ALTERNATIVES STUDY

San Juan Generating Station

Public Service of New Mexico

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Prepared by

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EXECUTIVE SUMMARY

Public Service of New Mexico (PNM) is reviewing alternatives for compliance with future regulations for reducing carbon emissions from power generation. Alternatives include evaluation of switching to lower-carbon fuel supplies, capture and sequestration of CO_2 emissions, and the repowering of some combination of the San Juan Generating Station (SJGS) Units to determine future strategies for operation of the Station. Pursuant to determining the strategies, PNM retained Sargent & Lundy, L.L.C. (S&L) to perform a San Juan Generating Station Alternatives Study.

The purpose of this study was to compare application of carbon capture and sequestration (CCS) technology to repowering of either Unit 1 or Unit 2 in combination with Unit 3 or Unit 4 with natural gas fired Combustion Turbine Generators (CTGs) and Heat Recovery Steam Generators (HRSGs). The steam produced in the HRSGs would repower the existing Unit 1 or Unit 2 and Unit 3 or Unit 4 Steam Turbine Generators (STGs); and, the other two units would be retired in place. As part of the evaluation of the repowering alternative, this study also evaluated the availability of natural gas to be fired in the CTGs. Finally, the feasibility of installing a Fluor Carbon Capture System on all four units was evaluated as a potential lower carbon option.

This study encompassed the following major tasks:

- Optimize and evaluate thermal performance of repowering concepts for SJGS - Unit 1 or Unit 2 and Unit 3 or Unit 4 using the General Electric Company (GE) F Class CTGs.
- Perform a natural gas supply study.
- Perform an evaluation of implementing a Fluor Carbon Capture System to achieve 90% carbon capture on all four Units at SJGS. The qualitative application of CCS to achieve 45% carbon capture is also considered.

This report presents the findings and results of the evaluations identified above comparing the different combustion turbine arrangements and the Carbon Capture process to select the best strategies for future operation of the Station.

The following combustion turbine arrangements were evaluated at three ambient temperatures to provide seasonal variation in plant performance:

- GE 7FA.05 in a 4 x 4 x 1 configuration for Unit 1 or Unit 2

- GE 7FA.05 in a 5 x 5 x 1 configuration for Unit 3 or Unit 4

Note that the terminology 4 x 4 x 1 refers to four (4) CTGs with four (4) HRSGs providing steam to one (1) STG; and, 5 x 5 x 1 refers to five (5) CTGs with five (5) HRSGs providing steam to one (1) STG. Also, while GE F Class CTGs were used as a basis for comparison of the alternatives in this high level screening study, Mitsubishi Heavy Industries and Siemens manufacture comparable size CTGs and should be considered in any further evaluation of the repowering alternative. For this high level screening study, a representative technology was selected. If repowering is selected for further evaluation, the cycle and equipment selection would be optimized in the next phase.

The repowering heat balances presented in Appendix A were evaluated by S&L to provide a preliminary assessment of whether there would be any potential fatal flaws in repowering the Unit 1 or Unit 2 and Unit 3 or Unit 4 STGs. As shown in the heat balance summary tables, Appendix A, the low pressure (LP) stage is the limiting factor during the winter case as steam velocity approaches sonic velocity, making the winter case the output limit of the steam turbine. Based on a comparison of the Unit 1 and Unit 2 STGs, the Unit 2 STG should be repowered; because, it has lower exhaust losses (larger annulus area) and a better heat rate (STG section efficiencies are better than Unit 1), as indicated in Appendix B. The repowered Unit 2 would have an approximate Net Power Output of 1,006 MW, a Net Unit Heat Rate of 6,150 BTU/kWh [Lower Heating Value (LHV)], and a Net Unit Heat Rate of 6,826 BTU/kWh [Higher Heating Value (HHV)] at annual average ambient conditions.

The Unit 3 and Unit 4 STGs are identical. Therefore, for the purposes of this evaluation, Unit 3 was selected because it is adjacent to Unit 2. Repowering of Unit 2 and Unit 3 would give PNM the flexibility of demolishing the retired Unit 1 and Unit 4 in the future to provide space for future expansion of the station. However, there may be other factors that warrant selection of Unit 4 over Unit 3, such as better operating history or recent upgrades. Nevertheless, the repowered Unit 3 would have an approximate Net Power Output of 1,228 MW, a Net Unit Heat Rate of 6,299 BTU/kWh (LHV), and a Net Unit Heat Rate of 6,992 BTU/kWh (HHV) at annual average ambient conditions.

The heat and mass balances analyses performed by S&L as part of this study are based on information received for the current Rankin Cycle operating condition with feedwater heaters. From this data, information can be deduced regarding turbine efficiencies, pressure ratios, exhaust conditions, and other thermodynamic parameters. Since a complete Thermal Kit was not available, some cycle and performance conditions were assumed based on engineering judgment.

Typically, for combined cycle repowering of an existing steam turbine, the extraction steam from the turbine is eliminated and all feedwater heating is accomplished in the HRSG. This provides the most efficient cycle. Based on the heat and mass balance thermodynamic results, these steam turbines are good candidates for repowering with combustion turbine/combined cycle technology. However, it results in a change from the design steam path flows and parameters through the turbine, which requires an evaluation of the internal components from a mechanical strengths perspective.

This study is a conceptual screening analysis meant to provide a comparative analysis between the options. For that reason, the level of accuracy in the estimates is plus or minus 30%. If the repowering alternative is considered further, a detailed steam path audit should be performed on the existing steam turbines by the STG Original Equipment Manufacturer (OEM), GE, or another qualified OEM in the next phase of project development. This audit will assess the physical condition of the steam turbines with the repowered steam path conditions and identify any potential optimization of the cycle performance and output.

Using the data from the heat balances, an estimate of the expected plant air emissions was developed. Table ES-1 below identifies the anticipated Air Quality Control Systems (AQCS), which would be installed with the repowered units.

Table ES-1. Assumed Air Pollution Controls for the Repowered Units

Pollutant	Control
NO_X	SCR
CO	Good combustion
VOC	Good combustion
PM_{10} / $PM_{2.5}$	Firing natural gas
SO_2	Firing natural gas
CO_2	Firing natural gas

Maximum hourly emissions estimates for base load operation of the repowered Unit 2 and Unit 3 are presented in Table ES-2.

Table ES-2. Maximum Hourly Emission Estimates for Unit 2 and Unit 3

Pollutant	Gas Firing – Controlled (per CTG/HRSG)	
NO_X	13.6 lb/hr	2.0 ppm
CO	37.3 lb/hr	9.0 ppm
VOC	3.3 lb/hr	1.4 ppm
PM_{10} / $PM_{2.5}$	18.7 lb/hr	0.0109 lb/mmBtu
SO_2	2.6 lb/hr	0.0014 lb/mmBtu
Unit 2 CO_2	217,466 lb/hr	808.2 lb CO_2/MWh_{net} (4)
Unit 3 CO_2	217,466 lb/hr	827.1 lb CO_2/MWh_{net} (4)

Notes:

1. Emissions estimates based on performance data provided by GE and assumed NO_X reduction with SCR. Estimates are presented on a per CTG basis, except for the lb CO_2/MWh_{net} (See Note 4).
2. PM_{10} / $PM_{2.5}$ emissions estimates include front and back half.
3. Concentrations are corrected to 15% O_2 dry.
4. CO_2 emissions are based on 4 CTGs for Unit 2 and 5 CTGs for Unit 3; and, the net output includes the STG output.

Detailed emissions can be found in Appendix C.

A conceptual General Arrangement (GA) Drawing was developed to show the configuration of the CTGs, HRSGs, and associated equipment for the repowering alternative. The location chosen for the four CTGs and four HRSGs required for repowering the Unit 2 STG is south of Unit 1; and, the location chosen for the five CTGs and five HRSGs required for repowering the Unit 3 STG is north of Unit 4. These areas are presently used for miscellaneous structures and laydown of material. Thus, the miscellaneous structures must be demolished and the material relocated. The demolition and relocation costs are included in the cost estimates developed for the project. The conceptual GA Drawing of the repowered units is presented in Appendix D.

Included in Appendix E is a summary level project schedule for repowering SJGS Unit 2 and Unit 3. The schedule includes critical procurement, engineering, construction, and startup activities. The repowering schedule is based on S&L's database for F-frame combined cycle projects and experience with steam turbine repowering projects using combustion turbines. The schedule shows a 41 month period for repowering Unit 2, with Unit 3 following seven months later.

Order-of Magnitude cost estimates were developed for repowering Unit 2 and Unit 3. The cost estimates are presented in Appendix F. The cost estimates are conceptual in nature, and based largely on a data base from similar projects. No significant preliminary engineering has been performed to develop the project details; and, specific site characteristics have not been fully analyzed. Allowances have been included where necessary to cover issues that are likely to arise. The resulting estimated values fall within the ±30% range with the inclusion of the designated contingency.

A summary of the estimates for repowering Unit 2 and Unit 3 is presented in Table ES-3.

Table ES-3. Summary of Order-of-Magnitude Cost Estimates for Repowering Unit 2 and Unit 3

Configuration	Unit 2 – 4 x 4 x 1	Unit 3 – 5 x 5 x 1	Station Total
Direct Project Costs ($M)	$675	$848	$1,523
Indirect Project Costs ($M)	$37	$44	$81
Contingency ($M)	$84	$105	$189
Total Project Costs ($M)	$796	$997	$1,793
Gross Output, Annual Average (MW_{gross})	1,032	1,259	2,291
$ / kW_{gross} (Incl. Steam Turbine Capacity)	$772	$792	$783
Net Output, Annual Average (MW_{net})	1,006	1,228	2,234
$ / kW_{net} (Incl. Steam Turbine Capacity)	$792	$812	$803

As directed by PNM, S&L contacted El Paso Natural Gas (EPNG) on a confidential basis to determine the availability of natural gas in sufficient quantity required to repower Unit 2 and Unit 3. EPNG advised that they have the capacity to provide the required quantity of natural gas to the facility at a pressure well above the 450 psig required for the GE Frame 7F CTGs. A conceptual estimate of the cost of the 15 mile underground natural gas pipeline from the EPNG System is $23,000,000, based on the present installed cost of buried steel piping. S&L also contacted the Transwestern Pipeline Company (Transwestern Pipeline) on a confidential basis to determine the availability of natural gas. Transwestern Pipeline advised that they have adequate capacity to supply the necessary natural gas at the required pressure. A conceptual estimate of the cost of the 30 mile underground natural gas pipeline from the Transwestern Pipeline System is $43,500,000, based on the present installed cost of buried steel piping.

The installation of a Carbon Capture and Sequestration (CCS) System for each of the four units at SJGS was evaluated. For the purposes of this evaluation, published data was used for the cost of the CCS System based on the Fluor Econamine technology; and, the Integrated Environmental Control Model, developed by the Department of Energy (DOE), was used to determine sizing and auxiliary power requirements for the system. This data was compared to other data available to S&L from a variety of sources and adjusted, as necessary.

Knowledge concerning CCS is based on a technology that is rapidly evolving. Currently, the largest CO_2 capture systems operate on slip-streams of no more than 20 MW of flue gas. Several commercial scale facilities have been announced at the 100 MW to 235 MW range as early demonstrations of the technology, although none are yet in service. It is anticipated that technology suppliers will not likely offer guarantees and warrantees (with liquidated damages) for this technology until the 2015 to 2017 time frame. Commitment to CCS at the scale of SJGS at this time would entail considerable risk due to the uncertainty in cost and performance. All current demonstration projects are proceeding with U.S. government support in the form of grants to off-set the high cost and risk associated with the technology.

With installation of a CCS System on each of the four units, the reduction in total annual emissions for CO_2 and sulfur are substantial, as shown in Table ES-4. The total reduction in CO_2 emissions possible for the plant is nearly 15 million tons per year, based on a 100% capacity factor. Sulfur emissions in the form of SO_2 and SO_3 are reduced by more than 6,000 tons per year, also based on a 100% capacity factor.

Table ES-4. Annual CO_2 and Sulfur Emission Reductions

Emissions Reductions	**Unit 1 Ton/yr**	**Unit 2 Ton/yr**	**Unit 3 or Unit 4 Ton/yr**	**Total SJGS Ton/yr**
CO_2 to Sequestration (or EOR)	2,908,262	3,011,000	4,455,000	14,829,262
Additional SO_2 Removed	1,261	1,261	1,866	6,255
Additional SO_3 Removed	54	54	80	270

Once the CO_2 has been recovered from the flue gas, it must be sequestered. Basically, there are three sequestration alternatives:

- Find a suitable location in a saline aquifer for permanent storage.
- Find a suitable location nearby for beneficial use to recover methane from deep coal seams or for enhanced oil recovery (EOR).
- Tie into an existing pipeline to transport the CO_2 to an area where EOR is currently being practiced.

Kinder-Morgan operates the largest CO_2 pipeline in the U.S, located about 25 miles from the plant on the east side of Farmington, NM. For the purposes of this study, S&L has assumed that PNM can negotiate with Kinder-Morgan for transporting the CO_2. The cost for the necessary transport pipeline is about $50,000,000. S&L has not assumed any revenues from the sale of CO_2.

A conceptual GA Drawing was developed to show the configuration of the CCS System at the four units. The conceptual GA Drawing of the CCS Systems is presented in Appendix D.

A discussion concerning a conceptual schedule for implementation of CCS Systems at SJGS is presented in Section 4 of this report. Conceptually, the schedule should be similar to the 36 month period for implementation of Wet Flue Gas Desulfurization Systems; however, the lead time for the CO_2 compressors and the CO_2 pipeline may increase that schedule.

S&L examined the capital costs published in a number of DOE reports and from past S&L studies. Based on this data, the anticipated costs for the CCS facility were developed with the high degree of retrofit associated with the application of the Econamine FG Plus technology at SJGS. Due to the constraints of the site, there are extensive retrofit costs associated with the location of the equipment. These include:

- Long duct runs from the existing chimneys to the process location
- Use of new chimneys rather than return ducts to the existing chimneys and more pressure drop
- Long pipe runs to connect the regeneration facility located in a separate area from the absorber area

The operation of a CCS System requires a substantial amount of heat to regenerate the solvent. This heat may be provided by steam taken from the steam turbine cycle between the intermediate pressure (IP) and low pressure (LP) steam turbines. Approximately 40% of the total IP/LP steam is extracted from the turbine cycle, which results in a derating of approximately 13% in the gross power output of each unit. In addition to the unit derating resulting from steam extraction, the increased auxiliary power required for the operation of the CCS facility consumes an additional 19% of unit output. As a result of these power deratings, the net unit output is reduced by approximately 34% for the entire station.

Table ES-5 presents a summary of the capital cost estimate for installing CCS Systems on all four units and the performance data associated with the retrofit of CCS to each of the SJGS units.

Table ES-5. Summary of Carbon Capture System Cost Estimates and CO_2 Emissions (all Four Units)

CCS Summary Data for SJGS	Unit 1	Unit 2	Unit 3	Unit 4	Station Total
Capital Cost					
Direct Project Costs ($M)	$591	$591	$774	$774	$2,730
Indirect and Other Project Costs ($M)	$101	$101	$131	$131	$464
Contingency ($M)	$118	$118	$155	$155	$546
Total Project Costs ($M)	$810	$810	$1,060	$1,060	$3,740
Cost for CO_2 Pipeline ($M)					$50
Plant Output & Normalized Cost					
Existing Gross Power Output, (MW_{gross})	368	381	573	573	1,895
Existing Net Power Output, (MW_{net})	342	354	533	533	1,762
Net Power Output w/CO_2 Capture, (MW_{net})	223	231	352	352	1,158
$ / kW_{net} Output w/CO_2 Capture	$3,632	$3,506	$3,011	$3,011	$3,230
CO_2 Emissions Summary					
Annual CO_2 Sequestered (ton/yr @ 100% CF)	2,908,262	3,011,000	4,455,000	4,455,000	14,829,262
Annual CO_2 Emissions (ton/yr @ 100% CF)	323,132	334,547	495,024	495,024	1,647,727
Uncontrolled CO_2 Emissions, (lb CO_2/MWh_{net})	2,156	2,156	2,121	2,121	2,135
Controlled CO_2 Emissions, (lb CO_2/MWh_{net})	331	331	322	322	325

The information provided in this report can be included in a pro forma type financial analysis to determine the best strategy for the possible application of CCS technology at SJGS, compared to the other alternatives presented.

Table ES-6 presents the uncontrolled CO_2 emissions to the controlled CO_2 emissions on a lb CO_2/ $MWhr_{net}$ basis for the repowering and compares the alternatives of repowering to implementing CCS Systems to reduce CO_2 emissions to the existing emissions from the plant today fired with coal. Although 90% of the CO_2 is reduced in the CCS System, the actual emissions are only reduced by 85% on a net power output basis. For the natural gas repowering alternative, the CO_2 emissions are reduced by 62% on a net MWh Basis.

Table ES-6. Comparison of CO_2 Emissions per Net Power Output for Each Alternative

CO_2 Emissions Summary	Uncontrolled Emissions (1) (lb CO_2/MWh_{net})	Controlled Emissions (2) (lb CO_2/MWh_{net})
Unit 1	2,156	331
Unit 2	2,156	331
Unit 3	2,121	322
Unit 4	2,121	322
Station Average with Coal	2,135	325
Repowered Unit 2 (average ambient)	797	N.A.
Repowered Unit 3 (average ambient)	816	N.A.
Station Average - Repowered on Natural Gas (3)	807	N.A.
Notes: 1) Uncontrolled emissions are based on the existing net MW output for coal firing. 2) Controlled emissions are based on the new net MW output for coal firing with CCS.		

Table ES-7 summarizes the overall results of the study comparing the current output with the revised output for repowering Unit 2 and Unit 3 and for implementing CCS Systems on all four units. The capital cost for implementation of CCS Systems on all four units is over twice the cost of repowering Unit 2 and Unit 3. On an annual basis, the reduction in CO_2 emissions is greater with CCS Systems than with repowering; however, repowering still reduces the amount of CO_2 emitted from the SJGS, while increasing, rather than decreasing, station capacity.

Table ES-7. Overall Study Data Summary

Summary Analysis	**Existing Coal Fired Units 1 - 4**	**Natural Gas Repowered Unit 2 and Unit 3**	**CCS Systems on Units 1 - 4**
Current Output,(MW_{gross})	1,895	N.A.	N.A.
Current Output,(MW_{net})	1,762	N.A.	N.A.
Repowered Output, (MW_{net})	N.A.	2,234	N.A.
Output with CCS (MW_{net})	N.A.	N.A.	1,158
Total Capital Cost for Alternative ($M)	N.A.	$1,793	$3,740
Normalized Capital Cost, ($/$kW_{net}$)	N.A.	$803	$3,230
Current Annual CO_2 Emissions (ton/yr)	16,476,990	N.A.	N.A.
Post-Modification Annual CO_2 Emissions (ton/yr)	N.A.	7,898,349	1,647,727
% CO_2 Reduction from Existing Annual Total	N.A.	52.1%	90%

1. INTRODUCTION

Public Service of New Mexico (PNM) is reviewing alternatives for fuel supplies, emissions, and repowering of San Juan Generating Station (SJGS) – Unit 1 through Unit 4 to determine future strategies for operation of the Station. Pursuant to determining the strategies, PNM retained Sargent & Lundy, L.L.C. (S&L) to perform a San Juan Generating Station Alternatives Study.

San Juan Generating Station is located 15 miles west of Farmington, New Mexico and is comprised of Unit 1 [367 Megawatts (MW) at Valves Wide Open (VWO) – Normal Pressure (NP)], Unit 2 [381 MW at VWO + 5% Over Pressure (OP)], Unit 3 (573 MW at VWO - NP), and Unit 4 (573 MW at VWO – NP). All four units fire coal produced in an adjacent mine. The steam generating units for Units 1 and 2 were manufactured by Foster Wheeler Corporation (Foster Wheeler); and, the steam generating units for Units 3 and 4 were manufactured by The Babcock & Wilcox Company (B&W). All four units include Electrostatic Dust Precipitators (ESPs), Powdered Activated Carbon (PAC) Injection Systems, Pulse Jet Fabric Filters (baghouses), and Wet Flue Gas Desulphurization (WFGD) Systems. All four steam turbine generators (STGs) were manufactured by General Electric Company (GE). Unit 1, Unit 3, and Unit 4 were upgraded by GE and Unit 2 was upgraded by Siemens.

The purpose of this study was to evaluate repowering of Unit 1 or Unit 2 and Unit 3 or Unit 4 with natural gas fired Combustion Turbine Generators (CTGs) coupled with Heat Recovery Steam Generators (HRSGs). The steam produced in the HRSGs would repower the existing Unit 1 or Unit 2 and Unit 3 or Unit 4 STGs; and, the other two units would be retired in place. As part of the evaluation of the repowering alternative, this study also evaluated the availability of natural gas to be fired in the CTGs. Finally, the feasibility of installing a Fluor Carbon Capture System on all four units was evaluated as a potential lower carbon option.

As part of this study, the following tasks were performed:

- Optimize and evaluate thermal performance of repowering concepts for SJGS - Unit 1 or Unit 2 and Unit 3 or Unit 4 using the GE F Class CTGs. This task includes the following activities:
  - Prepare heat balances based on firing natural gas.
  - Determine Gross Power Output, Net Power Output, Heat Rate before and after repowering, and fuel consumption.

- Determine the capacity of the existing STGs, the capability of the existing STGs to accommodate the steam generated in the HRSGs, and any STG Low Pressure exhaust flow limitations.
- Determine if auxiliary firing in the HRSGs should be used to maximize the STG capabilities.
- Determine any impacts to the heat rejection systems and any increases or decreases in water usage.
- Provide predictions of expected emissions from the repowered units.
- Evaluate the existing plant equipment to be reused in the new plant configuration.
- Develop a conceptual General Arrangement (GA) Drawing of the repowered units.
- Prepare a conceptual schedule for the repowering project.
- Develop an Order-of-Magnitude Cost Estimate for repowering the Units (+/- 30%).

While GE F Class CTGs were used as a basis for comparison of the alternatives in this high level screening study, Mitsubishi Heavy Industries and Siemens manufacture comparable size CTGs and should be considered in any further evaluation of the repowering alternative. For this high level screening study, a representative technology was selected. If repowering is selected for further evaluation, the cycle and equipment selection would be optimized in the next phase.

- Perform a natural gas supply study, including the following activities:
  - Determine the availability of a sufficient supply of natural gas in the region.
  - Determine the required and available supply pressure of the natural gas.
  - Identify a potential routing of the pipeline from the main natural gas transmission line to the Station.
  - Develop an Order-of-Magnitude cost estimate for the pipeline routed from the main natural gas transmission line to the Station.
- Perform an evaluation of implementing a Fluor Carbon Capture System to achieve 90% carbon capture on all four Units at SJGS, including the following activities:
  - Determine the capability of the existing STGs to provide the required steam and the impacts on the operation of the units. If necessary, evaluate the necessity of providing steam from an alternative source.
  - Determine the impacts of the cooling water requirements on the Station's water demands.
  - Determine the impacts of the waste/effluent streams from the CO_2 Scrubber.
  - Determine the impacts of the new booster fans on operation of the existing draft system, including the impacts of the new flue gas flow paths.
  - Determine the impacts of the new electrical loads on the existing auxiliary power system, including the need for new auxiliary power transformers.
  - Determine the ability to site the CO_2 Recovery System on the Station's property.

- Provide a suggestion for location of the CO_2 sequestration site for use in determining the compressor and pipeline costs.
- Develop a conceptual GA Drawing of the Fluor Carbon Capture System.
- Prepare a conceptual schedule for the implementing the Fluor Carbon Capture System at the Station.
- Develop a +/- 30% Order-of-Magnitude Cost Estimate for the Fluor Carbon Capture System.

A qualitative evaluation of implementing a Fluor Carbon Capture System to achieve 45% carbon capture on all four units at SJGS was also performed.

The optimization and evaluation of the thermal performance of repowering concepts for SJGS - Unit 1 or Unit 2 and Unit 3 or Unit 4 using the GE F Class CTGs is presented in Section 2. The natural gas supply study is presented in Section 3. The evaluation of implementing a Fluor Carbon Capture System to achieve 90% and 45% carbon capture on all four Units at SJGS is presented in Section 4.

2. THERMAL PERFORMANCE OF REPOWERING CONCEPTS

2.1 SELECTION OF METEOROLOGICAL CONDITIONS

San Juan Generating Station is located 15 miles west of Farmington, New Mexico. The closest and most representative meteorological station with available data is located at the Four Corners Regional Airport.

For the purposes of the performance evaluation, the following three cases were chosen to evaluate winter, annual average, and summer meteorological data:

- 99% dry-bulb temperature and mean coincident relative humidity
- Annual average dry-bulb temperature and relative humidity
- 1% dry-bulb temperature and mean coincident relative humidity

The parameters and respective references are listed in Table 2-1 below.

