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COMBINED CYCLE PLANT OPTIMIZATION STUDIES

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ABSTRACT

Combustion turbine manufacturers, engineering companies, plant owners, and developers often site the benefits of using a reference, or standardized design when planning for a new combined cycle (CC) plant. Reference designs, proponents suggest, can lower the cost of proposals, reduce engineering and construction schedules, decrease design costs, and increase purchasing leverage by enabling commitments to multi-unit orders. But relying on design shortcuts such as reference designs can lead to less than optimal financial results. Reference designs may be based on assumptions that are not optimized for the specific function and/or site. Or, a reference design may produce desired results for base-load plants, but not for peaking or cycling-load plants. Even simple technology enhancements may produce dramatic improvements to project profitability under some conditions, but not others.

These examples suggest that short-term benefits of reference designs should not overshadow the importance of plant optimization and customization to minimize fuel and capital costs and maximize electricity revenues. The long-term financial returns of operational efficiencies can dramatically impact profitability and investment return. As a result, financial impacts of plant design choices must be carefully evaluated and selected so that long-term return is maximized.

The objective of this study was to demonstrate the significance of plant design decisions on the performance and economics of CC power plants, as well as demonstrate the use of software tools to help plant developers quickly test and compare plant design decisions. The study compares several major plant design options, including heat recover steam generator (HRSG) design, HRSG duct firing, inlet cooling via absorption chilling, inlet cooling via media-type evaporative cooling, and inlet cooling via high pressure fogging. Sensitivity analyses on capacity factor, fuel costs, and electricity prices were also performed in each case. SOAPP-CT (State-of-the-Art Power Plant - Combustion Turbine) software, a tool that automates plant conceptual design, was used to estimate plant performance, operational costs, and financial return. Recent project experience was incorporated in the selection of design options and financial parameters. This paper presents a brief description of one of the CT inlet cooling evaluations and summarizes the results of the study.

EVALUATION METHODOLOGY

The objective of the study was to compare equipment selections, cycle parameters, and internal rate of return (IRR, a commonly used measure of financial profitability) and then select the CC plant design that maximizes plant profitability. Two types of evaluation methodologies were used as a basis for comparison. The first is a traditional approach, which assumes average annual electricity, fuel, ambient temperatures, average capacity factor, and other parameters; this method is suitable when plant operations and costs, such as fuel costs, are fairly constant throughout the year.

The second evaluation approach involves defining a sufficient number of plant operating cases to simulate annual plant operations and allow for realistic variations in plant operations and costs while intelligently dividing the operability of the plant into individual periods, or sub-cases. The periods can be defined to fit the plant operating strategy (e.g., seasons of the year, operating rationale such as full-time versus stand-by or peaking duty, or implementation of inlet chilling only at ambient temperatures above 80°F (27°C)). The importance of using multiple periods to define an equivalent annual evaluation case is clear when considering fluctuations that plant operators must address in actual operation, such as high ambient temperatures, which can significantly reduce CT performance, or fuel and electricity price volatility on a seasonal or time-of-day basis, which can impact profitability. For example, the following recent gas pricing fluctuations range from $2.04 / GJ to $4.74 / GJ:

Previous Years:
1998 = $2.15 / MBtu ($2.04 / GJ)
1999 = $2.55 / MBtu ($2.42 / GJ)
Year 2000:
March Futures = $2.80 / MBtu ($2.65 / GJ)
June Futures = $4.00 / MBtu ($3.79 /GJ)
September Futures = $5.00 / MBtu ($4.74 / GJ)

Some planners currently use $3.80 / MBtu ($3.60 / GJ) (for long term contracts - interruptible). Dramatic fluctuations in natural gas prices can significantly impact design evaluation results such as IRR, and therefore influence plant design choices. Similarly, Figure 1 illustrates recent extreme electricity price fluctuations for the East Central Region.

The wide variations in CT performance and gas and electricity pricing indicate that project developers need an analysis method that accounts for variables with significant real-world variations. The equivalent annual evaluation method (the simplified analysis used in this study) is summarized in Table 1.

