6

Feasibility Study for Conversion of Prairie Island to Natural Gas Fired Generation

UTILITY ENGINEERING

November 20, 2002

EXHIBIT
Public
57

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Gregory Scott	Chair
Edward A. Garvey	Commissioner
Marshall Johnson	Commissioner
LeRoy Koppendrayer	Commissioner
Phyllis A. Reha	Commissioner

CURE attachment

In the Matter of a Petition of Northern States Power Company dba Xcel Energy for Review of the Prairie Island Contingent Request for Proposals

ISSUE DATE: February 13, 2002 5/26/09

DOCKET NO. E-002/M-01-1480

In the Matter of Northern States Power Company's Application for Approval of its 2000-2014 Resource Plan

DOCKET NO. E-002/RP-00-787

ORDER DIRECTING ANALYSIS OF NATURAL GAS CONVERSION OF PRAIRIE ISLAND UNIT 1 AND REQUIRING CONSULTATION

PROCEDURAL HISTORY

On August 29, 2001, the Commission issued its ORDER APPROVING XCEL ENERGY'S 2000-2014 RESOURCE PLAN, AS MODIFIED in this matter. In its Order, the Commission accepted an agreement proposed by several parties, including Xcel, under Xcel would provide a status report on the issue of the fairness of its bidding process to renewable resource generation by July 15 and propose a Request for Proposals (RFP) to the Commission by September 30. In Order Paragraph 9, the Commission directed Xcel to abide by its agreement to propose an RFP by September 30, 2001.

On September 28, 2001, Xcel submitted a letter to the Commission. In its letter, Xcel stated that it would submit an RFP for the Prairie Island contingency bid for regulatory review on October 1 but requested an additional 30 days to submit its all-source bidding RFP.

On October 1, 2001, Xcel filed an RFP for the Prairie Island contingency bid and filed a 2001 All-Source RFP on November 8, 2001.[1] This Order focuses on the Prairie Island contingency bid RFP filed October 1, 2001.

[1] Issues raised by the Minnesota Department of Commerce (the Department) regarding Xcel's failure to file its All-Source bid by October 1, 2002 and failure to make a timely request for permission to file it at a later date were addressed in a previous Order in this matter: ORDER DENYING REQUEST FOR ORDER TO SHOW CAUSE AND REQUIRING REPORT, INFORMATION, AND CONSULTATION, Docket No. E-002/M-00-622 (February 11, 2002).

57-1

During the 30-day review and comment period for the Prairie Island contingency bid RFP,[2] no party filed objections to the RFP or requested an investigation. The Department and the Company identified modifications to the RFP, however, and Xcel filed a finalized RFP on November 8, 2001.

On December 3, 2001, Xcel conducted the pre-bid conference at its offices in Minneapolis.

On January 4, 2002, the Izaak Walton League of America (IWLA), Citizens United for Renewable Energy (C.U.R.E.), and Minnesotans for an Energy Efficient Economy (ME3) filed a letter noting that the Company's RFP does not mention the option of converting Unit 1 of the Prairie Island facility to natural gas. These parties requested that the Commission order the Company to notify potential bidders of its desire to consider bids for natural gas conversion of Unit 1 in this RFP.

The Commission met to consider this matter on January 31, 2002.

FINDINGS AND CONCLUSIONS

Two unfortunate things have occurred. First, in its Prairie Island contingency bid RFP (invitation to submit bid to replace the energy currently provided by its Prairie Island nuclear plant), Xcel did not explicitly open the door to proposals to convert Unit 1 into a gas-fueled generator. The possibility of gas conversion is a logical option for consideration. Second, no party objected to this omission and the bid process has moved ahead.

At this point, the Commission will not interrupt the bid process or require the Company to notify potential bidders of its desire to consider bids for natural gas conversion of Unit 1, as requested by IWLA, C.U.R.E., and ME3. At this stage of the process, this would pose an unwarranted risk of sending an unsettling signal to the potential bidders.

In order to have adequate information in the record to thoroughly examine the options, however, the Commission will secure a detailed analysis of converting Prairie Island Unit 1 to natural gas-

---

[2] Step 2 of Xcel's Commission-approved bid process is as follows: NSP will file a proposed Request for Proposals (RFP) with the Commission and serve it on the Parties. Absent a request for investigation by any party, NSP may issue the request for proposals (RFP) to potential bidders 30 days after the filing without Commission approval. See *In the Matter of the Petition of Northern States Power Company for Review of its 1999 All Source Bid Request Proposals*, E-002/M-99-888, ORDER GRANTING INTERVENTION (September 29, 2000), pages 1-2 and ORDER REJECTING REQUESTS FOR FURTHER INVESTIGATION, APPROVING FINAL BID SELECTIONS, AND OPENING DOCKET REGARDING EXTERNALITY VALUES (February 7, 2001), pages 1-2.

filed generation. Having a reasonable estimate of the costs and benefits of conversion will allow the Commission to compare them with the costs and benefits of bids received through the contingent bid process.

Two practical questions arise:

> 1) who should perform the conversion analysis/report: the Company or an independent entity retained by the Company and
>
> 2) when should the report be submitted to the Commission: at the time Xcel files its short list of bidders, about July, 1, 2002, or when it files its next resource plan, December 1, 2002?

On the timing question, the Commission's concern is not to receive the conversion information so late in the bid process that conversion would be precluded as practical matter. All parties assure the Commission, however, that submission on the later date would not preclude the conversion option. Since a later submission date may yield a more thorough analysis, the Commission will designate the later date, December 1, 2002.

As to who should perform the analysis, the Commission's initial inclination for an independent evaluator was based in its concern that the integrity of an analysis conducted by Xcel would certainly be subject to question. IWLA, C.U.R.E., and ME3, however, expressed their confidence in or acceptance of the Company doing the study, noting that the study will have to stand on its own merits in any event and that any independent evaluator would be selected by the Company and would need to rely substantially on the Company's information in making its analysis, diminishing the value to be gained from requiring an independent contractor.

Finally, IWLA, C.U.R.E., and ME3 requested and the Company agreed that the parties should meet to discuss scoping issues, i.e. what the conversion analysis/report should contain. The three parties stated, for example, that the generation costs should be segregated from the plant decommissioning costs. The Commission agrees that this kind of discussion is a good idea and will so order. The parties may find it beneficial to include the Department in these discussions.

ORDER

1. Xcel shall perform and submit a detailed analysis (report) of converting Prairie Island Unit 1 to natural gas-fired generation.

2. The Company shall meet with the parties (IWLA, C.U.R.E., and ME3) to discuss the scope of its conversion analysis (report).

3. The Company shall file its report (conversion analysis) by December 1, 2002, the date set for filing its next resource plan,

4. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

(S E A L)

This document can be made available in alternative formats (i.e., large print or audio tape) by calling (651) 297-4596 (voice), (651) 297-1200 (TTY), or 1-800-627-3529 (TTY relay service).

THE IZAAK WALTON LEAGUE OF AMERICA

CURE attachment

January 3, 2002

5/26/09

Dr. Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 7th Place East
St. Paul, MN 55101-2147

Re: Northern States Power Company 2001 Prairie Island Contingency Request for Supply Proposals for Contingencies in 2007 and 2008

Docket #: E-002/RP-00-787

Dear Dr. Haar:

You may recall the discussion of contingency bids for replacement power for Prairie Island at the final hearing on Xcel Energy's (Xcel or Company) 2000-2014 Integrated Resource Plan. During this discussion, in conjunction with Xcel's proposal to replace the steam generator in Unit 1 in 2004, Chair Scott raised the question of including a bid for conversion of Unit 1 to natural gas as part of the bidding process. The question was addressed to Mr. Alders who replied that Xcel could not bid on its own plant, so an independent bid would have to be submitted. He indicated that a transfer of assets would have to take place if the bid were pursued. Howerver, he did not indicate any major problem with the option at the bidding level. We note that gas conversion of Unit 1 was not mentioned in the Company's recently released 2001 Prairie Island Contingency Request For Proposals. We wish to bring the timeliness of exploring this option to your attention for the following two reasons:

1) Unit 1 will fall below acceptable capacity, according to Xcel, in the 2004 timeframe. The Company's proposal is to replace the steam generator at that time. Several parties have raised concerns about the timeliness of such an investment, due to lack of resolution of waste storage and other factors. The Commission chose not to approve steam generator replacement in the 2000-2014 IRP.

2) Conversion of Unit 1 could impact the costs and risks of decommissioning in 2007, precluding appropriate resolution of waste storage issues.

The Company has acknowledged that the location of the Prairie Island plant is important electrically to Xcel's system. In statements made to CURE by Goodhue County officials, the Company has been clear with the County that the plant is too valuable to close and that Xcel would likely convert the plant to another fuel source rather than close it.

NATIONAL OFFICE
707 Conservation Lane
Gaithersburg, Maryland 20878-2983
Phone: (301) 548-0150
Fax: (301) 548-0146
E-mail: general@iwla.org

THE IZAAK WALTON LEAGUE OF AMERICA
www.iwla.org

MIDWEST OFFICE
1619 Dayton Avenue, Suite 202
St. Paul, Minnesota 55104-6206
Phone: (651) 649-1446
Fax: (651) 649-1494
E-mail: midwestoffice@iwla.org

57-2

CURE submitted an information request to Xcel during the IRP process regarding this conversion plan, and asked also for a list of nuclear facilities that have been converted to natural gas. Xcel's response to this information request was delayed until the day after final comments were due, several months later. CURE submitted the conversion section of the Appel report to the Electric Energy Task Force (@1997) in lieu of having information from Xcel. This section by Ron Sundberg, a local engineer specializing in conversion technologies, confirmed that it is technically possible to convert the 500 MW Unit 1 to a double turbine steam generator powered by natural gas, and gain efficiency and output to make up most of the 1000 MW's of both units. In addition, the conversion could feasibly utilize, in part, the existing equipment and might include a district heating benefit to local communities.

The Prairie Island Indian Community and Department both raised concerns about moving forward with steam generator replacement for Unit 1 in 2004. We further note that investigation of any alternative configuration of generation at that site would help the Company and the Commission to evaluate options for the future. For these reason we recommend that the Company be required to notify potential bidders of its desire to consider bids for natural gas conversion of Unit 1 in the instant RFP.

Respectfully yours,

William Grant Director Izaak Walton League of America Midwest Office	Kristin Eide-Tollefson C.U.R.E.	Michael Noble Executive Director Minnesotans for an Energy Efficient Economy

CURE #4

☐ **Non Public Document – Contains Trade Secret (or Privileged) Data**
☐ **Public Document – Trade Secret Data Has Been Excised**
☒ **Public Document**

Northern States Power Company
Docket No. E002/RP-00-787
Response To Communities United for Resp. Energy Information Request No. 7
Date Received: November 15, 2000

Question:

In 1994 there was mention, by NSP, during the legislative session that a conversion plan for Prairie Island existed. No documentation was produced. NSP has told city/county officials in Red Wind/Goodhue County at several junctures over the last 8 years that Prairie Island was too valuable to close and that they would convert rather than close the facility should the necessity arise. CURE has indicated its interest in conversion technologies in several venues over the last 5 years. We are particularly interested in responses to the following questions:

1) Please identify (not produce)
   a) The conversion plan which would have been the referent in the 1994 session;

   b) Any requirements for contingency conversion plans for Prairie Island from any permitting or funding agent.

2) Please provide copy of the conversion section of the Appel report to the Electric Energy Task Force and identify additional research or application in addition to the information provided in that report known to NSP on the conversion potential of nuclear plants.

3) Please provide a list of nuclear plants that have been converted to other forms of generation for the following categories:
   a) Plants converted which were never operational (as nuclear plants);

   b) Plants converted which were partially operational;

   c) Plants converted which had been fully operational.

4) Please explain what conversion NSP may have been referring to in its discussion with Red Wing / Goodhue Co. (testimony provided upon request).

Response:

1) I have not been successful in finding any conversion plan that might have been referred to in 1994. NSP did prepare a technology screening study in 1996 that was shared with the Legislative Electric Energy Task Force consultants. The screening study was a high level examination of technology approaches that might be used to repowering the Prairie Island site using natural gas. The results of the study are fairly summarized in the Appel report (Study B, Section B8) We are aware of no requirements for contingency conversion plans for Prairie Island from any permitting or funding agent.

2) Section B8 of the Appel report is enclosed.