Table 2-1. Meteorological Data

Parameters	Value	Notes
99% dry-bulb temperature and mean coincident relative humidity	6 °F 100% RH	“Weather Data Handbook 1980” data for Farmington, NM
Annual average dry-bulb temperature and relative humidity	53 °F 47% RH	"Climate Design Data 2009 ASHRAE Handbook" data for Farmington, NM
1% dry-bulb temperature and mean coincident relative humidity	95 °F 18% RH	“Weather Data Handbook 1980” data for Farmington, NM

2.2 CYCLE OPTIMIZATION AND HEAT BALANCES FOR ALTERNATIVES CONSIDERED

Based on discussions with PNM, it was determined that the steam turbines have been modified. The evaluation was therefore based on the heat and mass balances provided for the modified steam turbines. The heat balances and thermal kit information for the existing STGs for Unit 1 through Unit 4 received from PNM were incorporated into the analytical model. Based on a comparison of the Unit 1 and Unit 2 STGs, the Unit 2 STG should be repowered; because, it has lower exhaust losses (larger annulus area) and a better heat rate (STG section efficiencies are better than Unit 1), as indicated in Appendix B. The Unit 3 and Unit 4 STGs are identical. Therefore, for the purposes of this evaluation, Unit 3 was selected because it is adjacent to Unit 2. Repowering of Unit 2 and Unit 3 would give PNM the flexibility of demolishing the retired Unit 1 and Unit 4 in the future to provide space for future expansion of the station. However, there may be other factors that warrant selection of Unit 4 over Unit 3, such as better operating history or recent upgrades. The existing Unit 2 and Unit 3 steam turbines were modeled in a matching reference case, which provides an accurate representation of steam turbine performance when operating in the new configuration with varying steam conditions.

The GateCycle™ Program (Version 5.52.0.r) was utilized to predict plant performance in the repowered units, which assumes zero extraction flow from the existing steam turbine (i.e., all feedwater preheating is achieved in the HRSG), and the capability of admitting low pressure steam from the HRSG at the steam turbine crossover point. The steam turbine is controlled in the sliding pressure mode of operation with varying inlet pressure to achieve optimum performance. The Basis for the Repowered Heat Balances for both Units 2 and 3 is CTGs operating at 100% load at annual average, 99% Dry Bulb and 1% Dry Bulb; Evaporative Cooling for ambient temperatures greater than 59 °F; three (3) pressure level HRSG with integral deaerator; and no HRSG duct firing. HRSG bypass dampers were not included in the design basis.

The increase in steam flow rate to the back end of the low pressure (LP) turbine section approaches the design limits for this typical frame size; but, it does not exceed the mass flow limit. However, the exhaust flow conditions for the winter case, with low condenser pressure, should be verified by the steam turbine OEM. The heat and mass balances analyses performed by S&L are based on information received for the current Rankin Cycle operating condition with feedwater heaters. From this data, information can be deduced regarding turbine efficiencies, pressure ratios, exhaust conditions, and other thermodynamic parameters. Since a complete Thermal Kit was not available, some cycle and performance conditions were assumed based on engineering judgment.

Typically, for combined cycle repowering of an existing steam turbine, the extraction steam from the turbine is eliminated and all feedwater heating is accomplished in the HRSG. This provides the most efficient cycle. Based on the heat and mass balance thermodynamic results, these steam turbines are good candidates for repowering with combustion turbine/combined cycle technology. However, it results in a change from the design steam path flows and parameters through the turbine, which requires an evaluation of the internal components from a mechanical strengths perspective.

This study is a conceptual screening analysis meant to provide a comparative analysis between the options. For that reason, the level of accuracy in the estimates is plus or minus 30%. If the repowering alternative is considered further, a detailed steam path audit should be performed on the existing steam turbines by the STG Original Equipment Manufacturer (OEM), GE, or another qualified OEM in the next phase of project development. This audit will assess the physical condition of the steam turbines with the repowered steam path conditions and identify any potential optimization of the cycle performance and output.

A summary of the results for the repowered Unit 2 and Unit 3 are provided in Table 2-2 and Table 2-3, respectively. Data concerning the existing Unit 1 and Unit 4 are also presented in the tables.

Table 2-2. Summary of Heat Balance Results for Units 1& 2

	Existing Unit 1 GE HB	Existing Unit 2 Siemens HB WB-11293, dated 8/2008	Repowered Combined Cycle Unit (4 x 4 x 1)		
			Annual Average	Winter	Summer
Gross STG Power Output (kW_{gross})	367,858	381,236	334,081	338,303	337,430
Gross CTG Power Output (kW_{gross})	N/A	N/A	697,936	765,652	686,309
Unit Gross Power Output (kW_{gross})	367,858	381,236	1,032,017	1,103,956	1,023,739
Assumed Auxiliary Power (%)	7%	7%	2.5%	2.5%	2.5%
Unit Net Power Output (kW_{net})	342,108	354,522	1,006,217	1,076,356	998,149
Gross Turbine Heat Rate (Btu/kWh_{gross})	7,889	7,728	-	-	-
Net Unit Heat Rate (Btu/kWh_{net}), LHV	-	-	6,150	6,246	6,168
Net Unit Heat Rate (Btu/kWh_{net}), HHV (See Note)	10,462	10,462	6,826	6,933	6,847
CO_2 Emissions (lb CO_2/MWh_{net})	2156	2156	796.5	808.2	799.2
CO_2 Emissions (ton/yr) @ 100% Capacity Factor and Annual Average Ambient Conditions	3,231,394	3,345,547	3,510,377	-	-
Note: The Net Unit Heat Rate (Btu/kWh), HHV was obtained from a previous San Juan Generating Station study.					

Table 2-3. Summary of Heat Balance Results for Units 3 & 4

	Existing Unit 3 GE HB AA08-100, Dated 1-14-2008	Existing Unit 4 GE HB AA08-100, Dated 1-14-2008	Repowered Combined Cycle Unit (5 x 5 x 1)		
			Annual Average	Winter	Summer
Gross STG Power Output (kW_{gross})	573,639	573,639	386,954	391,241	393,144
Gross CTG Power Output (kW_{gross})	N/A	N/A	872,420	957,066	857,886
Unit Gross Power Output (kW_{gross})	573,639	573,639	1,259,374	1,348,307	1,251,030
Assumed Auxiliary Power (%)	7%	7%	2.5%	2.5%	2.5%
Unit Net Power Output (kW_{net})	533,484	533,484	1,227,894	1,314,597	1,219,750
Net Turbine Heat Rate (Btu/kWh_{net})	7,827	7,827	-	-	-
Net Unit Heat Rate (Btu/kWh_{net}), LHV	-	-	6,299	6,392	6,310
Net Unit Heat Rate (Btu/kWh_{net}), HHV (See Note)	10,293	10,293	6,992	7,095	7,004
CO_2 Emissions (lb CO_2/MWh_{net})	2,121	2,121	815.9	827.1	817.5
CO_2 Emissions (ton/yr) @ 100% Capacity Factor and Annual Average Ambient Conditions	4,950,024	4,950,024	4,387,972	-	-
Note: The Net Unit Heat Rate (Btu/kWh), HHV was obtained from a previous San Juan Generating Station study.					

Appendix A includes the complete results from the heat and mass balance analyses developed in evaluating the repowering alternatives.

Note that the stack temperatures are higher in the repowered configurations than typically expected with a combined cycle plant with a three (3) pressure level HRSG. This is attributed to the LP turbine section with a design crossover pressure of 170.1 psia for Unit 2 and 177.4 psia for Unit 3 at the maximum flow condition. For the repowered configurations evaluated, the crossover pressure is 173.6 psia for Unit 2 and 149.1 psia for Unit 3 at the maximum flow condition (winter). The optimum crossover pressure for a “greenfield” combined cycle plant would be between 55 psia to 70 psia. Therefore, the higher pressures in the cold-end of the HRSG raised the temperatures resulting in less utilization of available low energy.

2.3 STEAM PATH ANALYSIS

The maximum gross steam turbine generator output did not equal the existing output for any of the alternatives evaluated. Using the current steam turbine configuration, the LP turbine exhaust flow rate was used as the limiting factor. The maximum LP exhaust flow rates for each unit are shown in Table 2-4. Also, the LP turbine exhaust velocity was compared to sonic velocity for the given steam conditions to determine if exhaust flows approach a choke flow situation. As the results presented in Appendix A reflect, the outputs calculated for the winter condition (lowest condenser backpressure based on lowest recorded cooling water temperature), represent the maximum achievable steam turbine output. In these cases, the LP steam turbine exit velocity approaches the sonic velocity limit (choke flow) resulting in the maximum steam flow that can be passed by the LP turbine. Operating the steam turbine near design limits is not a concern unless there are unknown deficiencies that have developed or concerns inherent with the aging of the equipment. These issues, if there are any would be identified and addressed in the next phase of project development with the steam path audit.

For both Unit 2 and Unit 3, the LP steam turbines exhaust flow approaches the maximum steam turbine exhaust flow and sonic velocity; therefore, supplemental firing of the HRSG was not considered. The output loss from repowering the steam turbines cannot be gained by supplemental firing because of the LP steam turbines exhaust limits. In order to maintain the LP exhaust flow below the maximum steam turbine exhaust flow for Unit 3, an evaporator pinch of 50°F was used to limit the amount of steam production.

As previously stated, the evaluation provided in this report is a thermodynamic analysis. If repowering of Unit 2 and Unit 3 is given further consideration, a detailed Steam Path analysis should be performed by the STG OEM, GE. The OEM, or other steam turbine component supplier, needs to evaluate how the changes in the steam path flow affects internal component stresses.

The OEM would provide recommendations for turbine modifications that would allow for the base repowered performance and identify the minimum modifications required to achieve repowered performance. The OEM may identify other enhancements that could improve cycle efficiency along with the costs associated with such improvements. The steam path efficiency can often be improved with newer state of the art components, such as advanced design steam path (ADSP) Dense Pack rotors, advanced aerodynamic and bowed blades, longer last stage blades, and brush seals. The OEM would also provide heat balances showing the efficiency improvements at full load and low load conditions to ensure component integrity during start-up.

Table 2-4. STG Maximum Exhaust Flow

	OEM	Turbine Uprate Manufacturer	Turbine Last Stage Blade Length (in.)	LP STG Exhaust Annulus Area (in^2)	LP STG Number Flow Ends	Approximate LP ST Maximum Exhaust Flow (lb/hr)
Unit 1	GE	GE	33.5	66.1	2	1,983,000
Unit 2	GE	Siemens	37.7	82.3	2	2,469,000
Unit 3	GE	GE	26	41.1	4	2,466,000
Unit 4	GE	GE	26	41.1	4	2,466,000

2.4 HEAT REJECTION SYSTEM AND WATER USAGE EVALUATION

In order to match the existing heat rejection system for Unit 2 and Unit 3 the existing unit condenser data sheets were used to model the condenser performance. The condenser surface area and duty was used to predict condenser performance in the other heat balance cases created - the current system with CCS and the repowered steam turbines at Annual Average, Winter, and Summer conditions. Based on this method, the modeling inputs and assumptions are summarized in Table 2-5.

Table 2-5 Heat Rejection System Inputs and Assumptions

	Unit 2			Unit 3		
Condenser Design Pressure	2.45 in. Hg	DeLaval Unit 2 Surface Condenser Data Sheet		5.0 in. Hg	Foster Wheeler Condenser Data Sheet Units 3 and 4	
Circulating Flow Rate through Condenser (gpm)	160,000	DeLaval Unit 2 Surface Condenser Data Sheet		205,000	Foster Wheeler Condenser Data Sheet Units 3 and 4	
Circulating Flow Rate through Cooling Tower	168,421	Calculated by model using steam conditions on Siemens Heat Balance		215,789	Calculated by model using steam conditions on GE Heat Balance	
Cooling Water Temperature Rise across Condenser	21 °F	DeLaval Unit 2 Surface Condenser Data Sheet		23.98 °F	Foster Wheeler Condenser Data Sheet Units 3 and 4	
Cooling Tower Cells	11 cell	Site photographs		20 cell	Site photographs	
Cooling Tower Approach	14 °F	S&L engineering judgment		14 °F	S&L engineering judgment	
Cooling Tower Cycles of Concentration	4	S&L engineering judgment		4	S&L engineering judgment	
Closed Cooling Water Flow Rate (gpm)	8,421	5% of circulating flow rate through cooling tower		10,789	5% of circulating flow rate through cooling tower	
Repowered Cycle Makeup [Inlet Air Cooling (Evaporation and Bleedoff, COC = 2), HRSG Blowdown (HP & IP Drums), DA Vent]	Annual Average	Winter	Summer	Annual Average	Winter	Summer
	50 gpm	51.6 gpm	331.9 gpm	60.9 gpm	62.6 gpm	413.2 gpm

The flows required from the existing heat rejection system reflect the calculated demands taken from the repowered unit heat balances, and remain within the current system capacities. Based on the review of the existing Circulating Water System and the performance results, the capacity of the existing heat rejection system is sufficient for the repowering. Also, the repowered cycle make-up flows are provided for comparison to the existing annual fresh water requirements.

2.5 AIR QUALITY CONTROL REQUIREMENTS

Table 2-6 provides a list of assumed Air Quality Control Systems (AQCS) that will be required for the repowered units. The controls technologies listed are expected to meet BACT requirements, if necessary.

Table 2-6. Assumed Air Pollution Controls for Repowered Units

Pollutant	Control
NO_X	SCR
CO	Good combustion
VOC	Good combustion
PM_{10} / $PM_{2.5}$	Firing natural gas
SO_2	Firing natural gas
CO_2	Firing natural gas

Maximum hourly emissions estimates for base load operation of the repowered Unit 1 or Unit 2 and Unit 3 or Unit 4 are presented in Table 2-7, and detailed emissions data can be found in Appendix C. The emissions estimates are preliminary and, if necessary, should be further evaluated based on guaranteed emissions data from GE.

Table 2-7. Maximum Hourly Emission Estimates for Unit 2 and Unit 3

Pollutant	Gas Firing – Controlled (per CTG/HRSG)	
NO_X	13.6 lb/hr	2.0 ppm
CO	37.3 lb/hr	9.0 ppm
VOC	3.3 lb/hr	1.4 ppm
PM_{10} / $PM_{2.5}$	18.7 lb/hr	0.0109 lb/mmBtu
SO_2	2.6 lb/hr	0.0014 lb/mmBtu
Unit 2 CO_2	217,466 lb/hr	808.2 lb CO_2/ MWh_{net} (4)
Unit 3 CO_2	217,466 lb/hr	827.1 lb CO_2/ MWh_{net} (4)
Notes:		
1. Emissions estimates based on performance data provided by GE and assumed reduction with SCR. Estimates are presented on a per CTG basis, except for the lb CO_2/MWh_{net} (See Note 4).		
2. PM_{10} / $PM_{2.5}$ emissions estimates include front and back half.		
3. Concentrations are corrected to 15% O_2 dry.		
4. CO_2 emissions are based on 4 CTGs for Unit 2 and 5 CTGs for Unit 3; and, the net output includes the STG output.		

Depending on the potential operating scenarios for the repowered units, the project may trigger the PSD permitting requirements. However, the facility may be able to "net out" of PSD requirements by estimating the change in emissions due to the project. If the change in emissions does not exceed the respective PSD/NSR significant emission rate, the project will not be subject to PSD permitting requirements for that pollutant.

2.6 ANNUAL CO_2 EMISSIONS FOR REPOWERED UNITS

The low carbon density of methane compared to coal coupled with the higher efficiency of the combined cycle for the repowered steam turbines results in a 52% reduction of CO_2 emissions compared with the operation of the existing units with coal (uncontrolled) on an annual tonnage basis. The annual CO_2 emissions for the repowered units operating at a 100% capacity factor are provided in Table 2-8. Note that the emissions for CO_2 on a lb/MWh_{net} basis is a 62% reduction compared to the existing coal fired emissions.

Table 2-8. Annual CO_2 Emissions for Repowered Units

CO_2 Emissions Summary	Unit 2 4 x 4 x1	Unit 3 5 x 5 x 1	Unit 2 and 3 Total	Units 1 - 4 Coal Fired
Combustion Turbine CO_2 Emissions lb/hr, each	200,364	200,364	1,803,276	3,761,934
Unit Annual Emission, ton/yr @ 100% CF	3,510,377	4,387,972	7,898,349	16,476,990
Emissions, lb CO_2/MWh_{net}	797	816	807	2,135

2.7 GENERAL ARRANGEMENT OF REPOWERED UNITS

S&L prepared a conceptual GA Drawing for the SJGS Units consisting of two blocks of GE Frame 7 CTGs and HRSG combinations in a 4 x 4 x 1 configuration for repowering the existing Unit 2 STG and in a 5 x 5 x 1 configuration for repowering the existing Unit 3 STG. The general location of the major equipment is based on constructability and flexibility of operations, as well as overall cost efficiency.

The GA Drawing is presented in Appendix D. The following paragraphs discuss the location for major equipment to be installed and the existing equipment to be reused as a part of the repowering project.

2.7.1 CT/HRSG Locations

The location chosen for the four CTGs and four HRSGs required for repowering the Unit 2 STG is south of Unit 1; and, the location chosen for the five CTGs and five HRSGs required for repowering the Unit 3 STG is north of Unit 4. These areas are presently used for miscellaneous structures and laydown of material. Thus, the miscellaneous structures must be demolished and the material relocated. The conceptual GA Drawing of the repowered units is presented in Appendix D. The Order-of-Magnitude cost estimate is based on this arrangement and includes demolition of the miscellaneous structures and relocation of the material.

2.7.2 Aqueous Ammonia Storage Tanks

Storage tanks will be provided for the 19% aqueous ammonia required for the Selective Catalytic Reduction (SCR) System. The tanks will be sized for an NO_X reduction from 9 ppm inlet to 2 ppm outlet. Based on the Average Annual Case and five days storage, with no weekend delivery, one 18,000 gallon storage tank will be provided for Unit 2 and one 20,000 gallon storage tank will be provided for Unit 3. The tank sizes are based on 25% margin and relatively standard tank sizes.

2.7.3 Closed Cooling Water System

The cooling demand for the CTGs and other ancillary equipment was considered large enough that a new closed loop cooling water system may be necessary. The capacity of the system has been estimated at a flow of 8,400 gpm for Unit 2 and 10,800 gpm for Unit 3 based on heat balance performance analysis. The following major equipment is required to implement the new Closed Cooling Water System:

- Closed Cooling Water Heat Exchangers – (2 per Unit; 4 total)
- Closed Cooling Water Pumps – (2 per Unit; 4 total)
- Closed Cooling Water Head Tanks – (1 per Unit; 2 total)

This evaluation is based on using the cooling tower from one of the two retired units as part of the closed cooling water system. Also, further study might identify the potential to reuse the existing Closed Cooling Water cooling tower or some closed cooling equipment from the retired units.

2.7.4 HRSG Feedwater Pumps

For the repowered configuration, each new feedwater system will include 2 x 100% capacity motor-driven feedwater pumps per HRSG.

2.7.5 New Fuel Gas Metering and Reduction (M&R) Stations

The repowering project will require that a new natural gas supply line be installed from the main natural gas transmission line to the station. Two new M&R stations must be installed, one for Unit 2 and one for Unit 3, as shown on the GA Drawing.

2.8 EXISTING MECHANICAL EQUIPMENT TO BE REUSED FOR REPOWERED UNITS

A review of the SJGS existing equipment was performed to identify the equipment that could be reused. This evaluation is based on reusing the following equipment as part of the repowering project:

- Unit 2 and Unit 3 Steam Surface Condensers
- Unit 2 and Unit 3 Condensate Pumps
- Unit 2 and Unit 3 Circulating Water Pumps

- Unit 2 and Unit 3 Mechanical Draft Cooling Towers
- Station Demineralized Water System
- Station Instrument/Station Air Compressors
- Station Fire Water Pumps

If repowering of Unit 2 and Unit 3 is given further consideration, a detailed review of the condition and capacity of this equipment should be performed.

2.9 ELECTRICAL EQUIPMENT REQUIRED FOR REPOWERED UNITS

2.9.1 Main Power

Each CTG output will be connected to an individual 2-winding Generator Step-Up (GSU) Transformer via self-cooled isolated phase bus duct (IPBD). A Generator Circuit Breaker (GCB) will be included within the IPBD. The GCB will be used to synchronize the incoming CTG voltage to the 345 kV switchyard voltage. The GCB will also allow the CTG to be isolated from the 345 kV system, while the 345 kV system powers the off-line, start-up, and shut-down loads via the GSU and Unit Auxiliary Transformer (UAT).

The GSU transformers will be a 65 °C rise, ONAN/ONAF/ONAF mineral oil filled type design with spill containment.

2.9.2 Auxiliary Power System

Each new CTG/HRSG block will have two 2-winding UATs and a double-ended primary medium voltage (MV) substation to power the loads associated with operation of the CTG and the HRSG. The UAT will be tapped from the IPBD between the GCB and the GSU to allow back-feeding the auxiliaries from the 345 kV system when the CTG is off-line.

The UATs will be a 65 °C rise ONAN/ONAF/ONAF mineral oil filled type design with spill containment. The ONAN MVA rating will be sufficient to power the individual CTG/HRSG operating loads, while the forced air ratings provide a higher UAT output during a contingency situation, such as loss of a UAT.

The MV switchgear will be rated at 4160 volts. MV controllers will be included to feed the 4000 Vac rated motor driven auxiliary loads (boiler feedwater pumps), while conventional metal clad switchgear type vacuum power circuit breakers will be included for the Main, Tie, and Secondary Unit Substation (SUS) transformer services.

MV Bus-Ties will be included for the MV switchgear line-ups associated with each block of CTGs and HRSGs. The bus ties will be made via power circuit breakers and non-segregated phase bus (NSPB) ducts.

The SUS transformers will be a 65 °C rise ONAN/ONAF mineral oil filled type design with spill containment. The transformer self-cooled rating will support the normal configuration; i.e. Tie Breaker OPEN, while the forced-air cooled rating will support the contingency configuration; i.e. Tie Breaker CLOSED and one Main Breaker OPEN.

The low voltage (LV) switchgear will be rated 480 volts, and the 480 Vac system neutral will be solidly grounded to align with the present LV system design.

Double-ended, Main-Tie-Main, type LV Unit substations will be provided to power the CTG and HRSG LV auxiliaries of each block of CTGs and HRSGs. Power circuit breakers will be included to feed the motor control centers (MCCs) as well as all 460 V motors rated 75 HP and higher. Motors rated less than 75 HP will be fed via combination motor starters located in MCCs.

The electrical switchgear and MCC equipment will be delivered to the site in pre-fabricated, weather-protected power and control center type equipment enclosures complete with Distributed Control System (DCS) Input/Output (I/O) cabinets, HVAC, and lighting. The interconnecting power, control, and instrumentation cabling will be pre-made and tested in the factory to the extent practical consistent with shipping limitations to the site. Unit substation transformers will be located outdoors, adjacent to the electrical equipment enclosures.

A common pre-fabricated, weather-protected, power and control center type equipment enclosure will also be included to house the DC Batteries, Chargers, and UPS equipment associated with each block of CTGs and HRSGs.

A single emergency diesel engine generator will be included to provide 480 Vac 3-phase essential service type power for all CTGs and HRSGs; however, the existing station emergency diesel engine generator and back-up power feed system should be evaluated to determine if a new diesel engine generator is required.

2.10 ELECTRICAL EQUIPMENT TO BE REUSED FOR REPOWERED UNITS

The existing Unit 2 and Unit 3 electrical equipment will fundamentally remain "as-is." Retiring the existing boilers will substantially reduce the present loading on the existing Auxiliary Transformers, Start-up Transformer, and 4160 V (for Unit 1 and Unit 2) and 6900 V (for Unit 3 and Unit 4) Station Service Switchgears. With the reduced bus loading, the transformer taps may need adjustment to obtain a suitable 4160 V or 6900 V bus voltage operating range.

The circulating water pumps, condensate pumps and associated steam turbine loads will be fed from the existing station auxiliary power system. This study precludes the reuse of electrical capacity that will be made available by retiring of existing boilers (i.e. fans, mills, etc.), for powering of new CTG/HRSG loads. This is due to the age of the existing equipment as well as the relatively long distance between existing switchgear and the CTG/HRSGs. A more thorough review of reuse of existing electrical equipment could be performed as part of a subsequent study.

