An Investigation of Site-Specific Factors for Retrofitting Recirculating Cooling Towers at Existing Power Plants

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List of Acronyms and Abbreviations

AFDC	allowance for funds used during construction
Avg.	average
bhp	brake horsepower
Btu	British thermal unit
C.F.	capacity factor
CM	construction management
COE	cost of electricity
CT	cooling tower
CW	circulating water
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
ºF	degrees Fahrenheit
FTE	full time equivalent
gpm	gallons per minute
h	hour
hp	horsepower
kW	kilowatt
kW_e	kilowatt electric
kWh	kilowatt hour
lb	pound
LP	low pressure
MM	million
MW	megawatt
MW_e	megawatt electric
MWh	megawatt hour
MW_t	megawatt thermal
NETL	National Energy Technology Laboratory
No.	number
O&M	operating and maintenance
OH	overhead
psia	pounds per square inch atmospheric
psig	pounds per square inch gauge
USGS	U.S. Geological Survey
Yr.	year

Glossary

AFDC – Allowance for Funds used During Construction; a monthly allowance for interest paid on monies spent during the construction phase of a project.

Capacity factor – Actual power generated, in kilowatt hours, compared to the maximum power that could be generated over a defined time period, usually all year.

Cell array – A geometric arrangement of cooling tower cells.

Circulating water system – A cooling water system that circulates cold water to the steam condenser and hot water to a cooling tower for cooling.

Condensing backpressure – The pressure at which steam condenses inside the condenser.

Cooling tower – A heat exchanger transferring waste heat from circulating water to the atmosphere.

Cooling tower retrofit – Adding a cooling tower to a site that does not already incorporate one.

Cooling tower temperature range – The difference in temperature between the hot water entering and the cold water leaving the cooling tower.

Dew point – The dry-bulb temperature at which condensation begins if an air-vapor mixture is cooled at constant pressure.

Double-flow LP cylinder – A low-pressure turbine section comprising two expansion flow paths.

Drift eliminators – Devices in a cooling tower that capture droplets of water in the airflow leaving the tower, preventing their discharge to the atmosphere.

Dry Bulb Temperature - The temperature of ambient air as measured by a standard thermometer or other similar device.

Energy Penalty - The loss of electricity generating capacity incurred when a cooling system is unable to perform at design efficiency. The energy penalty is associated with insufficient cooling of the turbine exhaust steam and usually is manifested by an increase in steam turbine back pressure. This study expresses the penalty as “the percentage of plant output,” or phrased differently, “the percentage of additional energy that would have to be used to generate the same amount of electricity.” In this study, the energy penalty also includes additional power needed for pumps and fans in cooling tower systems.

Evaporative cooling tower – A heat exchanger transferring waste heat from circulating water to the atmosphere, which uses evaporation of water as a means of heat transfer.

Last-stage blades – The last stage of turbine blades in the steam expansion flow path of a steam turbine.

Mean ambient wet bulb data – Statistical mean, or average, of discrete ambient wet bulb temperature data.

Mechanical draft evaporative cooling tower – An evaporative cooling tower using a motor-driven fan to propel a stream of air through the tower.

Once-through cooling water system – A cooling water system that does not recirculate the water. The water flows from the intake to the heat load and then to the discharge in a direct path.

Parasitic power losses – See plant auxiliary load below.

Plant auxiliary loads – Electrical power requirements of auxiliary equipment necessary to support operation of the plant.

Plume abatement – A means of reducing the visual and local environmental impacts (fog, icing) of the plume of saturated air leaving an evaporative cooling tower.

Power block – Major buildings and structures comprising the power plant; typically includes the boiler (reactor building in the case of a nuclear plant), steam turbine, particulate control device (electrostatic precipitator or baghouse), wet scrubber (if included), draft equipment (fans), ducting, and stack. Other equipment and structures may be included, if contiguous with the boiler and turbine buildings.

Pultruded – A continuous molding manufacturing process utilizing glass or fibrous reinforcement in a polyester or vinyl ester resin matrix.

Recirculating wet cooling tower – Same as an evaporative cooling tower.

Regenerative feedwater heating – The use of steam extracted from different locations in the steam turbine, steam expansion flow path to progressively heat condensate and feedwater.