51-3

3) a) We are aware of two plants that fall in this category, Zimmer in Ohio, Midland in Michigan.

b) None to our knowledge.

c) Pathfinder(South Dakota-oil); Elk River(Minnesota-coal); Fort St Vrain (Colorado-natural gas combined cycle) Zion (Illinois, transmission support via electric motor drives for the existing generators)

4) We do not know what was being referred to in Red Wing and Goodhue County. If the exchange you are referring to occurred after the 1996 screening work and Appel Report, that work may have been the study work being referred to.

Response By:	James Alders
Title:	Manager Regulatory Adm
Department:	Regulatory Services
Telephone:	612 330 6732
Date:	March 8, 2001

CURE #4

B8

CONVERSION OF NUCLEAR AND COAL PLANTS TO LESS ENVIRONMENTALLY DAMAGING ENERGY SOURCES

Is it feasible to convert existing nuclear power and coal-fired electric generating plants to utilization of energy sources that result in significantly less environmental damage; if so, what are the short-term and long-term costs and benefits of doing so; how do shorter or longer time periods for conversion affect the cost/benefit analysis?

Summary

Existing coal-fired or nuclear electric generating plants can be adapted to use less environmentally damaging energy sources. Common approaches include replacing the fossil or nuclear fueled steam source with a natural gas fired steam generator, or using the waste heat from a gas turbine generator to generate steam that can be used to power the existing turbine generator. Typically, an attempt is made to use the steam turbine/generator and as much of the existing plant as practical.

In some cases it is practical to convert existing coal-fired generating plants to burn biomass. Some of the benefits of biomass fuel can be gained by cofiring or blending another fuel with the coal. In some situations, it is practical to produce a gaseous fuel that can be burned in an existing boiler, from biomass by using a thermal gasification process.

Biomass fuels are often not competitive with fossil fuels in traditional generation plants. When biomass fuel is derived from either waste or a byproduct there is concern about long-term fuel supply and price instability. Several technologies have been developed that would provide a dependable and consistent source of fuel and thus, over the long term, reduce the cost of electricity produced from biomass fuels. NSP is presently considering proposals from developers of biomass technologies for electric generation, including Whole Tree Energy™ and gasification combined cycle (see Section B1).

A preliminary design for repowering a coal-fired unit at TVA's Watts Bar plant with the Whole Tree Energy™ technology was conducted in 1992. The estimated capital cost for repowering one

57-4

CURE- Communities United for Responsible Energy
P.O. Box 130 Frontenac, MN 55026

Utility Information Request
No. 7
Requested from: Jim Alders

Date of Request: 11/13/00
Due: 11/23
Subject:
Conversion of nuclear facilities

In 1994 there was mention, by NSP, during the legislative session that a conversion plan for Prairie Island existed. No documentation was produced. NSP has told city/county officials in Red Wing/ Goodhue County at several junctures over the last 8 years that Prairie Island was too valuable to close and that they would convert rather than close the facililty should the necessity arise. CURE has indicated its interest in conversion technologies in several venues over the last 5 years. We are particularly interested in responses to the following questions:

1) Please identify (not produce):
   a) The conversion plan which would have been the referent in the 1994 session;
   b) Any requirements for contingency conversion plans for Prairie Island from any permitting or funding agent.

2) Please provide copy of the conversion section of the Appel report to the Electric Energy Task Force and identify additional research or application in addition to the information provided in that report known to NSP on the conversion potential of nuclear plants.

3) Please provide a list of nuclear plants that have been converted to other forms of generation for the following catagories:
   1) Plants converted which were never operational (as nuclear plants);
   2) Plants converted which were partially operational;
   3) Plants converted which had been fully operational.

4) Please explain what conversion NSP may have been referring to in its discussion with Red Wing/Goodhue Co. (testimony provided upon request).

60 MW unit was \$410/kW in 1991 dollars, or about \$475/kW in 1996 dollars. The estimated cost of electricity from the repowered plant was about 3.5¢/kWh in 1996 dollars.

Repowering

The term "repowering" is usually used to describe the conversion of an existing plant to a new energy source. Technical approaches that could be used to repower electric generating plants in Minnesota are presented in this section. Capital cost estimates and the cost of electricity from the repowered plant are also discussed. It must be emphasized that any costs presented can be used only as a guide. Reliable cost information can obtained only from plant-specific analysis and preliminary design.

Repowering With Natural Gas

In the simplest situation, a coal-fired boiler can be adapted to burn natural gas. The modification would involve securing a source of natural gas, and installing gas burners within the existing coal-fired boiler. In many cases, it may be necessary to site a new natural gas pipeline specifically for the repowered plant. While this conversion is relatively simple, it is likely that the plant would be derated (perhaps by as much as 10%) since the boiler heat exchanger would not have been designed for the burning characteristics of natural gas. The fuel and ash handling operations in the plant would be simplified, but the plant would now be operating on a more expensive fuel, since the cost of natural gas, on a Btu basis, can be expected to be 2 to 2.5 times the cost of coal.

In the case of a nuclear plant, the nuclear reactor system could be replaced by new natural gas-fired steam generation equipment.

Natural gas has wide availability, but this must be evaluated in terms of the plant location. It will generally be delivered by pipeline. However, the pipeline must be evaluated in terms of its ability to meet the needs of the repowered plant in addition to those of the current consumers. This may require consideration of a new pipeline dedicated to the repowering.

Combustion Turbine Combined Cycles

The efficiency of generating electricity can be improved considerably by including a gas-fired combustion turbine in an existing plant cycle. The combustion turbine is one of the more flexible components in a generation system. When the combustion turbine is integrated with another generation system such as a steam turbine, it is referred to as a combined cycle. In this case, waste heat from the combustion turbine is used to drive a steam turbine generator and thus increase the efficiency of the overall system. The overall efficiency of combined cycle plants is now approaching 60% – almost twice the efficiency of a coal- or biomass-fired plant.

The combustion turbine is very similar to an aircraft jet engine with the addition of a power turbine with a shaft to power an electric generator. Many of the combustion turbines used in industry today are jet engine designs that have been adapted for land-based power generation.

The thermal efficiency of a gas turbine engine is no greater than the efficiency of a coal-fired steam cycle power plant. However, almost all of the energy that is not converted into shaft power is rejected as heat in the turbine's exhaust gases. The exhaust gas from the turbine is relatively clean, high in oxygen and at a temperature of around 1,000°F. The heat in the combustion turbine exhaust can be recovered to produce steam by using a heat recovery steam generator (HRSG). In a combined cycle, the steam from the HRSG is used to power a steam turbine generator. Additional natural gas can be burned in the turbine exhaust to provide higher temperature and pressure conditions for the steam turbine. This is termed "supplemental firing".

When an existing plant is repowered using the combined cycle, the steam from the HRSG is used to drive the existing steam turbine. Since this approach makes use of heat that might otherwise be wasted, the thermal efficiency is higher than for a standard steam cycle plant. The electric generating capacity of the repowered plant will be greater than the original plant when the gas turbine generator is included. An important consideration in this repowering scheme is matching the design steam conditions of the existing turbine.

The capital cost of a combined cycle generating plant is on the order of $600/kW of installed generating capacity. If significant portions of an existing plant can be utilized in a repowering this cost can be significantly reduced. The cost of electricity produced from a combined cycle plant depends on the cost of natural gas that has been allocated to the plant. A Minnesota combined cycle plant could produce electricity in the 3¢/kWh range.

Biomass and Biomass Cofiring

In some cases it is practical to convert existing coal-fired generating plants to burn biomass. Some of the benefits of biomass fuel can be gained by cofiring or blending another fuel with the coal. In some situations, it is practical to produce a gaseous fuel that can be burned in an existing boiler, from biomass by using a thermal gasification process.

Characteristics of Biomass Fuel

Fuel derived from biomass is a potentially renewable resource with fewer environmental impacts than fossil fuels. Biomass contains negligible amounts of sulfur and nitrogen and hence will not contribute significantly to acid rain. Burning biomass fuels produced in a renewable closed-loop cycle can be considered to have no net carbon emissions.

The ash that results from burning biomass such as wood is much easier to dispose of than the ash from coal. The alkaline character of the ash makes it attractive as a soil conditioner and it can often be beneficially spread on crop land.

Electricity produced from biomass is often more expensive than that produced from conventional fuels. Typically, biomass and waste fuels contain less energy per unit mass and have higher transportation costs than conventional fuels. The chemical and physical properties of many biomass fuels also reduce combustion efficiency compared to coal or natural gas. Without processing, the properties of biomass fuel are not as uniform as those of other commercial fuels.

Using Biomass Fuel Directly

Older plants that have stoker-fed boilers can often burn wood chips or other processed biomass fuel without extensive modification. However, this is at the expense of a significant derating of the power plant capacity. The derating results from the lower heating value and high moisture content of the biomass and might be as much as 30%. Older, smaller coal-fired plants are the best candidates for repowering with biomass. NSP and Minnesota Power have successfully repowered several such plants with biomass and waste fuels. The capacity of these plants is typically less than 50 MW and the fuel needs match the biomass/waste fuel resource available. If the plant is near the end of its useful life a relatively small additional investment will provide new capacity.

The repowering of an older coal-fired plant is complicated by Federal Clean Air Act (CAA) emission regulations. Because most of the coal-fired boilers in Minnesota were commissioned before the CAA, they are not required to meet the more stringent Federal New Source Performance Standards or the requirements of the Federal New Source Review and are subject only to the state requirements. If the plant is modified to burn another fuel, such as biomass, the emission control equipment must be upgraded to meet the federal requirements. Generally, if an older plant is modified to burn biomass, it must meet all of the federal standards, as well as the New Source Review. There are, however some exceptions, including modifying a plant to burn certain waste fuels such as refuse derived fuel (RDF).

Cofiring

Often it is practical to blend a biomass fuel with coal in an existing utility boiler. This is termed cofiring, and the biomass blended might represent around 5% to 15% of the heating value of the fuel. Cofiring is a well-established technology, and electric utilities and industry have retrofitted coal-fired boilers to cofire biomass or waste fuels such as wood wastes, tire-derived fuel (TDF) and refuse-derived fuel (RDF). Minnesota Pollution Control Regulations allow the cofiring of as much as 30% by weight of municipal solid waste or refuse-derived fuel. Also, there are no limit restrictions on cofiring with biomass such as wood, as long as significant plant modifications are not required.

Cofiring can provide the following advantages:

- A reduction in SO_2 and NO_x emissions relative to 100% coal firing.
- A lower incremental capital cost and a higher efficiency compared to a new dedicated biomass boiler. Also, the variability in fuel composition is less of a problem since the biomass or waste fuel is only a fraction of the fuel fired.
- Waste fuels are often less expensive than coal.
- Mixing biomass ash with coal ash provides a more environmentally acceptable ash.

Possible disadvantages of cofiring relate to derating of the boiler due to the higher moisture content and reduced heating value of the fuel stream.

Gasification

Gasification can be used to produce a gaseous fuel from peat, coal, wood or other biomass. This gaseous fuel can be burned directly in an appropriate furnace, or after processing and clean-up, the gas can be used to power a combustion turbine or reciprocating engine. Thus, gasifying a biomass feedstock is a means of utilizing existing boiler equipment or using biomass to power a gas turbine or reciprocating engine. The capital cost of the gasification equipment is a significant part of the cost of repowering a coal fired plant.

The product of biomass gasification is often referred to as low Btu to medium Btu gas. It typically has a heating value on the order of 100-500 Btu/cubic foot or 10% to 50% of the heating value of natural gas. Tars/oils and corrosive constituents are also released as part of the gasification process. These may be removed by cooling, filtering and otherwise processing the gas. The cleaning of the biomass gas reduces the overall efficiency of the process. Often, the most economic approach is to burn the gas directly (dirty) in an appropriate furnace.

Repowering With Biomass Crops

Biomass fuels are often not competitive with fossil fuels in traditional generation plants. When biomass fuel is derived from either waste or a byproduct there is concern about long-term fuel supply and price instability. Several technologies have been developed that would provide a dependable and consistent source of fuel and thus, over the long term, reduce the cost of electricity produced from biomass fuels. NSP is presently considering proposals from developers of biomass technologies for electric generation, including Whole Tree Energy™ and gasification combined cycle (see Section B1).

A preliminary design for repowering a coal-fired unit at TVA's Watts Bar generating plant with the Whole Tree Energy™ technology was conducted in 1992. This plant consists of four 60 MW coal-fired generating units. All four units started operating in 1945 and the plant last produced electrical power in 1982. The preliminary design indicated that the plant could be repowered using the WTE technology for a cost of $410/kW in 1991 dollars, or about $475 in 1996 dollars, and that the resulting cost of electricity from the plant would be around 3.5¢/kWh in 1996 dollars.