2.11 INSTRUMENTATION AND CONTROLS

2.11.1 Distributed Control System (DCS)

Conceptually, the existing plant-wide DCS will be reused for the repowered SJGS Units. Each of the CTGs, however, will be designed and furnished with its own DCS system by the CTG manufacturer. These individual CTG control systems will be datalinked to the plant-wide DCS network. The existing DCS system for the Balance of Plant (BOP) equipment is intended to handle all the control and monitoring functions required for the repowered Units' BOP equipment and systems, including all the "to-be-retained" existing "hardwired" controls, which will remain in the existing control room(s). Some of the new BOP subsystems and major equipment items may still be provided with their own Programmable Logic Controllers (PLCs) for control and monitoring, such as any fuel gas conditioning skids, for cost reasons and overall best design practices to ensure particular subsystem integrity. In any such instances, these subsystem PLCs will also be datalinked to the plant-wide DCS for monitoring and data acquisition purposes. Remote I/O units and, most likely, distributed DCS processors will be located in the various PCC buildings and in other plant areas, as dictated by the location and density of the I/O for the repowered plant. A plantwide fiber network will be used to interconnect all the DCS equipment.

If repowering of Unit 2 and Unit 3 is given further considering, a review of the existing DCS should be performed to determine which parts of the DCS can be reused for the repowered units.

2.11.2 Continuous Emissions Monitoring System (CEMS)

A separate CEMS enclosure will be provided for each HRSG stack. Conceptually, the plan is to use an extractive-type CEMS system, with probes mounted in each stack, directing the sampled gas via manufacturer-supplied umbilicals to multi-gas analyzers.

2.11.3 Field-Mounted BOP Instruments

The plan is to provide the appropriate new instruments required to monitor and control the new BOP equipment and systems. Instrumentation for critical control loops will be made triple redundant for input to the plant DCS.

2.12 PROJECT IMPLEMENTATION PLAN

Included in Appendix E is a summary level project schedule for repowering SJGS Unit 2 and Unit 3. The schedule includes critical procurement, engineering, construction, and start-up activities. The repowering schedule is based on S&L's database for F-frame combined cycle projects and experience with steam turbine repowering projects using combustion turbines.

From engineering authorization to commercial operation of the repowered Unit 2 is 41 months. The repowered Unit 3 is shown as being commercial seven months later. One four month outage, per unit, is required. Critical parallel outage activities are as follows:

- Steam turbine modifications and tie-in to block.
- Condenser reconfiguration.
- Electrical and control system reconfiguration and tie-in.

Note that the schedule shows that the CTGs are commissioned prior to the outage, allowing generation from each unit to be uninterrupted. HRSG construction and construction testing will be completed before the steam turbine outage, to minimize the outage duration.

Based on current projects and recent surveys of major equipment suppliers, the following lead-times were used in the development of the schedule; however, lead-times are subject to market pressure and need to be constantly reviewed:

- Combustion Turbines – 18 months
- HRSGs – 15 months (1st materials)

- Alloy Pipe Material – 12 months
- Alloy Pipe Fabrication – 6 months
- Transformers – 16 months
- Power Control Centers – 12 months
- DCS – 12 months

The project's critical path is:

- Purchase CTGs
- Purchase HRSGs
- HRSG manufacturer's engineering, fabrication, and delivery
- CTG/HRSG foundation design
- Selection of the Foundations Contractor
- Installation of the first HRSG
- Start Steam Turbine outage
- Steam Turbine overhaul, 10 weeks
- HRSG chemical cleans/steam blows
- HRSG/CTG/STG performance tuning
- Commercial operation of the first repowered unit

The conceptual schedule is based on the following major installation contracts:

- Demolition
- Underground/Foundations
- Mechanical General Work, including steel erection
- Electrical General Work

2.13 CAPITAL AND OPERATING COST SUMMARY

2.13.1 Capital Cost Estimate Summary

Order-of Magnitude cost estimates were developed for the repowered Unit 2 and Unit 3. The cost estimates are presented in Appendix F. The cost estimates are conceptual in nature, and based largely on a data base from similar projects. No significant preliminary engineering has been performed to develop the project details; and, specific site characteristics have not been fully analyzed. Allowances have been included where necessary to cover issues that are likely to arise. The resulting estimated values fall within the ±30% range with the inclusion of the designated contingency.

A summary of the Order-of Magnitude cost estimates is presented in Table 2-9.

Table 2-9. Summary of Order-of-Magnitude Cost Estimates

Configuration	Unit 2 – 4 x 4 x 1	Unit 3 – 5 x 5 x 1	Station Total
Direct Project Costs ($M)	$675	$848	$1,523
Indirect Project Costs ($M)	$37	$44	$81
Contingency ($M)	$84	$105	$189
Total Project Costs ($M)	$796	$997	$1,793
Gross Output, Annual Average (MW)	1,032	1,259	2,291
$ / kW_{gross} (Incl. Steam Turbine Capacity)	$772	$792	$783
Net Output, Annual Average (MW)	1,006	1,228	2,234
$ / kW_{net},(Incl. Steam Turbine Capacity)	$792	$812	$803

2.13.2 Exclusions

These cost estimates are intended to reflect the current day costs associated with the repowering effort described in this report. There are, however, items that have been specifically excluded from the estimates. In order to establish the overall project costs, the following items must also be accounted for:

- Transmission system upgrades
- Power or fuel system interconnect fees
- Off-site fuel gas supply piping
- Fuel gas metering & regulating stations

- Off-site road improvements
- Owner's internal costs, including interest during construction
- Permitting costs
- Public relations expenses
- Escalation
- Project financing
- Operating expenses, including spare parts
- Fuel costs during startup operations
- Outage costs, including loss of revenue

This list is for information and is not necessarily all inclusive. Note that the estimated costs of the off-site fuel gas supply piping and fuel gas metering & regulating stations are included in the estimates presented in Section 3 of this report.

2.13.3 Operation and Maintenance (O&M) Cost Analysis

O&M costs and reliability for repowered plants such as SJGS should be similar to those of large conventional combined cycle plants, but with better economics in the case of SJGS due to the large scale of the operation. A repowered SJGS would have nine CTs operating at one site, totaling approximately 2,300 MW_{gross}.

The following table provides staffing information for some repowered stations, where staffing information is available through FERC reporting:

Plant	Operator	Configuration	CTs	MW (2007)	Staff (2007)
Fort Myers	Florida Power & Light Co.	6x6x2 7FA (repower)	6	1,644	43
H. L. Culbreath Bayside	Tampa Electric Co.	7x7x2 7FA (repower)	7	2,014	59
Lauderdale	Florida Power & Light Co.	4x4x2 MHI 501F (repower)	4	1,043	32
Manatee	Florida Power & Light Co.	4x4x2 7FA (repower)	4	1,225	27
Sanford (FLPL)	Florida Power & Light Co.	8x8x2 7FAs (repower)	8	2,378	59

All of these stations are in Florida. The staff size averages approximately 38 MW per person, suggesting total staff for a repowered SJGS in the range of 55 to 60 people. A conventional 2 x 2 x 1 combined cycle configuration using 7FA CTGs has a staff of 30 to 32 people, for a MW per person ratio of only 17; so, labor cost per MW at SJGS after repowering would be favorable relative to a conventional combined cycle installation.

Unfortunately O&M cost data are not reported to FERC for most of the repowered stations listed above, and those that are reported are unrealistically low ($1.00 to $1.50 per MWh averages reported for Lauderdale and Manatee at about 75% capacity factor operation) and thus might be incomplete.

S&L recently completed a review of O&M costs for large combined cycle units and found total fixed and variable O&M cost national averages approximately $4/MWh (costs adjusted to 2010 dollars) for plants operating as intermediate load range facilities (approximate capacity factor of 75%). Lower capacity factors give higher costs, and vice-versa.

O&M costs for SJGS will depend on:

- local costs of labor, water, ammonia, etc.;
- pricing negotiated with the OEM of the equipment for CTG maintenance ("contractual service agreement" or earlier called "long-term service agreement"), which is a significant portion of variable O&M cost;
- approach to plant maintenance (all-in contractual service agreement vs. parts and service contract with OEM and either internal or third-party contractor services); and
- plant operating regime (ratio of operating hours to starts), where costs rise when the operating hours to starts ratio gets below about 25:1.

Assuming an hours to starts ratio of 30 or higher, a reasonable basis for studies of alternatives at SJGS is to assume $9 to $12 per kW per year as fixed O&M cost and $3.00 to $3.50 per MWh as variable O&M cost, resulting in overall costs in the $4 to $5/MWh range for operation at 75% capacity factor. Given a favorable MW per person ratio for staff and that having nine CTGs at one site is a good basis for negotiating an economical contractual service agreement The low end numbers presented here could be considered as reference values and the higher ones as conservative values.

2.13.4 Reliability

Reliability data is not reported separately for large repowered steam units; but, we would expect experience to be similar to that of large conventional combined cycle units. NERC GADS data for combined cycle stations over 500 MW for the period 2004-2008 (149 unit-years of data) yields the following statistics:

Average Availability Factor.................................. 92.8%
Equivalent Availability Factor.............................. 91.0%
Equivalent Forced Outage Rate 2.7%

This O&M information could be used in any financial analysis of the repowering alternative.

3. NATURAL GAS SUPPLY STUDY

As indicated in Appendix A, the natural gas demand for repowering SJGS Unit 2 with four GE 7FA CTGs is approximately 117,000 scfm; and, the natural gas demand for repowering SJGS Unit 3 with five GE 7FA CTGs is approximately 146,000 scfm. Thus, the total natural gas demand is approximately 263,000 scfm for Unit 2 and Unit 3.

As directed by PNM, S&L contacted El Paso Natural Gas (EPNG) on a confidential basis to determine the availability of 263,000 scfm from their natural gas transmission pipelines in the area. Mr. Steve Dynes (719-329-5633) of EPNG advised that EPNG has the capacity to provide the required quantity of natural gas to the facility. Also, EPNG advised that they are capable of delivering the necessary capacity of natural gas to SJGS at a pressure above the 450 psig required for the GE Frame 7F CTGs.

For 263,000 scfm, Transwestern Pipeline Company (Transwestern Pipeline) recommended 24" Schedule 20 carbon steel pipe, while EPNG stated that a larger pipe size may be necessary. EPNG stated that they would need additional information to perform an analysis to determine the recommended pipe size. However, the additional information that they required would have compromised the confidentiality of this study. Thus, 24" Schedule 20 carbon steel pipe was used for the purposes of this study. A conceptual routing from Farmington, NM to the station was developed based on following U.S. Route 64, as shown in Appendix G. The routing resulted in approximately 15 miles of pipeline. The estimated cost of 15 miles of buried 24" Schedule 20 carbon steel pipe is $23,000,000, based on the present installed cost of buried steel piping. The estimate includes a tie in to the existing pipeline, filter separator, metering, flow control, and launch and receiving equipment. Note that the estimate does not include a natural gas dew point heater, as EPNG advised that the natural gas is "pipeline" quality and a natural gas dew point heater should not be required.

EPNG estimated that installation of the natural gas pipeline would take 24 months including all governmental approvals.

In addition to the EPNG pipelines, Energy Transfer owns a 30" natural gas pipeline, which is part of the ETC – Transwestern Pipeline. This pipeline has a compressor station in Bloomfield, NM, which is approximately 30 miles south and east of SJGS.

S&L contacted the Transwestern Pipeline on a confidential basis to determine the availability of 263,000 scfm from the 30" natural gas transmission pipeline. Mr. Steven Hearn (281-714-2027) of Transwestern Pipeline advised that the Bloomfield Compressor Station has five compressors with a total capacity of 44,000 horsepower. The compressor station is next to the Company's Blanco Hub, which has the capacity of transporting 1600 mmmBTU/day. By comparison, 263,000 scfm is 402.9 mmmBTU/day, so Transwestern Pipeline has adequate capacity to supply the necessary natural gas. At the compressor station, the natural gas is boosted up from a suction pressure of 870 psig to the pressure necessary to meet the demand. On the day of the contact, the pressure was being boosted up from 870 psig to 970 psig. Thus, the facility is capable of delivering the necessary capacity of natural gas to SJGS at a pressure well above the 450 psig required for the GE Frame 7F CTGs.

As previously stated, Transwestern Pipeline recommended 24" Schedule 20 carbon steel pipe for 263,000 scfm of natural gas. A conceptual routing from Bloomfield, NM to the station was developed based on following U.S. Route 64, as shown in Appendix G. The routing resulted in approximately 30 miles of pipeline. A conceptual estimate of the cost of 30 miles of buried 24" Schedule 20 carbon steel pipe is $43,500,000, based on the present installed cost of buried steel piping. The estimate includes a tie in to the existing pipeline, filter separator, metering, flow control, and launch and receiving equipment. The estimate does not include a natural gas dew point heater, as Transwestern Pipeline advised that the natural gas is "pipeline" quality and a natural gas dew point heater should not be required.

Transwestern Pipeline also estimated that installation of the natural gas pipeline would take 24 months, including all governmental approvals.

4. IMPLEMENTATION OF CARBON CAPTURE AND SEQUESTRATION SYSTEMS

4.1 INTRODUCTION

The installation of a Carbon Capture and Sequestration (CCS) System for each of the four units at SJGS was evaluated. For the purposes of this evaluation, published data was compared to in-house data to develop the cost of the CCS System based on the Fluor Econamine technology. The Integrated Environmental Control Model, developed by the Department of Energy (DOE) was used to determine the material balance, equipment sizing, and auxiliary power requirements for the system. This data was compared to other data available to S&L from a variety of sources and adjusted, as necessary.

SJGS is located approximately 25 miles from one of the largest commercial CO_2 pipelines in the U.S. The pipeline is operated by Kinder-Morgan to supply CO_2 for enhanced oil recovery (EOR) in Texas. This 30-inch pipeline runs from the McElmo Dome near Cortez, Colorado to Texas. For the purposes of this evaluation, S&L assumed that PNM may be able to sell CO_2 to the pipeline as a "non-revenue" transaction. In other words, it is assumed that the CO_2 would be disposed of by transfer to the pipeline company without generating any revenue. The idea here is that there may be no recoverable value in the CO_2 product itself. While the market value of the CO_2 is not included in this evaluation, if PNM wants to look at implementing CCS at SJGS, the idea of selling the CO_2 to the pipeline company would need to be investigated further to determine if there is a potential for generating revenue based on the sale. This was not explored as a part of the study due to the confidential nature of the study at this time. The basic costs of CO_2 sequestration considered in this analysis are the costs for compression and delivery of CO_2 to the Kinder-Morgan pipeline via a 25-mile 24" Schedule 140 pipeline.

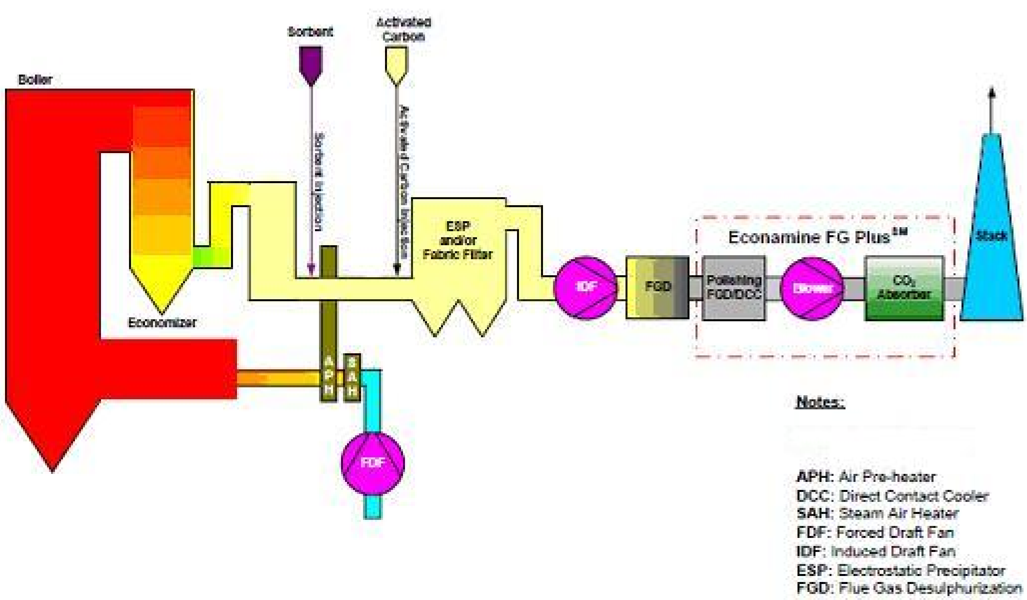
A recent technical paper about the geology of northern New Mexico suggests that sequestration in the local geology is viable.[1] S&L did not pursue a local sequestration alternative for this analysis. This would need to be investigated further if PNM is interested in pursuing a CCS option at SJGS.

[1] CO_2 sequestration potential beneath large power plants in the Colorado Plateau-Southern Rocky Mountain Region, USA.; R.G. Allis, T.C. Chidsey, C. Morgan, and J. Moore. Conference on Carbon Sequestration, Alexandria, VA, May 5-8, 2003.

4.2 TECHNOLOGY DESCRIPTION

Fluor's proprietary amine-based technology for large scale post-combustion CO_2 capture is the Econamine FG Plus^{SM} (EFG+).[2] The original EFG technology is the first and the most widely applied process that has extensive proven operating experience in the removal of carbon dioxide from high oxygen content flue gases (up to 15 vol.%). Fluor has enhanced the technology and given the "plus" to the name to differentiate it from earlier versions of the process. The process is installed after all other pollutants are removed from the flue gas. Figure 4-1 is an example of a typical power plant configuration with the EFG+ system installed shown without a Selective Catalytic Reduction (SCR) System as it might be configured at SJGS.

Figure 4-1. Typical Configuration with EFG+ System (w/o SCR)

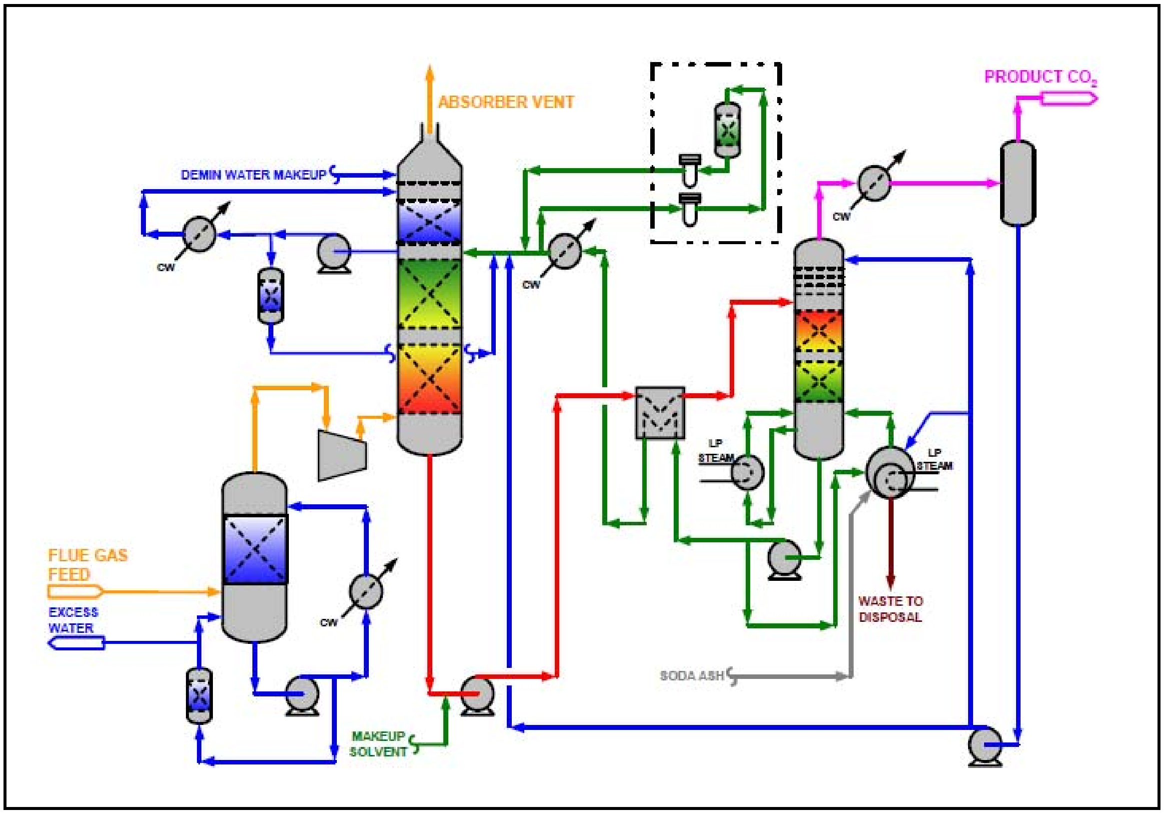


[2] Fluor's Econamine FG Plus^{SM} Technology For CO_2 Capture at Coal-fired Power Plants; Satish Reddy, Dennis Johnson, John Gilmartin; "Mega" Symposium; August 25-28, 2008; Baltimore, MD.

Over the past 20 years, Fluor has installed over 25 Econamine plants around the world. These facilities are used for separation of CO_2 from gas streams for an assortment of applications, including beverage production, enhanced oil recovery (EOR), and production of organic products, such as methanol and urea. One of their facilities is located in Carlsbad, New Mexico that removes CO_2 from a natural gas production well; and, the CO_2 is used for EOR. In Bellingham, Massachusetts, a plant was operated on the exhaust of a natural gas fired combustion turbine to provide CO_2 for the food industry. This plant was closed due to decreased operation of the CTG. One of the largest facilities is installed at a refinery in Saudi Arabia, where a 40 foot diameter absorber tower is used to capture the CO_2 from refinery gas. These examples are typical of the "readiness" of the technology as viewed by Fluor. Of all the commercial installations installed by Fluor, none have been installed on coal-fired boilers; and, the largest represents about a 20 MW equivalent flow of flue gas. However, Fluor is actively seeking an opportunity to demonstrate their technology on a coal facility. They are currently operating a small pilot facility at a coal-fired power plant in Germany

Monoethanoloamine (MEA) is the basic ingredient of the EFG+ solvent. However, the solvent formulation is specially designed to recover CO_2 from low pressure, oxygen containing streams, such as boiler and reformer stack gas and gas turbine flue gas streams. Figure 4-2 shows a typical flow sheet for the EFG+ process.

Figure 4-2. Typical Flow Sheet for Fluor EFG+ Process



Generic MEA based plants operate at low concentrations of approximately 18 wt% to 20 wt%. Fluor's standard Econamine FGSM plants are based on an MEA concentration of 30 wt%. The latest EFG+ plants are designed with MEA concentrations greater than 30 wt%. The improved solvent formulation results in increased reaction rates, which decreases the required packing volume in the absorber, thereby lowering capital cost. The improved solvent also has higher solvent carrying capacity for carbon dioxide, thus decreasing the solvent circulation rate, which reduces the plant steam requirement and decreases the capital cost for solvent circulation equipment.

The flue gas operating temperature for the EFG+ process is about 110 °F. A direct contact cooler (DDC) is used to reduce the temperature of the incoming flue gas to this temperature prior to contact with the CO_2 solvent. The booster fan for the process is typically located after the DCC to minimize fan horsepower.

Flue gas is contacted in the absorber where the solvent captures the CO_2. To improve mass transfer in the absorber, a structured packing is used to provide contact surface for the gas and liquid. The packing is selected to minimize the pressure drop associated with the use of the packing. The maximum diameter currently considered for the CO_2 absorber is about 60 feet. For units requiring larger diameters, it is recommended that multiple trains be considered.

The solvent is regenerated by heating in a tower called a stripper. Heat to the stripper is provided by boiling the solution. This boiling is accomplished by heating the solution with steam in a device termed a reboiler. Steam at about 50 psig is supplied to the reboiler either from the power plant or from a supplemental source such as an auxiliary boiler or HRSG coupled with a combustion turbine. For the purposes of this study, the initial investigation focused on steam extraction from the scrubbed unit.

The CO_2 is recovered from the stripper is cooled to condense the steam from the stripper, and the water is returned to the column. The CO_2 is then compressed and dried. Compression to typically 2500 psig is required to transport the CO_2 to a sequestration site or to an EOR location.

Heat is conserved in the process by cross heat exchange between the solution from the absorber and stripper.

The presence of acid gases such as SO_2, HCl, HF, and NO_2 in the flue gas can degrade the Econamine Solvent over time. These pollutants in the flue gas increases the complexity and operating cost of the CO_2 capture process (regardless of the technology). Impurities in the flue gas lead to the formation of Heat Stable Salts (HSS) in any amine system. HSS are the product of acid-base reactions between amines and different acidic species in the flue gas. The HSS must be converted back into amine through a reclaiming process. In order to avoid excessive HSS build-up rates, the flue gas impurities must be reduced to a very low level upstream of the EFG+ absorber. Typically less than 10 ppm is recommended by most technology suppliers.

The design of the existing Wet Flue Gas Desulfurization (WFGD) Systems may not be sufficient to reach these low levels for SO_2 removal.

