Appendix B

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

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UTILITY ENGINEERING

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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) * Duct Burners Included	943 1063*	6815 7298*	510,921*	542*
4) Repower Both Nuclear Units (4x1)	1886	6815	NA	NA
5) Present Plant - Nuclear Units	1070	10470 (9783 design)		

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.
- 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.

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

Repowering

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 burner equipped configuration matches the current nuclear output well, it was used in as the base repowering scenario. Repowering both plants in a 4x1 configuration results in a site output of 1886 MW, which is 826 MW above current output and above known equipment and transmission limits. A 4x1 configuration also allows for future conversion to a 6x1 configuration with an increase from 943 MW to 1412 MW if dictated by system load.

Engineering Issues and the Heat Balance Model

A heat recovery steam generator is most efficient when steam is generated at multiple pressure levels. This contradicts the conventional boiler method of using steam turbine extractions to heat the feedwater. Instead, steam is introduced into the steam turbine at different points, with the steam turbine designed to handle the additional flow at lower pressures. Given the above, the use of the existing feedwater heaters at Prairie Island would rob the HRSGs of heat absorption capability, so the feedwater heaters have been removed from the conceptual design. Since the PI turbines were designed to operate in a saturated steam nuclear cycle, the blades have moisture separation features. The ability to drain the separated moisture has been retained in the model, assuming that the extraction points would be converted into level controlled drip legs of sufficient size to handle the drain capacity.

When a conventional plant steam turbine is repowered with combined cycle steam, the turbine is typically restricted to a maximum amount of exhaust flow. The result of the Low Pressure (LP) steam flow limitation is that the bowl pressure after the throttling valves drops to the point that continuing to use the steam chest costs performance. Most combined cycle steam turbines are designed without a control stage and operate with valves wide open to accommodate rapid fluctuations in heat input to the HRSG, due to a number of variables affecting the gas turbine performance. Load is controlled by changing the load point of the gas turbines. In order to allow the HRSGs to dampen thermal changes, the control stage and steam chest can be removed, but for the purpose of the model, the steam turbine is assumed to operate with the steam chest valves wide open.

The LP steam flow limitation also constrains the output capability of the repowered steam turbine. This is shown in the decrease in STG output from approximately 535 MW (nuclear) to 447 MW (repowered 6x1). Depending on the actual design of the steam turbine, it is possible that additional flow could be forced through the exhaust to allow more output, but this model uses the steam turbine heat balance exhaust flow as the limit. Capacity for a seventh CTG-HRSG train may be available. This would involve additional design work and an extensive evaluation of the PI steam turbine design.

Configuration Efficiencies

Trial performance runs of 2x1, 4x1, 4x1 with duct burners, and 6x1 configurations were made in the heat balance model. The results are presented in Table 2 below, Configuration Efficiencies of a Single Repowered Unit.

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.

- 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 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