnight costs and capital costs.

FIGURE B.1
COST AND PERFORMANCE CHARACTERISTICS OF VARIOUS GENERATION TECHNOLOGIES[120]

Technology	Online Year[1]	Size (mW)	Leadtimes (Years)	Base Overnight Costs in 2005 ($2004/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost in 2005[3] (2004 $/kW)	Variable O&M[5] ($2004 mills/kWh)	Fixed O&M[5] ($2004/kW)	Heatrate in 2005 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New[7]	2009	600	4	1,167	1.07	1.00	1,249	4.18	25.07	8,844	8,600
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2009	550	4	1,349	1.07	1.00	1,443	2.65	35.21	8,309	7,200
IGCC with Carbon Sequestration	2010	380	4	1,873	1.07	1.03	2,065	4.04	41.44	9,713	7,920
Conv Gas/Oil Comb Cycle	2008	250	3	556	1.05	1.00	584	1.88	11.37	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2008	400	3	532	1.08	1.00	575	1.82	10.65	6,752	6,333
ADV CC with Carbon Sequestration	2010	400	3	1,021	1.08	1.04	1,147	2.68	18.12	8,613	7,493
Conv Combustion Turbine[5]	2007	160	2	388	1.05	1.00	407	3.25	11.03	10,842	10,450
Adv Combustion Turbine	2007	230	2	367	1.05	1.00	385	2.89	9.59	9,227	8,550
Fuel Cells	2008	10	3	3,787	1.05	1.10	4,374	43.64	5.15	7,930	6,960
Advanced Nuclear	2013	1000	6	1,744	1.10	1.05	2,014	0.45	61.82	10,400	10,400
Distributed Generation -Base	2008	2	3	791	1.05	1.00	831	6.49	14.60	9,650	8,900
Distributed Generation -Peak	2007	1	2	951	1.05	1.00	998	6.49	14.60	10,823	9,880
Biomass	2009	80	4	1,659	1.07	1.02	1,809	3.13	48.56	8,911	8,911
MSW - Landfill Gas	2008	30	3	1,443	1.07	1.00	1,544	0.01	104.03	13,648	13,648
Geothermal[6,7]	2009	50	4	2,100	1.05	1.00	2,205	0.00	75.00	32,173	35,460
Conventional Hydropower[6]	2009	500	4	1,320	1.10	1.00	1,452	3.20	12.72	10,338	10,338
Wind	2008	50	3	1,091	1.07	1.00	1,167	0.00	27.59	10,280	10,280
Solar Thermal[7]	2008	100	3	2,589	1.07	1.10	3,047	0.00	51.70	10,280	10,280
Photovoltaic[7]	2007	5	2	3,981	1.05	1.10	4,598	0.00	10.64	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2005.

[2]The technological optimism factor is applied to the first four units of a new, unproven design, or regulatory structure. It reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[3]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2005.

[4]O&M = Operations and maintenance.

[5]Combustion turbine units can be built by the model prior to 2007 if necessary to meet a given region's reserve margin.

[6]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[7]Capital costs are shown before investment tax credits are applied.

[120] U.S. DOE, Energy Information Administration (EIA). Costs shown likely do not include the recent rapid escalation in capital costs due to market supply/demand forces as discussed in Chapter 7.

APPENDIX C

FIGURE C.1: COST COMPARISION OF VARIOUS GENERATION TECHNOLOGIES, September 2005[121]