Even with the deployment of high efficiency pollutant removal technologies, there are still residual quantities of SO_2 and H_2SO_4, ammonia (if an SCR is used for NO_X control), particulates, and other trace constituents that remain in the flue gas entering the carbon capture system. For this reason, Fluor has assessed that it is more cost-effective to remove HSS precursors before the flue gas encounters the solvent. The pre-treatment step to remove HSS forming precursors is a part Fluor's process design strategy for coal-fired power plants by adding scrubbing capability into the DCC. As the temperature of the flue gas entering the absorber is decreased, the efficiency of the EFG+ process increases. The DCC is included in the EFG+ flowsheet to sub-cool the flue gas to a temperature below the adiabatic saturation temperature. The DCC can be designed to achieve SO_X removal in addition to flue gas cooling. A polishing scrubber can be added to the DCC to further reduce SO_X to very low levels.

Fluor has developed several enhancements to their technology that are not employed in the DOE studies performed to baseline the costs of the technology. These include:

- Including a polishing scrubber in the DCC to minimize costs.
- Using a cooler in the absorber column to reduce the temperature rise due to CO_2 absorption to improver operations (Figure 4-3).
- Using a vapor recompression system on the reboiler to reduce the steam requirements for the process (Figure 4-4).
- Improvements to solvent regeneration systems to minimize the impact of HSS formation.
- Using lined, concrete vessels to reduce the capital costs of the absorber and DCC.

Figure 4-3. Absorber Column Configuration with Cooler

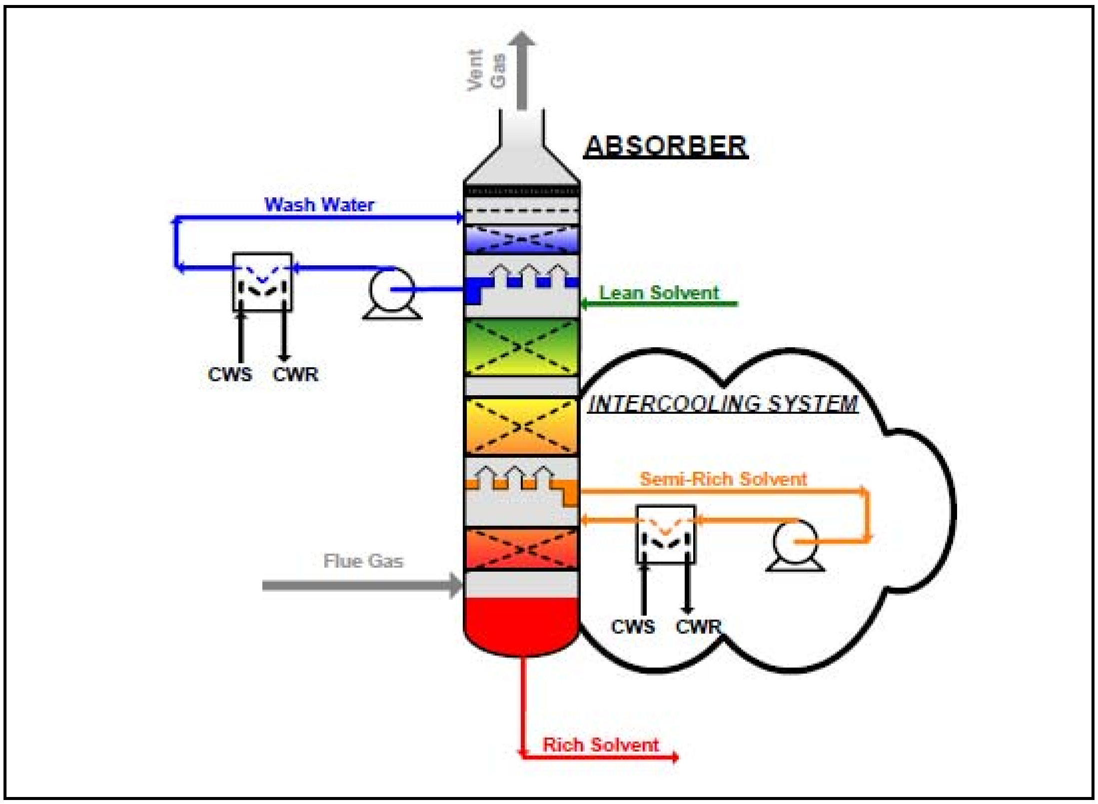
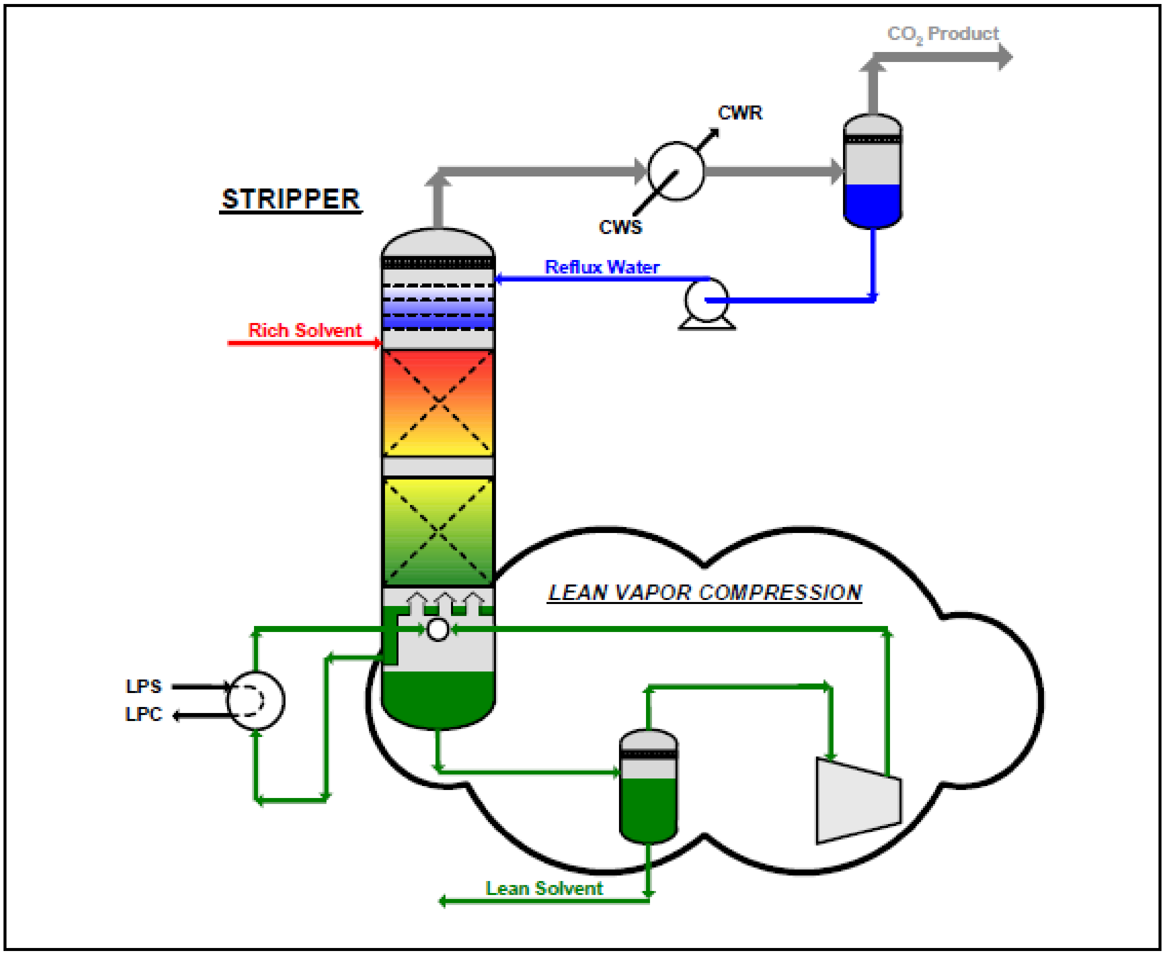


Figure 4-4. Vapor Recompression System Configuration



4.3 TECHNOLOGY DEMONSTRATION STATUS

Knowledge concerning CCS is based on a technology that is rapidly evolving. Currently, the largest CO_2 capture systems operate on slip-streams of no more than 20 MW of flue gas. In August of 2009, NRG submitted a proposal to the U.S. DOE to construct a 60 MW slip-stream demonstration of the Fluor EFG+ technology on their Parish Unit 7. They requested DOE support for this project, but were not selected. At this time, there are no announced demonstrations for the EFG+ technology; however, Fluor is very committed to the commercialization of their technology.

Several small commercial scale facilities have been announced at the 100 MW to 235 MW scale as early demonstrations of the technology. One that has been selected for demonstration is the Alstom Chilled Ammonia process. This process will be demonstrated on a 235 MW slip steam at the AEP Mountaineer Plant in West Virginia. The other demonstration project awarded by DOE is to Basin Electric at their Antelope Valley Plant in North Dakota. This project was originally announced to demonstrate a 120 MW slip stream with the Powerspan ECO_2 technology. This project has recently changed to a demonstration of the HTC Pure Energy technology.

There are many other technologies being tested around the world for CCS. The earliest any suppliers are considering offering technologies for full commercial scale with guarantees and warranties is likely to be in the 2015 to 2017 time frame.

Commitment to CCS at the scale of SJGS at this time would entail considerable risk due to the uncertainty in cost and performance. All current demonstration projects are proceeding with U.S. government support in the form of grants to off-set the high cost and risk associated with the technology.

4.4 SAN JUAN GENERATING STATION CCS PROCESS DATA SUMMARY

The integration of a CCS System into the operation of each of the units at SJGS requires significant quantities of steam for regeneration of the CO_2 solvent; cooling water for the flue gas, stripper cooling, and CO_2 compressor cooling; and auxiliary power (aux power) to operate the CCS equipment. These quantities are summarized in Table 4-1.

Table 4-1 Auxiliary Power, Steam, and Cooling Loads

CCS Data for SJGS	Unit 1	Unit 2	Unit 3	Unit 4	Total Plant
Existing Plant Data					
Plant Gross Output, (MW_{gross})	368	381	573	573	1,895
Total Plant Heat Input, (mmBtu/hr)	3,581	3,707	5,485	5,485	18,258
Existing Aux Power, (MW)	26	27	40	40	133
Existing Net Power, (MW_{net})	342	354	533	533	1,762
Existing Heat Rate, (Btu/kW_{net}, HHV)	10,462	10,462	10,293	10,293	10,360
Total LP Steam, (lb/hr)	1,962,539	2,031,868	2,969,330	2,969,330	
Existing Cooling Water Flow, (gpm)	168,421	168,421	215,789	215,789	768,420
CCS Requirements					
Steam to CO_2 System, (lb/hr)	849,108	879,104	1,299,456	1,299,456	4,327,124
Steam Extracted from IP/LP, (lb/hr)	734,757	760,713	1,145,777	1,145,777	3,787,024
LP Steam to CO_2 System, %	37	37	39	39	-
Additional Cooling Water Flow for CO_2, (gpm)	119,943	124,180	192,701	192,701	629,525
Plant Derating, (MW)	50	52	73	73	248
Plant Gross Power Derating, %	13.6	13.6	12.8	12.8	13.1
Revised Gross Output, (MW_{gross})	318	329	500	500	1,647
Aux Power for Carbon Capture, (MW)	33	34	51	51	169
Aux Power for CO_2 Compression, (MW)	37	38	57	57	189
Total Aux Load for CCS Plant (MW)	70	72	108	108	358
Total Aux Load for CCS Plant, %	19	19	19	19	19
Net Change w/CCS					
Total New Net Power, (MW)	223	231	352	352	1,158
New Heat Rate, (Btu/kW_{net}, HHV)	16,074	16,074	15,604	15,604	15,789
Total Plant Power Net Reduction, %	34.9%	34.9%	34.0%	34.0%	34.4%

The regeneration of the CO_2 solvent for a CCS system requires extensive energy use. This study is based on providing the energy from the steam turbine cycle. The steam is extracted from the cross-over between the intermediate-pressure (IP) and low-pressure (LP) steam turbines. The quality of steam required for the process is 50 psig saturated. The pressure and temperature available at the cross over is of a higher quality and must be attemperated prior to delivery to the CCS System. As shown in Table 4-1, the quantity of steam required for the process represents approximately 40% (37% to 39%) of the total steam flow to the LP steam turbines. Removal of this much steam from the steam turbines results in an approximate 13% (13.6% to 12.8%) derating of the gross output of each generating unit.

The emissions from the plant are significantly altered by the use of an amine based CCS System. The CO_2 is reduced by 90% on each unit. Sulfur emissions are virtually eliminated. A new emission is ammonia (NH_3). Ammonia is a decomposition product of the solvent estimated to emit as much as 50 to 55 ppm from the chimney of each of the units[3]. A summary of emissions before and after installation of the CCS System is presented in Table 4-2 for Unit 1 or Unit 2 and Table 4-3 for Unit 3 or Unit 4. Note that Unit1 was assumed to have the same heat input as Unit 2 for sizing the CCS System in this study.

Table 4-2 San Juan Generating Station Unit 1 or Unit 2 Emission Summary

		Unit 1 or Unit 2			
Stream Characteristics		**Existing FGD Outlet**		**CO_2 Absorber Outlet**	
Temperature	^oF	129		148	
Pressure	psia	12.241		12.241	
N_2	lb/hr-vol%	2,720,121	68.18	2,720,121	76.29
O_2	lb/hr-vol%	173,455	3.80	173,455	4.26
H_2O	lb/hr-vol%	405,862	15.83	401,400	17.51
CO_2	lb/hr-vol%	763,805	12.18	76,381	1.36
SO_2	lb/hr-ppmv	289	32	1	0
SO_3	lb/hr-ppmv	12	1	0	0
HCl & HF	lb/hr-ppmv	0	0	0	0
NH_3	lb/hr-ppmv	0	0	119	55
Total Flow	lb/hr-acfm	4,063,546	1,224,961	3,371,478	1,130,633
MW & Moisture	g/mol-lb/lb	28.520	0.108	26.478	0.135
Uncontrolled CO_2 Emissions	lb/MWh_{net}	2,156		-	
Controlled CO_2 Emissions	lb/MWh_{net}	-		331	

[3] Data calculated by DOE's IECM version 6.1

Table 4-3 San Juan Generating Station Unit 3 or 4 Emission Summary

		Unit 3 or Unit 4			
Stream Characteristics		**Existing FGD Outlet**		**CO_2 Absorber Outlet**	
Temperature	^oF	129		148	
Pressure	psia	12.241		12.241	
N_2	lb/hr-vol%	4,272,628	68.39	4,272,628	76.22
O_2	lb/hr-vol%	331,276	4.64	331,276	5.17
H_2O	lb/hr-vol%	620,654	15.45	609,400	16.91
CO_2	lb/hr-vol%	1,130,193	11.51	113,019	1.28
SO_2	lb/hr-ppmv	428	30	2	0
SO_3	lb/hr-ppmv	18	1	0	0
HCl & HF	lb/hr-ppmv	0	0	0	0
NH_3	lb/hr-ppmv	0	0	181	53
Total Flow	lb/hr-acfm	6,355,197	1,915,397	5,326,506	1,777,589
MW & Moisture	g/mol-lb/lb	28.483	0.105	26.607	0.129
Uncontrolled CO_2 Emissions	lb/MWh_{net}	2,121			
Controlled CO_2 Emissions	lb/MWh_{net}			322	

The reduction in total annual emissions for CO_2 and sulfur are substantial, as shown in Table 4-4. The total reduction in CO_2 emissions possible for the plant is nearly 15 million tons per year, based on a 100% capacity factor. Sulfur emissions in the form of SO_2 and SO_3 are reduced by more than 6,000 tons per year, also based on a 100% capacity factor. Although 90% of the CO_2 in the flue gas is removed, the actual emission reduction of CO_2 on a net basis is about 85% due to the reduction in net power output.

Table 4-4 Annual CO_2 and Sulfur Emission Reductions

Emissions Reductions	**Unit 1 Ton/yr**	**Unit 2 Ton/yr**	**Unit 3 or Unit 4 Ton/yr**	**Total SJGS Ton/yr**
CO_2 to Sequestration (or EOR)	2,908,262	3,011,000	4,455,000	14,829,262
Additional SO_2 Removed	1,261	1,261	1,866	6,255
Additional SO_3 Removed	54	54	80	270

4.5 CONCEPTUAL IMPLEMENTATION SCHEDULE

The time requirements for implementation of CCS discussed herein is based upon the date of contract award for procurement of the system. Prior to an award, the time for preparation of bid specifications, evaluation of bids, and award is typically about 6 months, at a minimum, for a project of this magnitude. The schedule for construction of a CCS system would be somewhat similar to the construction of a WFGD system with several additional items to consider. These include the procurement and installation of the CO_2 compressors and the construction of the pipeline to the CO_2 sequestration site.

Based on the construction schedule for WFGD Systems, the construction of the CO_2 removal system would likely take approximately 36 months. The long lead time item for WFGD systems is scheduling for new stack construction. However, the demand for new stacks has slowed down, somewhat, so this period of time may be shorter in the future.

The CO_2 compressors are large specialty devices that require special fabrication. This order should be placed early in the project schedule due to the long delivery times.

The installation of the pipeline will require obtaining rights-of-way and governmental approvals required for pipeline construction. The schedule should be similar to that required for a natural gas pipeline. However, due to the controversial nature of CO_2 today, it may attract more public scrutiny than a similar pipeline with a less controversial content. If there are no challenges to the pipeline, it should be completed in two years. If challenged, the construction might require a much longer period of time.

4.6 CAPITAL AND OPERATING COST SUMMARY

For the purposes of this estimate, a variety of tools were used to estimate the size of the CCS facility and equipment and to estimate the total costs of the facility. Since there are few published costs for CCS Systems, and no commercial operating facilities exist, these costs are order of magnitude in accuracy. Retrofit factors were used to take into account the variation in Balance of Plant (BOP) costs that are associated with the facility.

Operating costs are identified for the major consumables associated with the plant, for fixed labor and maintenance.

4.6.1 Capital Cost Analysis

S&L examined the capital costs published in a number of DOE reports [4&5] and from past S&L studies. Based on this data, the anticipated costs for the CCS facility were developed with the high degree of retrofit associated with the application of the Econamine FG Plus technology at SJGS.

Due to the constraints of the site, there are extensive retrofit costs associated with the location of the equipment. These include:

- Long duct runs from the existing chimneys to the process location
- Use of new chimneys rather than return ducts to the existing chimneys and more pressure drop
- Long pipe runs to connect the regeneration facility located in a separate area from the absorber area

The direct installed costs for the CCS facility are approximately $591 for Unit 1 or Unit 2 (Unit 1 is assumed to be the same size as Unit 2 to provide a conservative estimate) and $774 million for Unit 3 or Unit 4. Including the additional indirect and owner's costs, the total installed cost for the entire SJGS is $3.71 billion. An additional $50 million should also be added for a 25 mile pipeline to transport the CO_2 to the existing Kinder-Morgan pipeline on the east side of Farmington, NM. These costs are summarized in Table 4-5.

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[4] Cost and Performance Baseline for Fossil Energy Plants; DOE/NETL-2007/1281; Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report; May 2007

[5] CO_2 Capture Ready Coal Power Plants; DOE/NETL-2007/1301; April 2008

Table 4-5 CCS Capital Cost Summary

Capital Cost Summary	**Unit 1** $MM	**Unit 2** $MM	**Unit 3** $MM	**Unit 4** $MM	**Total Plant** $MM
Direct Costs for CCS Plant	591	591	774	774	2,730
Indirect Costs	59	59	77	77	272
Startup and Consumables (2%)	12	12	15	15	54
Spare Parts (2%)	12	12	15	15	54
Owner's Costs (3%)	18	18	24	24	84
Contingency (20%)	118	118	155	155	546
Total Project Cost	**810**	**810**	**1,060**	**1,060**	**3,740**
Allowance for CO_2 Pipeline (25 miles of 24-inch Schedule 140 pipe)					50
Total Project Cost $/kW$_{net}$ (existing output)	2,368	2,288	1,989	1,989	2,123
Total Project Cost $/kW$_{net}$ (new output)	3,632	3,506	3,011	3,011	3,230

Note: The estimated CO_2 pipeline cost is not included in the Total Project Cost in $/kW$_{net}$.

4.6.2 Operating Cost Analysis

The operating costs are composed of fixed and variable costs. The fixed cost component includes plant labor and maintenance. For the purposes of the estimate, the labor was estimated at about $1 million per year. No savings were assumed for multiple unit staffing. Maintenance was estimated at 2.5% of direct capital cost for installed equipment.

Variable costs considered the required makeup for the major consumables to the CCS process. The annual requirements for each unit and the total station are in Table 4-6. These are based on a 100% capacity factor for the year, so adjustments can be readily made by multiplying the annual total by the projected capacity factor for each unit. The consumption for the major consumables associated with the operation of the carbon capture system was calculated using the DOE IECM program.

Table 4-6 CCS Consumables (100% Capacity Factor)

Plant Consumables	Units 1 or 2	Units 3 or 4	Total Plant
Plant Capacity Factor	100%	100%	-
Plant Makeup Water Addition, 1000 gal/yr	48,590	84,240	265,660
Caustic Soda for Prescrubber, tons/yr	3,201	4,736	15,874
Amine Makeup, tons/yr	3,140	4,724	15,728
Activated Carbon, tons/yr	2,071	3,185	10,512
Scrubber Solids to Waste Disposal, tons/yr	80,706	119,574	400,560

The unit cost for the major consumables associated with the operation of the carbon capture system, shown in Table 4-7, was estimated using the DOE IECM program or from other in-house sources.

Table 4-7 Unit Cost of Consumables (100% Capacity Factor)

Cost of Consumables	units	$/unit
MEA Sorbent	ton	2400
Activated Carbon	ton	2000
Caustic (50% NaOH)	ton	400
Reclaimer Waste Disposal	ton	220.9
Water (1000 gal)	1000 gal	1.00

Table 4-8 summarizes the annual fixed and variable costs for each unit and the entire SJGS. Variable costs were totaled from the values above, while fixed costs used the assumptions listed in this section.

Table 4-8 Annual Operating & Maintenance Cost for CCS at SJGS

O&M Costs	Units 1 or 2	Units 3 or 4	Total Plant
Fixed Maintenance (2.5% of Direct Cap)	14.8	19.4	68.4
Operating Labor	1.0	1.0	4.0
Variable Costs (100% CF)	21.5	66.4	175.8

4.7 QUALITATIVE DISCUSSION OF RESULTS

The operation of a Carbon Capture and Sequestration (CCS) system requires a considerable amount of new cooling capacity. For the purposes of the study, this cooling capacity was assumed to be provided by additional cooling water. However, if the availability of cooling water is prohibitive at SJGS, then dry cooling may be an option. Application of dry cooling would increase the total capital cost considerably. This can be evaluated in the future, if installation of CCS systems at SJGS is to be considered further.

The application of CCS systems to any power plant requires significant space. The installation of the required equipment requires approximately 27 acres, not including the area used for pipe racks to interconnect the sub-system equipment located at diverse locations across the site. The installation of CCS systems at SJGS is a difficult retrofit, due to the lack of existing space near the current chimneys. As a result, both the absorber and regeneration sub-systems are located at a significant distance from the existing power plant equipment. Installation of ductwork and piping to connect all these systems adds significantly to the retrofit cost of the plant.

The best location for Unit 1 and Unit 2 absorber systems is in the current coal storage area. This assumes that coal storage in this area can be either eliminated or relocated with minimal disruption to plant operation. If this is not possible, the alternative would be to locate the Unit 1 and Unit 2 absorbers adjacent to the Unit 3 and 4 absorbers.

4.7.1 Impact of CCS on Plant Cooling Water Systems

The installation of the CCS system represents an increase of about 82% to the total cooling water demand. Cooling is required for three primary purposes:

- Cooling the flue gas from 129 °F exiting the WFGD Systems to 110 °F entering the absorber.
- Cooling and condensing the water in the vapor leaving the stripper column associated with solvent regeneration.
- Cooling CO_2 during the compression cycle.

For this study, S&L did not reduce the condenser flow to the existing steam turbines and thus was able to improve the performance of the condenser by lowering the temperature and condenser back pressure from 2.5 inches Hg to about 1.5 inches Hg. If the flow to the condensers could be reduced by the relative amount of steam diverted from the steam turbines, approximately 40% to reduce the total cooling water demand to the existing plant, the total cooling water requirement could be reduced for the CCS system. However, since the condensers are not designed for such a flow reduction, it would likely be necessary to plug tubes in the condenser to accommodate the reduction in flow. Reducing condenser flow would reduce the cooling water demand for the CCS system from about 634,000 gpm to about 340,000 gpm, and would lower the total increase for CCS to 44% above the current usage (based on diverting the balance from the existing condensers). This would reduce makeup water requirements by about 148,000,000 gallons per year. This approach would need to be studied more thoroughly to determine if reducing condenser flow is technically feasible.