Another concept that could be used to repower an existing plant utilizes a portion of an agricultural crop. In this case alfalfa is harvested and the stems are used as a fuel after the high nitrogen leaves are converted into a meal product. Thus, there are two income streams from the crop.

The portion of the crop used for fuel is converted to a low-Btu gas fuel by a gasification process. The low-Btu gas is cleaned of impurities so that it can be used as fuel for a gas combustion turbine. Heat is recovered from the combustion turbine exhaust to make steam for a condensing steam turbine generator.

The cost of a complete 75 MW electric generation facility, including the gas turbine and steam turbine, was estimated at $1643/kW in 1994 dollars. The projected cost of electricity would be 5.2¢/kWh in 1994 dollars. This would be $1743/kW and 5.5 ¢/kW in 1996 dollars.

This concept could be used to repower an existing coal-fired plant. The cost would be reduced if the steam turbine generator and plant infrastructure could be used in the repowered plant. In the most limited situation, a new fuel processing and electric generation system could be sited at the existing facility. If practical, the repowering system would be designed so that the steam from the HRSG would power the turbine generator from the existing plant. The plant size most suited to this approach would likely have an original capacity of 50 to 75 MW. A 75 MW repowered facility would likely use a 30 MW steam turbine from the existing plant, however, if the original plant size were near that of the repowered plant, it may require less overall modification. An estimate of the cost of repowering a coal fired plant with this concept was made by adjusting the cost estimate for a new plant for the equipment and infrastructure that might be reused from an existing plant. It is estimated that the cost of repowering would be around $1,200/kW in 1996 dollars for a 75 MW generating plant. It is likely that the cost of electricity produced would be somewhat less than in the case an entirely new plant.

Repowering a Nuclear Plant With Natural Gas

A nuclear power plant uses a nuclear reactor as a heat source to produce steam that is expanded through a turbine to drive an electric generator. Repowering typically could involve replacing the reactor with a fossil fuel-fired heat source to produce the steam. This steam source could be a conventional fossil-fueled boiler or the heat recovery steam generator on a gas turbine exhaust (combined cycle).

The decision to decommission an operating nuclear plant is very complex and is discussed separately at the end of this section. An important consideration is the best economic utilization of the plant assets. The lowest cost of electricity would likely result from operating the plant until shutdown is indicated by relicensing or technical requirements. There are other issues that may be important to a certificate of need or siting for a repowered plant. In the case of the Ft. St. Vrain nuclear station in Colorado, the Public Utilities Commission considered the safety of a natural gas fired plant located at a nuclear spent fuel storage site. The conclusion was that the facility was safe and should be permitted; however, this is an example of the issues that could be considered.

Repowering Schemes

A wide range of schemes have been proposed for repowering nuclear power plants. The options range from reusing none of the existing equipment and just using the site and plant infrastructure as a location for new generation, to including the steam turbine and electric generator in the repowering. The objective in repowering a plant is to use as much of the existing plant as practical. The amount of existing equipment that can be used in the repowering depends on the technology used in the nuclear plant, as well as the amount of electrical generating capacity that is desired from the repowered facility. The two nuclear plants in Minnesota use different technologies and would thus require very different schemes for repowering.

The Prairie Island reactor is a pressurized water reactor. This technology features a heat exchanger between the reactor and the steam turbine. As a result, the existing steam turbine does not become contaminated from exposure to radioactive material. The Monticello reactor, by contrast, is termed a boiling water reactor. In this case the water heated by the reactor also passes through the turbine as steam, and the turbine does become contaminated. Thus, if the Prairie Island plant were to be repowered, the turbine and generator could be included in the operation of new facility. The turbine at the Monticello plant would be contaminated and could not be included.

The existing steam turbine and generator is a valuable asset and would be used if it fits the repowering scheme. The first consideration is to match the steam conditions of the new steam source to the design inlet conditions of the existing turbine.

Schemes that Might be Used at Prairie Island

In the simplest approach, a natural gas-fired steam generator would be designed to produce steam at the required pressure and temperature for the existing turbine. This approach, however, would not provide the most efficient or lowest cost of electric production. Steam turbines for nuclear plants such as Prairie Island are designed to receive steam at near saturation conditions rather than the higher temperature and pressure superheated steam conditions that are standard for a modern fossil power plant.

The approach that would be likely to produce the lowest cost of electricity is to use the existing turbine as part of a combustion turbine combined cycle. In this case the existing turbine would receive steam from heat that is recovered from the exhaust of a combustion turbine that also drives an electric generator. This would provide considerably better economics; however, it would also substantially increase the plant electrical capacity.

If the objective of the repowering design is to minimize the production cost of electricity and use as much of the existing turbine equipment as possible, the ultimate capacity of the plant would be as much as 2 to 4 times that of its current output. At this capacity, there would be questions of adequate supply of natural gas. There would also be additional generating capacity that may not be needed.

Another approach would be to convert only one of the units at Prairie Island, thus matching the output of the repowered plant to near that of the present plant. In either case, the cost of electricity produced would be greater because of the additional capital investment, and higher fuel cost.

Schemes that Might be Used at Monticello

The existing turbine in the Monticello plant would not likely be used in a repowering scheme since it would be contaminated from exposure to steam produced in the nuclear reactor. The most likely approach to repowering would be a new generating plant based either on a combined cycle gas turbine or a new biomass-fueled facility at the present plant location.

Examples of Refueled or Repowered Plants

The cost of refueling or repowering a plant is specific to the plant and the design. Examples of plants that have been refueled or repowered are presented in this section.

Cofiring with Biomass

Cofiring is an established technology. There are several very good examples of coal-fired plants that have been modified to allow cofiring with alternative fuels.

EPRI analyzed the cofiring of a 200 MW plant with coal and wood. [EPRI 1993] In this case, the plant was adapted to burn approximately 15% wood waste (measured by heat content). The capital cost was estimated at $204/kW in 1991 dollars, or $236/kW in 1996 dollars. It was concluded from the analysis that the breakeven cost for wood, i.e., the cost for the wood fuel where the plant could produce electricity at the same cost as with 100% coal was -$24.22/ton. Thus, the utility would need to receive or be paid $24.22 for each ton of wood burned. This would only be feasible if the wood were a waste product and the cost of alternative disposal such as in a land fill was greater than $24.22/ton. This is generally not the case. Waste wood is typically sold to power plants for $10-20/dry ton, plus transport costs.

The French Island plant is an older 30 MW coal-fired plant located just outside of La Crosse, Wisconsin. In the early 1980s NSP replaced one of the original boilers with a bubbling fluidized bed combustion unit so that the plant could burn waste wood. In 1985, NSP in cooperation with La Crosse County developed a joint project to process municipal solid waste into refuse-derived fuel (RDF) to be burned in the modified plant. At this time, the other boiler unit was modified so that it could burn RDF. In 1990, the plant burned 68% wood and 32% RDF.

The Red Wing and Wilmarth plants are older NSP coal-fired plants with original capacities of approximately 25 MW. The facilities are located in Red Wing and Mankato, MN. In the early 1980s the plants were adapted to burn RDF from the Metro region processed at the Ramsey/Washington County waste processing facility.

The Hibbard Plant is an older plant in Duluth owned by Minnesota Power. Units 3 and 4 have not produced electricity since the early 1980s. When the Lake Superior Paper Industries mill on nearby property was constructed, Units 3 and 4 boilers were refurbished and converted to burn a coal, gas, wood mix to supply process steam to the paper mill. The retrofitted boilers were equipped with electrostatic precipitators for particulate control and were designed to meet applicable New Source Performance Standards for SO_2, NO_x, CO particulate and opacity. In additional to the process steam needs of the paper mill, the boilers have the capacity to produce enough steam to generate approximately 30 MW of electricity.

Examples of Combined Cycle Repowering

We are not aware of any plants in Minnesota that have been repowered utilizing the combined cycle. In 1990, Minnesota Power hired the consulting firm of Sargent & Lundy to assess the cost and feasibility of repowering the Syl Laskin plant. A large natural gas pipeline traverses MP's service area passing close to the Laskin plant. The pipeline can be fed from both Canadian and domestic sources of natural gas. The preliminary design included the reuse of the existing steam turbine/generator set as well as much of the existing infrastructure. The plant capacity would increase from about 50 MW to 250 MW. MP concluded that the plant could be repowered for a relatively low capital cost assuming the existing plant would otherwise be retired.

In another recent example outside Minnesota, Virginia Power replaced two of its older coal-fired units with a combined cycle plant at its Chesterfield Station. The original plant had a capacity of 70 MW. The two combined cycle units supply almost 400 MW of capacity, and although they were designed as intermediate duty units, they have performed well enough that Virginia Power has been using them as baseload units. The capital cost of the combined cycle conversion was $600/kW. The cost of natural gas committed to the plant is $2.50/million Btu. This provides a variable cost of electricity of 2¢/kWh (cost of capital not included).

Examples of Repowered Nuclear Plants

There are very few examples of nuclear power plants that have been repowered, and only one or two that have actually run as a nuclear plant before they were decommissioned and repowered. This includes plants such as the Midland plant in Michigan that was converted to a natural gas-fired cogeneration plant as it was being constructed. None of the repowering examples apply particularly well to either the Prairie Island or the Monticello plants.

The most recent example of a repowered nuclear power plant is the Ft. St.. Vrain Station owned by the Public Service Company of Colorado. This plant was designed as a 330 MW nuclear generating station. The reactor type is different from either of the two reactors in Minnesota; it is a high temperature gas-cooled reactor. This is significant in that the steam turbine operates at higher steam inlet conditions and thus this design is somewhat more favorable for some of the natural gas repowering approaches.

The decision to end nuclear operation was made in 1989. The plant was decommissioned and defueled at a cost of $315 million. The Ft. St. Vrain combined cycle repowering scheme utilizes two natural gas-fired combustion turbines and two heat recovery steam generators. The output of the repowered plant will total 471 MW. The total cost of the repowering has been capped at $200 million in 1993 dollars. This equates to about $508/kW of capacity in 1996 dollars. This does not include capital costs of adding natural gas pipeline transmission.

The Future for Nuclear Power Plants

The popular view of nuclear plants is that they are too expensive, particularly in relation to today's wholesale market price. This view, however, may well be incomplete, because:

1. Today's market price is not likely to be the steady-state price in the future. Rather than 1.5-2.5¢/kWh, a more realistic 3.5-4.5¢/kWh is probably a better forecast.
2. Many nuclear plants are expensive only because of capital recovery obligations; their operating cost profiles are in many cases quite cheap (on the order of 1-2¢/kWh).

In the future some nuclear plants will become valuable assets, not only to their owners (because of their cash flow potential), but also to society at large (because excess electric generating capacity will shrink, and they will be able to operate and deliver the product cheaply). Today, the need to recover past investments – in many cases an order of magnitude greater than originally anticipated – is what pushes nuclear costs so high for many plants. This need constitutes a big part of today's stranded asset debate in California and other states.

In the short term (3-5 years), recovery of past investment may well remain an acute problem for many owners, but 10 years in the future much of the sunk investment will have been recovered or written off. If the market price of power begins to inch back up, some nuclear assets could turn into "cash cows". The biggest uncertainty apart from market prices is the ability of nuclear plant owners to control future investment needs and costs of decommissioning and waste disposal.

There has been for some years an idea, among some nuclear plant owners, to extend the operating licenses of their plants beyond the original 40 years to 60 years. They have been exploring with the Nuclear Regulatory Commission (NRC) approaches to accomplishing this. The life extension process among nuclear owners has not yet gathered momentum, despite the potential cash flow opportunities, in part because of the threat of additional investment needs. As a prelude to a life extension application, a nuclear owner will likely need to do a thorough condition assessment, and in many cases the owner may be fearful of what will be found.

In Conclusion

The future for nuclear power assets is problematic at best. The non-economic problems of nuclear technology are real, and quite difficult. Such issues as the appropriate level of safety, enforcement, and permanent waste disposal are still without answers, and are so fundamental that they may yet override the economics of nuclear power regardless of how electricity markets change in the future.

However, it is critical to keep several possibilities in mind:

- Excess electric capacity is probably not permanent. As it shrinks over time, market prices will probably tend to rise.
- Nuclear assets can be operated relatively cheaply. Once initial investments are paid off or written off, nuclear costs to deliver electricity may drop significantly.
- The keys to nuclear cost control in the future are 1) the need for ongoing investment, and 2) the need to budget fully for the ultimate costs of decommissioning and long-term waste storage. If control is not possible, owners may decide that walking away early is preferable to walking away later.