Spray deck – The horizontal deck surface of a cooling tower where the cooling water is released via spray nozzles to drain downward by gravity, and be cooled by evaporation as it falls to the basin below.

Steam condensing enthalpy – A measure of the thermal energy released by the steam as it condenses.

Steam cycle performance – Thermal performance of the steam thermodynamic cycle.

Subcritical steam generator – A device generating steam at subcritical pressure and temperature (less than 3,208 psia/705 °F).

Supercritical steam generator – A device generating steam at supercritical pressure and temperature (greater than 3,208 psia/705 °F).

Turbine generator – A steam turbine and electric generator set. The steam turbine provides the motive power to drive the electric generator, which produces electricity.

Wet bulb temperature – The temperature of ambient air as measured by a thermometer in which the bulb is kept moistened and ventilated. The resulting measurement equates to the dynamic equilibrium temperature attained by a water surface when the rate of heat transfer to the surface by convection equals the rate of mass transfer away from the surface by evaporation. The wet bulb temperature is the lowest temperature at which evaporation can occur for specific ambient conditions (dry bulb temperature and relative humidity).

1. INTRODUCTION

The protection of aquatic organisms found in the water bodies of the United States has been an important focus of environmental regulations in the United States. In 1972, Congress enacted section 316(b) of the Clean Water Act addressing the withdrawal of cooling water from surface water bodies. The congressional language mandated that:

> "Any standard established pursuant to section 301 or section 306 of this Act and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact."

The U.S. Environmental Protection Agency (EPA) promulgated final section 316(b) regulations in 1976. However, in 1979, EPA formally withdrew its section 316(b) regulations as a result of a successful Federal court challenge initiated by a consortium of 58 utilities. Over the past 20 years, in the absence of Federal guidelines, many States have adopted their own regulations with respect to the implementation of section 316(b) requirements regarding cooling water intake structures. In many cases, the States had adopted a site-specific approach to determine what constitutes best technology available for minimizing adverse environmental impact.

The regulatory environment had changed by 1995 when the U.S. District Court, Southern District of New York, entered a Consent Decree between the EPA and the Hudson Riverkeeper that obligated the Agency to issue cooling water intake structure regulations within 7 years. The Consent Decree was modified on November 21, 2000 to: a) finalize new facility regulations by November 9, 2001 (Phase I); b) propose existing source large utility and non-utility power producer regulations by February 28, 2002 and issue final regulations by August 28, 2003 (Phase II); and c) propose regulations by June 15, 2003 and issue final regulations by December 15, 2004 for other existing facilities not covered in b) above (Phase III).

EPA's Phase II proposal addressing existing facilities has been released and can be found at http://www.epa.gov/waterscience/316b/. As currently written, the proposal presents several options under consideration for the final rule. One of the options suggests that existing, once-through cooled facilities be required – based on water body type and intake flow capacity – to retrofit with recirculating wet cooling towers as a method to meet reductions in organism impingement and entrainment. EPA estimates that this option would affect 50 to 60 existing steam-condensing power generation facilities.

When considering a recirculating wet cooling tower retrofit to an existing once-through cooled facility, there are several significant site-specific issues and assumptions that must be fully analyzed a priori. Among these issues are effect on turbine performance, increased plant parasitic power losses, land space consideration, tower size and type, permitting restrictions, tower plume and noise abatement, and tower drift loss control, just to name a few. The purpose of this report is to evaluate the feasibility of a wet recirculating cooling tower retrofit at four existing steam-condensing power plants with respect to the aforementioned issues. The plants that were evaluated are the Surry Power Station (nuclear, Units 1 and 2), Hudson Generating

Station (Unit 1/gas, Unit 2/coal), Barney M. Davis Power Station (natural gas, Units 1 and 2), and Big Bend Station (coal, Units 1, 2, 3, and 4). These plants were studied because of their representative fuel type and their geographic location, which underscored the very site-specific nature of the wet recirculating cooling tower retrofit option.