SOAPP-CT WORKSTATION

Another critical component of the analysis methodology is EPRI's SOAPP-CT WorkStation, which automates plant conceptual design, as well as the selection of heat and material balances, equipment selection and sizing, fuel types, environmental issues, and other plant design factors. SOAPP-CT then automatically estimates plant performance, operational costs, and IRR. Figure 2 illustrates SOAPP-CT software operation sequence:

The unit data group of the SOAPP-CT Workstation allows users to input specific key design attributes of a specific CC unit. First, the user selects the desired CT model, choosing from a database of commercially available 50- and 60-Hz models that range in size from 20 MW to 220 MW. The user then selects simple cycle, combined cycle, and cogeneration cycles configurations, depending upon the variables being compared. In the next step, the user configures each major equipment item and selects process design conditions (e.g., HRSG steam pressures and temperatures, as well as pinch and approach points). Inlet air cooling can be selected, steam turbine condenser pressure can be defined, and capital, fuel, O&M and other cost adjustments can also be made. Overall, the user can select 400 inputs to allow for proper definition of the plant design being tested.

Other key groups allow the user to input site data, fuel data, and economic data. Specifically, the site data input group allows the user to input expected ambient conditions (e.g., temperature and elevation), environmental criteria (e.g., emissions limits), site conditions (e.g., seismic zone and cooling water conditions), and certain site-specific cost and economic inputs. In addition, the user can enter cost adjustments for construction labor and productivity, makeup water, operator salaries, and other O&M activities. The fuel data group allows the user to define the available fuels and fuel usage, primary and secondary fuels, and a secondary fuel usage factor. The economic data group contains the information required to perform the capital and O&M cost estimates, as well as the financial analyses. Following is a summary list of the SOAPP-CT WorkStation output:

Design Criteria	Project Schedule	Reference Plant Layout Drawings
Equipment & Motor Lists	Capital Cost Estimates	O&M Cost Estimates
Performance & Emission Data	Reference Diagrams	Financial Pro Forma

Because so many project-specific site and financial variables interact with the design, no single parameter can be used to judge the optimum solution for any particular project. The value of the SOAPP-CT WorkStation for plant developers is its ability to integrate performance, cost, and financial analysis capabilities into one product; combine them with a flexible data input structure; and enable a large number of "what if" design scenarios for plant developers seeking to reduce risk and optimize financial returns. The SOAPP-CT user can optimize plant designs by changing technical and financial criteria, and then assessing the design against project and market uncertainties. As a result, the SOAPP-CT Workstation is a valuable tool for evaluating the impacts of key design decisions on overall performance, financial return, and project risk.

PLANT DEFINITION

For the purposes of this study, a specific plant configuration was applied to all CC plant designs (see Table 2).

COMBUSTION TURBINE INLET COOLING OVERVIEW

One of the most effective ways to improve CC plant performance is to boost CT output by cooling the inlet combustion air entering the turbine. Because CTs are constant volume machines – and air mass flow through the turbine is directly defined by the air's density – changes in air temperature and density can impact CC turbine performance. For example, as ambient air temperature increases, its density decreases, thus permitting less air mass flow to enter the turbine. This decreased mass flow can reduce the CT's power capability dramatically. Typically, power output drops by one percent for every two degrees Fahrenheit increase in temperature. If the inlet temperature is 20°F (11.1°C) above ISO conditions, the gas turbine power drops by approximately 10 percent. Inlet air cooling improves turbine performance because it counteracts unfavorable air temperature conditions by simply increasing air density, thus allowing the CT to regain its lost power. Inlet air cooling also improves air compression efficiency; at higher temperatures, air is more difficult to compress, so by introducing cooler air to the CT, more work is available for the turbine shaft to convert into electrical energy.