REFERENCES

Colorado Public Utilities Commission (Contact: Morey Wolfson). 1996. "Ft. St. Vrain Nuclear Defueling, Decommissioning, and Repowering Information".

Edison Electric Institute (EEI). 1993. "Statistical Yearbook of the Electric Utility Industry, 1992". EEI, Washington DC, 1993.

Electric Power Research Institute (EPRI). 1995. "Biomass Energy: Cost of Crops and Power". Prepared by George A. Wiltsee Jr. and Evan E. Hughes. EPRI TR-102107-Vol. 2, Final Report, October 1995.

Electric Power Research Institute (EPRI). 1993. "Strategic Analysis of Biomass and Waste Fuels for Electric Power Generation". Prepared by Appel Consultants, Inc. EPRI TR-102773, Final Report, December 1993.

Electric Power Research Institute (EPRI). 1992. "Waste-to-Energy Screening Guide". EPRI TR-100670. Electric Power Research Institute, Palo Alto, CA, August 1992.

Energy Information Administration (EIA). 1992. "Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets". Service Report SR/EMEU/92-02, November 1992.

Energy Performance Systems, Inc. 1992. "Final Report, Watts Bar Conversion to Whole Tree Energy™". Tennessee Valley Authority, Southeastern Regional Biomass Energy Program, 1992.

Farhar, Barbara C. 1993. "Trends in Public Perceptions and Preferences on Energy and Environmental Policy". National Renewable Energy Laboratory, Golden, CO, 1993.

Jenkins, Alec F., and Hugh E. Reilly. 1996. "Tax Barriers to Four Renewable Electric Generation Technologies". 1996 ASME/JSME/JSES International Solar Energy Conference.

Johansson, Thomas B., Henry Kelly, Amulya K.N. Reddy, and Robert H. Williams. 1993. "Renewable Fuels and Electricity for a Growing World Economy: Defining and Achieving the Potential". In Johansson et. al. (Eds), Renewable Energy: Sources for Fuels and Electricity. Island Press, 1993.

Koplow, Douglas N. 1993. "Federal Energy Subsidies: Energy, Environmental, and Fiscal Impacts". The Alliance to Save Energy Report, Washington DC, 1993.

Levitt, Theodore. 1980. "Market Success through Differentiation – of Anything". Harvard Business Review, January 1980.

McCormick, Robert. 1996. "Customer Choice, Consumer Value: An Analysis of Retail Competition in the American Electric Industry". Citizens for a Sound Economy, 1996. As reported in Electric Utility Week, June 3, 1996, pp. 11-12.

Minnesota. 1996. "Findings of Fact, Conclusions, Recommendation and Memorandum". State of Minnesota Office of Administrative Hearings, Pursuant to Laws of Minnesota 1993, Chapter 356, Section 3. March 1996.

Minnesota Power Company. 1994. "Laskin Units 1 & 2 and Boswell Units 1& 2 Gas Combined Cycle Repower". Minnesota Power 1994 Resource Plan, Page 76.

Natural Resources Defense Council (NRDC). 1996. Presentation by Kari Smith to a solar energy conference in Palm Springs on March 15, 1996. As reported by IRP Report, McGraw-Hill Inc., April 1996.

Navarro, Peter. 1996. "Electric Utilities: The Argument for Radical Deregulation". Harvard Business Review, January-February 1996, pp. 112-125.

Patti, F.J. 1996. "Technical Considerations in Repowering a Nuclear Plant for Fossil Fueled Operation". Brookhaven National Lab, Upton, NY. (1996), 6p, DOE Contract AC0276CH00016.

Power Engineering. 1996. "Coal Units Convert to Gas-fired Combined Cycle". May 1996, Volume 100, No. 5, Page 50.

Public Service Company of Colorado. 1996. "Annual Status Report, 1996, Fort St. Vrain Repowering Project". March 31, 1996.

Public Utilities Commission of Colorado. 1994. Select pages from the PUC's Decision allowing PSCo to repower Ft. St. Vrain, adopted June 28, 1994.

Union of Concerned Scientists (UCS). 1993. "Powering the Midwest: Renewable Energy for the Economy and the Environment". 1993.

Vansant, C., and Michael Hilts. 1993. "WTE in North America: Managing 110,000 TPD". Solid Waste & Power, May/June 1993.

Yanney, Fred G. 1996. "Comments of the California Municipal Utilities Association Regarding Joint Applications Filed with the Federal Energy Regulatory Commission". Before the Public Utilities Commission of the State of California, R.94-04-031, I.94-04-032, May 28, 1996.

Yergin, Daniel. 1991. The Prize: The Epic Quest for Oil, Money & Power. Touchstone, Simon & Schuster, New York 1991.

CURE #5

Appendix B

Feasibility Study for Conversion of Prairie Island to Natural Gas Fired Generation

57-5

Feasibility Study for Conversion of Prairie Island to Natural Gas Fired Generation

UTILITY ENGINEERING

November 20, 2002

Table of Contents

Abstract

This report documents a general feasibility study that examines the conversion of the Prairie Island site from nuclear to natural gas generation. A number of plausible alternatives were investigated. These alternatives involve the replacement or repowering of nuclear capacity with natural gas combustion turbine platforms.

Although all of the scenarios involve some use of existing plant and equipment, the repowering option uses the most existing plant and equipment and in particular employs the existing steam turbine generators. The generation alternatives investigated include simple cycle capacity replacement, combined cycle capacity replacement, and combined cycle repowering. These alternatives are detailed below.

1. Replace the nuclear capacity with gas turbine generators running in simple cycle mode
2. Replace the nuclear capacity with two standard natural gas combined cycle plants
3. Repower one nuclear unit with steam from a combined cycle plant and retire the other nuclear unit
4. Repower both nuclear units with steam from two separate combined cycle plants

Budgetary capital and Operation and Maintenance (O&M) cost estimates for each generation scenario are provided. The study provides brief discussions of significant technical and licensing issues that introduce project risk and influence feasibility. The study also includes discussions of key advantages and disadvantages of the various generation alternatives. For each alternative, a complementary real-life example is presented to show a known commercial implementation of a similar project. Supporting data is provided in the appendices.

For reasons identified herein, the combined cycle replacement option (2) and the repower one nuclear unit option (3) provide the most effective alternatives to replace the Prairie Island generating capacity. Accordingly, more detailed information regarding the implementation, construction, and scheduling of these particular alternatives is provided. Option (4) is not a practical engineering solution and is not treated in detail beyond the necessary discussion of the constraints that restrict feasibility. Although the simple cycle option (1) is not nearly as favorable a replacement for the Prairie Island capacity as options (2) and (3), plant cost and other relevant data for simple cycle are provided at certain points for comparison purposes.

Table 1 below, Summary of Prairie Island Natural Gas Generation Alternatives, shows the salient results of this analysis.

Table 1
Summary of Prairie Island Natural Gas Generation Alternatives

Generation Alternative	Net Plant Output (MW)	Unit Net Heat Rate at ISO Conditions (BTU/kwh LHV)	Total Capital Requirement ($1000)	Normalized Capital Cost ($/kw)
1) Simple Cycle Replacement of Both Nuclear Units	999	10539	571,645	572
2) Combined Cycle Replacement of Both Nuclear Units	1036	6366	643,812	597
3) Repower One Nuclear Unit (4x1)	943	6815	510,921*	542*
* Duct Burners Included	1063*	7298*		
4) Repower Both Nuclear Units (4x1)	1886	6815	NA	NA
5) Present Plant - Nuclear Units	1070	10470 (9783 design)		

1R

Analysis Approach and Key Assumptions

The feasibility study employed EPRI's State of the Art Power Plant (SOAPP) CT workstation to develop the plant financial models. For the repowering case, the GE Gate Cycle workstation was used to determine a plant heat balance and a viable conceptual design. The following list shows significant assumptions and inputs used in the analysis.

- Plant heat rate results are given at the performance point using natural gas as the primary fuel.
- Natural gas supply costs, project development and management costs, and other soft costs such as interest during construction that add to capital cost are included in addition to process capital costs. break out
- Environmental externalities have not been quantified or monetized.
- The results are presented in 2002 dollars.
- Existing equipment not used in the scenarios was assumed to be abandoned-in-place, decommissioning costs were assumed to be unaffected, and demolition costs are excluded.
- Offsite transmission costs such as those that may be needed to preserve system stability are not included. These costs may have a material effect and should be investigated further if a more detailed study is contemplated. A brief discussion of transmission issues is included herein.
- Because this study concerns general feasibility, the plant configurations have not been economically optimized. The costs presented herein reflect approximate costs associated with reasonable and viable plant designs.
- The physical characteristics of the site are deemed adequate for the scenarios. Additional site restrictions such as underground obstacles, barriers to construction, or contaminated soils are not contemplated.
- Environmental costs to support BACT controls for NOx are included.
- The repowering analysis is limited to replacing the reactor steam with that from a natural gas CT/HRSG combination. Other forms of repowering such as coal boiler or gasification are not considered herein.
- Existing plant equipment reused in the natural gas generation scenarios is assumed to be in good working order.

Simple Cycle Capacity Replacement

Scenario

The simple cycle capacity replacement scenario involves installation of twelve combustion gas turbines at the PI site operating in simple cycle mode to replace the nuclear capacity.

Description

A simple cycle plant consists of a combustion gas turbine operating in open cycle mode. A simple cycle plant is run intermittently and is principally used for peak shaving. The plant heat rates are less efficient than combined cycle plants, but the plant response time to serve load is faster. Typical startup times are on the order of 20 minutes. Because of their higher heat rates and associated higher variable operating costs, these plants are higher up in the dispatch order and would not be expected to operate more than 15% of the time. A total of 12 units are assumed, with each 6-unit block producing approximately 500 MW. Turbine inlet air fogging was assumed as a performance enhancement. A General Electric 7EA combustion gas turbine with Dry Low Nitrogen (DLN) combustors was chosen as the base unit for this study. The 7EA machine is a typical base unit for large peaking plants. Great River Energy has a six unit peaking plant (Lakefield Junction) in Trimont, MN, which is based on the 7EA platform. The 7EA is also the platform used at Duke's Vermillion Plant in Lincoln County, NC. At 1200 MW, this 16-unit plant is the largest peaking plant in the United States.

Major Retained Equipment and Facilities

For this scenario, the following existing equipment was assumed to be available and incorporated into the cost model: Switchyard and Administration Buildings.

Key Advantages

- The large turbine order (12 units) may allow for some savings on price. Turbine availability concerns have been obviated by recent plant cancellations and reduced order flow to suppliers.
- A simple cycle is an uncomplicated and modular design with the fastest construction schedule, which allows for quick asset mobilization.
- Can be installed with relatively little disruption to the operation of nuclear units

Key Disadvantages

- The simple cycle peaking capacity does not replace the baseload capacity lost with the nuclear unit shutdown. The ability to control system voltage and frequency within the transmission system may be adversely affected. This may degrade transmission system reliability. See Transmission Issues section below.

Combined Cycle Capacity Replacement

Scenario

The combined cycle capacity replacement scenario involves the installation of two standard 2x1 natural gas combined cycle plants, each with new steam turbine generators, to replace the nuclear capacity at Prairie Island.

Description

A typical combined cycle plant consists of a combustion gas turbine (CTG), matched with an unfired Heat Recovery Steam Generator (HRSG), providing steam to a steam turbine generator (STG). For this analysis, the industry standard 2x1 plant configuration was assumed. That is, two CTGs, each with a matched HRSG, providing steam to a single steam turbine generator was assumed for the base plant. In a combined cycle plant, the gas turbine generators contribute approximately two-thirds of the total plant power. A typical output for this configuration is 500 MW per plant. In order to fully replace the PI generation capacity and utilize the existing transmission capacity, two standard plants are needed.

Combined cycle plants are highly efficient units that are suitable for base load and mid-range dispatch. Net thermal efficiencies for these plants are on the order of 53% LHV. The plant is assumed to operate in baseload mode, although it is well suited for cycling duty of approximately 16 hours a day. Combined cycle plants are usually shutdown during weekends and evenings when the spark spread for non-peak power makes these units unprofitable.

The gas turbine platform for this analysis is the Seimens -Westinghouse 501 FD. For these analyses, the gas turbines are assumed to be equipped with Dry Low NOx (DLN) combustors, and each HRSG has an integral Selective Catalytic Reduction (SCR) unit to reduce stack gas NOx emissions.