4.7.2 Impact of Steam Extraction on Existing Steam Turbines

The extraction of 40% of the low-pressure steam from each of the steam turbines represents a significant quantity of steam. It is likely that this amount can be tolerated at full load. However, this extraction will likely inhibit the ability of each unit to operate at reduced loads. Minimum load operation of the steam turbine will need to be limited above corresponding values for the boiler, when the CCS system is in operation.

A preliminary calculation of piping size was performed to estimate the relative size for the steam piping. The size of the steam piping to transport the steam from each of the SJGS units to the regeneration/stripper area of the CCS system is relatively large. The pipe diameter for Unit 1 and Unit 2 is about 38-inches in diameter and the size for Unit 3 and Unit 4 is 44-inches in diameter. A combined pipe for all four units to transport steam to the regeneration area is 80-inches in diameter. These sizes are needed to transport the large volumes of low pressure steam without incurring erosion or high pressure drop.

There are no published studies on the impact of extraction of this quantity of steam on the performance of the turbine shaft thrust bearings. If a more detailed study is desired, S&L would recommend consulting the STG OEM, GE, to ascertain their opinion on the impact of this operation on bearing life.

4.7.3 Impact of Booster Fans on Existing Plant

The overall pressure drop across the CO_2 recovery system is anticipated to be in excess of 27-inches of water. The pressure drop across the duct work was not specifically calculated for this estimate but due to the long duct runs, the overall fan pressure would be expected to be in excess of 30-inches total. The duct run for Unit 1 is about 300 feet; and, the duct run for Unit 2 is about 500 feet to the area where the CO_2 absorber system is located. The duct runs for Unit 3 and Unit 4 are over 1500 feet to the area where the CO_2 absorber system is located.

The installation of booster fans with this high a differential pressure has not been considered on the existing SJGS equipment, such as the boilers, baghouses, and WFGD Systems.

4.7.4 Impact of CCS on Plant Electrical Systems

The electrical auxiliary power needed for implementation of CCS across the entire plant requires about 360 MW (the entire gross output of Unit 1 or Unit 2). The auxiliary power for Unit 1 or Unit 2 is about 70 MW and for Unit 3 or Unit 4 about 110 MW. Due to the large requirements, it would be recommended to have multiple large auxiliary power transformers added to the switch yard that take their feed off the 345 kV transmission lines. This would help isolate the existing auxiliary power bus from power transients associated with the CCS system. The CO_2 compressors, which require about one-half of the auxiliary power load, will likely be powered by 13 kV motors.

4.7.5 Impact of CCS on Plant Arrangement

The overall area required for all plant related equipment spread across the site is about 27 acres not including inter-connecting pipe racks. Equipment is located in six general areas:

- Area 1 - Unit 1 and Unit 2 absorber area
- Area 2 - Unit 3 and Unit 4 absorber area
- Area 3 - Regeneration area all units
- Area 4 - CO_2 Compression and drying all units
- Area 5 - New cooling tower area
- Area 6 - Auxiliary power switchyard area

The arrangement of equipment at the SJGS is very congested near the existing chimneys. There is no room to locate the absorber portions of the CCS systems in any proximity to the existing chimneys. There appears to be adequate space to the north of the plant to locate the solvent regeneration systems, CO_2 compression and drying, and cooling towers.

For Unit 1 and Unit 2 (Area 1), the most convenient location closest to the plant for locating the direct contact cooler, absorber, booster fans, and related pumps and other equipment would be in an area currently on the west side of the existing coal storage pile. This location would require a duct run of about 300 feet to 500 feet from each respective unit. It would be more convenient to install a new wet stack near the CO_2 system rather than return the treated flue gas back to the existing stack. This would simplify construction and minimize outage time.

For Unit 3 and Unit 4 (Area 2), there is no location close to the plant to locate the absorber equipment. The only area appears to be an area west of the plant currently occupied by construction offices, warehouses, and parking. Some transmission lines would need to be relocated. The location requires flue gas duct runs of approximately 1500 feet. Again, the installation of a new stack reduces construction interference and simplifies installation reducing outage time.

The regeneration systems (Area 3) are located north of the Unit 3 cooling towers. This is a distance of about 600 feet north of the end of the turbine room. Steam piping from each of the units can be collected and piped to this location for distribution to each of the solvent stripper systems. Condensate would be returned to the units in a single pipe.

The CO_2 compression system (Area 4) is conveniently located north of the regeneration system. A new cooling tower (Area 5) is located just west of this area. The cooling tower is convenient to the stripper overhead-coolers and to the compressor inter-coolers, which represent most of the cooling demand. Cooling water will be transported across the pipe racks to areas 1 and 2 for flue gas cooling needs.

The area just north of the existing switch yard (Area 6) is required for installation of four (4) new auxiliary power transformers (assuming one per unit) to supply the auxiliary power required for the process. This power should be fed from the 345 kV side to minimize electrical transients in the plant.

4.7.6 Possible Savings with Shared Common Systems

There are savings possible from the use of shared common facilities that were not considered for an estimate at this high a level. These include:

- Use of shared reagent makeup tanks and preparation systems
- Using a shared regeneration system designed for the entire plant with only three (3) trains instead of four (4) trains.
- Optimization of CO_2 compression and drying systems for the entire station output.
- Optimization of cooling water use.

Another option that could be considered for cost savings would be to exhaust the flue gas from the absorber columns directly from stacks supported by the equipment. This would eliminate the need for a new separate stack, which would require coordination with the system supplier.

4.7.7 Alternative Steam Supply Sources

Supplying steam from the existing station IP/LP crossover results in a derating of the plant of about 15% of the gross generation. Using an alternative source of steam would eliminate this issue. Such a source could be either a steam boiler or a combustion turbine with a HRSG. The new steam source could also provide power generation, which would provide additional capacity to replace the auxiliary power demand of the CCS System.

Another alternative that has been considered in past studies includes installing a new back-pressure steam turbine to provide steam from the exhaust to the CCS System. This turbine would take all steam being diverted to the CCS System and reduce the amount of steam to the existing condensing turbines.

All these options require extensive modeling of the steam systems with the CCS System to evaluate the full integration of all the equipment into an efficient and cost effective design. Extensive steam integration was not undertaken for this scoping study.

4.7.8 Impact of Altered Flue Gas Flow Paths

Long flue gas duct runs are required to deliver flue gas from the existing stacks to the CCS Systems. Rather than returning the treated flue gas to the existing stack with equally long duct runs, new stacks are considered a good approach to simplifying duct work design and minimizing the total pressure drop for the CO_2 system. For this design we would recommend two new twin-stacks, one for Unit 1 and Unit 2 and one for Unit 3 and Unit 4.

4.7.9 Impact of Wastes/Effluents from the CCS System

There are two new waste streams that will be generated by the installation of the CCS Systems. One is a stream from the treatment of the flue gas to remove SO_2 to very low levels, and the other is a stream of waste solvent.

As stated earlier in the description of the process, SO_2 from the WFGD Systems is pretreated in a caustic soda wash to reduce levels to less than 10 ppm. This neutralized sodium sulfate is blown down for treatment. This water would most likely be evaporated in a waste pond for disposal.

The spent solvent must be purged from the stream to prevent accumulation of heat stable salts that build up from contamination by acids in the flue gas. This stream represents about 220 tons per year of material. This will likely require disposal in drums at a certified land fill.

The other stream that should be considered is the cooling tower blowdown from the new cooling tower, which will be incremental to the existing cooling tower blowdown.

Other waste streams, such as boiler blow-down and demineralizer waste, will all be present, but will not represent a major increase from current requirements at SJGS.

4.7.10 Impact of Partial Capture (45% Removal) on Plant Design

Applying partial capture (bypassing 50% of the flue gas for each unit) would reduce the utility impacts associated with steam extraction and cooling water demand. However, reducing the amount of flue gas scrubbed would not dramatically reduce the size of the direct contact cooler or absorber such that they could fit closer to the existing equipment. The location for the CO_2 equipment would need to be the same and the cost for pipe racks and ductwork would still be substantial. Construction of a new stack is most cost effective if considered for the entire gas flow from a single unit.

The absorbers for Unit 1 and Unit 2 at 90% capture are near the maximum size recommended for this type of equipment. Reducing the capture to 45% would reduce the diameter from about 52 to about 36 feet. The stripper diameter would be reduced from about 26 to about 18 feet. However, if additional removal was ever required, the addition of a second train would be very costly.

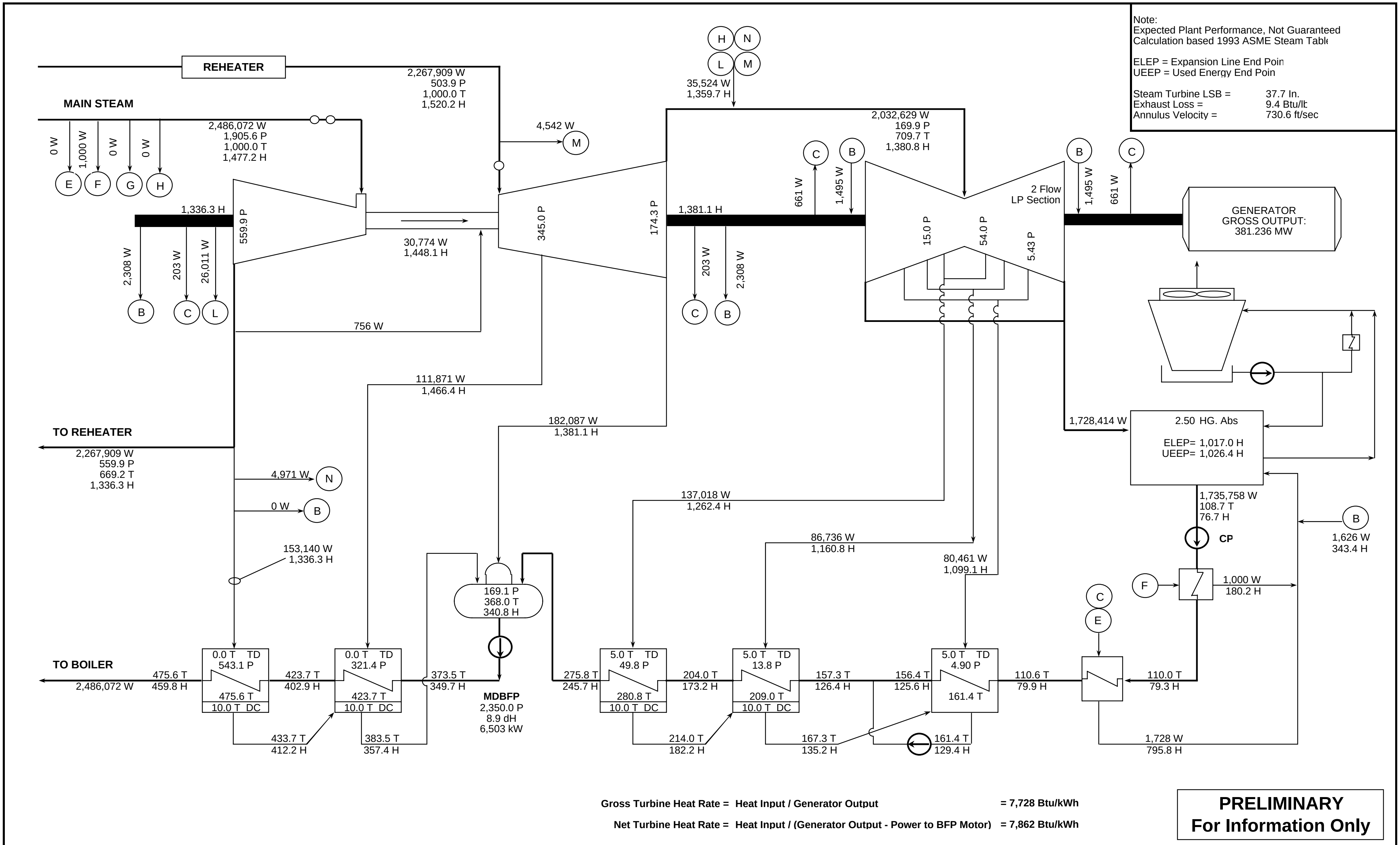
For Unit 3 and Unit 4, the plant is too large for a single absorber, so two 46 foot diameter towers were considered. Therefore, the installation of 50% scrubbing on either of these units would be more practical, since their design is based on two trains for each unit. The regeneration system was sized for a single train, which would later have to be upgraded if it was installed initially for only one-half the plant output. This could be overcome if both Units 3 and 4 were retrofit for 50% capture with a single regeneration system essentially designed for 100% of the total flow, which is a single unit requirement. Space for future installation of an additional regeneration system would allow for future expansion, if required.

APPENDIX A.
UNIT 2 AND UNIT 3 HEAT BALANCES

Existing Unit

Existing Unit with CO_2 Capture

Repowering with Combined Cycle



Legend:

W=	Flow, lb/h
P=	Pressure, Psia
T=	Temperature, °F
H=	Enthalpy, Btu/lb

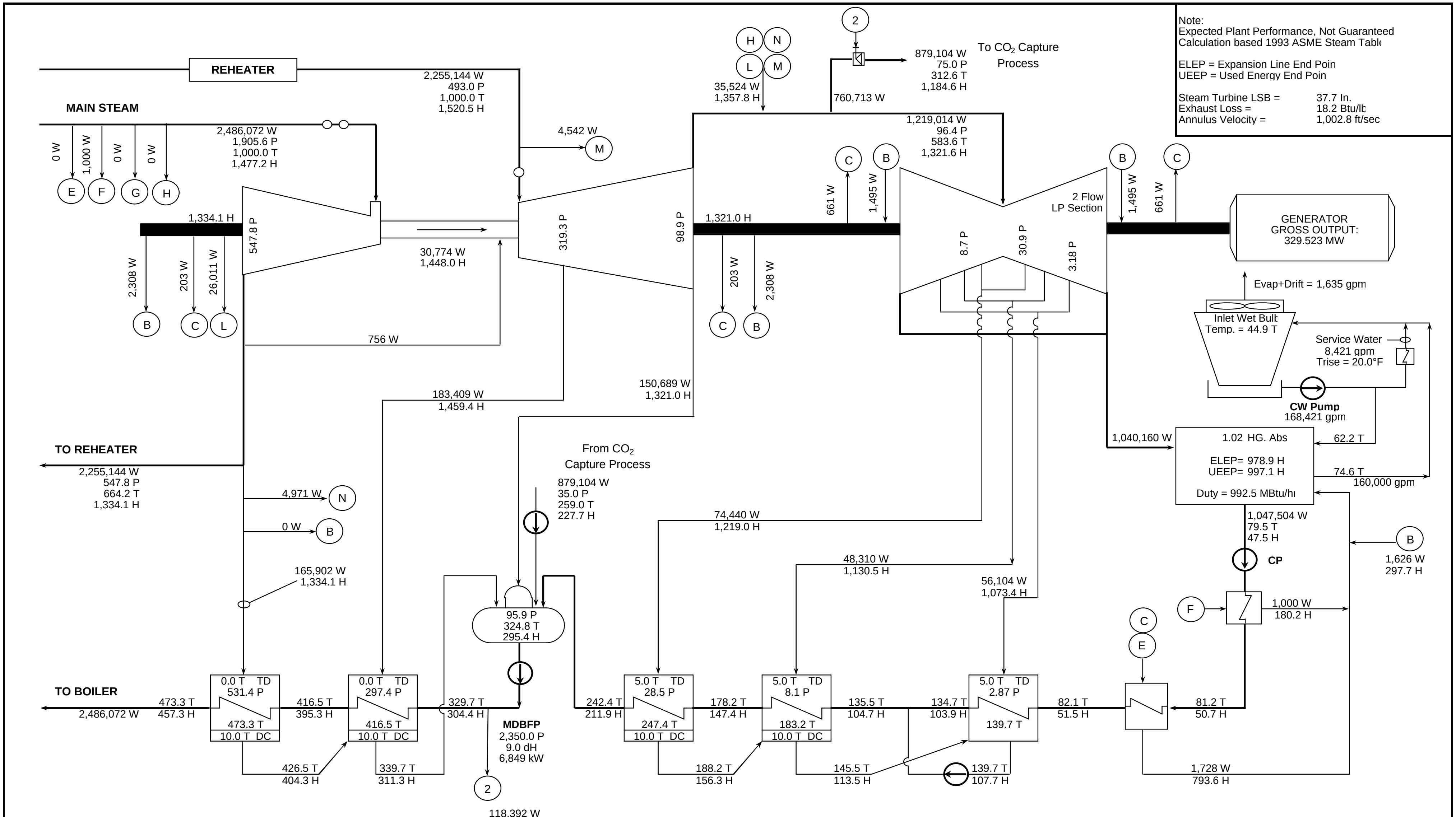
Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	1/26/2010	L. Papadopoulos			Original Issue	11278-018
1	2/9/2010	L. Papadopoulos				
						GateCycle Model/Case

San Juan Unit 2

Existing Unit Operation
Siemens WB-11293 dated 7-8-2008

Sargent & Lundy LLC



Ambient Dry Bulb =	53.0 T
Ambient Wet Bulb =	42.9 T
Relative Humidity =	47.0%
Site Elevation (AMSL) =	5,303 ft
Steam Turbine Gross =	329.5 MW

Gross Turbine Heat Rate = Heat Input / Generator Output = 8,970 Btu/kWh

Net Turbine Heat Rate = Heat Input / (Generator Output - Power to BFP Motor) = 9,161 Btu/kWh

PRELIMINARY
For Information Only

Legend:
W= Flow, lb/hr
P= Pressure, Psia
T= Temperature, °F
H= Enthalpy, Btu/lb

Drawing Release Record

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0	1/26/2010	L. Papadopoulos			Original Issue	11278-018
1	2/9/2010	L. Papadopoulos				
						GateCycle Model/Case

San Juan Unit 2

Existing Unit with CO_2 Capture Process Extraction

Sargent & Lundy LLC

D:\\\Current Coal Plant 350 MW - with CO2 (DA)

Sargent & Lundy LLC

PRELIMINARY
San Juan Unit 2
Estimated Performance Summary
4x4x1 CC Repowering

CASE DESCRIPTION	Annual Average	Winter Peak	Summer Peak
Ambient Dry Bulb Temperature	53°F	6°F	95°F
Relative Humidity	47%	100%	18%
Ambient Wet Bulb Temperature	42.9°F	6.0°F	62.8°F
Site Elevation (ft AMSL)	5303.0	5303.0	5303.0
Cycle Configuration (# CT x # HRSG x # ST)	4 x 4 x 1	4 x 4 x 1	4 x 4 x 1
Number of CT's	4	4	4
Fuel Type	Natural Gas	Natural Gas	Natural Gas
COMBUSTION TURBINE CHARACTERISTICS (per CT)			
CT Frame	GE 7FA.05	GE 7FA.05	GE 7FA.05
Load Condition	100%	100%	100%
Evaporative Cooler (ON/OFF)	OFF	OFF	ON
Compressor Inlet Air Temperature (°F)	53.	6.	66.
Inlet Air Cooling Water Consumption (lb/hr) Evap & Bleedoff	0.	0.	35,139.
Fuel Lower Heating Value (Btu/lb)	21,515.	21,515.	21,515.
Fuel Flow Rate (lb/hr)	71,903.	78,113.	71,541.
Fuel Inlet Temperature (°F)	365.	365.	365.
Heat Input to CT, LHV (MMBtu/hr)	1,547.0	1,680.6	1,539.2
Exhaust Gas Flow Rate (lb/hr)	3,393,000.	3,632,000.	3,406,000.
Exhaust Gas Temperature (°F)	1,112.	1,083.	1,116.
Exhaust Analysis, % Vol.			
Argon	0.89	0.89	0.88
Nitrogen	74.55	74.93	73.56
Oxygen	12.44	12.42	12.28
Carbon Dioxide	3.81	3.87	3.76
Water	8.31	7.89	9.53
CT Gross Output (kW)	174,484.	191,413.	171,577.
CT Gross Heat Rate, LHV (Btu/kWh)	8,866.	8,780.	8,971.
CT Gross Heat Rate, HHV (Btu/kWh)	9,841.	9,746.	9,958.
HRSG CHARACTERISTICS (per HRSG)			
Heat Input to Duct Burner, LHV (MMBtu/hr)	0.000	0.000	0.000
Main Steam Flow Rate (lb/hr)	421,497.	429,587.	428,245.
Main Steam Pressure (psia)	1,416.8	1,431.4	1,438.8
Main Steam Temperature (°F)	1,005.0	985.6	1,004.4
Main Steam Enthalpy (Btu/lb)	1,496.4	1,484.3	1,495.3
Hot Reheat Flow Rate (lb/hr)	466,706.	480,874.	474,660.
Hot Reheat Pressure (psia)	444.8	454.4	452.4
Hot Reheat Temperature (°F)	1,005.0	984.4	1,005.0
Hot Reheat Enthalpy (Btu/lb)	1,525.2	1,513.8	1,525.0
IP Superheater Flow Rate (lb/hr)	54,831.	61,088.	55,523.
IP Superheater Pressure (psia)	463.2	473.1	471.0
IP Superheater Temperature (°F)	586.4	585.3	588.3
IP Superheater Enthalpy (Btu/lb)	1,293.5	1,292.0	1,294.0
LP Superheater Flow Rate (lb/hr)	24,151.	24,132.	26,064.
LP Superheater Pressure (psia)	179.0	192.9	182.5
LP Superheater Temperature (°F)	580.9	583.6	578.4
LP Superheater Enthalpy (Btu/lb)	1,314.0	1,314.3	1,312.4
Condensate Preheater Inlet Flow Rate (lb/hr)	626,891.	670,764.	615,292.
Condensate Preheater Inlet Pressure (psia)	283.7	280.0	280.9
Condensate Preheater Inlet Temperature (°F)	140.0	140.0	140.0
Condensate Preheater Inlet Enthalpy (Btu/lb)	108.7	108.7	108.7
HRSG Exhaust Stack Gas Characteristics			
HRSG Exhaust Gas Temperature (°F)	234.2	236.7	237.8
HRSG Exhaust Gas Flow Rate (lb/hr)	3,393,000.	3,632,000.	3,406,000.
HRSG BLOWDOWN CHARACTERISTICS (Per HRSG)			
HP Evaporator Blowdown Flow Rate (lb/hr)	4,258.	4,339.	4,326.
IP Evaporator Blowdown Flow Rate (lb/hr)	554.	617.	561.
DEAERATOR CHARACTERISTICS (Per HRSG)			
DA Operating Pressure (psia)	182.6	196.3	186.7
Main Boiler Feedwater Inlet Flow Rate (lb/hr)	576,672.	596,904.	585,355.
Main Boiler Feedwater Inlet Temperature (°F)	349.0	353.1	353.0
Main Boiler Feedwater Outlet Flow Rate (lb/hr)	551,042.	571,291.	557,923.
Main Boiler Feedwater Outlet Temperature (°F)	374.3	380.2	376.1
BFW Temperature Rise (°F)	25.3	27.1	23.1
Primary Pegging Steam Flow Rate (lb/hr)	19,429.	21,691.	18,214.
Auxiliary Pegging Steam Flow Rate (lb/hr)	0.	0.	0.
Vent Steam Flow Rate (lb/hr)	1,442.	1,492.	1,463.
PUMP CHARACTERISTICS			
HP Feedpump Control Valve Discharge			
Total Flow Rate per HRSG (lb/hr)	425,755.	433,926.	432,571.
Pressure (psia)	1,475.0	1,491.2	1,498.2
Temperature (°F)	377.4	383.5	379.3
Enthalpy (Btu/lb)	352.6	359.0	354.6
IP Feedpump Control Valve Discharge			
Total Flow Rate per HRSG (lb/hr)	125,287.	137,365.	125,351.
Pressure (psia)	472.6.	484.5.	480.4.
Temperature (°F)	375.0.	381.0.	376.8.
Enthalpy (Btu/lb)	348.6.	355.0.	350.6.
Condensate Pump Discharge			
Total Flow Rate from Condenser (lb/hr)	2,026,640.	2,084,865.	2,066,984.
Pressure (psia)	350.0	350.0	350.0
Temperature (°F)	102.6	91.8	111.9
Enthalpy (Btu/lb)	71.6	60.8	80.8