Alternative	Installed Capacity (MW)	Fuel	Capital Cost ($/kW) (2011 COD)	Fixed O&M ($/kW-yr) (2005$)	Var O&M ($/MWh) (2005$)	Capacity Factor (%)	Fuel Cost ($/Mbtu) (in 2011)	Heat Rate (Btu/kWh)	Prod Tax Credit?	Levelized Busbar Cost ($/MWh, 2011 COD)	
										IOU	Public Power
Sub-critical PC	600	PRB	1,765	10.62	2.24	88	1.21	9,560		**58.41**	**47.21**
SCPC	600	PRB	1,800	10.62	2.23	88	1.21	9,369		**58.81**	**47.37**
NGCC	600	Nat gas	601	4.72	3.20	88	7	7,400		**77.94**	**75.51**
IGCC	535	IL Bitum	2126	24.38	5.91	88	2.47	9,612		**83.84**	**71.05**
Wind											
w/o backup	600	NA				40	NA	NA	No	**50**	**50**
Wind/Gas combo	1200	Nat gas				88	7	7,400	No	**72.89**	**65.12**
Wind/Gas combo	1200	Nat gas				88	7	7,400	Yes	**67.43**	**65.12**

FIGURE C.2: COST COMPARISION OF VARIOUS GENERATION TECHNOLOGIES, October 2006[122]

Alternative	Installed Capacity (MW)	Fuel	Capital Cost ($/kW) (2012 COD)	Fixed O&M ($/kW-yr) (2005$)	Var O&M ($/MWh) (2005$)	Capacity Factor (%)	Fuel Cost ($/Mbtu) (in 2010)	Heat Rate (Btu/kWh)	Prod Tax Credit?	Levelized Busbar Cost ($/MWh, 2012 COD)	
										IOU	Public Power
Sub-critical PC	600	PRB									
SCPC	630	PRB	2,168	10.62	2.23	88	1.71	9,095	NA	**69.62**	**56.38**
NGCC	500	Nat gas									
IGCC	535	IL Bitum	2,600								
Wind											
w/o backup	600	NA				40	NA	NA	No	**60**	**60**
Wind/Gas combo	1200	Nat gas				88	7.60*	6,704	No	**80.78**	**77.77**
Wind/Gas combo	1200	Nat gas									

- Cost shown is in 2011. Other costs in this column are in 2010.

121 ***Baseload Generation Alternatives*, Burns and McDonnell, September 2005**.

122 ***Baseload Generation Alternatives*, Burns and McDonnell, Revised October 2006. This table includes recent market escalation.**

APPENDIX D

SOUTH DAKOTA PERMITTING PROCESS FLOW CHARTS[123]

The charts provided in this Appendix D are a general description of South Dakota State permits required for construction and operation of power facilities of each of the technologies addressed in this report. This is not an exhaustive list. Consult with the Department of Environment and Natural Resources for the most current information and details for specific applications - http://www.state.sd.us/denr/ENVIRO/. Figure D.1 supplies an overview summary of what permits would be required for each specific generation technology. Figures D.2 through D.7 show the process and timetable for how the various licensing processes progress.

FIGURE D.1
SUMMARY OF REQUIRED SOUTH DAKOTA PERMITS BY TECHNOLOGY TYPE

	Air Quality Operating Permit	**Groundwater Discharge Permit**	**NPDES Discharge Permit**	**Oil and Gas Permit**	**Solid Waste Permit**	**Water Rights Permit**
Process Diagram	Figure D.2	Figure D.3	Figure D.4	Figure D.5	Figure D.6	Figure D.7
PC	X	X	X		X	X
IGCC	X	X	X	X	X	X
Nuclear Power		X	X			X
Wind Power[124]			X			

[123] South Dakota Department of Environment and Natural Resources, http://www.state.sd.us/denr/ENVIRO/
[124] NPDES permit shown based on Navitas project permitting. Wind projects may entail additional permits to the extent gas- or oil-fired peaking facilities are necessary to provide reliable capacity.