A wide range of inlet air cooling technologies is used in CC plants today. Traditionally, designers have used mechanical chillers or media-type evaporative coolers. More recently, high pressure inlet fogging has grown in popularity, and some plants are experimenting with fogging over-spray techniques. The purpose of this discussion is not to compare the technical merits of alternative inlet air cooling technologies. Rather, the goal is to demonstrate that plant developers must carefully evaluate each inlet cooling option with respect to climate, water treatment cost, economic funding available, project economics, plant operating cycle, and other critical factors impacting financial performance – before finalizing plant design. A seemingly obvious choice at the start of project development may not be the most economic choice over the life of the plant. A brief description of each inlet cooling technology follows:

- Media-type evaporative cooling is the most common form of inlet air cooling technology. The technique uses a honeycomb-like cellulose fiber material (the medium) that is installed across the inlet and wetted. As air is pulled through the material, the water evaporates to cool the inlet air. Cooling is limited to the wet bulb temperature, and the technique is normally only able to recover approximately 85 percent of this cooling (i.e., 85 percent effectiveness). Although the equipment is relatively inexpensive, the technique requires a substantial duct enlargement for the required low air velocities. Planners must also consider that the evaporative cooler adds moderately to inlet air pressure drop, resulting in a decrease in CT performance. Therefore, plant performance degrades in cool weather due to this pressure loss. Design evaluations must include this decrease to properly evaluate the technology's benefits.

- High pressure inlet fogging is a rapidly growing and increasingly accepted technology. In this technique, a very fine water spray using a series of small nozzles cools the inlet air. Demineralized water is pumped to these nozzles at a pressure of 1000 to 3000 psig (6890 to 20680 kPag). Effectiveness is rated at 100% (all available water is evaporated into the air, thus reaching wet bulb temperature), and inlet air pressure drop is very low. The sprays are normally placed downstream of the inlet air filters. This technology is quite inexpensive and requires low operating power.

- Steam absorption chilling is capable of achieving the largest temperature drops because cooling is not limited to the humidity in the air. Steam-driven compressors that operate in a manner similar to standard refrigeration cycles accomplish the chilling. For planners, the drawbacks of the technology are high capital costs, as well as higher O&M costs. The main advantage of this system is low inlet temperature.

CASE DESCRIPTION

Location. For the purposes of this study, Phoenix, Arizona was chosen as the site for the plant due to the high potential for cycle optimization, given the area's hot, yet dry environment. The American Society of Heating Refrigeration and Air Conditioning Engineers (ASHRAE) projects that the following climate data for summer conditions in Phoenix are equaled or exceeded in 1 percent of summer hours: 109°F (43°F) dry bulb and 71°F (22°C) wet bulb. These arid conditions present 38°F (21°C) of capability for evaporative cooling. However, water costs in Phoenix are high--estimated at 5 to 6 times greater than other parts of the U.S. The trade-off between the financial savings from inlet cooling and increased water costs presents a complex evaluation that demonstrates the strategic value of SOAPP-CT calculations.

Electricity Assumptions. Although electricity prices may periodically reach spikes of over \$1900/MWh under high-demand summer conditions, the highest level of free market electricity pricing for a single period was assumed to be \$70/MWh in this study (see Table 3). By doing so, overall project economics are reasonable, resulting in a conservative evaluation. Clearly, operation of the plant during periods of \$250/MWh, \$500/MWh, or \$1000/MWh would greatly improve the already favorable project economics.

Natural Gas Assumptions. With natural gas prices increasing sharply over the past 12-18 months, plant profitability across the U.S. has decreased. Models that continue to predict a high priced gas market indicate decreased future profitability. Two modeling methods, however, can reduce the impact of such a high-priced market: 1) use of a less conservative gas pricing model that predicts a return to levels of \$2.00 / MBtu (\$1.90 / GJ) to \$2.50 / MBtu (\$2.37 / GJ), or 2) use of more aggressive gas price futures purchasing, in which better prices are secured through medium to long-term purchase contracts. For the purposes of this analysis, moderate gas pricing, in the \$3.00/MBtu (\$2.84/GJ) to \$4.50/MBtu (\$4.27/GJ) range, was utilized (see Table 4).