PRELIMINARY

San Juan Unit 2

Estimated Performance Summary

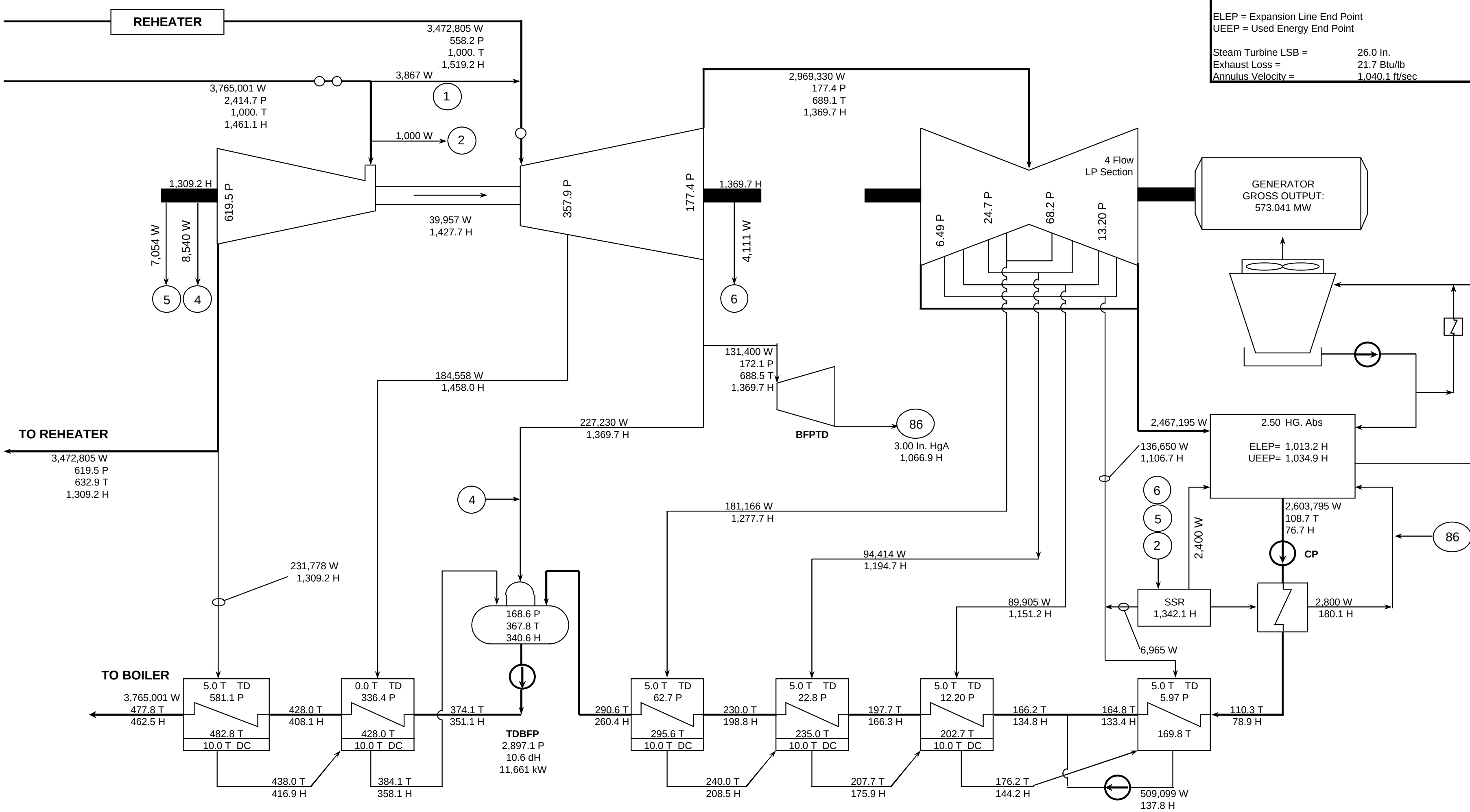
4x4x1 CC Repowering

CASE DESCRIPTION	Annual Average	Winter Peak	Summer Peak
STEAM TURBINE CHARACTERISTICS	TC2F 37.7 in. LSB	TC2F 37.7 in. LSB	TC2F 37.7 in. LSB
Main Steam Throttle Flow Rate (lb/hr)	1,685,989.	1,718,347.	1,712,979.
Main Steam Throttle Pressure (psia)	1,317.8	1,331.4	1,338.3
Main Steam Throttle Temperature (°F)	1,000.0	980.6	999.4
Main Steam Throttle Enthalpy (Btu/lb)	1,496.5	1,484.5	1,495.5
HP Section Bowl Pressure, PB (psia)	1,291.6	1,305.0	1,311.2
Cold Reheat Steam Flow Rate (lb/hr)	1,648,898.	1,680,543.	1,675,294.
Cold Reheat Steam Pressure (psia)	482.9.	492.9.	491.0.
Cold Reheat Steam Temperature (°F)	729.9.	715.3.	729.4.
Cold Reheat Steam Enthalpy (Btu/lb)	1,374.7.	1,366.0.	1,374.0.
Hot Reheat Steam Flow Rate (lb/hr)	1,866,823.	1,923,495.	1,898,641.
Hot Reheat Steam Pressure (psia)	427.0.	436.2.	434.4.
Hot Reheat Steam Temperature (°F)	1,000.0.	979.4.	1,000.0.
Hot Reheat Steam Enthalpy (Btu/lb)	1,523.0.	1,511.7.	1,522.8.
LP Steam Flow to ST (lb/hr)	2,000,519	2,057,834	2,040,593
LP Steam Pressure to ST (psia)	170.1	173.6	173.4
LP Steam Temperature to ST (°F)	739.6	722.6	739.5
LP Steam Enthalpy to ST (Btu/lb)	1,395.9	1,387.0	1,395.7
LP Turbine Exhaust Steam Flow Rate (lb/hr)	2,000,519.	2,057,834.	2,040,593.
LP Turbine Exhaust UEEP (Btu/lb)	1,034.4	1,029.3	1,038.5
LP Turbine Exhaust Loss (Btu/lb)	18.8	33.6	11.3
LP Turbine Exhaust Annulus Velocity (ft/sec)	998.2	1,382.8	792.8
LP Turbine Exhaust Sonic Velocity (ft/sec)	1,384.9	1,371.8	1,395.9
Turbine Backpressure (In. HgA)	2.10	1.51	2.76
Gross Steam Turbine Output (kW)	334,081.	338,303.	337,430.
CONDENSER CHARACTERISTICS (Approximate)			
Operating Pressure (psia)	1.032	0.740	1.356
Operating Pressure (in Hg Abs)	2.10	1.51	2.76
Temperature of Condensing Steam (°F)	102.7	91.8	112.1
CW Flow Rate Through Condenser (gpm)	160,000	160,000	160,000
CW Temperature Into Condenser (°F)	70.1	56.0	79.7
CW Temperature Out Of Condenser (°F)	94.2	81.0	104.1
Circulating Water Temperature Rise (°F)	24	25	24
Terminal Temperature Difference, TTD (°F)	8.5	10.9	8.0
Total Heat Rejection (MMBtu/hr)	1,927.5	1,994.8	1,955.5
COOLING TOWER CHARACTERISTICS (Approximate)			
CW Flow Rate Into Cooling Tower (gpm)	168,421	168,421	168,421
CW Temperature Into Cooling Tower (°F)	94.0	80.7	103.9
Air Inlet Wet Bulb Temperature (°F)	44.9	6.0	64.8
Current Approach Temperature (°F)	25.4	49.9	15.5
Current Range Temperature (°F)	23.7	24.8	23.6
Drift Rate (%)	0.0010%	0.0010%	0.0010%
Cycles of Concentration	4	4	4
Evaporation Loss (gpm)	2,929.	1,894.	4,101.
Drift Loss (gpm)	2.	2.	2.
Blowdown (gpm)	975.	630.	1,365.
Blowdown Temperature (°F)	70.1	56.0	79.6
Makeup (gpm)	3,905.	2,525.	5,468.
Makeup Temperature (°F)	60.0	60.0	60.0
Total Cooling Tower Heat Rejection (MMBtu/hr)	2,022.8	2,090.2	2,050.8
FUEL GAS PERFORMANCE HEATER CHARACTERISTICS (Per CT)			
Natural Gas Flow Rate (lb/hr)	71,903.	78,113.	71,541.
Natural Gas Inlet Temperature (°F)	50.0	50.0	50.0
Natural Gas Outlet Temperature (°F)	365.0	364.9	365.0
Heating Water Inlet Flow Rate (lb/hr)	70,000.	75,660.	68,604.
Heating Water Inlet Temperature (°F)	440.2	442.9	442.5
Heating Water Outlet Temperature (°F)	257.7	259.6	257.2
CYCLE MAKEUP CONDITIONS			
Makeup Flow Rate to Cycle (gpm)	50.0.	51.6.	331.9.
Makeup Temperature (°F)	60.0	60.0	60.0
TOTAL PLANT PERFORMANCE			
Total Gross CT Electrical Output (kW)	697,936.	765,652.	686,309.
Total Gross Steam Turbine Electrical Output (kW)	334,081.	338,303.	337,430.
Total Gross Plant Electrical Output (kW)	1,032,017.	1,103,956.	1,023,739.
Total Auxiliary Power (%)	2.50	2.50	2.50
BOP Auxiliary Power (kW)	25,800.	27,600.	25,590.
Total Auxiliary Power (kW)	25,800.	27,600.	25,590.
Net Plant Electrical Output (kW)	1,006,217.	1,076,356.	998,149.
Net Plant Electrical Heat Rate, LHV (Btu/kWh)	6,150.	6,246.	6,168.
Net Plant Electrical Heat Rate, HHV (Btu/kWh)	6,826.	6,933.	6,847.

Note:
Expected Plant Performance, Not Guaranteed.
Calculation based 1997 ASME Steam Table

ELEP = Expansion Line End Point
UEEP = Used Energy End Point

Steam Turbine LSB =	26.0 In.
Exhaust Loss =	21.7 Btu/lb
Annulus Velocity =	1,040.1 ft/sec



Gross Turbine Heat Rate = Heat Input / (Generator Output+Aux. Turbine Output) = 7,678 Btu/kWh

Net Turbine Heat Rate = Heat Input / Generator Output = 7,834 Btu/kWh

PRELIMINARY
For Information Only

Legend:
W= Flow, lb/hr
P= Pressure, Psia
T= Temperature, °F
H= Enthalpy, Btu/lb

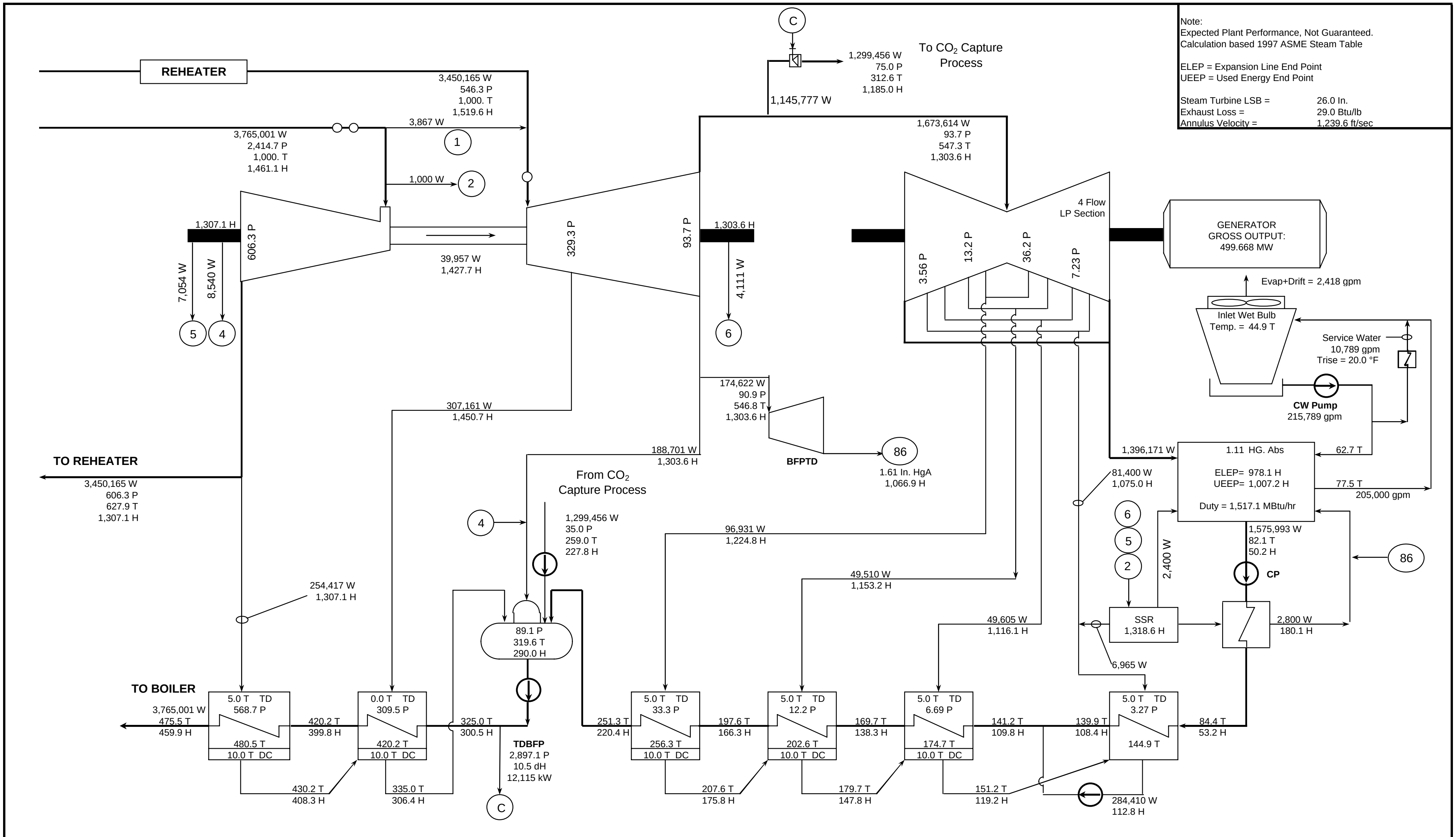
Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	1/26/2010	L.Papadopoulos			Feasibility Study	11278-018
1	2/9/2010	L.Papadopoulos				
						GateCycle Model/Case

San Juan Unit 3
Existing Unit Operation

GE AA08-100 dated 1-14-2008

Sargent & Lundy LLC



Ambient Dry Bulb =	53.0 T
Ambient Wet Bulb =	42.9 T
Relative Humidity =	47.0%
Site Elevation (AMSL) =	5,303 ft
Steam Turbine Gross =	500 MW

Gross Turbine Heat Rate = Heat Input / (Generator Output+Aux. Turbine Output) **= 8,798 Btu/kWh**

Net Turbine Heat Rate = Heat Input / Generator Output **= 9,011 Btu/kWh**

PRELIMINARY
For Information Only

Legend:
W= Flow, lb/hr
P= Pressure, Psia
T= Temperature, °F
H= Enthalpy, Btu/lb

Drawing Release Record

Rev.	Date	Prepared	Reviewed	Approved	Purpose	Project No.:
0	1/26/2010	L.Papadopoulos			Feasibility Study	11278-018
1	2/9/2010	L.Papadopoulos				
						GateCycle Model/Case

San Juan Unit 3

Existing Unit with CO2 Capture Process Extraction

Sargent & Lundy LLC

PRELIMINARY

San Juan Unit 3
Estimated Performance Summary
5x5x1 CC Repowering

CASE DESCRIPTION	Annual Average	Winter Peak	Summer Peak	
Ambient Dry Bulb Temperature	53°F	6°F	95°F	
Relative Humidity	47%	100%	18%	
Ambient Wet Bulb Temperature	42.9°F	6.0°F	62.8°F	
Site Elevation (ft AMSL)	5303.0	5303.0	5303.0	
Cycle Configuration (# CT x # HRSG x # ST	5 x 5 x 1	5 x 5 x 1	5 x 5 x 1	
Number of CT's	5	5	5	
Fuel Type	Natural Gas	Natural Gas	Natural Gas	
COMBUSTION TURBINE CHARACTERISTICS (per CT)				
CT Frame	GE 7FA.05	GE 7FA.05	GE 7FA.05	
Load Condition	100%	100%	100%	
Evaporative Cooler (ON/OFF)	OFF	OFF	ON	
Compressor Inlet Air Temperature (°F)	53.	6.	66.	
Inlet Air Cooling Water Consumption (lb/hr) Evap & Bleedoff	0.	0.	35,148.	
Fuel Lower Heating Value (Btu/lb)	21,515.	21,515.	21,515.	
Fuel Flow Rate (lb/hr)	71,903.	78,113.	71,541.	
Fuel Inlet Temperature (°F)	365.	365.	365.	
Heat Input to CT, LHV (MMBtu/hr)	1,547.0	1,680.6	1,539.2	
Exhaust Gas Flow Rate (lb/hr)	3,393,000.	3,632,000.	3,406,000.	
Exhaust Gas Temperature (°F)	1,112.	1,083.	1,116.	
Exhaust Analysis, % Vol.				
Argon	0.89	0.89	0.88	
Nitrogen	74.55	74.93	73.55	
Oxygen	12.44	12.42	12.28	
Carbon Dioxide	3.81	3.87	3.76	
Water	8.31	7.89	9.53	
CT Gross Output (kW)	174,484.	191,413.	171,577.	
CT Gross Heat Rate, LHV (Btu/kWh)	8,866.	8,780.	8,971.	
CT Gross Heat Rate, HHV (Btu/kWh)	9,841.	9,746.	9,958.	
HRSG CHARACTERISTICS (per HRSG)				
Heat Input to Duct Burner, LHV (MMBtu/hr)	0.000	0.000	0.000	
Main Steam Flow Rate (lb/hr)	384,564.	391,653.	390,225.	
Main Steam Pressure (psia)	1,374.0	1,387.7	1,393.6	
Main Steam Temperature (°F)	1,005.0	986.2	1,004.9	HRSG Evaporator Pinch is 50°F so ST
Main Steam Enthalpy (Btu/lb)	1,497.7	1,486.0	1,497.1	exhaust flow limit is not exceeded
Hot Reheat Flow Rate (lb/hr)	457,229.	470,162.	464,904.	
Hot Reheat Pressure (psia)	393.0	401.1	399.6	
Hot Reheat Temperature (°F)	1,005.0	985.1	1,005.0	
Hot Reheat Enthalpy (Btu/lb)	1,526.7	1,515.8	1,526.5	
IP Superheater Flow Rate (lb/hr)	81,405.	87,405.	82,694.	
IP Superheater Pressure (psia)	409.2	417.6	416.0	
IP Superheater Temperature (°F)	597.3	595.8	598.7	
IP Superheater Enthalpy (Btu/lb)	1,304.6	1,303.1	1,304.9	
LP Superheater Flow Rate (lb/hr)	9,665.	11,121.	10,673.	
LP Superheater Pressure (psia)	153.5	165.7	156.3	
LP Superheater Temperature (°F)	588.3	579.7	581.0	
LP Superheater Enthalpy (Btu/lb)	1,319.7	1,314.3	1,315.7	
Condensate Preheater Inlet Flow Rate (lb/hr)	611,540.	631,588.	606,415.	
Condensate Preheater Inlet Pressure (psia)	284.0	280.0	281.5	
Condensate Preheater Inlet Temperature (°F)	140.0	140.0	140.0	
Condensate Preheater Inlet Enthalpy (Btu/lb)	108.7	108.7	108.7	
HRSG Exhaust Stack Gas Characteristics				
HRSG Exhaust Gas Temperature (°F)	270.9	276.7	273.5	
HRSG BLOWDOWN CHARACTERISTICS (Per HRSG)				
HP Evaporator Blowdown Flow Rate (lb/hr)	3,884.	3,956.	3,942.	
IP Evaporator Blowdown Flow Rate (lb/hr)	822.	883.	835.	
DEAERATOR CHARACTERISTICS (Per HRSG)				
DA Operating Pressure (psia)	156.6	169.5	160.0	
Main Boiler Feedwater Inlet Flow Rate (lb/hr)	551,673.	568,987.	557,128.	
Main Boiler Feedwater Inlet Temperature (°F)	336.0	343.2	339.1	
Main Boiler Feedwater Outlet Flow Rate (lb/hr)	540,611.	556,494.	545,100.	
Main Boiler Feedwater Outlet Temperature (°F)	361.8	368.2	363.5	
BFW Temperature Rise (°F)	25.8	25.0	24.5	
Primary Pegging Steam Flow Rate (lb/hr)	18,610.	18,808.	17,934.	
Auxiliary Pegging Steam Flow Rate (lb/hr)	0.	0.	0.	
Vent Steam Flow Rate (lb/hr)	1,379.	1,422.	1,393.	
PUMP CHARACTERISTICS				
HP Feedpump Control Valve Discharge				
Total Flow Rate per HRSG (lb/hr)	388,448.	395,610.	394,167.	
Pressure (psia)	1,430.4	1,445.7	1,451.1	
Temperature (°F)	364.8	371.2	366.6	
Enthalpy (Btu/lb)	339.3	346.0	341.2	
IP Feedpump Control Valve Discharge				
Total Flow Rate per HRSG (lb/hr)	152,163.	160,885.	150,933.	
Pressure (psia)	417.5.	426.9.	424.3.	
Temperature (°F)	362.5.	368.8.	364.2.	
Enthalpy (Btu/lb)	335.3.	342.0.	337.1.	

PRELIMINARY
San Juan Unit 3
Estimated Performance Summary
5x5x1 CC Repowering

CASE DESCRIPTION	Annual Average	Winter Peak	Summer Peak	
Condensate Pump Discharge				
Total Flow Rate from Condenser (lb/hr)	2,408,342.	2,481,975.	2,452,865.	
Pressure (psia)	350.0	350.0	350.0	
Temperature (°F)	100.6	99.9	106.9	
Enthalpy (Btu/lb)	69.6	68.8	75.8	
STEAM TURBINE CHARACTERISTICS	TC4F 26. in. LSB	TC4F 26. in. LSB	TC4F 26. in. LSB	
Main Steam Throttle Flow Rate (lb/hr)	1,922,819.	1,958,267.	1,951,126.	
Main Steam Throttle Pressure (psia)	1,274.9	1,287.7	1,293.1	
Main Steam Throttle Temperature (°F)	1,000.0	981.2	999.9	
Main Steam Throttle Enthalpy (Btu/lb)	1,497.8	1,486.3	1,497.2	
HP Section Bowl Pressure, PB (psia)	1,236.8	1,249.3	1,254.5	
Cold Reheat Steam Flow Rate (lb/hr)	1,880,517.	1,915,186.	1,908,201.	
Cold Reheat Steam Pressure (psia)	426.6.	435.0.	433.6.	
Cold Reheat Steam Temperature (°F)	706.5.	692.5.	706.8.	
Cold Reheat Steam Enthalpy (Btu/lb)	1,364.9.	1,356.7.	1,364.7.	
Hot Reheat Steam Flow Rate (lb/hr)	2,286,144.	2,350,809.	2,324,520.	
Hot Reheat Steam Pressure (psia)	377.3.	385.0.	383.6.	
Hot Reheat Steam Temperature (°F)	1,000.0.	980.1.	1,000.0.	
Hot Reheat Steam Enthalpy (Btu/lb)	1,524.5.	1,513.6.	1,524.3.	
LP Steam Flow to ST (lb/hr)	2,376,771	2,449,501	2,420,812	
LP Steam Pressure to ST (psia)	145.8	149.1	148.5	
LP Steam Temperature to ST (°F)	736.0	719.0	735.9	
LP Steam Enthalpy to ST (Btu/lb)	1,395.3	1,386.5	1,395.1	
LP Turbine Exhaust Steam Flow Rate (lb/hr)	2,376,771.	2,449,501.	2,420,812.	Flow Limit Approx.: 2,466,000 lb/hr
LP Turbine Exhaust UEEP (Btu/lb)	1,056.1	1,051.9	1,056.4	
LP Turbine Exhaust Loss (Btu/lb)	32.1	34.0	24.6	
LP Turbine Exhaust Annulus Velocity (ft/sec)	1,267.5	1,326.1	1,086.9	
LP Turbine Exhaust Sonic Velocity (ft/sec)	1,398.7	1,395.1	1,404.6	
Turbine Backpressure (In. HgA)	1.98	1.94	2.39	
Gross Steam Turbine Output (kW)	386,954.	391,241.	393,144.	
CONDENSER CHARACTERISTICS				
Operating Pressure (psia)	0.973	0.951	1.174	
Operating Pressure (in Hg Abs)	1.98	1.94	2.39	
Temperature of Condensing Steam (°F)	100.8	100.0	107.1	
CW Flow Rate Through Condenser (gpm)	205,000	205,000	205,000	
CW Temperature Into Condenser (°F)	71.5	69.9	77.8	
CW Temperature Out Of Condenser (°F)	94.5	93.4	101.1	
Circulating Water Temperature Rise (°F)	23	24	23	
Terminal Temperature Difference, TTD (°F)	6.3	6.6	6.0	
Total Heat Rejection (MMBtu/hr)	2,346.5	2,410.1	2,375.6	
COOLING TOWER CHARACTERISTICS				
CW Flow Rate Into Cooling Tower (gpm)	215,789	215,789	215,789	
CW Temperature Into Cooling Tower (°F)	94.3	93.2	100.9	
Air Inlet Wet Bulb Temperature (°F)	44.9	6.0	64.8	
Current Approach Temperature (°F)	26.9	64.0	13.6	
Current Range Temperature (°F)	22.5	23.2	22.5	
Drift Rate (%)	0.0010%	0.0010%	0.0010%	
Cycles of Concentration	4	4	4	
Evaporation Loss (gpm)	3,566.	2,567.	5,071.	
Drift Loss (gpm)	2.	2.	2.	
Blowdown (gpm)	1,186.	854.	1,688.	
Blowdown Temperature (°F)	71.5	69.8	77.8	
Makeup (gpm)	4,755.	3,423.	6,762.	
Makeup Temperature (°F)	60.0	60.0	60.0	
Total Cooling Tower Heat Rejection (MMBtu/hr)	2,463.4	2,527.0	2,492.5	
FUEL GAS PERFORMANCE HEATER CHARACTERISTICS (Per CT)				
Natural Gas Flow Rate (lb/hr)	71,903.	78,113.	71,541.	
Natural Gas Inlet Temperature (°F)	50.0	50.0	50.0	
Natural Gas Outlet Temperature (°F)	365.0	365.1	365.0	
Heating Water Inlet Flow Rate (lb/hr)	70,000.	72,597.	66,554.	
Heating Water Inlet Temperature (°F)	427.0	431.5	429.7	
Heating Water Outlet Temperature (°F)	241.5	237.2	235.4	
CYCLE MAKEUP CONDITIONS				
Makeup Flow Rate to Cycle (gpm)	60.9	62.6	413.2	
Makeup Temperature (°F)	60.0	60.0	60.0	
TOTAL PLANT PERFORMANCE				
Total Gross CT Electrical Output (kW)	872,420.	957,066.	857,886.	
Total Gross Steam Turbine Electrical Output (kW)	386,954.	391,241.	393,144.	
Total Gross Plant Electrical Output (kW)	1,259,374.	1,348,307.	1,251,030.	
Total Auxiliary Power (%)	2.50	2.50	2.50	
BOP Auxiliary Power (kW)	31,480.	33,710.	31,280.	
Total Auxiliary Power (kW)	31,480.	33,710.	31,280.	
Net Plant Electrical Output (kW)	1,227,894.	1,314,597.	1,219,750.	
Net Plant Electrical Heat Rate, LHV (Btu/kWh)	6,299.	6,392.	6,310.	
Net Plant Electrical Heat Rate, HHV (Btu/kWh)	6,992.	7,095.	7,004.	