FIGURE D.2
AIR QUALITY MAJOR SOURCE PERMIT PROCESS

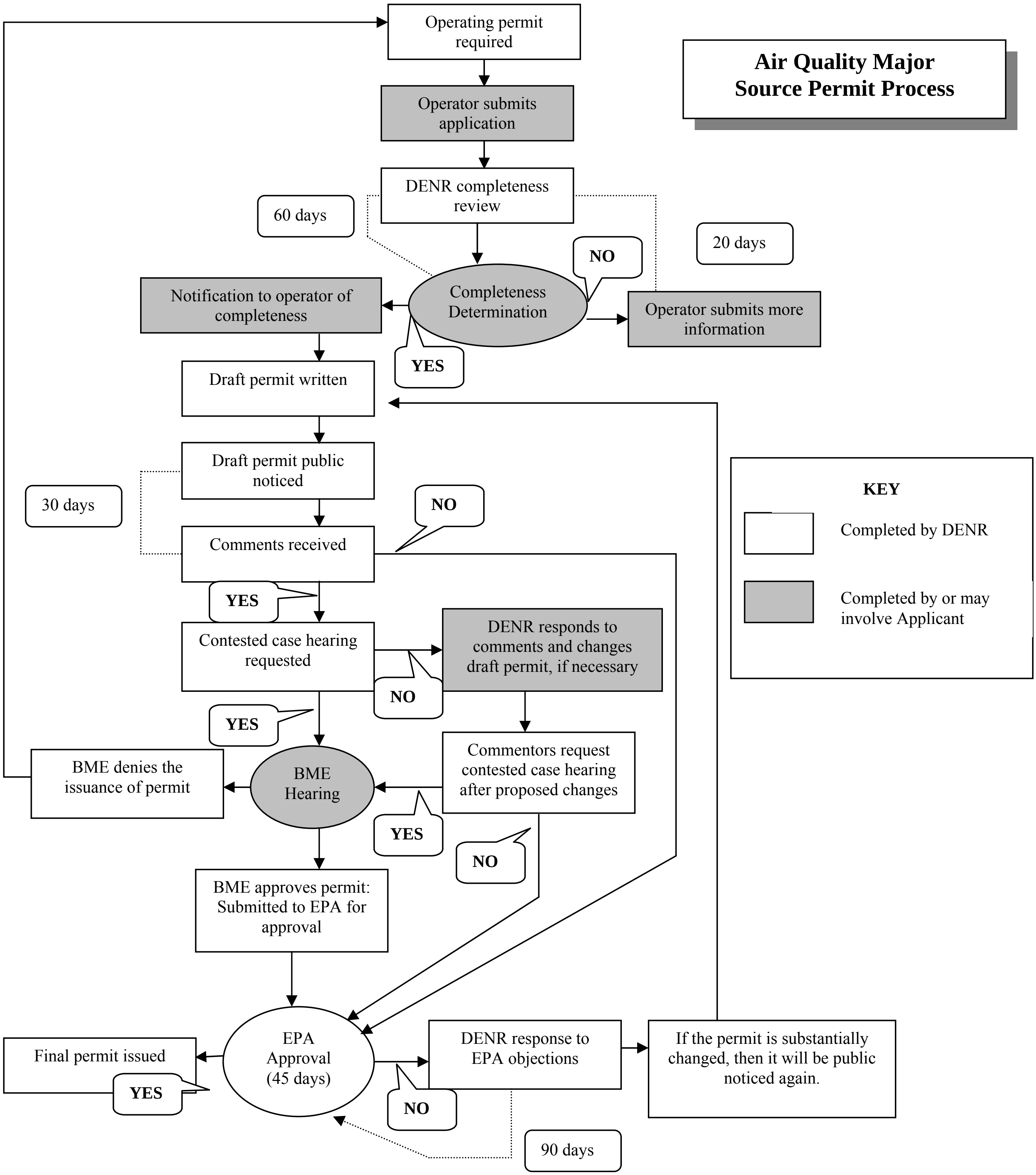


FIGURE D.3
GROUND WATER DISCHARGE PERMIT PROCESS

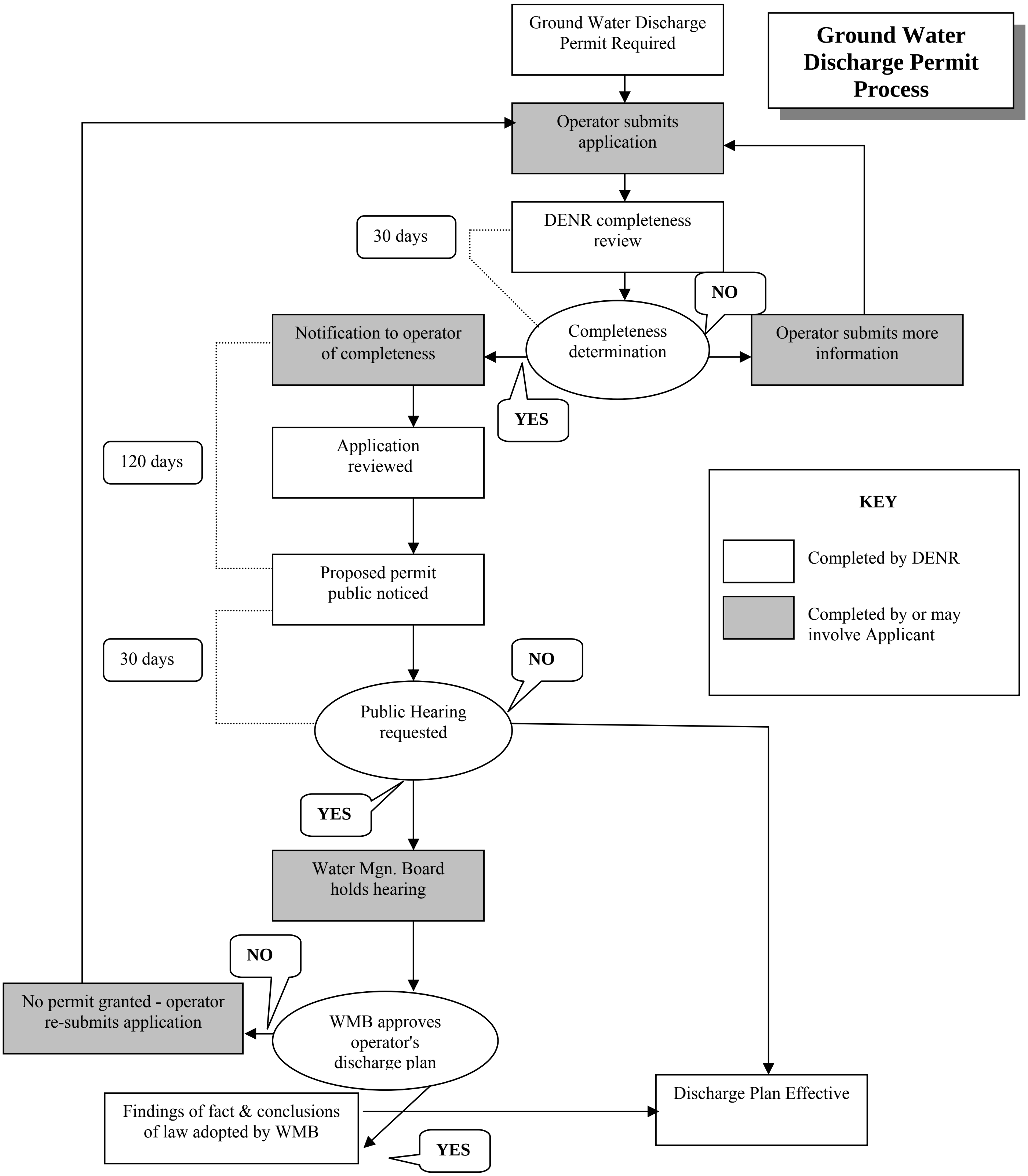