PLANT OPERATION STRATEGY

The chosen operating strategy for the subject plant was cycling, with a capacity factor of 60 percent. During the hottest months (when electricity prices would be most likely to spike upward), the plant would be operated full-time. During the coldest months, the plant would only be operated part-time, or not at all. The spreadsheet tool in the SOAPP-CT Workstation allows the user to specify the desired operating plan for the plant under such varying conditions (see Table 5).

DEFINITION OF CASES FOR EVALUATION

Based on the operating conditions governing the plant, a total of six cases were developed to best represent the entire year's operation. The data from each of the six cases were combined using weighted averaging in order to produce the equivalent annual case for each. The six cases are profiled in Table 6.

RESULTS

The results from the study are presented in Table 7. Table 8 illustrates the incremental impact of each technology in terms of three key parameters: process capital, cash flow to equity (base year only), and overall internal rate of return.

INLET AIR COOLING RESULTS

As expected, the base design results in the case with the lowest IRR (33.37 percent), with a total plant cost of $474.80 per net kW. The relatively high IRR resulted from the selected electricity pricing and associated operating hours, which are currently valid. The SOAPP-CT WorkStation provides project developers with the ability to quickly run additional analyses at lower future electricity prices.

Of the three cooling technologies, the highest overall IRR – 35.47 percent – resulted when inlet fogging was used. The results were only slightly better than the 35.21 percent IRR that the standard evaporative cooling plant recorded. One might expect the IRR of a fogging-enhanced plant to be significantly better than one using evaporative cooling. The surprisingly narrow margin results from a subtle but important fact: a fogging-enhanced plant can produce a more powerful CT, which means that more exhaust is produced and hence more steam is produced. In order to accommodate the larger flow of steam, a larger HRSG and steam turbine must be purchased. Additionally, the plant requires a larger water treatment facility since its effectiveness is 15% higher than the standard evaporative cooling plant. In short, the additional plant enlargements absorbed the capital saved by using inlet fogging. However, the larger plant was more efficient on a $/kW basis, resulting in the larger IRR. One additional consideration is relevant: when comparing evaporative and spray inlet cooling on an operational basis, plant developers should be aware that a fogging system could result in a decline in CT durability, as well as damage due to overspray.

The inlet chilling IRR was better than the base design IRR, but not as economic as either of the two evaporative cooling designs. The greater initial capital cost of the inlet chilled plant was the primary factor for the marginal IRR improvement. If the cost of raw water increased by 25 to 30 percent, inlet chilling would probably become the best design choice. These factors must be thoroughly evaluated prior to committing to a technology during the design phase of a new CC plant.

Much of this study is predicated on several key parameters, which could vary quite considerably, including the following:

- Combustion turbine performance (i.e., the amount of output lost at higher ambient temperatures)
- Raw water costs
- Operation and maintenance costs
- Water treatment costs
- Electricity pricing
- Gas pricing
- Seasonal anomalies (such as an exceedingly hot summer)

The recently-published EPRI report on this subject (*Combined Cycle Plant Optimization Studies*, EPRI report 1000684, December 2000) provides the results of analysis for the following plant equipment evaluation case studies--each with three electricity price categories:

- HRSG steam/water cycle parameters (four design cases at two capacity factors)
- HRSG inlet duct firing (four ambient cases)
- CT inlet air cooling (six ambient cases with three different technologies, plus the base case)

CONCLUSION

To compete in today's global market, optimizing new CC plant designs to achieve the best financial return and competitive electricity pricing is crucial. The scenarios discussed in this paper demonstrate that a seemingly obvious choice at the start of project development may not be the most economic choice over the life of the plant. The findings suggest that considering major equipment options on a site-by-site basis can improve equity returns and reduce financial risk. In addition, carefully examining the application that each plant is designed to meet is recommended, followed by assessment of technologies needed to meet the specific application.

To facilitate the evaluation and proposal development process, EPRI's SOAPP-CT WorkStation integrates performance, cost, and financial analysis capabilities into a single product, combining them with a flexible data input structure that allows the user to optimize the plant design to technical and financial criteria, and assess it against project and market uncertainties. In addition, users can create "what if" scenarios to evaluate the impacts of key design decisions on overall performance and financial return to reduce project risk. These functionalities enable project planners to quickly, accurately, and cost-effectively produce custom proposals that address each project's unique requirements, while reducing overall business risk.