APPENDIX B.
UNIT 1 AND 2 STEAM TURBINE COMPARISON

San Juan Unit 1 & 2 ST Comparison
Steam Turbine Efficiencies

January 5, 2010

Case Description:	UNIT 1	UNIT 2
	GE	Siemens
	VWO	VWO + 5%OP
	1800P/1000F/1000F	1905P/1000F/1000F
	TC2F - 33.5"LSB	TC2F - 37.7"LSB
	2.5 In. HgA	2.5 In. HgA
	1967 ASME	1967 ASME
Main Steam Flow Rate	2,384,782 lb/hr	2,486,070 lb/hr
Percent of VWO Flow Rate	N/A	N/A
Reheat Flow Rate	2,156,515 lb/hr	2,270,340 lb/hr
HP Steam Turbine		
Inlet Pressure	1,814.7 psia	1,905.7 psia
Inlet Temperature	1,000.0 °F	1,000.0 °F
Inlet Enthalpy	1,480.1 Btu/lb	1,477.2 Btu/lb
Inlet Entropy	1.57415 Btu/lb-°R	1.56724 Btu/lb-°R
Outlet Pressure	468.2 psia	560.6 psia
Outlet Enthalpy	1,325.9 Btu/lb	1,336.4 Btu/lb
Outlet Entropy	1.59097 Btu/lb-°R	1.58190 Btu/lb-°R
Outlet Isentropic Enthalpy	1,307.7 Btu/lb	1,320.0 Btu/lb
HP ST Efficiency	89.4 %	89.6 %
IP Steam Turbine		
Inlet Pressure	416.1 psia	504.5 psia
Inlet Temperature	1,000.0 °F	1,000.0 °F
Inlet Enthalpy	1,522.8 Btu/lb	1,520.2 Btu/lb
Inlet Entropy	1.75864 Btu/lb-°R	1.73608 Btu/lb-°R
Outlet Pressure	147.6 psia	174.5 psia
Outlet Enthalpy	1,385.9 Btu/lb	1,381.1 Btu/lb
Outlet Entropy	1.76677 Btu/lb-°R	1.74455 Btu/lb-°R
Outlet Isentropic Enthalpy	1,376.4 Btu/lb	1,371.3 Btu/lb
IP ST Efficiency	93.5 %	93.4 %
LP Steam Turbine		
Inlet Pressure	146.5 psia	170.1 psia
Inlet Enthalpy	1,385.9 Btu/lb	1,381.1 Btu/lb
Inlet Entropy	1.76758 Btu/lb-°R	1.74730 Btu/lb-°R
Outlet Pressure	2.50 In HgA	2.50 In HgA
Outlet Pressure	1.2279 psia	1.2279 psia
UEEP Enthalpy	1,049.2 Btu/lb	1,026.5 Btu/lb
ELEP Enthalpy	1,033.8 Btu/lb	1,017.0 Btu/lb [1]
Outlet Entropy	1.85600 Btu/lb-°R	1.81606 Btu/lb-°R
Outlet Isentropic Enthalpy	998.9 Btu/lb	987.4 Btu/lb
Exit Steam Quality	94.2 %	92.0 %
LP ST UEEP Efficiency	87.0 %	90.1 %
LP Exhaust Flow Rate	1,693,136 lb/hr	1,730,169 lb/hr
LP Exhaust Annular Area	66.1 ft^2	82.3 ft^2
LP Exhaust Specific Volume	259.1 ft^3/lb	253.0 ft^3/lb
Annulus Velocity	921.7 ft/sec	738.8 ft/sec
Exhaust Losses	15.4 Btu/lb	9.5 Btu/lb [1]
Plant Summary		
Final Feedwater Enthalpy	441.3 Btu/lb	460.0 Btu/lb
Gross Steam Turbine Output	367.858 MW	381.206 MW
Gross Turbine Heat Rate	7,889 Btu/kW-hr	7,728 Btu/kW-hr

Notes:
1. Determined by S&L matched Heat Balances using Gate Cycle

APPENDIX C.
REPOWERED UNIT 2 AND UNIT 3 ESTIMATED EMISSIONS

PNM - San Juan Generating Station
GE 7FA.05 4x1 & 5x1 Combined Cycle

Ref Case No.		Annual Average	Winter Peak	Summer Peak
Case Description	Ambient Temp - % Load	53 F - 100% Load	6 F - 100% Load	95 F - 100% Load
	Fuel	Natural Gas	Natural Gas	Natural Gas
	Evaporative Coolers	Off	Off	On
	Duct Firing (Fired / Unfired)	Unfired	Unfired	Unfired
Controlled Emissions (Per CT/HRSG)		ppmvd@15%O_2	ppmvd@15%O_2	ppmvd@15%O_2
	NO_X	2.0	2.0	2.0
	CO	9.0	9.0	9.0
	VOC	1.4	1.4	1.4
	NH_3	5.0	5.0	5.0
		lb/hr	lb/hr	lb/hr
	NO_X	12.5	13.6	12.5
	CO	34.3	37.3	34.1
	SO_2	2.41	2.62	2.40
	PM_{10} / $PM_{2.5}$	18.65	18.70	18.64
	VOC	3.06	3.32	3.04
	H_2SO_4	0.48	0.52	0.48
	NH_3	11.6	12.6	11.5
	CO_2	200,364	217,466	199,438
Stack Conditions (4x4x1)	Stack Diameter, ft	20.0	20.0	20.0
	Flow Rate, acfm	1,224,973	1,313,632	1,242,061
	Velocity, ft/sec	65.0	69.7	65.9
	Temperature, ^oF	234.2	236.7	237.8
Stack Conditions (5x5x1)	Stack Diameter, ft	20.0	20.0	20.0
	Flow Rate, acfm	1,289,733	1,389,052	1,305,605
	Velocity, ft/sec	68.4	73.7	69.3
	Temperature, ^oF	270.9	276.7	273.5

Emissions Summary
GE 7FA.05 (4x1 & 5x1) Combined Cycle
PRELIMINARY

CASE		Annual Average 53 F - 100% Load	Winter Peak 6 F - 100% Load	Summer Peak 95 F - 100% Load
PNM - San Juan Generating Station **GE 7FA.05 Combined Cycle** **Gas Fired Emission Estimates (per CT/HRSG)**		**Unfired**	**Unfired**	**Unfired** **Evaporative Cooler**
SITE CONDITIONS				
Ambient Temperature	^oF	53	6	95
Relative Humidity	%	47	100	18
Site Elevation	feet	5,303	5,303	5,303
Atmospheric Pressure	psia	12.11	12.11	12.11
FACILITY CONDITIONS (Note 1)				
CT Fuel Type		Natural Gas	Natural Gas	Natural Gas
CT Model		GE 7FA.05	GE 7FA.05	GE 7FA.05
CT Load	%	100	100	100
CT Evap Cooler	ON/OFF	Off	Off	On
CT Gross Power Output	kW	174,484	191,413	171,577
CT Heat Consumption (LHV)	MBtu/hr	1,547.0	1,680.6	1,539.2
CT Heat Consumption (HHV)	MBtu/hr	1,716.6	1,864.9	1,708.0
CT Fuel Flow Rate	lb/hr	75,052	81,533	74,673
CT Fuel Flow Rate	MSCF/hr	1.69	1.83	1.68
CT Exhaust Gas Flow Rate	lb/hr	3,393,000	3,632,000	3,406,000
CT Exhaust Gas Temperature	^oF	1,112	1,083	1,116
NATURAL GAS ANALYSIS (Note 2)				
	MW	mol %	mol %	mol %
Nitrogen, N_2	28.01	0.479	0.479	0.479
Carbon Dioxide, CO_2	44.01	1.180	1.180	1.180
Carbon Monoxide, CO	28.01	0.000	0.000	0.000
Hydrogen, H_2	2.02	0.000	0.000	0.000
Methane, CH_4	16.04	95.879	95.879	95.879
Ethane, C_2H_6	30.07	1.961	1.961	1.961
Propane, C_3H_8	44.10	0.290	0.290	0.290
Iso-Butane, C_4H_{10}	58.12	0.060	0.060	0.060
n-Butane, C_4H_{10}	58.12	0.060	0.060	0.060
Iso-Pentane, C_5H_{12}	72.15	0.026	0.026	0.026
n-Pentane, C_5H_{12}	72.15	0.016	0.016	0.016
n-Hexane, C_6H_{14}	86.18	0.050	0.050	0.050
n-Heptane, C_7H_{16}	100.21	0.000	0.000	0.000
Ethylene, C_2H_4	28.05	0.000	0.000	0.000
Propylene, C_3H_6	42.08	0.000	0.000	0.000
neo-Pentane, C_5H_{12}	72.15	0.000	0.000	0.000
Oxygen, O_2	32.00	0.000	0.000	0.000
Water, H_2O	18.02	0.000	0.000	0.000
Total		*100.00*	*100.00*	*100.00*
Fuel LHV	Btu/lb	20,612	20,612	20,612
Fuel HHV	Btu/lb	22,872	22,872	22,872
Fuel LHV	Btu/ft^3	917.7	917.7	917.7
Fuel HHV	Btu/ft^3	1,018.3	1,018.3	1,018.3
HHV/LHV Ratio		1.110	1.110	1.110
Total Sulfur, S **(Note 3)**	grains/100 ft^3	0.50	0.50	0.50
COMBUSTION TURBINE EXHAUST ANALYSIS (Note 4)				
Argon, Ar	% vol	0.890	0.890	0.880
Nitrogen, N_2	% vol	74.55	74.93	73.56
Oxygen, O_2	% vol	12.44	12.42	12.28
Carbon Dioxide, CO_2	% vol	3.81	3.87	3.76
Water, H_2O	% vol	8.31	7.89	9.53
Total		*100.0*	*100.0*	*100.0*
Molecular weight	lb/lbmol	28.39	28.45	28.26
COMBUSTION TURBINE EMISSIONS (per CT) (Note 5)				
NO_X	ppmvd @ 15% O_2	9.0	9.0	9.0
NO_X	ppmvd	11.2	11.3	11.2
NO_X as NO_2	lb/hr	56.4	61.2	56.1
CO	ppmvd @ 15% O_2	9.0	9.0	9.0
CO	ppmvd	11.2	11.3	11.2
CO	lb/hr	34.3	37.3	34.1
VOC	ppmvd @ 15% O_2	1.4	1.4	1.4
VOC	ppmvd	1.7	1.8	1.7
VOC	ppmvw	1.6	1.6	1.6
VOC	lb/hr	3.1	3.3	3.0
SO_2	ppmvd @ 15% O_2	0.28	0.28	0.28
SO_2	ppmvd	0.34	0.35	0.34
SO_2	lb/hr	2.41	2.62	2.40
SO_3 Oxidation **(Note 6)**	%	8	8	8
SO_3	ppmvd @ 15% O_2	0.022	0.022	0.022
SO_3	ppmvd	0.027	0.028	0.027
SO_3	lb/hr	0.241	0.262	0.240
PM10				
Total (Front & Back Half)	lb/hr	18.00	18.00	18.00
Total (Front & Back Half)	lb/mmBtu	0.0105	0.0097	0.0105
CO_2	ppmvd @ 15% O_2	30,656	30,788	30,270
CO_2	ppmvd	38,100	38,700	37,596
CO_2	lb/hr	200,364	217,466	199,438

Emissions Summary
GE 7FA.05 (4x1 & 5x1) Combined Cycle
PRELIMINARY

Project No. 11278-018
February 24, 2010

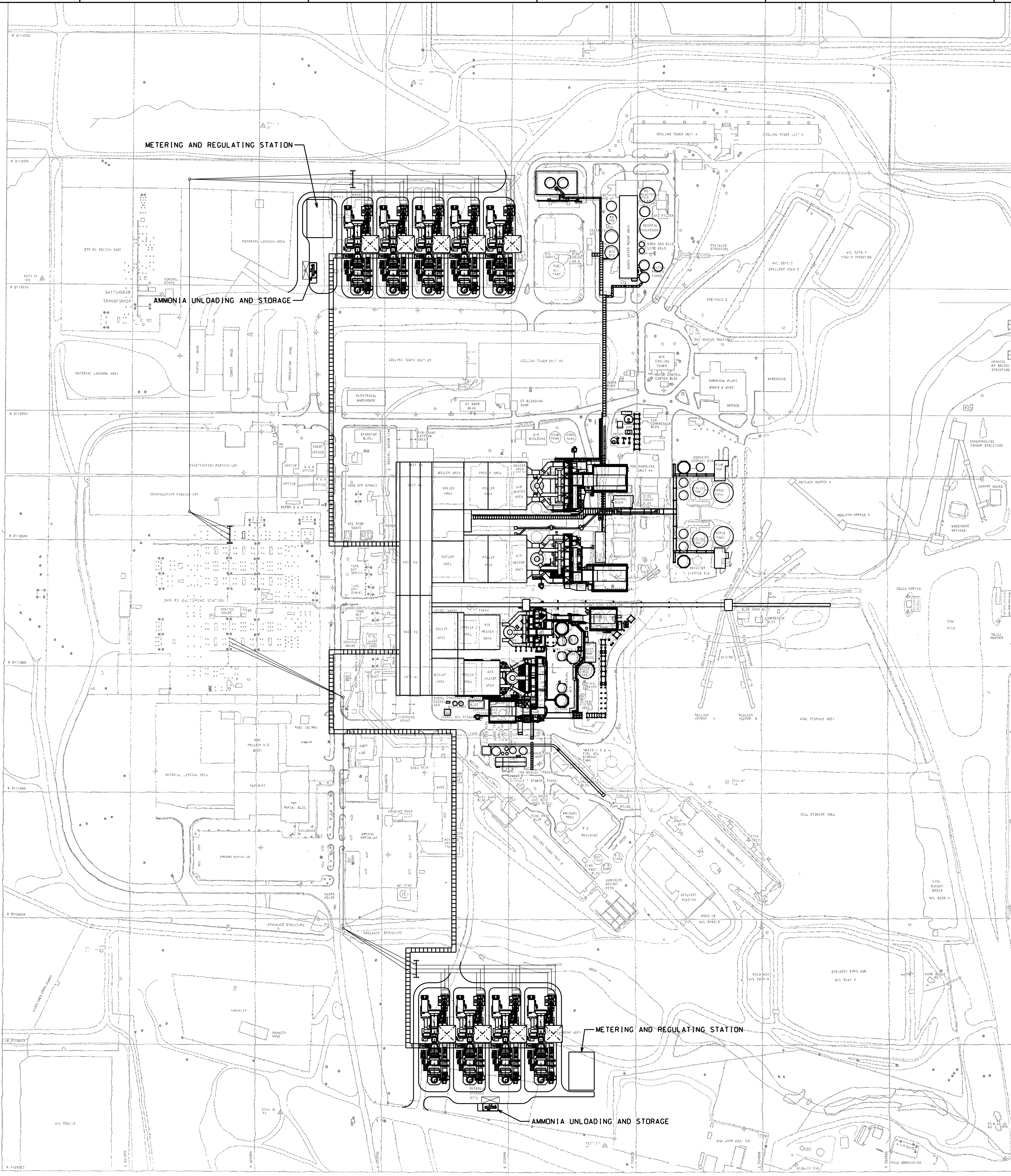
CASE		Annual Average	Winter Peak	Summer Peak
		53 F - 100% Load	6 F - 100% Load	95 F - 100% Load
PNM - San Juan Generating Station GE 7FA.05 Combined Cycle Gas Fired Emission Estimates (per CT/HRSG)		Unfired	Unfired	Unfired Evaporative Cooler
POST SCR EMISSIONS (per CT/HRSG)				
Hours of Operation **(Note 8)**	hours/year	8,760	8,760	8,760
NO_X **(Note 9)**	ppmvd @ 15% O_2	2.0	2.0	2.0
NO_X Removal Efficiency **(Note 7)**	% decrease	77.8	77.8	77.8
NO_X	ppmvd	2.5	2.5	2.5
NO_X	lb/hr	12.5	13.6	12.5
NO_X	lb/MBtu (HHV)	0.0073	0.0073	0.0073
NO_X	ton/yr	54.9	59.6	54.6
NH_3	ppmvd @ 15% O_2	5.0	5.0	5.0
NH_3	ppmvd	6.21	6.28	6.21
NH_3	lb/hr	11.6	12.6	11.5
NH_3	lbmol/hr	0.7	0.7	0.7
NH_3	ton/yr	50.8	55.1	50.5
CO	ppmvd @ 15% O_2	9.0	9.0	9.0
CO	ppmvd	11.2	11.3	11.2
CO	lb/hr	34.3	37.3	34.1
CO	lb/MBtu (HHV)	0.0200	0.0200	0.0200
CO	ton/yr	150.4	163.2	149.6
VOC	ppmvd @ 15% O_2	1.4	1.4	1.4
VOC	ppmvd	1.7	1.8	1.7
VOC	lb/hr	3.1	3.3	3.0
VOC	lb/MBtu (HHV)	0.0018	0.0018	0.0018
VOC	ton/yr	13.4	14.5	13.3
SO_2	ppmvd @ 15% O_2	0.28	0.28	0.28
SO_2	ppmvd	0.34	0.35	0.34
SO_2	lb/hr	2.41	2.62	2.40
SO_2	lb/MBtu (HHV)	0.00140	0.00140	0.00140
SO_2	ton/yr	10.5	11.5	10.5
SO_3 Oxidation across SCR **(Note 10)**	% increase	5	5	5
SO_3 Oxidation across SCR	lb/hr	0.15	0.16	0.15
SO_3	ppmvd @ 15% O_2	0.04	0.04	0.04
SO_3	ppmvd	0.04	0.05	0.04
SO_3	lb/hr	0.39	0.43	0.39
SO_3	lbmol/hr	4.89E-03	5.31E-03	4.86E-03
H_2SO_4	lb/hr	0.48	0.52	0.48
H_2SO_4	lb/mmBtu	0.000228	0.000228	0.000228
H_2SO_4	ton/yr	2.1	2.3	2.1
$(NH_4)_2SO_4$, Ammonium Sulfate **(Note 11)**	lb/hr	0.65	0.70	0.64
$(NH_4)_2SO_4$, Ammonium Sulfate	ton/yr	2.8	3.1	2.8
PM10				
Total PM10	lb/hr	18.65	18.70	18.64
Total PM10	lb/MBtu (HHV)	0.0109	0.0100	0.0109
Total PM10	grains/scf	0.0028	0.0027	0.0028
Total PM10	grains/dscf	0.0031	0.0029	0.0031
Total PM10	ton/yr	81.7	81.9	81.7
CO_2	ppmvd @ 15% O_2	33,435	33,426	33,458
CO_2	ppmvd	41,553	42,015	41,556
CO_2	lb/hr	200,364	217,466	199,438
CO_2	lb/mmBtu (HHV)	116.7	116.6	116.8
CO_2	ton/yr	877,593	952,500	873,540
Aqueous Ammonia (per CT/HRSG)				
Purity **(Note 12)**	%	19.0	19.0	19.0
Consumption	lb/hr	146.5	159.0	145.7
Stack Conditions (per CT/HRSG)				
Internal Diameter **(Note 13)**	ft	20.0	20.0	20.0
Flow	lb/hr	3,393,146	3,632,159	3,406,146
Flow	scfm	767,543	820,141	774,235
Flow	dscfm	703,760	755,432	700,457
Temperature (4x4x1)	^oF	234.2	236.7	237.8
Flow (4x4x1)	acfm	1,224,973	1,313,632	1,242,061
Exit Velocity (4x4x1	ft/s	65.0	69.7	65.9
Temperature (5x5x1)	^oF	270.9	276.7	273.5
Flow (5x5x1)	acfm	1,289,733	1,389,052	1,305,605
Exit Velocity (5x5x1	ft/s	68.4	73.7	69.3

Notes:

MBtu = 10^6 Btu

1. Performance information, including CT Output, Heat Input, Exhaust Gas Flow, and Duct Firing Rates were obtained from: GE 7FA.05 4x1 & 5x1 Combined Cycle Heat Balance Cases dated 2/9/10
2. Natural gas heating value based on generic gas analysis.
3. Fuel S content assumed to be 0.5 gr/100scf based on 40 CFR 72.2 definition of "pipeline natural gas".
4. Exhaust Gas compositions were based on information provided in the heat balances referenced in Note 1.
5. Combustion turbine emission rates were based on GE 7FA.05 performance data sheet dated 12/15/09. CO and VOC ppm provided by GE are on a dry and wet basis, respectively, at actual O2. GE's CO and VOC ppm values are included in this evaluation. However, the values are conservative corrected to 15% O2 on a dry basis. PM emissions provided by GE only include filterable PM. To account for both filterable and condensable PM, the emission rate provided by GE was doubled based on the conservative assumption that PM composition is 50% filterable and 50% condensable.
6. Assumed 8% SO_2 to SO_3 oxidation during the combustion of natural gas.
7. NOx removal efficiency is estimated based on reduction that is expected throughout life of catalyst.
8. Emission Calculations included in this spreadsheet are based on 8,760 hour/year operation for each case (per CT/HRSG).
9. Assumed a post-SCR NOx emission rate of 2.0 ppmvd @ 15% O2.
10. SO_2 to SO_3 oxidation across the SCR is assumed to be 5%.
11. Assumed 100% conversion of SO_3 to (NH4)2SO4, and all $(NH_4)_2SO_4$ is captured as front half particulate matter.
12. Assumed aqueous ammonia purity of 19.0%
13. Assumed an Internal Stack Diameter of 20 feet for HRSG stack.