FIGURE D.4
SURFACE WATER QUALITY PERMIT PROCESS

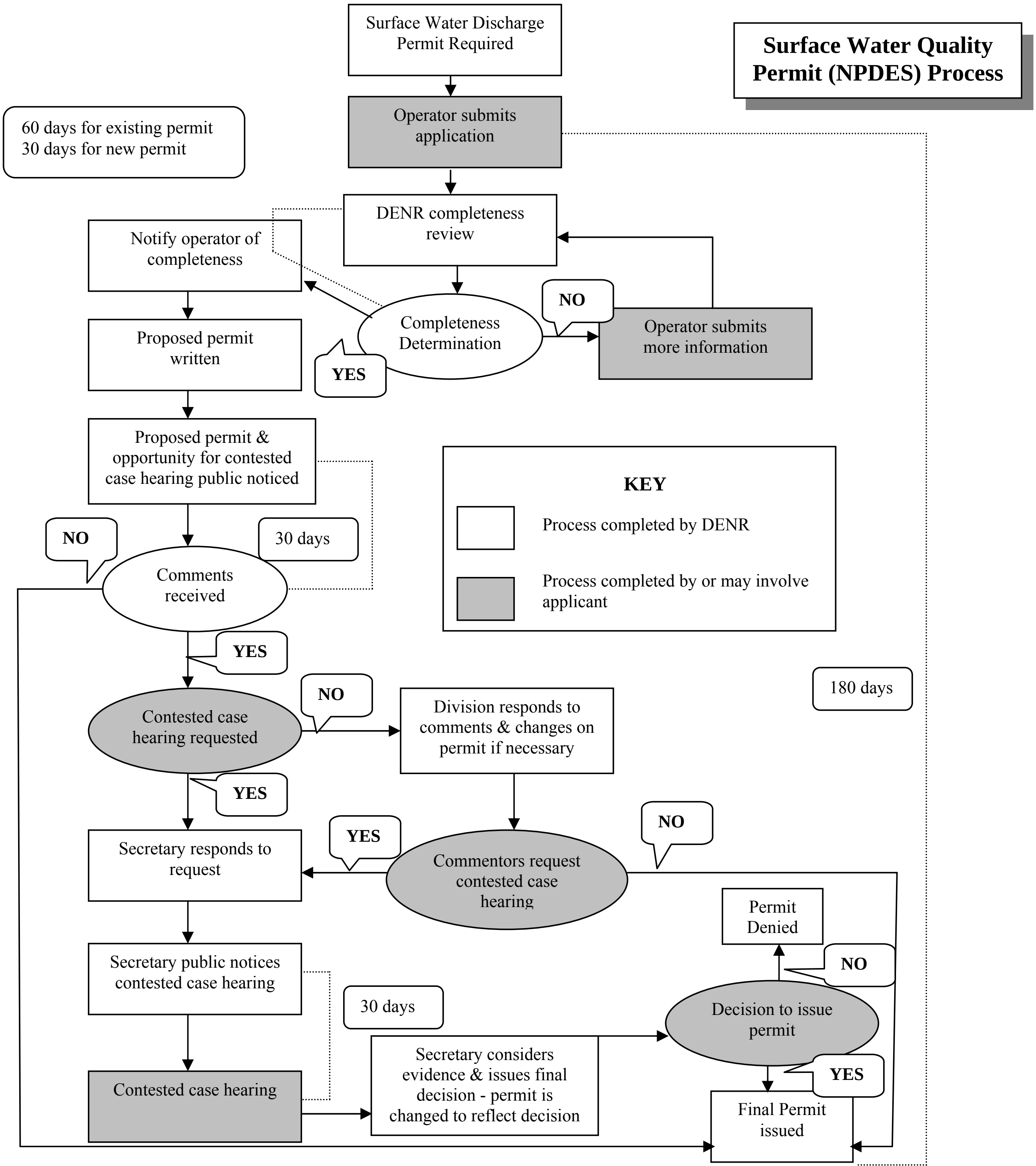


FIGURE D.5
OIL AND GAS PERMIT PROCESS

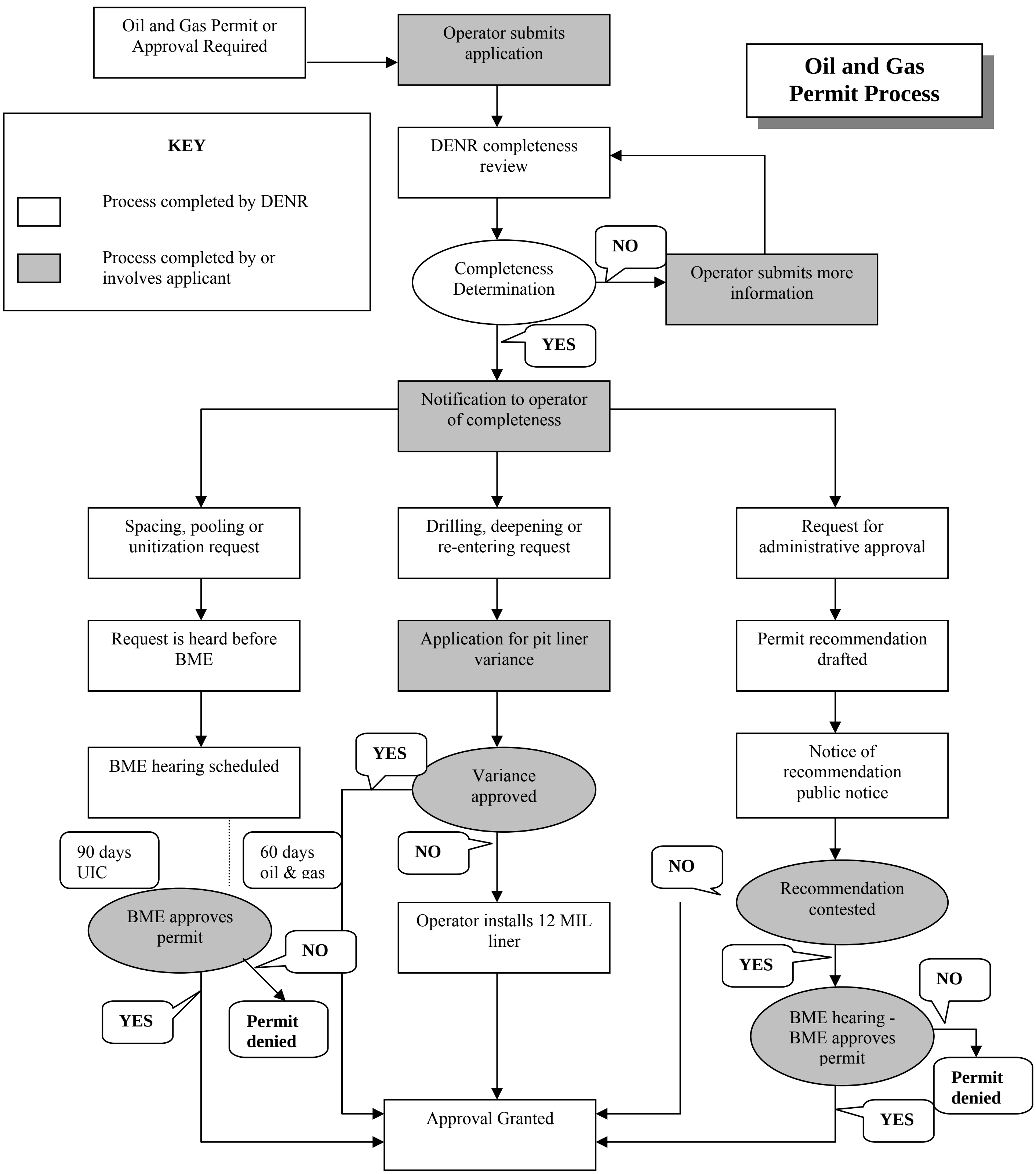