Figure 1. 1999 Daily On-Peak Electric Price Volatility in the East Central Region

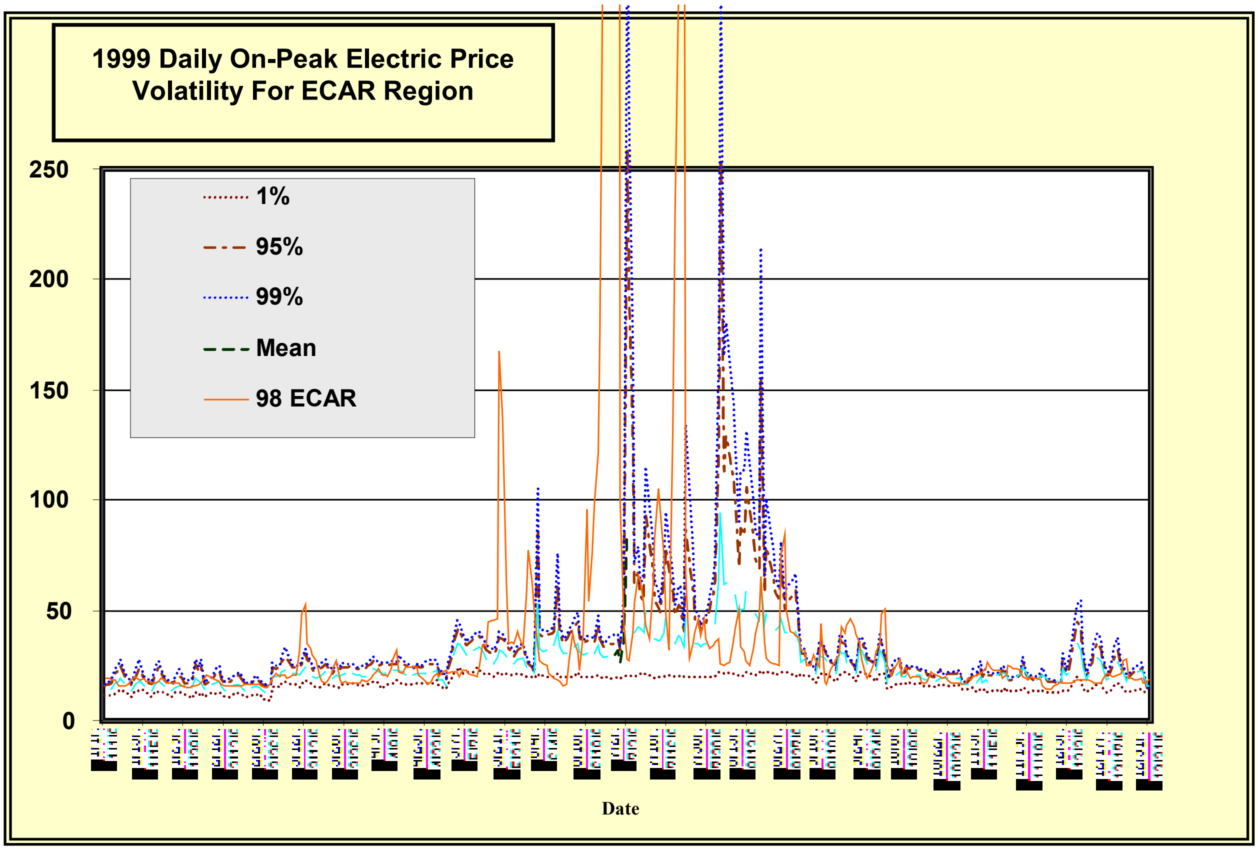

Figure 2: SOAPP Software Operation

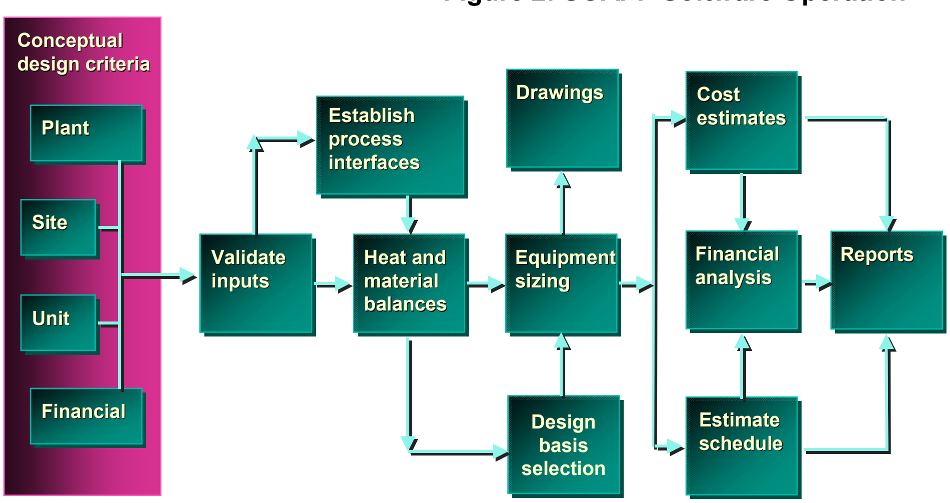

Table 1: Equivalent Annual Evaluation Method

Definition Steps: Defining plant requirements and operating modes	
1	Type of plant – Usually a base design and an optional design are defined.
2	Electricity pricing information. Define export and host as applicable
3	Export steam requirements are determined, if any.
4	Approximate (planned) duct firing, if any.
5	Fuel costs. Define type of fuel and base year fuel costs.
6	Average annual temperatures (dry bulb). Compiled with hours/year to assist definition of configurations to be analyzed.
7	Operation philosophy. Define operating strategy during different conditions.
8	Target output (approximate). Specify approximate desired electrical output of plant during each operating condition.
9	Operating case definitions. Define operating hours, shutdown hours, case numbers, and operating temperatures.
10	Case configuration description. Data is compiled from previous steps into cases.
Analysis Steps: Running SOAPP-CT software analyses for each plant operating case, then iterating to refine analysis and develop a "SOAPP Equivalent Input" case.	
11	Generate case results. Data from individual SOAPP-CT runs is copied into spreadsheet.
12	Generate SOAPP equivalent annual case. Data from individual cases is compiled into single, representative case.