E.G.'s

The Sacramento Municipal Utility District (SMUD) is currently engaged in the design and licensing of a natural gas combined cycle plant at the decommissioned Rancho Seco nuclear power plant facility. This project is known as the Cosumnes Power Plant Project - CPP. According to their submittals to the California Energy Commission (Docket 01-AFC-19), a total of 1000MW of combined cycle replacement power is planned for this project. The proposed plant uses the existing switchyard and some other facilities. The plants are scheduled for construction in two phases consisting of 500 MW each. The first phase is scheduled for commercial operation in 2005 and the second phase, if completed, is scheduled for 2008.

Florida Power and Light (FPL) is currently engaged in the early stages of the siting process for a stand alone combined cycle 550 MW plant to be located adjacent to Exelon Nuclear's Limerick Generating Station. This project is an example of constructing a natural gas plant at an operating nuclear generation site. Although limited public information has been provided, it appears that there are no plans to shutdown the nuclear units as part of this project or to share any significant equipment. As of June 2002, the NRC was preparing to review the impacts on nuclear operations with input from Exelon, which is a requirement of the Limerick operating license. The siting process has, however, been halted as the township's decision to allow the plant construction has recently been overturned. The following is an excerpt of an article that appeared in the October 3, 2002 edition of the Philadelphia Inquirer.

> A three-judge panel in Montgomery County Court on Tuesday overturned an unpopular decision by township officials to allow the plant to be built in the Linfield section. The movement against the gas-powered plant, which opponents argued did not belong in a light-industrial zone, also helped topple the political careers of four township supervisors who backed it. The $300 million plant was slated to be running at a site near Peco's nuclear power plant by next summer. It would have employed 20 to 25 full-time workers and contributed about $3 million a year to the tax rolls of Limerick Township, Montgomery County, and the Spring-Ford Area School District. FPL Energy and its local subsidiary, Limerick Partners L.L.C., could not be reached for comment. They have 30 days to appeal the decision to Commonwealth Court.

Major Retained Equipment and Facilities

For this scenario, the following existing equipment was assumed to be available and incorporated into the cost model: Water Treatment System, Switchyard, Circulating Water System, Cooling Tower, Administration Buildings.

Key Advantages

- High thermal plant efficiencies
- Relatively short starting times for a baseload unit
- Excellent part-load operating performance and flexible duty cycle
- Standardized design and construction
- Modular design and construction reduces AFUDC
- Fewer design compromises needed to match new equipment with older existing equipment
- Gas turbines can be installed in simple cycle mode prior to full combined cycle mode to reduce the impact of the lost capacity

Key Disadvantages

- Higher initial capital costs

<u>Repowering</u>

Discussion

The attractiveness of repowering is usually due to savings from the use of existing equipment permits and public acceptance of the existing site as a generating facility. Repowering projects avoid the cost and uncertainty of siting a new facility while the plant heat rate is typically improved over the existing unit and the capacity of the existing plant increases. In the case of replacing existing fossil-fueled boilers, repowering also can significantly reduce plant emissions. Most repowering projects in the United States have involved replacing a fossil-fueled heat source.

The performance improvements coupled with the reduction in emissions make repowering an efficient choice where capacity additions are needed. A typical increase in repowered output (MW) is triple the original plant output. The concept of repowering involves replacing the original steam generation source with more efficient equipment that is thermally matched to the existing steam turbine generator. A repowering option retains as much auxiliary equipment as possible. Repowering is designed to improve the overall thermal efficiency of the plant while keeping site development costs low and while keeping capital costs low by using existing equipment. Because nuclear fuel costs are much lower than fossil fuels improving the plant heat rate is less of an economic incentive for repowering at Prairie Island.

Because of the optimization engineered into the greenfield combined cycle design equipped with integral steam turbine generators, a repowered plant will not be as thermally efficient as a new combined cycle plant. In order for a repowering project to be an efficient use of capital compared to a greenfield generation alternative, the equipment cost savings derived from repowering need to exceed the inherent efficiency advantages of the greenfield alternative for a given amount of deployable MW to the grid. That is, the efficiency difference should not be so great as to result in a material shifting of the dispatch order of the repowered plant over a greenfield alternative. In deregulated markets, an investment in repowering option is not typically warranted if the end result is to simply displace an existing unit in the dispatch order.

Repowering of steam power plants with gas turbine generators and HRSGs is being accomplished in various applications. Colorado Public Service repowered the existing steam turbines at the previously decommissioned Fort St. Vrain nuclear facility in 1999. This plant was originally rated at 330 MW and has been repowered to approximately 720 MW with the installation of three GE 7FA gas turbines and three HRSGs. While there is considerable experience with repowering to replace fossil fueled boilers with gas turbine exhaust (dating to approximately 1960), there have been no nuclear repowering projects other than Fort St. Vrain in the United States.

Florida Power & Light (FP&L) is repowering the 540 MW oil-fired Fort Myers plant with combined cycle technology to ultimately increase plant capacity to approximately 1440 MW. This project provides an example of repowering a steam turbine generator that is very similar in capacity to the existing Prairie Island steam turbines. Thermal efficiency is expected to increase from approximately 39.6% to 53.7% LHV at ISO load conditions. Six GE Frame 7FA combustion gas turbines and six Foster Wheeler HRSGs with triple pressure and reheat are being installed to replace the oil-fired boiler. The six gas turbines were initially installed in a simple cycle configuration and provided an additional 912 MW from the Fort Myers site. Full combined cycle repowered operation is scheduled for fall of 2002. The cost of this single-unit repowering project was approximately $450 to 500 million.

Scenarios

The PI repowering scenarios involve installation of combustion turbine generators running in combined cycle using the existing steam turbine generators. The design parameters for the existing steam turbine generators were used in the model. Two scenarios were examined: 1) repower a single unit and, 2) repower both units.

Description

The GE Frame 7FA unit with Dry Low Nitrogen (DLN) combustors was used as the base CTG in the simulation because it provides sufficiently high gas exhaust temperature for the reheat cycle. The efficiency and output of a steam turbine is a function of the gas turbine exhaust temperature. The 7FA is the most widely used unit in modern combined cycle applications. It has an extensive operating history and proven reliability. Siemens-Westinghouse has installed a G class machine with slightly higher efficiencies at a few locations, but these machines do not yet have a detailed history of reliability.

According to the heat balance model, six gas turbines are needed to efficiently repower an existing steam turbine at Prairie Island. The performance of one repowered plant in a 6x1 configuration is estimated as follows.

Net Plant Output - 1418.2 MW
Net Plant Heat Rate - 6599 Btu/kWh LHV
Repowered ST Generator Output – 446.6 MWW (of 535 MW available)

To efficiently operate the existing STGs, six CTGs are needed to replace the steam flow formerly provided by the nuclear reactor. Repowering one nuclear STG results with a more efficient 6x1 configuration results in a site output of approximately 1412 MW, which is approximately 352 MW above current output. Repowering both plants in a 6x1 configuration would result in a site output of 2836 MW, which is 1700 MW above current output. Since these results exceed equipment limits, the 6x1 configuration was not further analyzed. See Transmission Issues section below.

Four CTGs in a 4x1 configuration were used so that current site capacity was matched and output was within known switchyard equipment and transmission limits. Repowering a single nuclear STG with a 4x1 configuration would result in a site output of 943 MW and 1060 MW with a duct burner performance enhancement. Since a duct

Table 2

Configuration Efficiencies of a Single Repowered Unit

Configuration	Net Plant Output (MW)	Net Plant Heat Rate (BTU/kwh, LHV)	STG Output (MW) (535 MW avail.)
2x1	450	6939	127
4x1	943	6815	280
4x1 with duct burners	1060	7310	401
6x1	1418	6599	447

Major Retained Equipment and Facilities

For the PI repower scenario, the following existing equipment and facilities were assumed to be available and incorporated into the cost model: STG, Condenser and Condensate System, Water Treatment System, Switchyard, Circulating Water System, Cooling Tower, Turbine Building, Administration Buildings.

Key Advantages

- Lower initial capital costs. The repowering option uses the most existing plant equipment. The repower option saves the process cost of a new STG, which according to the manufacturer is approximately $35M FOB per STG at Prairie Island. With engineering and other costs, approximately $100M in capital cost savings could be realized over a combined cycle plant.
- Replaces baseload duty cycle of existing plant
- A repowered plant provides relatively efficient power if the conceptual design heat rate can be achieved. Note, however, that the existing steam turbine generators will not be optimized within a repowered steam cycle.
- If justifiable, an option exists to increase current site capacity by adding additional gas turbine generators from 4x1 to 6x1 or repowering the other plant.
- Gas turbines can be installed in simple cycle mode prior to full combined cycle mode to provide excess power or reduce the impact of the lost capacity.

Key Disadvantages

- Non-standardized design introduces uncertainties and longer installation cycles. These risks will be monetized by higher engineering fees, higher project contingency costs, and higher financing costs. For example, the Mystic project in Massachusetts, which is a first of a kind design in that it is the largest combined cycle plant in the US, is behind schedule and as of July 1, 2002, is experiencing hundreds of millions of dollars in cost overruns.
- Large natural gas capacity requirements and modifications.
- The attendant poorer reliability of older existing equipment retained in a repowered plant will likely result in higher maintenance costs over new equipment.

1R
Con.

- The most optimal 6x1 repower configuration is not practical as it results in a plant output that will require switchyard modifications, cooling tower upgrades, and may require significant transmission system upgrades.
- Repowering in a phased construction approach to maintain continuity of site power output introduces significant regulatory uncertainty and risk if one nuclear unit is maintained operational. See Nuclear Issues section below.
- The repowered plant's duty cycle is not as flexible as that for a combined cycle unit.

Natural Gas Requirements

Discussion

Each scenario relies on a combustion turbine for power conversion. Consequently, the project must have access to a reliable high-pressure supply of natural gas. The combined cycle CTs will require significant volumes of gas provided on a 24-hour firm basis that will require capacity additions for the natural gas supplier. This involves a firm design load of approximately 200,000 mcf/day of natural gas for the combined cycle and single repower alternatives depending on the configuration and dispatch characteristics.

The simple cycle plants were assumed to require gas on a 5x16 summer operation protocol. Although gas pressures within interstate gas transmission lines are typically maintained above 1000 psig, the pressure levels maintained within the LDC's system are substantially lower (<100 psig) and are insufficient for proper operation of a large CT. Gas pressure within a distribution system is typically increased by adding compressor facilities, by enlarging or paralleling with existing high-pressure mains, and by constructing new supply mains. This results in significant additions to capital costs. For the purposes of this study, it was assumed that natural gas would be available at the site at sufficient pressure to eliminate the need for an onsite gas compressor.

In addition to equipment costs, the large gas loads associated with CT operation will require the supplier or a third party to actively manage the gas supply to maintain capacity and system integrity, which will tend to increase the plant O&M costs.

The two potential natural gas suppliers for the Red Wing Station are Viking Gas Transmission Company (Viking), an Xcel subsidiary, and Northern Natural Gas Company (Northern), formerly an Enron subsidiary now owned by Dynegy. On August 19th, Dynegy sold the Northern pipeline to MidAmerican Energy Holdings.

Viking

In order to supply gas to the PI site, Viking will need to install a 47-mile lateral line and a metering station. In addition, the mainline will have to be expanded to accommodate the high gas throughputs of the various plants. The capacity of the existing mainline is insufficient to supply the large gas load and this requires significant infrastructure modifications to increase system capacity. The mainline cost shown below is the up front capital required to expand Viking's mainline to move the additional volumes from Emerson to the proposed lateral. Table 3 below shows a summary of Viking gas costs to support the various scenarios.

Table 3
Viking Gas Capital Costs (000s)

Plant Configuration	Lateral	Metering Station	Compression and Mainline Improvements	Total
Two Simple Cycle Replacement Units	$29,870	$430	$262,000	$292,300
Two Combined Cycle Replacement Units	$25,620	$275	$176,000	$201,895
One Repowered Unit (6x1)	$29,870	$350	$220,000	$250,220
Two Repowered Units	$29,870	$480	$289,225	$319,575

Northern Natural Gas

The Northern Natural Gas (NNG) system is physically closer to the PI site than the Viking system. The length of the lateral would be approximately 28 miles and would originate from the NNG Farmington compressor site. The NNG system is not as capacity constrained as the Viking pipeline and requires less mainline modifications to accommodate the proposed PI load. Table 4 below shows the Northern Natural Gas costs to support the various scenarios. Given the clear cost advantages, it was assumed that NNG would act as the project gas supplier.