FIGURE D.6
SOLID WASTE PERMIT PROCESS

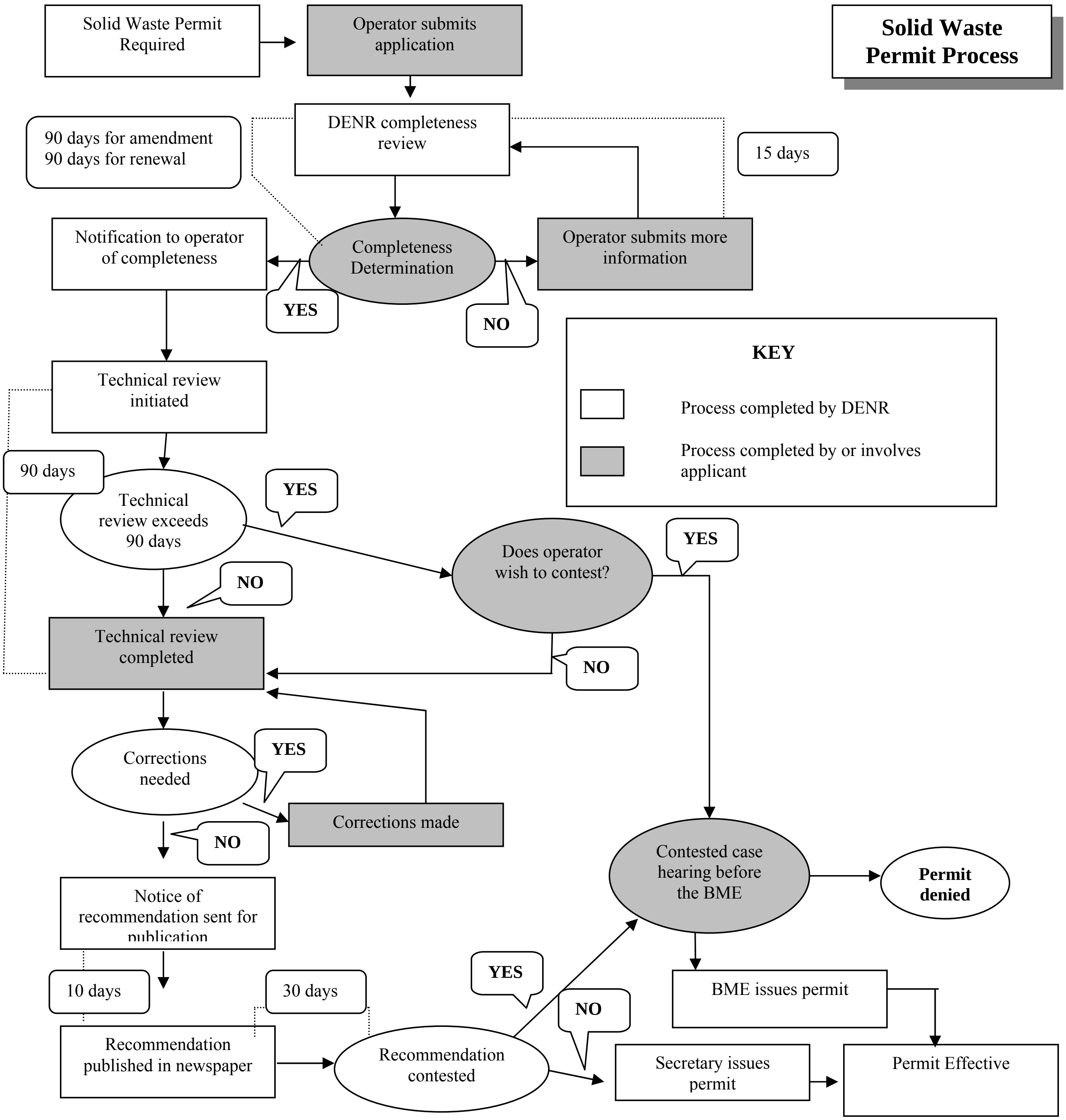
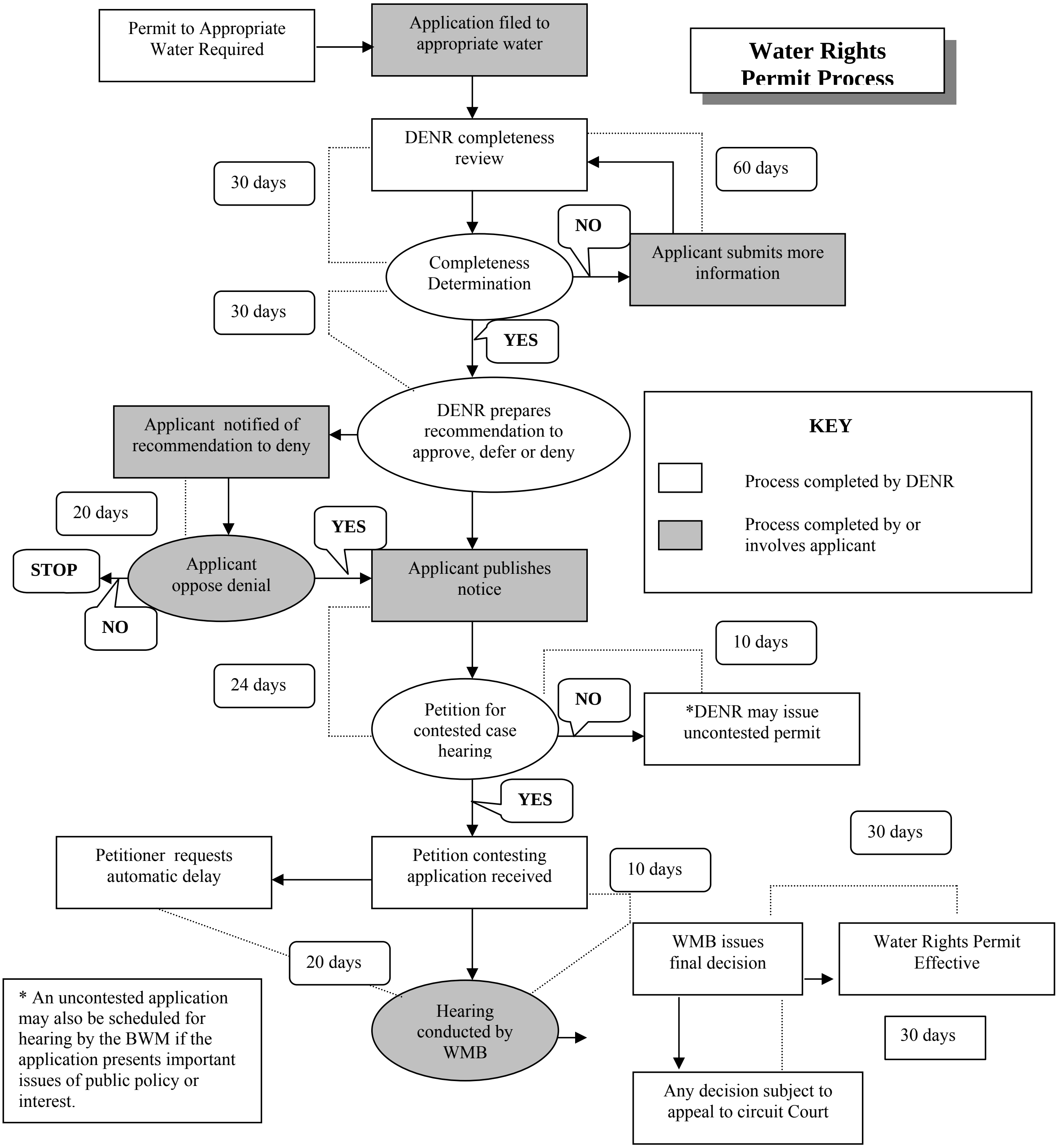


FIGURE D.7
WATER RIGHTS PERMIT PROCESS



Appendix E

GENERIC DEVELOPMENT STEPS FOR A WIND ENERGY PROJECT[125]

125 United States Government Accountability Office, "Wind Power's Contribution to Electric Power Generation and Impact on Farms and Rural Communities" September, 2004.

APPENDIX F

SCHULTE ASSOCIATES LLC CONTACT INFORMATION

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Schulte Associates is an executive management consulting firm with a specialty practice in energy-related industries.

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