13	Generate SOAPP equivalent annual case results. Data from SOAPP-CT run are copied into a spreadsheet.
14	Steps 12, 13, 14 are repeated as necessary until the SOAPP equivalent annual case most precisely replicates combination of individual cases.
15	Operating data, capital and O&M cost estimates and financial data from the SOAPP equivalent annual case are reviewed. A determination is made if additional cases are needed to reach the optimization desired. Additional cases are developed if needed.
16	The final results of the optimization are obtained.

Table 2: Plant Configurations

Design / Model Parameter	Value
Plant Duty	Cycling (capacity factor = approximately 60%)
Configuration	One CT One HRSG One steam turbine
Combustion Turbine	GE PG7241 FA Single fuel (natural gas), dry low NO_x combustor
HRSG	Three pressure w/ reheat, integral dearator, 1800 psia high pressure (HP), 490 psia intermediate pressure (IP), 60-75 psia low pressure (LP)
Steam Turbine	Reheat, 2 casing, 1 flow, axial exhaust
Heat Rejection System	Phoenix sites: air cooled condenser
Electricity Pricing	Moderate
Electricity Pricing Escalation	2.0 % / year
Fuel Costing	Moderate
Fuel Cost Escalation	3.5 % / year
Plant Book Life	20 years
Plant Tax Life	15 years

Table 3: Electricity Prices for Phoenix CC Plant Site

Electricity Pricing - Target, current, estimate, or other basis.			
Specify expected electricity pricing.			
		$/MW hr	
	Winter	Spring/Fall	
Peak			
Export	$50.00	$70.00	
Host	n/a		
Average			
Export	$40.00	$35.00	
Host	n/a		
Low			
Export	$30.00	$30.00	
Host	n/a		