APPENDIX D.
GENERAL ARRANGEMENT DRAWINGS



NORTH

150 0 150 300 450
GRAPHIC SCALE
DRAWING SCALE
1" = 150'-0"

HOLD INFORMATION		
NO.	DATE	DESCRIPTION
△		

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION		
REV.	DATE	DESCRIPTION
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B	02-22-2010	FINAL REPORT

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SPECIFICATION:

PROJECT NO.: 11278-018

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REVIEWED BY: J.G.GATZ

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CHICAGO, ILLINOIS 60603-5780

PNM

PROJECT

SAN JUAN GENERATING STATION

REPOWERING OF UNITS 2 AND 3
PUBLIC SERVICE COMPANY
OF NEW MEXICO

DRAWING TITLE

PRELIMINARY
GENERAL ARRANGEMENT
GE 7FA COMBINED CYCLE

DRAWING NUMBER	REVISION
SK-GA-001	B

SHEET 1 OF 1

ZL5878/0m1743/D:#SanJuan#SK-GA-SJ-001.dgn
Form GDG-0401-01-08. ANSI (Imperial) MicroStation Border - Size E - 34 x 44
Revision 10. Revision Date: 10-16-2009

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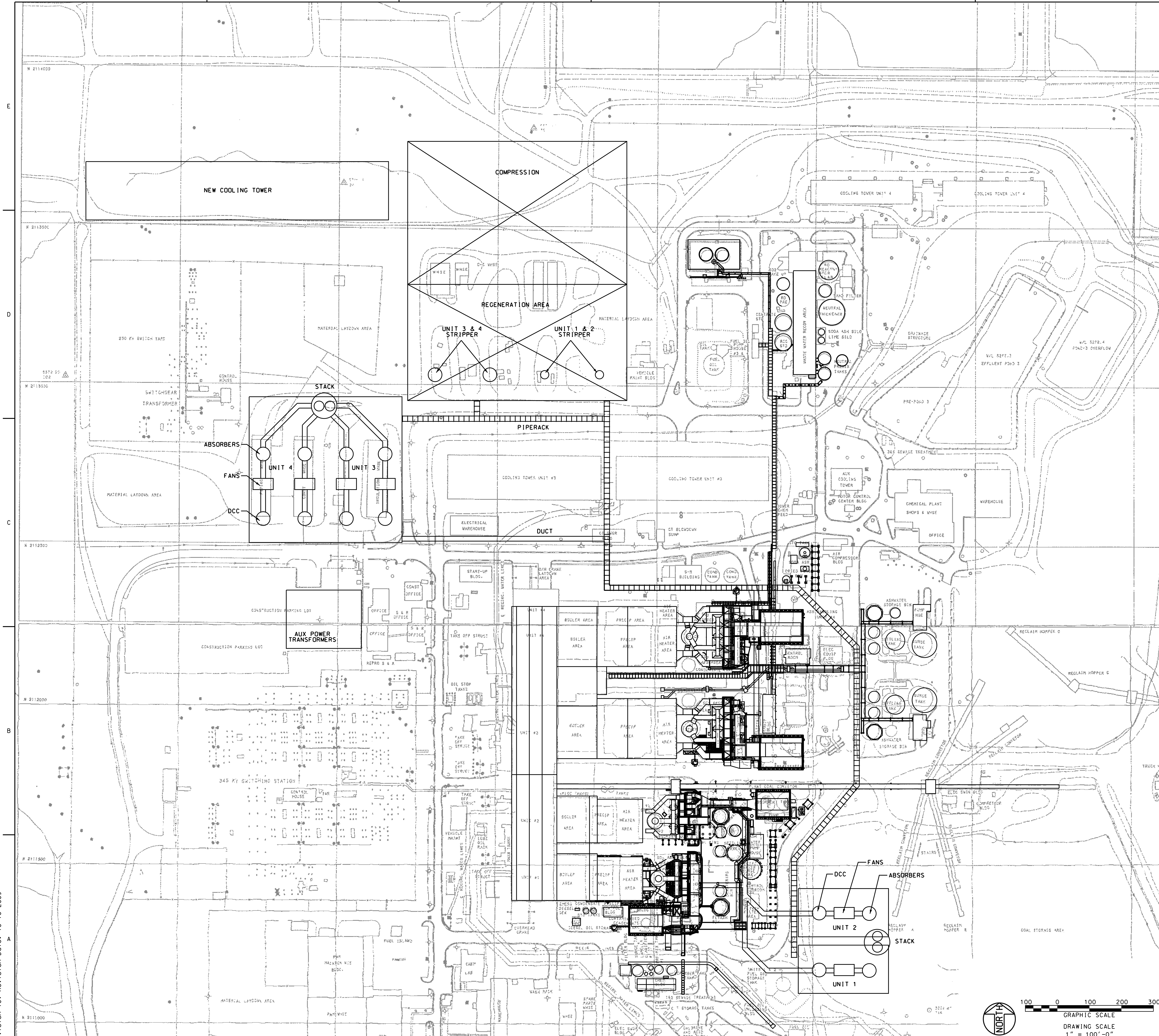

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REVIEWED BY: D.J.STOPEK

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CHICAGO, ILLINOIS 60603-5780

PNM

PROJECT

SAN JUAN GENERATING STATION

PUBLIC SERVICE COMPANY OF NEW MEXICO

DRAWING TITLE

PRELIMINARY
GENERAL ARRANGEMENT
CO2 EMISSION CAPTURE

DRAWING NUMBER	REVISION
SK-GA-002	B

SHEET 1 OF 1

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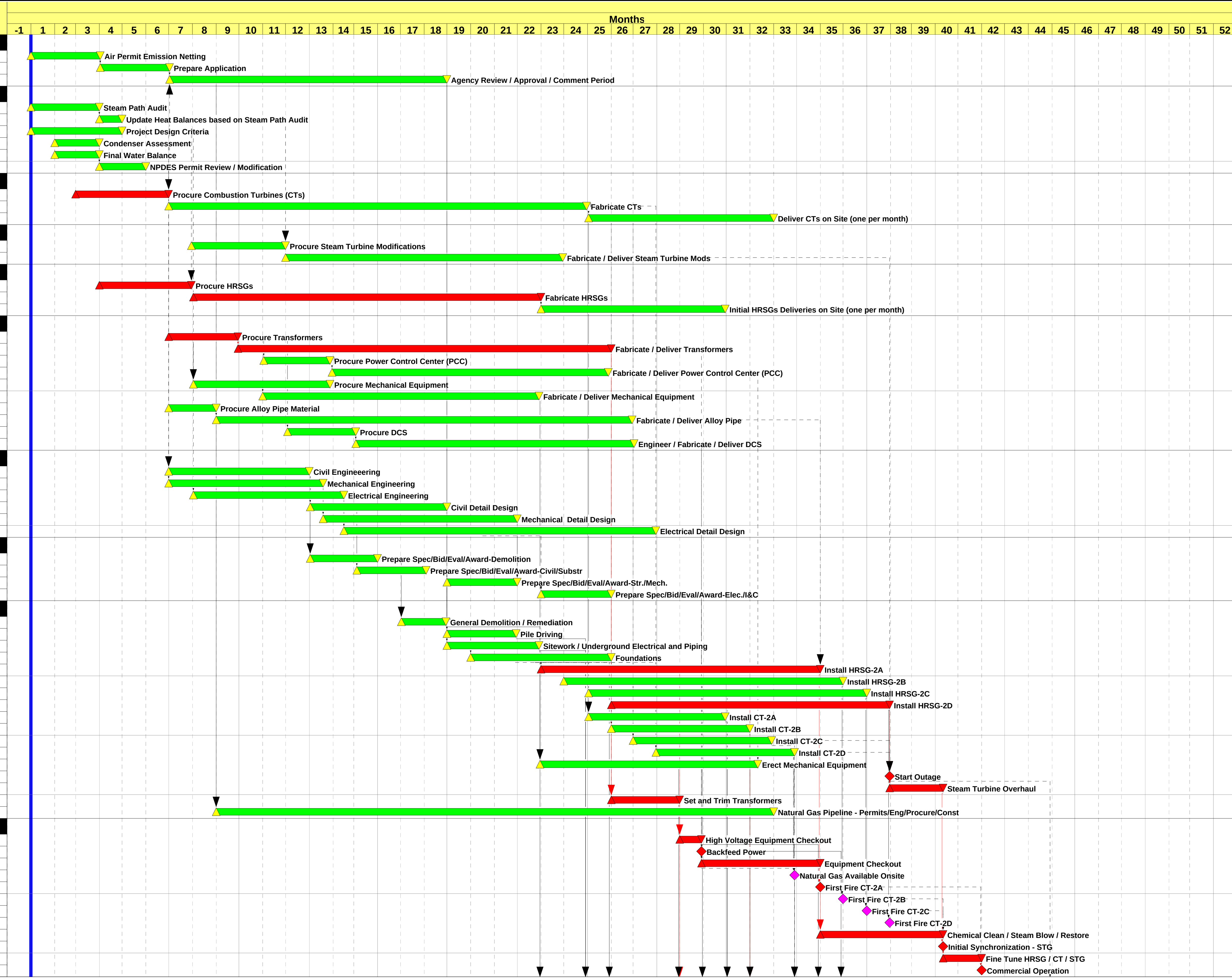
Form GDG-0401-01-08. ANSI (Imperial) MicroStation Border - Size E - 34 x 44
Revision 10. Revision Date: 10-16-2009

APPENDIX E.
REPOWERING PROJECT IMPLEMENTATION SCHEDULE

Act ID	Activity Description
AIR PERMIT ANALYSIS	
180	Air Permit Emission Netting
190	Prepare Application
200	Agency Review / Approval / Comment Period
INITIAL PROJECT ACTIVITIES	
120	Steam Path Audit
130	Update Heat Balances based on Steam Path Audit
140	Project Design Criteria
150	Condenser Assessment
160	Final Water Balance
170	NPDES Permit Review / Modification
COMBUSTION TURBINE PROCUREMENT	
1010	Procure Combustion Turbines (CTs)
1035	Fabricate CTs
1050	Deliver CTs on Site (one per month)
STEAM TURBINE MODIFICATIONS PROCUREMENT	
1315	Procure Steam Turbine Modifications
1340	Fabricate / Deliver Steam Turbine Mods
HRSG PROCUREMENT	
1305	Procure HRSGs
1320	Fabricate HRSGs
1332	Initial HRSGs Deliveries on Site (one per month)
BOP PROCUREMENT	
SC1080	Procure Transformers
SC1090	Fabricate / Deliver Transformers
SC1092	Procure Power Control Center (PCC)
SC1094	Fabricate / Deliver Power Control Center (PCC)
SC1100	Procure Mechanical Equipment
SC1110	Fabricate / Deliver Mechanical Equipment
SC1140	Procure Alloy Pipe Material
SC1145	Fabricate / Deliver Alloy Pipe
SC1155	Procure DCS
SC1175	Engineer / Fabricate / Deliver DCS
ENGINEERING / DESIGN	
SC1115	Civil Engineeering
SC1120	Mechanical Engineering
SC1130	Electrical Engineering
SC1150	Civil Detail Design
SC1160	Mechanical Detail Design
SC1170	Electrical Detail Design
CONSTRUCTION CONTRACTS (MULTIPLE LUMP SUM)	
SC1300	Prepare Spec/Bid/Eval/Award-Demolition
SC1301	Prepare Spec/Bid/Eval/Award-Civil/Substr
SC1302	Prepare Spec/Bid/Eval/Award-Str./Mech.
SC1304	Prepare Spec/Bid/Eval/Award-Elec./I&C
CONSTRUCTION - UNIT 2	
B11404	General Demolition / Remediation
B11408	Pile Driving
B11410	Sitework / Underground Electrical and Piping
B11420	Foundations
B11425	Install HRSG-2A
B11426	Install HRSG-2B
B11428	Install HRSG-2C
B11429	Install HRSG-2D
B11430	Install CT-2A
B11432	Install CT-2B
B11433	Install CT-2C
B11434	Install CT-2D
B11457	Erect Mechanical Equipment
B11480	Start Outage
B11490	Steam Turbine Overhaul
B11520	Set and Trim Transformers
B11530	Natural Gas Pipeline - Permits/Eng/Procure/Const
COMBINED CYCLE STARTUP - UNIT 2	
B11501	High Voltage Equipment Checkout
B11505	Backfeed Power
B11510	Equipment Checkout
B11512	Natural Gas Available Onsite
B11521	First Fire CT-2A
B11522	First Fire CT-2B
B11523	First Fire CT-2C
B11524	First Fire CT-2D
B11526	Chemical Clean / Steam Blow / Restore
B11531	Initial Synchronization - STG
B11536	Fine Tune HRSG / CT / STG
B11541	Commercial Operation



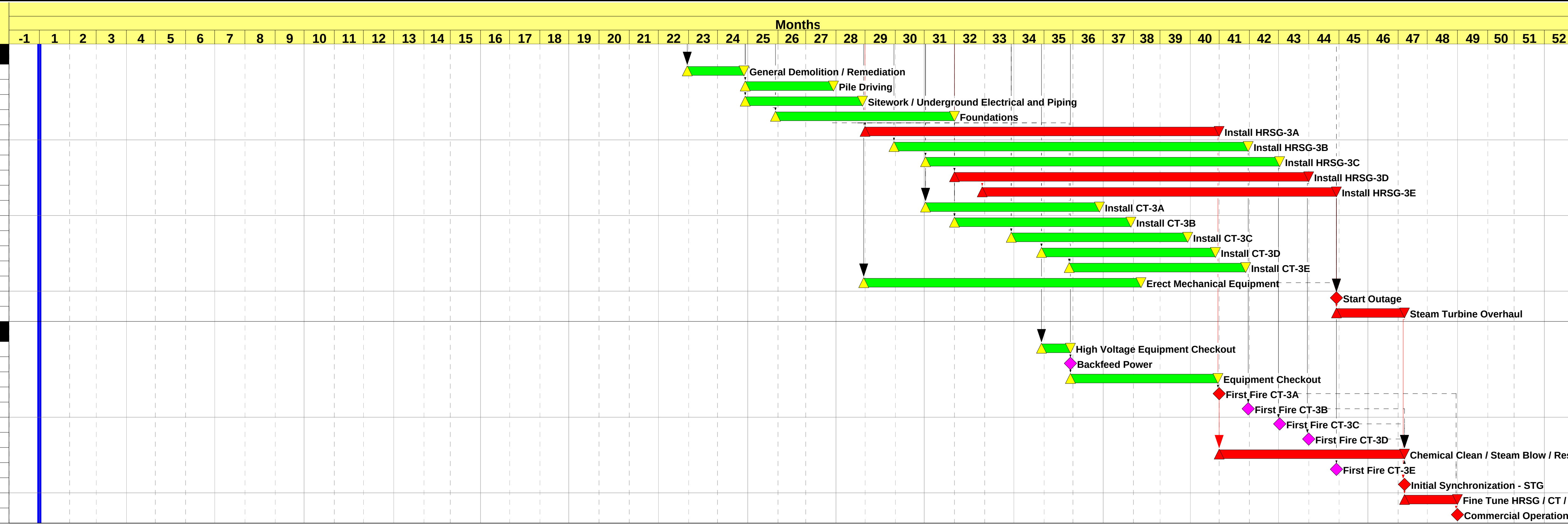
Run Date 18FEB10 13:35

Early Bar
Progress Bar
Critical Activity

SJR1

Public Service of New Mexico
San Juan Generating Station
Alternatives Study
Combined Cycle Repowering Schedule

Act ID	Activity Description
CONSTRUCTION - UNIT 3	
B21404	General Demolition / Remediation
B21408	Pile Driving
B21410	Sitework / Underground Electrical and Piping
B21420	Foundations
B21425	Install HRSG-3A
B21426	Install HRSG-3B
B21428	Install HRSG-3C
B21429	Install HRSG-3D
B21430	Install HRSG-3E
B21432	Install CT-3A
B21433	Install CT-3B
B21434	Install CT-3C
B21435	Install CT-3D
B21436	Install CT-3E
B21457	Erect Mechanical Equipment
B21480	Start Outage
B21490	Steam Turbine Overhaul
COMBINED CYCLE STARTUP - UNIT 3	
B21501	High Voltage Equipment Checkout
B21505	Backfeed Power
B21511	Equipment Checkout
B21521	First Fire CT-3A
B21522	First Fire CT-3B
B21523	First Fire CT-3C
B21524	First Fire CT-3D
B21526	Chemical Clean / Steam Blow / Restore
B21527	First Fire CT-3E
B21531	Initial Synchronization - STG
B21536	Fine Tune HRSG / CT / STG
B21541	Commercial Operation



Run Date 18FEB10 13:35

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Early Bar
Progress Bar
Critical Activity

SJR1

Public Service of New Mexico
San Juan Generating Station
Alternatives Study
Combined Cycle Repowering Schedule

Sheet 2 of 2

APPENDIX F.
ORDER-OF-MAGNITUDE REPOWERING COST ESTIMATES

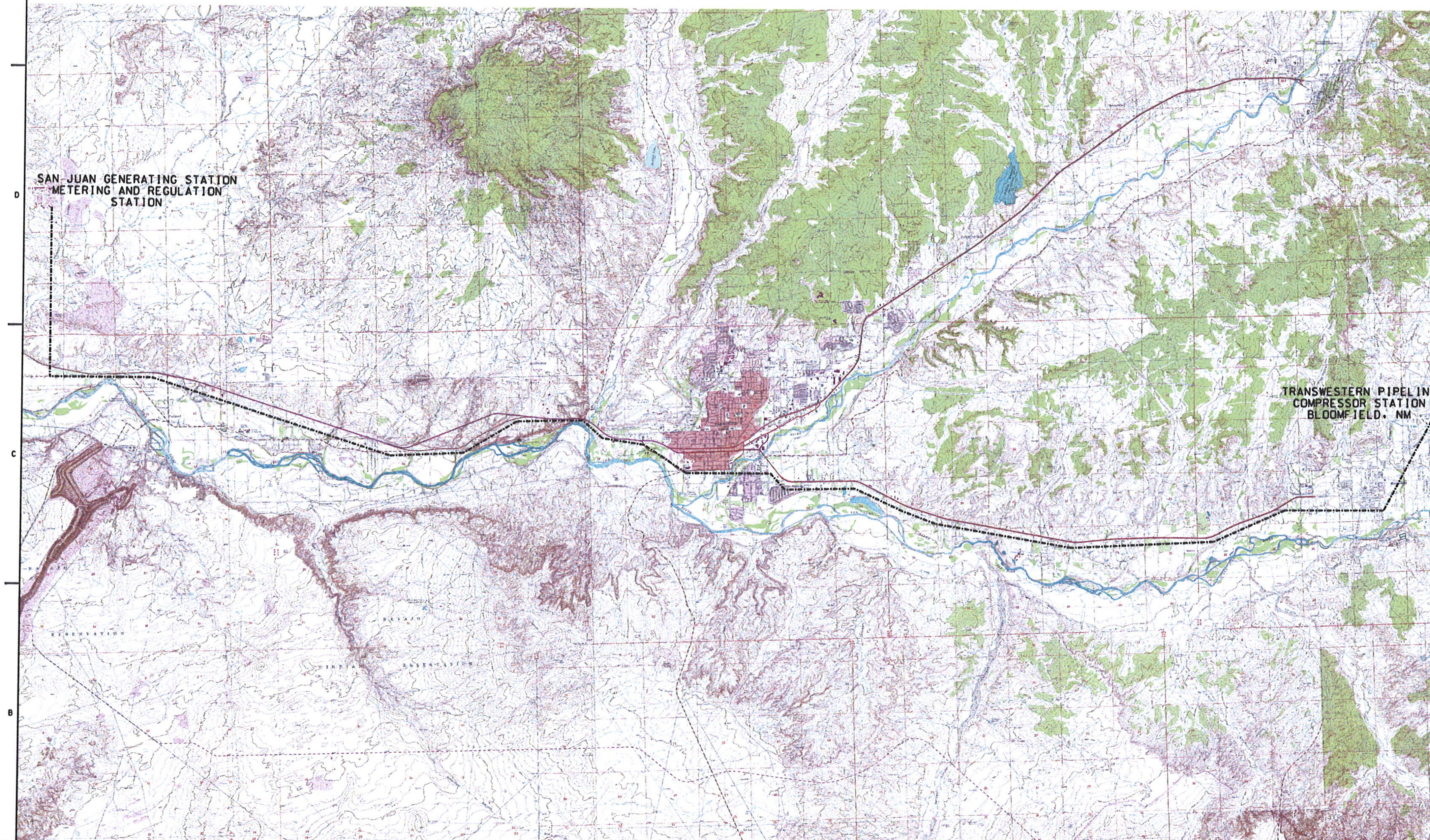
Sargent & Lundy

11278-018
TJM - 02/19/10

Public Service Co. of New Mexico
Repowering of SJGS Units 2 and 3
Summary of Estimated Present Day Capital Costs

Estimate No.	30394	30395	Total
	Unit 2 / Common	**Unit 3**	**Station Total**
Configuration	4x4x1 7FA.05	5x5x1 7FA.05	9x9x2 7FA.05
Costs			
Combustion Turbines w/ Accessories	238,148,544	297,685,680	535,834,224
HRSG's & Accessories.	130,864,784	163,580,980	294,445,764
Steam Turbine Mods & Control Upgrades.	3,050,000	3,750,000	6,800,000
Asbestos & Lead Paint Abatement in Existing ST Building	200,000	200,000	400,000
Condenser & Accessories, Mods / Upgrades.	1,000,000	1,250,000	2,250,000
ST Cooling System	existing	existing	existing
Water Supply.	existing	existing	existing
Pumps.	7,819,525	9,705,512	17,525,037
Heat Exchangers	1,675,591	1,994,522	3,670,113
Field Erected Tanks	1,200,000	-	1,200,000
Shop Fabricated Tanks	267,589	318,239	585,828
Ammonia Storage & Forwarding Equipment	769,673	779,673	1,549,346
Cranes & Hoists.	38,592	38,592	77,184
Fuel Gas Metering Station	by others	by others	by others
Fuel Gas Conditioning	3,599,346	4,499,183	8,098,529
Air Dryers.	55,799	55,799	111,598
Chemical Feed & Sample Systems.	1,118,294	1,329,642	2,447,936
Water Treating.	existing	existing	existing
Condensate Polishing	not included	not included	not included
Fire Protection.	915,174	1,143,968	2,059,142
BOP Mechanical Equipment	268,865	305,208	574,073
Alloy Piping	42,365,991	61,111,194	103,477,185
BOP Piping.	53,149,800	68,665,338	121,815,138
Valves & Specialties	9,519,738	11,125,598	20,645,337
Electrical Major Equipment	33,579,173	40,845,625	74,424,798
Electrical BOP.	20,744,477	25,762,094	46,506,571
Instrumentation & Controls	6,977,497	7,959,718	14,937,215
Switchyard Mods / Transmission Lines	978,904	1,972,655	2,951,559
Steel.	6,594,262	5,195,038	11,789,299
Buildings.	180,000	-	180,000
Foundations.	9,831,871	13,904,166	23,736,036
Demolition & Mods to Existing Structures.	2,912,718	3,660,440	6,573,157
Site Preparation, Drainage, & Yard Work.	6,505,616	6,595,807	13,101,423
Heavy Haul Subcontracts	4,000,000	5,000,000	9,000,000
Startup Craft Support.	1,698,975	2,038,770	3,737,745
Premium Time & Allowance to Attract Labor	33,363,708	41,829,200	75,192,908
Erector G&A and Profit.	43,709,200	55,095,400	98,804,600
Consumables.	2,316,420	2,908,516	5,224,936
Freight.	5,907,778	7,501,640	13,409,418
Subtotal Direct Project Costs	**675,327,904**	**847,808,197**	**1,523,136,101**
Indirect Project Costs.	36,883,200	44,195,200	81,078,400
Contingency (5% on C/T's, 15% on Others).	84,031,700	105,300,500	189,332,200
Escalation.	Not Incl.	Not Incl.	Not Incl.
Owner's Costs.	Not Incl.	Not Incl.	Not Incl.
Interest During Construction.	Not Incl.	Not Incl.	Not Incl.
Operating Spare Parts.	Not Incl.	Not Incl.	Not Incl.
Subtotal Project Costs	**796,242,804**	**997,303,897**	**1,793,546,701**
Gross Output, @ 53 Deg.F Ambient Temp. (MW)	**1,032**	**1,259**	**2,291**
$/kW (Incl. Steam Turbine Capacity)	**771.6**	**792.1**	**782.9**
Net Output, @ 53 Deg.F Ambient Temp. (MW)	**1,006**	**1,228**	**2,234**
$/kW (Incl. Steam Turbine Capacity)	**791.5**	**812.1**	**802.8**

APPENDIX G.
CONCEPTUAL ROUTINGS OF THE NATURAL GAS PIPELINES



NOTE:

THE CONCEPTUAL ROUTING OF THE NATURAL GAS PIPELINE FROM THE EL PASO NATURAL GAS SYSTEM IS THE SAME, BUT INITIATES NEAR FARMINGTON, NM.

CONCEPTUAL NATURAL GAS
PIPELINE ROUTING

GRAPHIC SCALE 4000 0 4000 8000 12000

DRAWING SCALE
1" = 4000'-0"

NORTH

HOLD INFORMATION		
NO.	DATE	DESCRIPTION
△		

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PREPARED BY: R.A.MILLER

REVIEWED BY: J.G.GATZ

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55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780

PROJECT

SAN JUAN GENERATING STATION

REPOWERING OF UNITS 2 AND 3
PUBLIC SERVICE COMPANY
OF NEW MEXICO

DRAWING TITLE

GENERAL ARRANGEMENT
CONCEPTUAL NATURAL GAS
PIPELINE ROUTING

DRAWING NUMBER	REVISION
SK-GA-003	B
SHEET 1 OF 1	

ZL5878/Om1743/D:#SanJuan#Civil#Sk-GA-SJ-003.dgn
Form GDG-0401-01-08, ANSI (Imperial) MicroStation Border - Size E - 34 x 44
Revision 10, Revision Date: 10-16-2009

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