Table 4
Northern Natural Gas Capital Costs (000s)

Plant Configuration	Lateral	Metering Station	Compression and Mainline Improvements	Total
Two Simple Cycle Units (interruptible)	$28,000	$600	NA	$28,600
Two Simple Cycle Units	$28,000	$600	$4100	$32,700
Two Combined Cycle Units	$22,700	$600	$4100	$27,400
One Repowered Unit	$28,000	$600	$4100	$32,700
Two Repowered Units	$34,600	$800	$5500	$40,900

Water and Cooling Requirements

The Prairie Island Circulating Water System is appropriated 615 million gal/day of surface (river) water by DNR permit #69-072. The well water permits for PI allow consumption of approximately 470 gpm. This allotment is well in excess of the makeup and cooling water requirements of any of the above scenarios. A typical combined cycle plant uses on the order of 3 to 5 million gal/day.

A simple cycle plant ~~does not require~~ significant amounts of makeup water. The maximum consumption would be approximately 750 gpm (per 6 unit block) if the gas turbines were operated on fuel oil. This consumption rate is well within the existing water permit. With onsite storage tanks, the simple cycle plants could feasibly operate within the capacity provided by the well water only. If only natural gas is used fuel, only insignificant amounts of water would be required as water or steam injection for NOx control would not be necessary.

The existing circulating water system and associated cooling towers can be used as heat sinks for the proposed alternatives. Cooling towers are not required for the simple cycle plants.

Transmission Issues

The MW outputs of the power block configurations used in this study were chosen to match and fully utilize the existing transmission capability of the site. If the new generating equipment supplies power in excess of the capability and ratings of the existing switchyard and transmission system, such as in the 6x1 repower case, switchyard and transmission modifications will be needed. For the simple and combined cycle cases and the 4x1 single repower case, the output of the new units is within the existing switchyard ratings, and no significant switchyard modifications were assumed.

An interconnection study is necessary to determine the transmission system impact of the alternative generation. As part of the siting process, all new generation facilities are analyzed to determine the impact on the reliability of the associated electrical transmission study. These studies include analyses of fault duty, stability, and system voltage support. Usually fault duty studies are undertaken first. If these results are favorable, additional studies are conducted. An interconnection study must be requested through the Midwest ISO or developed by a third party. Generally ISO studies are undertaken when a certain project is likely to be developed, and the generation is likely to eventually become part of the system model. An ISO study cost is approximately $40,000, depending on complexity. Since this feasibility study is preliminary and somewhat prospective in nature, interconnection studies were not performed.

NSP has examined thermal limitations for substation capacity increases for the 2001 All-Source Request for Supply Proposals. This indicative finding showed that approximately 800 MW could be added on the 345 KV bus at Prairie Island without exceeding loadings on transmission elements. Given this finding, all cases except the double repower case would not require mitigation for this particular facet of an interconnection study. It is very important to note, however, that the Prairie Island output is presently constrained by a flowgate on the Prairie Island-Byron interface such that *no* increases in capacity above the present capacity could be undertaken without system modifications.

Given these constraints and the increase in capacity above existing, the 6x1 repower configuration will require transmission and switchyard modifications and the double repower case will likely require transmission and switchyard modifications and additional modifications to demonstrate fault duty compliance. A full interconnection study is necessary to further evaluate feasibility and to determine more detailed cost estimates.

Nuclear Regulatory Issues

Natural Gas and Spent Fuel Interaction

There are two natural gas powered generation projects at former nuclear plant sites in the United States. These projects provide some insight into natural gas generation projects at Prairie Island. A repowering project at Fort St. Vrain (FSV) is complete and operational. A capacity replacement project at Rancho Seco is in the siting phase. Both of these projects involved previously decommissioned reactors with spent nuclear fuel completely transferred to an Independent Spent Fuel Storage Installation (ISFSI) prior to construction of the natural gas fired units. The repowering options at Prairie Island would involve evaluating the impact of large quantities of natural gas on site with spent nuclear fuel still located in the reactor or spent fuel storage pool.

Each of these projects was required to examine nuclear impacts to the spent fuel stored in the ISFSI. The NRC regards nuclear impacts as minimal as long as the new plant is greater than one half mile from the nuclear fuel and the new plant has been sufficiently isolated and secured from the existing nuclear plant. Gas and oil installations within ½ mile of an ISFSI require specific evaluations of the possible impacts to the nuclear fuel and prior NRC approval. This spatial isolation is a requirement of the ISFSI license at FSV. SMUD controls a large plat of land at the Rancho Seco site, and they were able to use the existing switchyard while locating the plant sufficiently far from the nuclear unit and the ISFSI. The SMUD project does not involve gas or oil impacts within ½ mile of the fuel. As of August 23, 2002, all of the Rancho Seco fuel was transferred to dry storage.

The ISFSI at FSV is located 1400 ft away from the nearest gas line. The NRC determined that this arrangement was satisfactory from a safety standpoint (FSV safety evaluation). This required examinations of the effects of postulated natural gas accidents. At FSV, the effects of a service line rupture, a main supply line rupture and a turbine building detonation were reviewed and found not to impact the safety function of the ISFSI.

Given the above, it would be in the nuclear safety and economic interests of a PI project to locate a natural gas power plant and supporting gas infrastructure at least one half mile from the fuel, whether the fuel is located in the spent fuel pool, the reactor, or the ISFSI. By examining the PI site layout, this appears at least geographically possible for the simple and combined cycle capacity replacement scenarios by locating these plants at the far northern boundary of the site. (Other analysis such as soil mechanics would have to be accomplished.) A gas line that is within ½ mile of an ISFI or a spent fuel pool does not, of itself, disqualify a project, but such a location will entail detailed failure mode and effects analyses for nuclear safety concerns.

The PI repower scenario that contemplates continued operation of one of the nuclear units during construction of a repowered unit entails significant regulatory uncertainty because of the safety ramifications of a failure mode and effects analyses. Repowering cannot be accomplished outside of the standard ½ mile interface area established by the NRC. The pressure drop between the HRSG superheater discharge and the existing steam turbine nozzle, which is a strong function of the length of the steam pipe run, should be minimized for plant efficiency.

There is no precedent that contemplates construction of a repowered plant that uses one of the two existing STGs at an operating nuclear power plant in the United States. High volume natural gas facilities introduce explosion hazards and safety concerns to an operating nuclear plant that would be hard to justify on a basis that repowering may have economic advantages over alternative generation. For instance, natural gas from a pipe failure could enter a structure through ventilation systems and be ignited and affect operators and nuclear safety equipment. Explosions have occurred at natural gas fired power plants. In 1999, a natural gas explosion destroyed a boiler at a KCPL coal plant. An explosion and large fire occurred at Sithe's South Boston 700 MW natural gas power plant on October 1, 2002.

Nuclear Safety and Project Reviews

It is estimated that from the time of a decision to pursue the repowering option that it would take approximately two years to complete the nuclear regulatory (NRC) review process. This two years includes 6 months for the licensee to prepare the required safety analyses for submittal, an estimated 6 months for review by the Nuclear Regulatory Commission and 1 year for public hearings should they be requested.

As part of the siting process, a repowering project would be subject to an analysis of feasible generation alternatives, which is required as part of the state's review to determine a given project's environmental impact. This would involve a review of the comparative merits of other reasonable alternatives to the repowering project that could satisfy the project objectives but may avoid or lessen the effects of the project. A competent reviewer would certainly need to examine the relative risks of repowering due to the proximity of nuclear fuel over other plausible alternatives such as siting replacement generation elsewhere. Because of the nuclear safety impacts, a favorable ruling for the repowering alternative, especially on a site with an operating nuclear plant, over other generation alternatives may be difficult to obtain regardless of an NRC approval. For these and other reasons, a repowering project would likely be the subject of legal challenges from interveners. There are no industry precedents for siting a natural gas power plant on a nuclear site where the reactor has not been decommissioned. The ability to successfully license a repowered plant at Prairie Island cannot be predicted with any certainty. These feasibility risks should be well understood prior to undertaking a repowering project.

Environmental Considerations

For the purposes of this study, it was assumed that Best Available Control Technology (BACT) environmental controls are installed consistent with recent MPCA requirements for similar plants in attainment areas. For the combined cycle and repowering cases, it was assumed that dry low NOx combustion turbines and SCRs were installed.

The specific environmental impacts of routing the gas line or constructing and operating the plant have not been identified. The cost of the environmental surveys and consulting work has been included in the model. Environmental externalities were not monetized for this analysis. There are no cost provisions for environmental mitigation measures, such as purchasing wetlands for the purpose of set asides for compensatory habitat. These issues would be addressed in a more detailed study.

Continuity of Site Capacity

Transition Time

The scenarios addressed herein postulate a simultaneous shutdown of both nuclear units in the last quarter of 2006 followed by operation of the replacement or repowered units on or about January 2007. Current planning indicates a shutdown of Unit One in mid 2006 and Unit Two in late 2006 if additional spent fuel casks are not installed. For simplification purposes, the analysis assumes a simultaneous shutdown of both nuclear units such that the commercial operation of the gas-fired units is assumed to approximately coincide with the nuclear shutdown.

These cases, however, are somewhat hypothetical with regard to complete continuity of site power in that the integration and operation of the gas-fired units for continuous service would involve some modification and preparation of equipment formerly used by the nuclear unit(s) presumed to shutdown. Depending on regulatory requirements, the final routing of the gas pipeline onto the site may be scheduled subsequent to the nuclear plant shutdown. First fire of associated plant equipment would occur after the gas line had been installed. In addition, system and integrated plant testing would also need to be accomplished. For the purposes of this report this time will be referred to as the transition time. Transition time should be scheduled to occur when the impact to the grid is minimized much like a planned outage is scheduled. In general, the transition time would be a function of how much equipment is retained from the existing plant to the new plant. Detailed planning and staging equipment can minimize transition time. There are, however, practical limits to optimizing this process because of the number of plant systems that need to be tested and certified for insurance, warranties, contractual requirements and other purposes.

Because of the uniqueness of this project, there are no direct examples available of transition time for a project of this type, but a reasonable estimate can be made from similar projects. A repower of a similar steam turbine at a fossil fueled plant (Ft. Myers) is expected to have a transition time of approximately 6 months. According to the EPRI model used for this study, the full testing phase of a typical combined cycle plant without nuclear complications is on the order of 7 months. Recent combined cycle projects have executed the testing phase in 4 to 6 months. Some have taken much longer. Given this information and allowing for nuclear-related contingencies, a reasonable estimate for transition time would be six months for a combined cycle replacement project and nine months for a repower of one unit. This estimate assumes that the NRC does not require any other additional testing or special requirements for nuclear safety purposes. If this occurs, which is not unlikely, the transition time will be extended, perhaps significantly.

Siting, Design, and Construction Times

Because of design standardization, combined cycle plants are being designed and constructed well within 3 years of a notice to proceed. Some combined cycle projects have been completed in 24 months or less. Simple cycle plants are less complex and can be completed in less time than combined cycle plants. The PI site has inherent advantages such as existing administrative buildings and other infrastructure that would contribute to a reduction in the construction time. The supporting off site natural gas infrastructure can be designed and constructed in 2 years and can be done in parallel with the power block design and construction. Allowing six months for up front siting work, no delays in regulatory approvals, and reasonable transition times (as defined above), the combined cycle and single unit repower generation alternatives could feasibly be completed by late 2006 if a decision is made by the second quarter 2003.

The timing of regulatory approvals for the repower cases, however, is subject to potentially lengthy delays due to siting issues and licensing uncertainty. A replacement simple or combined cycle plant that cannot be located outside of ½ mile from the area would also be subject to more detailed nuclear safety requirements and more uncertain regulatory approval times. See Nuclear Regulatory Issues above.

Phased Construction to Support an Extended Service Life of Nuclear Unit 2

The phased approach would involve a replacement of the retired capacity associated with the shutdown of one nuclear unit followed later by a replacement of the retired capacity associated with the shutdown of the second nuclear unit when the spent fuel pool is full. At the end of Phase 1, a gas-fired unit and a nuclear unit are providing power. At the end of Phase 2, two matching gas-fired units are providing power, and the nuclear units are retired. For the PI site this would involve an earlier shutdown of Unit One in fall of 2004 without initiation of its last fuel cycle in order to extend the service life of the Unit Two by approximately 18 months to mid 2008 (depending on the fuel burnup rate). This is not considered feasible or desirable for reasons discussed below.