Table 4: Gas Prices for Phoenix Site

3ase Year - Natural Gas or Fuel Oil				
Specify expected fuel pricing.				Basis: Energy Information Administration Natural Gas Monthly, June 2000 Prices of Nat Gas to Electric Utilities. Same prices used for Phoenix as for Chicago.
Fuel Type	Natural Gas			
		$/MBtu ($/GJ)		
	Winter	Spring / Fall	Summer	
Peak	4.50 (4.27)	4.00 (3.79)	4.00 (3.79)	
Average	3.25 (3.08)	3.25 (3.08)	3.25 (3.08)	
Low	3.00 (2.84)	2.75 (2.61)	3.25 (3.08)	

Table 5: Operation Philosophy of Cycling Plant

Operation Philosophy				
Specify expected operation of plant during each condition.				Cycling plant
Elect. Price				
	Winter	Spring/Fall	Summer	Note: Full = 100% of plant availability
Peak	Full	Full	Full	Part = 30-60% of plant availability
Average	art Time	Part Time	Full	Shutdown = 0% of plant availability
Low	hutdown	Shutdown	Shutdown	

Table 6: Operating Cases for Phoenix Case Study Using Evaporative Coolers

Case Configuration Description							
	Units		Case Numbers				
PHOENIX		1	2	3	4	5	6
Case Name		Moderate Average	Hot/Warm Peak	Cold Average	Moderate Peak	Cold Peak	Hot/Warm Average
Operating Hours	hrs / yr	1,816	1,758	908	1,116	537	335
Pct of Total Op Hrs	%	28.1%	27.2%	14.0%	17.2%	8.3%	5.2%
Perf Pt Dry Bulb	F (C)	64.0 (17.8)	93.5 (34.2)	48.3 (9.1)	88.9 (31.6)	67.0 (19.4)	74.4 (23.6)
Perf Pt Wet Bulb	F (C)	50.0 (10)	68.0 (20)	41.0 (5)	66.0 (18.9)	52.0 (11.1)	57.0 (13.9)
Duct Firing	Y/N	no	no	No	no	no	no
IAC Operation	Y/N	yes	yes	No	yes	yes	yes
CT Inlet Pres Drop (w/IAC)	in H2O (kPa)	5.0 (1.24)	5.0 (1.24)	5.0 (1.24)	5.0 (1.24)	5.0 (1.24)	5.0 (1.24)
CT Inlet Pres Drop (w/o)	in H2O (kPa)	3.75 (0.93)	3.75 (0.93)	3.75 (0.93)	3.75 (0.93)	3.75 (0.93)	3.75 (0.93)
Equip Avail Factor	%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Service Factor	%	57.0%	95.0%	57.0%	95.0%	95.0%	94.9%
Capacity Factor	%	57.0%	95.0%	57.0%	95.0%	95.0%	94.9%
Capacity Payments	$/MW-yr	0	0	0	0	0	0

Case Configuration Description							
	Units		Case Numbers				
PHOENIX		1	2	3	4	5	6
Case Name		Moderate Average	Hot/Warm Peak	Cold Average	Moderate Peak	Cold Peak	Hot/Warm Average
Energy Payments	$/MWh	35.00	70.00	40.00	60.00	50.00	45.00
Energy Pmt Escal	% / yr	2.00	2.00	2.00	2.00	2.00	2.00
Nat Gas Price	$/MBtu ($/GJ)	3.25 (3.08)	4.00 (3.79)	3.25 (3.08)	4.00 (3.79)	4.50 (4.27)	3.25 (3.08)
Nat Gas Price Escal	% / yr	3.50	3.50	3.50	3.50	3.50	3.50