It is not realistic to assume that a combined cycle or repowered plant can be fully completed by the fall of 2004. A simple cycle plant or the simple cycle portion of a combined cycle plant could possibly be completed if the project is authorized and notice to proceeds for various contracts are issued by early 2003 and no delays in siting, design, procurement, and construction, including natural gas infrastructure, are experienced. The combined cycle portion could be finished by early 2006. Given the unique nature of this project where the siting and construction necessarily involves a first-of-a-kind review of the impacts to an operating nuclear power plant (Unit Two), a streamlined fast track process with no delays is considered extremely unlikely.

A phased approach will cost more (estimate 30%-50%) because: 1) the Engineer Procure and Construct (EPC) contractor will require contingencies and incentives to complete the complex project on an abbreviated schedule, and 2) resources are mobilized at two different times as the second natural gas generation unit is completed years later from the first plant. This approach does provide some flexibility in that it sets up an option to cancel construction of the second unit if system load decreases or if other substitute generation capacity is added. If a phased construction approach for repowering were undertaken, the combustion turbines could be installed in increments, however the work available from the turbine would not be as efficiently utilized until all six CTs were installed. As discussed above, at interim gas turbine configurations the net plant output will decrease and the plant heat rate will degrade somewhat at configurations less than a 6x1 (2x1, 4x1). This approach would also cost more than an uninterrupted project.

Another consideration is that the cost to maintain a nuclear plant shutdown without a possession only license (which can be obtained from the NRC post decommissioning) can easily be as much or more as that needed to maintain it operating. Because of relatively inexpensive fuel costs, the variable operating costs at nuclear units are much less than those of a fossil unit. Because of higher labor, shutdown maintenance, and insurance costs, the fixed costs for a shutdown nuclear unit are significant. Finally, the economies of scale that are realized with both units operating would be lost.

Stand Alone Construction

In order to minimize impacts to the existing nuclear plant, the simple and combined cycle plants could be designed and built without the use of any existing site power equipment. Administrative buildings and non-safety related infrastructure could still be used. This would add approximately $20 million of equipment costs to the simple cycle plant and $50 million to the combined cycle plants. Of course this is not an option for the repowering alternatives. One potential feasibility risk element with this approach is that it would involve changes to the surface water appropriation and the existing circulating water system. These changes engender a much more expensive and less streamlined approach to the siting process due to the necessity to obtain changes in the plant water permits.

In addition, once stand-alone construction is contemplated, a competent generation planner would compare the costs of stand alone construction at PI with a greenfield generation project at carefully chosen offsite location. It is altogether likely that the greenfield site offsite would pose significantly less risk and also be price competitive with a stand alone project at PI.

Schedule

A representative Level 1 schedule has been provided in the appendix that shows an estimate of the power plant development and construction cycle to satisfy a 2007 startup. It was assumed the gas pipeline projects could be completed in parallel with the design and construct power plant tasks without affecting the critical path elements. According to Northern Natural Gas, a general time estimate for the design and FERC filing requirements for a project of this scope is one year. An in-service construction timeframe estimate for a project of this scope would also be approximately one year. There likely would be some overlap in these time horizons such that a reasonable project timeline estimate to complete the gas pipeline project would be 1.75 years.

Operations and Maintenance (O&M) Costs

The fixed and variable O&M costs for each practical scenario is given in Table 5, Alternatives Operations and Maintenance Costs below. Gas costs, which are highly volatile, were not included in the O&M estimates. The fixed O&M costs do not include any future capital upgrades. The variable costs assume 10% capacity factor for simple cycle and a 92% capacity factor for combined cycle and repower. These costs also do not include any costs to operate, maintain, demolish, or provide security for any of the PI nuclear facilities.

Table 5
Alternatives Operations and Maintenance Costs

Alternative	Fixed O&M ($/kw-yr)	Non-gas Variable O&M ($/MWh)
Simple Cycle Capacity Replacement	2.37	2.67*
Combined Cycle Capacity Replacement	3.23	1.79**
Repower One Unit with Duct Burners	3.15	1.68**
* 10% capacity factor ** 92% capacity factor		

Appendix

Schedule
Combined Cycle or Repower Plant

Schedule	Planned Start	Planned End	Planned Duration (Days)
Design, Procurement and Delivery	1/1/2004	9/1/2006	974
Engineering	1/1/2004	3/1/2006	790
Permitting	1/1/2004	6/1/2005	517
Procurement, Fabrication and Delivery	4/1/2004	9/1/2006	883
Construction	4/15/2005	11/1/2006	565
Mobilization and Site Preparation	4/15/2005	6/1/2005	47
Underground Piping, Elec and Misc Facilities	6/15/2005	3/15/2006	273
Field Erected Tanks	10/1/2005	2/1/2006	123
Substructure Work	5/15/2005	10/15/2005	153
Superstructure Work	1/1/2006	6/1/2006	151
HRSGs and Aux Installation	6/15/2005	8/1/2006	412
Combustion Turbine Installation	11/1/2005	9/1/2006	304
Steam Turbine Installation*	1/1/2006	6/1/2006	151
Balance Of Plant (BOP) Equip Installation	12/15/2005	10/15/2006	304
BOP Electrical Sys Installation	12/15/2005	10/15/2006	304
BOP Control and Instrumentation Installation	1/1/2006	11/1/2006	304
Final Site and Finish Architectural Work	8/1/2006	11/1/2006	92
Testing	4/1/2006	1/1/2007	275
Plant Startup	4/1/2006	12/1/2006	244
Combustion Turbine Startup	5/1/2006	10/1/2006	153
HRSG Startup	5/15/2006	11/1/2006	170
Steam Turbine Startup	4/15/2006	12/1/2006	230
Plant Performance Testing	12/1/2006	1/1/2007	31
Commercial Operating Date	1/1/2007	1/1/2007	

* Steam turbine integration for repower case

Cost and Emission Data

SIMPLE CYCLE

SIMPLE CYCLE COSTS

TOTAL PROCESS CAPITAL	364,105,984	
General Facilities	14,564,240	
Engineering and Home Office Fees	25,487,420	
Project Contingency	36,410,600	
Process Contingency	0	
TOTAL PLANT COST	440,568,256	
AFUDC or IDC		
See Capital Outlay Table		
TOTAL PLANT INVESTMENT	440,568,256	
Prepaid Royalties	0	
Preproduction Costs	18,875,486	
Inventory Capital	2,202,841	
Initial Cost - Catalyst and Chemicals	0	
Land	0	
Capital Cost Adders	32,700,000	
TOTAL CAPITAL REQUIREMENT	494,346,592	
TOTAL CAPITAL REQUIREMENT (Currency/net kW)		494.8
O + M and Fuel Costs		
(in Base Year (2002) Currency)		
Fixed O + M		
Direct Operating Labor	406,140	
- Number of Operating Staff	5	
Direct Maintenance Labor	519,770	
- Number of Maintenance Staff	9	
Annual Services, Materials, & Purchased Power		
- Annual O&M Services & Materials	552,259	
- Non-operating Purchased Power	397,264	
Indirect Labor Costs		
- Benefits	273,404	
- Home Office Costs	216,486	
TOTAL FIXED O+M	2,365,325	

SIMPLE CYCLE COSTS (Continued)

Variable O+M		
Scheduled Maintenance Parts & Materials		
- CT Inspection/Overhaul	1,998,717	
- HRSG Inspection/Refurbish	0	
- ST Inspection/Overhaul	0	
- BOP Refurbish	20,876	
Scheduled Maintenance Labor		
- CT Inspection/Overhaul	139,910	
- HRSG Inspection/Refurbish	0	
- ST Inspection/Overhaul	0	
- BOP Refurbish	32,861	
Unscheduled Maintenance Allowance	109,618	
Catalyst Replacement		
- SCR Catalyst Materials & Labor	0	
- CO Catalyst Materials & Labor	0	
Other Consumables		
- Raw water	11,830	
- Circulating water	0	
- NH3	0	
- H2SO4	12,979	
- NaOH	15,673	
- Misc	15,968	
Disposal Charges		
- Spent SCR catalyst	0	
- Spent CO catalyst	0	
- Other disposal	75	
Byproduct Credit	0	
Total Variable O+M	2,358,510	
Total Variable O+M (Currency/MWh)		2.67
Total Fixed and Variable O+M	4,723,835	
Fuel Cost		
Fuel Cost	31,934,028	
Fuel Cost (Currency/MWh)		36.17

SIMPLE CYCLE CAPITAL OUTLAY

Category	Total	1	2	3
Calendar Year (Jan 1 - Dec 31)		2004	2005	2006
Total Plant Cost				
In Base Year (2002) Currency	440,568,256	9,862,531	162,282,496	268,423,232
Amount of Escalation	32,458,140	398,446	9,932,987	22,126,706
Escalated Total Plant Cost	473,026,432	10,260,977	172,215,488	290,549,952
Other Outlays(*)	23,042,888	0	0	23,042,888
Gross Outlay	496,069,312	10,260,977	172,215,488	313,592,832
Investment Tax Credits	0	0	0	0
Other Income Tax Offsets	0	0	0	0
Net Total Capital Requirement				
Net Cash Outlay	496,069,312	10,260,977	172,215,488	313,592,832
AFUDC - Equity(**)	26,179,826			
AFUDC - Interest	16,696,738			
Total (Excluding capital cost adders)	538,945,856			
Gross Depreciable Investment		510,357,920		
Non-Depreciable Net Plant Outlay(***)	2,408,152			
Equity AFUDC	26,179,826			
Total Non-Depreciable Investment		28,587,978		
Capital Cost Adders	32,700,000			
Total Capital Requirement		571,645,888		
Less Investment Tax Credit		0		
Net Total Capital Requirement		571,645,888		

(*) Consists Of	
Land	0
Preproduction Costs	20,634,736
Prepaid Royalties	0
Inventory Cap + Init Cat/Chem	2,408,152
Total	23,042,888
(**) Consists of:	
Preferred Stock AFUDC	0
Common Equity AFUDC	26,179,826
Total	26,179,826
(***) Consists of:	
Land	0
Inventory Cap + Init Cat/Chem	2,408,152
Total	2,408,152

SIMPLE CYCLE EMISSIONS

Variable	Value	Units
PLANT DESIGN BASIS		
Ambient Air Temperature	59	F
Site Elevation Above MSL	695	ft
Cycle Type	Simple Cycle	
Number of Combustion Turbines Operating	12	
CT Primary Fuel Type	Natural Gas	
CT NOx Control Type - Primary Fuel	Dry Low NOx Combustors	
Inlet Air Cooling	Fogging	
CT Air Precooler Discharge Temperature	52	F
AIR EMISSIONS - COMBUSTION TURBINES		
Firing Primary Fuel		
CO2 Mass Flow Per CT Stack	113,904.96	lb/h
CO Mass Flow Per CT Stack	53.27	lb/h
NOx (As NO2) Mass Flow Per CT Stack	31.51	lb/h
SO2 Mass Flow Per CT Stack	0	lb/h
CO Concentration	25	ppmvd @ 15% O2
NOx Concentration	9	ppmvd @ 15% O2
SO2 Concentration	0	ppmvd @ 15% O2
Volumetric Flow Rate Per CT Stack	1,483,875	ft3/min-act
CO2 Mass Flow Total Plant	1,366,859.50	lb/h
CO Mass Flow Total Plant	639.24	lb/h
NOx (As NO2) Mass Flow Total Plant	378.07	lb/h
SO2 Mass Flow Total Plant	0	lb/h
LIQUID DISCHARGES		
Total Waste Water Discharge Peak Flow	962	gpm
Total Waste Water Discharge Average Flow	29	gpm

COMBINED CYCLE

COMBINED CYCLE COSTS

TOTAL PROCESS CAPITAL	452,102,016	
General Facilities	13,563,060	
Engineering and Home Office Fees	31,647,140	
Project Contingency	45,210,200	
Process Contingency	0	
TOTAL PLANT COST	542,522,368	
AFUDC or IDC		
See Capital Outlay Table		
TOTAL PLANT INVESTMENT	542,522,368	
TOTAL PLANT INVESTMENT ($/kW)		515.02
Prepaid Royalties	0	
Preproduction Costs	17,795,884	
Inventory Capital	2,712,611	
Land	0	
Capital Cost Adders	27,400,000	
TOTAL CAPITAL REQUIREMENT	590,430,848	
O + M and Fuel Costs (in Base Year (2002) $)		
Fixed O + M		
Direct Operating Labor	1,069,159	
- Number of Operating Staff	17	
Direct Maintenance Labor	901,818	
- Number of Maintenance Staff	15	
Annual Services, Materials, & Purchased Power		
- Annual O&M Services & Materials	348,525	
- Non-operating Purchased Power	115,347	
Indirect Labor Costs		
- Benefits	616,896	
- Home Office Costs	294,421	
TOTAL FIXED O+M	3,346,168	