Table 7: Summary of Inlet Air Cooling Study - Phoenix Area

Overall Summary		BASIS: SOAPP EQUIVALENT ANNUAL CASE			
Technology Utilized		**Evaporative Cooling**	**High Pressure Inlet Fogging**	**Steam Absorption Chilling**	**No Inlet Cooling**
Technical Data					
Number of CT's Operating	N/A	1	1	1	1
Gross CT Generator Output per CT	kW	162,017	163,456	163,584	152,784
Net Plant Heat Rate (HHV) at 100%	Btu/kWh	7,038	7,046	7,082	7,038
Net Plant Heat Rate (HHV) at 100%	kJ/kwh	7,426	7,435	7,472	7,426
Net Plant Heat Rate (LHV) at 100%	Btu/kWh	6,340	6,347	6,380	6,341
Net Plant Heat Rate (LHV) at 100%	kJ/kwh	6,690	6,697	6,731	6,691
Stack Exhaust Temperature	F	207	208	209	206
Stack Exhaust Temperature	C	97	98	98	97
Gross ST Output	kW	85,471	85,467	84,017	83,430
Throttle Steam Flow at ST	lb/hr	408,061	408,298	410,320	403,832
Throttle Steam Flow at ST	kg/hr	185,095	185,203	186,120	183,177
Turbine Backpressure	in Hg	3.59	3.70	3.68	3.83
Turbine Backpressure	kPa	12.15	12.53	12.46	12.97
Gross Plant Output	kW	247,488	248,923	247,601	236,214
Auxiliary Power	kW	4,506	4,524	4,390	4,235
Net Plant Output	kW	242,982	244,400	243,212	231,979
Weighted Capacity Factor	%	73.9%	73.9%	73.9%	73.9%
Total Energy Produced	MW-hr	1,557,248	1,566,335	1,558,709	1,486,734
Total Fuel Consumed	MBtu	10,959,911	11,036,396	11,038,255	10,463,634
Total Fuel Consumed	GJ	11,563,364	11,644,060	11,646,021	11,039,762
Financial Data					
Total Process Capital	$	102,587,000	102,622,000	102,736,000	100,131,000
General Facilities	$	2,051,740	2,052,440	2,112,680	2,002,620
Engineering & Home Office Fees	$	3,077,610	3,078,660	3,169,020	3,003,930
Project Contingency	$	5,129,350	5,131,100	5,281,700	5,006,550
Total Plant Cost	$	112,845,700	112,884,200	113,299,400	110,144,100
Total Plant Cost per net kW	$/kW	**464.42**	**461.88**	**465.85**	**474.80**
Total Fixed O&M	$	1,985,397	1,985,584	1,985,430	1,979,883
Total Variable O&M	$	2,395,673	2,411,476	2,324,901	2,292,281
Total Fixed and Variable O&M	$	4,381,070	4,397,060	4,310,331	4,272,164
Fuel Cost	$	42,490,232	42,785,732	42,795,784	40,570,040
Internal Rate of Return (IRR)	%	**35.21**	**35.47**	**33.99**	**33.37**

Table 8: Incremental Impact for Inlet Air Cooling Study - Phoenix Area

Incremental Impact		**BASIS: SOAPP EQUIVALENT ANNUAL CASE**			
Technology Utilized		**Evaporative Cooling**	**High Pressure Inlet Fogging**	**Steam Absorption Chilling**	**No Inlet Cooling**
Incremental Process Capital					
Total Process Capital	$	102,587,000	102,622,000	102,736,000	100,131,000
Incremental Process Capital	$	2,456,000	2,491,000	2,605,000	0
Percent Increase in Process Capital	%	2.45%	2.49%	2.60%	0.00%
Incremental Cash Flow to Equity					
Base Year Cash Flow to Equity	$	10,862,607	10,935,230	10,664,286	10,170,401
Incremental Cash Flow to Equity	$	692,206	764,829	493,885	0
Percent Increase in Cash Flow to Equity	%	6.81%	7.52%	4.86%	0.00%
Incremental Internal Rate of Return					
Internal Rate of Return	%	35.21	35.47	33.99	33.37
Incremental Internal Rate of Return	%	1.84	2.10	0.62	0.00
Percent Increase in Int. Rate of Return	%	5.51%	6.29%	1.86%	0.00%