COMBINED CYCLE COSTS (continued)

Variable O+M		
Scheduled Maintenance Parts & Materials		
- CT Inspection/Overhaul	9,312,600	
- HRSG Inspection/Refurbish	592,303	
- ST Inspection/Overhaul	744,000	
- BOP Refurbish	500,000	
Scheduled Maintenance Labor		
- CT Inspection/Overhaul	651,882	
- HRSG Inspection/Refurbish	177,691	
- ST Inspection/Overhaul	111,000	
- BOP Refurbish	85,199	
Unscheduled Maintenance Allowance	582,049	
Catalyst Replacement		
- SCR Catalyst Materials & Labor	177,024	
- CO Catalyst Materials & Labor	0	
Other Consumables		
- Raw water	1,831,258	
- Circulating water	0	
- NH3	50,773	
- H2SO4	39,568	
- NaOH	47,780	
- Misc	44,655	
Disposal Charges		
- Spent SCR catalyst	11,064	
- Spent CO catalyst	0	
- Other disposal	3,875	
Byproduct Credit	0	
Total Non Gas Variable O+M	14,962,721	
Total Non Gas Variable O+M ($/MWh) 92% CF		1.83
Total Fixed and Variable O+M	18,308,889	

COMBINED CYCLE CAPITAL OUTLAY

Category	Total	1	2	3
Calendar Year (Jan 1 - Dec 31)		2004	2005	2006
Total Plant Cost				
In Base Year (2002) Currency	516,219,648	21,360,704	57,966,872	436,892,064
Amount of Escalation	40,424,964	862,972	3,548,036	36,013,956
Escalated Total Plant Cost	556,644,608	22,223,676	61,514,908	472,906,016
Other Outlays(*)	21,705,646	0	0	21,705,646
Gross Outlay	578,350,208	22,223,676	61,514,908	494,611,648
Investment Tax Credits	0	0	0	0
Other Income Tax Offsets	0	0	0	0
Net Total Capital Requirement				
Net Cash Outlay	578,350,208	22,223,676	61,514,908	494,611,648
AFUDC - Equity(**)	23,202,630			
AFUDC - Interest	14,858,861			
Total (Excluding capital cost adders)	616,411,712			
Gross Depreciable Investment		590,387,456		
Non-Depreciable Net Plant Outlay(***)	2,821,663			
Equity AFUDC	23,202,630			
Total Non-Depreciable Investment		26,024,294		
Capital Cost Adders	27,400,000			
Total Capital Requirement		643,811,776		
Less Investment Tax Credit		0		
Net Total Capital Requirement		643,811,776		

(*) Consists Of	
Land	0
Preproduction Costs	18,883,982
Prepaid Royalties	0
Inventory Cap + Init Cat/Chem	2,821,663
Total	21,705,646

(**) Consists of:	
Preferred Stock AFUDC	0
Common Equity AFUDC	23,202,630
Total	23,202,630

(***) Consists of:	
Land	0
Inventory Cap + Init Cat/Chem	2,821,663
Total	2,821,663

COMBINED CYCLE EMISSIONS

Variable	Value	Units
PLANT DESIGN BASIS		
Ambient Air Temperature	59	F
Site Elevation Above MSL	695	ft
Cycle Type	Combined Cycle Cogeneration	
Number of Combustion Turbines Operating	4	
CT Primary Fuel Type	Natural Gas	
CT NOx Control Type - Primary Fuel	Dry Low NOx Combustors	
CT Air Precooler Discharge Temperature	59	F
Cooling System Type	Wet Mech Draft Cooling Twr	
SCR Configuration	Anhydrous Ammonia Injection	
NOx Conversion Efficiency (%), Primary Fuel	45	%
AIR EMISSIONS - HRSG's		
Firing Primary Fuel		
CO2 Mass Flow Per HRSG Stack	213,608.19	lb/h
CO Mass Flow Per HRSG Stack	40.42	lb/h
NOx (As NO2) Mass Flow Per HRSG Stack	33.2	lb/h
NH3 Mass Flow Per HRSG Stack	12.27	lb/h
SO2 Mass Flow Per HRSG Stack	0	lb/h
CO Concentration	10	ppmvd @ 15% O2
NOx Concentration	5	ppmvd @ 15% O2
NH3 Concentration	5	ppmvd @ 15% O2
SO2 Concentration	0	ppmvd @ 15% O2
Volumetric Flow Rate Per HRSG Stack	1,045,319	ft3/min-act
CO2 Mass Flow Total Plant	854,432.75	lb/h
CO Mass Flow Total Plant	161.68	lb/h
NOx (As NO2) Mass Flow Total Plant	132.81	lb/h
NH3 Mass Flow Total Plant	49.08	lb/h
SO2 Mass Flow Total Plant	0	lb/h
LIQUID DISCHARGES		
Raw Cycle Water Make-up Peak Flow	147	gpm
Raw Cycle Water Make-up Average Flow	98	gpm
Cooling Tower Make-up Peak Flow	7,319	gpm
Cooling Tower Make-up Average Flow	4,879	gpm
Cooling Tower Blowdown Peak Flow	1,403	gpm
Cooling Tower Blowdown Average Flow	936	gpm
Total Waste Water Discharge Peak Flow	18,747	gpm
Total Waste Water Discharge Average Flow	1,036	gpm
SOLID WASTES		
SCR Catalyst Material	Vanadium Pentoxide/Zeolite	
SCR Catalyst Volume	922	ft3
SCR Catalyst Replacement Frequency	5 to 10	years

REPOWER

REPOWER ONE UNIT 4X1 Costs

TOTAL PROCESS CAPITAL	342,284,992	
General Facilities	10,268,550	
Engineering and Home Office Fees	23,959,950	
Project Contingency	34,228;500	
Process Contingency	0	
TOTAL PLANT COST	410,742,016	
AFUDC or IDC		
See Capital Outlay Table		
TOTAL PLANT INVESTMENT	410,742,016	
TOTAL PLANT INVESTMENT ($/kW)		386
Prepaid Royalties	0	
Preproduction Costs	15,530,286	
Inventory Capital	2,053,709	
Initial Cost - Catalyst and Chemicals	0	
Land	0	
Capital Cost Adders	37,400,000	
TOTAL CAPITAL REQUIREMENT	465,725,984	
O + M and Fuel Costs		
(in Base Year (2002) $)		
Fixed O + M		
Direct Operating Labor	1,069,159	
- Number of Operating Staff	17	
Direct Maintenance Labor	901,818	
- Number of Maintenance Staff	15	
Annual Services, Materials, & Purchased Power		
- Annual O&M Services & Materials	374,337	
- Non-operating Purchased Power	120,404	
Indirect Labor Costs		
- Benefits	616,896	
- Home Office Costs	294,421	
TOTAL FIXED O+M		

REPOWER ONE UNIT Costs (Continued)

Variable O+M		
Scheduled Maintenance Parts & Materials		
- CT Inspection/Overhaul	8,863,800	
- HRSG Inspection/Refurbish	582,614	
- ST Inspection/Overhaul	744,000	
- BOP Refurbish	500,000	
Scheduled Maintenance Labor		
- CT Inspection/Overhaul	620,466	
- HRSG Inspection/Refurbish	174,784	
- ST Inspection/Overhaul	111000	
- BOP Refurbish	85,199	
Unscheduled Maintenance Allowance	529,098	
Catalyst Replacement		
- SCR Catalyst Materials & Labor	172,608	
- CO Catalyst Materials & Labor	0	
Other Consumables		
- Raw water	1,843,527	
- Circulating water	0	
- NH3	46,357	
- H2SO4	39,547	
- NaOH	47,755	
- Misc	44,781	
Disposal Charges		
- Spent SCR catalyst	10,788	
- Spent CO catalyst	0	
- Other disposal	3,698	
Byproduct Credit	0	
Total Non Gas Variable O+M	14,420,022	
Total Non Gas Variable O+M ($/MWh)		1.68
Total Fixed and Variable O+M	14,420,022	

REPOWER ONE UNIT Capital Outlay

Category	Total	1	2	3
Calendar Year (Jan 1 - Dec 31)		2004	2005	2006
Total Plant Cost				
In Base Year (2002) Currency	394,110,016	16,382,303	53,702,056	324,025,664
Amount of Escalation	30,658,974	661,845	3,286,995	26,710,134
Escalated Total Plant Cost	424,769,024	17,044,148	56,989,052	350,735,808
Other Outlays(*)	18,576,800	0	0	18,576,800
Gross Outlay	443,345,792	17,044,148	56,989,052	369,312,608
Investment Tax Credits	0	0	0	0
Other Income Tax Offsets	0	0	0	0
Net Total Capital Requirement				
Net Cash Outlay	443,345,792	17,044,148	56,989,052	369,312,608
AFUDC - Equity(**)	18,400,370			
AFUDC -- Interest	11,775,106			
Total (Excluding capital cost adders)	473,521,280			
Gross Depreciable Investment		452,966,720		
Non-Depreciable Net Plant Outlay(***)	2,154,211			
Equity AFUDC	18,400,370			
Total Non-Depreciable Investment		20,554,580		
Capital Cost Adders	37,400,000			
Total Capital Requirement		510,921,312		
Less Investment Tax Credit		0		
Net Total Capital Requirement		510,921,312		

(*) Consists Of	
Land	0
Preproduction Costs	16,422,588
Prepaid Royalties	0
Inventory Cap + Init Cat/Chem	2,154,211
Total	18,576,800
(**) Consists of:	
Preferred Stock AFUDC	0
Common Equity AFUDC	18,400,370
Total	18,400,370
(***) Consists of:	
Land	0
Inventory Cap + Init Cat/Chem	2,154,211
Total	2,154,211

REPOWER ONE UNIT 4X1 Emissions

Variable	Value	Units
PLANT DESIGN BASIS		
Ambient Air Temperature	59	F
Site Elevation Above MSL	695	ft
Cycle Type	Combined Cycle Cogeneration	
Number of Combustion Turbines Operating	4	
CT Primary Fuel Type	Natural Gas	
CT NOx Control Type - Primary Fuel	Dry Low NOx Combustors	
CT Air Precooler Discharge Temperature	59	F
Cooling System Type	Wet Mech Draft Cooling Twr	
SCR Configuration	Anhydrous Ammonia Injection	
NOx Conversion Efficiency (%), Primary Fuel	51	%
Include Duct Burners	Yes	
Duct Burner Use	Full-Time	
DB Primary Fuel Type	Natural Gas	
AIR EMISSIONS - HRSG's		
Firing Primary Fuel		
CO2 Mass Flow Per HRSG Stack	225,714.88	lb/h
CO Mass Flow Per HRSG Stack	57.35	lb/h
NOx (As NO2) Mass Flow Per HRSG Stack	34.77	lb/h
NH3 Mass Flow Per HRSG Stack	12.85	lb/h
SO2 Mass Flow Per HRSG Stack	0	lb/h
CO Concentration	14	ppmvd @ 15% O2
NOx Concentration	5	ppmvd @ 15% O2
NH3 Concentration	5	ppmvd @ 15% O2
SO2 Concentration	0	ppmvd @ 15% O2
Volumetric Flow Rate Per HRSG Stack	979,280	ft3/min-act
CO2 Mass Flow Total Plant	902,859.50	lb/h
CO Mass Flow Total Plant	229	lb/h
NOx (As NO2) Mass Flow Total Plant	139.07	lb/h
NH3 Mass Flow Total Plant	51.4	lb/h
SO2 Mass Flow Total Plant	0	lb/h
LIQUID DISCHARGES		
Raw Cycle Water Make-up Peak Flow	179	gpm
Raw Cycle Water Make-up Average Flow	119	gpm
Cooling Tower Make-up Peak Flow	8,681	gpm
Cooling Tower Make-up Average Flow	5,787	gpm
Cooling Tower Blowdown Peak Flow	1,664	gpm
Cooling Tower Blowdown Average Flow	1,110	gpm
Total Waste Water Discharge Peak Flow	21,951	gpm
Total Waste Water Discharge Average Flow	1,231	gpm

REPOWER ONE UNIT 4X1 Emissions (Cont.)

SOLID WASTES		
SCR Catalyst Material	Vanadium Pentoxide/Zeolite	
SCR Catalyst Volume	1,039	ft3
SCR Catalyst Replacement Frequency	37,386	years