2. SITE DESCRIPTIONS

The four plants selected for evaluation of a potential evaporative cooling tower retrofit are briefly described below. These sites were chosen because they represent the class of power plants that could be candidates for cooling tower retrofits and encompass the range of site specific issues that may need to be addressed. They represent all fuel types and have significantly different geographic locations. An aerial photograph and map of the surrounding area for each site are included in the back of this section of the report (Figure 2-1 through Figure 2-8). The selected plants are:

- Surry Power Station (Surry County, Virginia), Units 1 and 2
- Hudson Generating Station (Jersey City, New Jersey), Units 1 and 2
- Barney M. Davis Power Station (Corpus Christi, Texas), Units 1 and 2
- Big Bend Station (Tampa Bay, Florida), Units 1, 2, 3, and 4

A sketch of a proposed cooling tower arrangement has been prepared for each site, and is superimposed on the aerial photograph for each site. The site descriptions make reference to nearby facilities such as airports, highways, tourist attractions, etc. The presence of these site-specific features must be taken into account when considering the siting of evaporative cooling towers, since these towers can cause local fogging, icing, deposition of droplets containing dissolved solids, or have other impacts such as noise, or interpose high structures in the path of an approach to an airport. It is important to recognize the inextricable tie between these cooling tower siting challenges and the potential for increased capital/operating costs to overcome them.

Surry Power Station, Units 1 and 2

Surry Unit 1 and Unit 2 are identical nuclear power plants, based on Westinghouse pressurized water reactors generating a nominal 848 MW_e each. Each turbine generator has two double-flow low-pressure (LP) cylinders with 44-inch last-stage blades. Unit 1 was placed in service in December 1972 and Unit 2 in May 1973.

The site is on a point of land called Gravel Neck, which projects into the James River in Surry County, Virginia. The river is brackish. Both units share a common cooling water intake canal that is approximately 2 miles long. The cooling water is pumped from the James River into the intake canal, and a common discharge canal returns the water from the plant.

The immediate area around the plant power block is surrounded by structures or the cooling water intake and discharge canals. The most likely available vacant space for siting cooling towers that is accessible to both cooling water canals is southeast of the plant.

The Surry site is approximately 6 miles south and across the James River from the Jamestown National Historic Site. The Williamsburg Jamestown airport is 8 miles north of the site, and the Felker Army Airfield is 6 miles southeast. State parks and wetland areas surround the site. *Based on this preliminary analysis, it appears as though cooling tower plume abatement design measures may not be a requirement at the Surry site.*

Hudson Generating Station, Units 1 and 2

Hudson Station comprises two fossil-fuel-fired units. Hudson Unit 1 has a nominal 455 MW gas-fired supercritical steam generator with a turbine generator that has two double-flow LP cylinders with 28-inch last-stage blades. Hudson Unit 2, rated at a nominal 660 MW, has a coal-fired supercritical steam generator and a turbine with three double-flow LP cylinders with 28-inch last-stage blades. Unit 1 was placed in service in December 1964 and Unit 2 in December 1968.

The site is on the east shore of the Hackensack River on the outskirts of Jersey City, New Jersey. The river is brackish. There is an intake canal for the cooling water. The cooling water discharge appears to be on the river's edge downstream of the plant.

The immediate area around the power blocks for the two units is surrounded by the river on one side, the coal handling and storage facilities below, the substation above, and fuel oil storage facilities on the other side. The most likely large vacant area that can accommodate all the cooling towers in the same location is north of the plant across the railroad tracks.

The Hudson site is approximately ½ mile south of the New Jersey Turnpike, ¾ mile south of the Secaucus Railroad Station and ½ mile south of Amtrak tracks. Various Conrail tracks are immediately adjacent to the site on three sides. The plant is ½ mile north of Newark Avenue and the Pulaski Skyway (Route 9) and has warehouse storage sites on its immediate southern end. *The Hudson plant was deemed to require plume abatement design measures, based on its proximity to roads and its general location in a heavily urban setting.*

Barney M. Davis Power Station, Units 1 and 2

Barney Davis Station comprises two natural-gas-fired steam plants. Unit 1 has a nominal 353 MW gas-fired subcritical steam generator with a turbine generator that has one double-flow LP cylinder with 28-inch last-stage blades. Unit 2 has a nominal 351 MW gas-fired steam generator with a turbine that has one double-flow LP cylinder with 30-inch last-stage blades. Unit 1 was placed in service in May 1974 and Unit 2 in June 1976.

The site is approximately 1 mile inland from upper Laguna Madre, which is on the Gulf coast of Texas, just south of Corpus Christi. The seawater intake is at the end of the 1-mile-long canal to Laguna Madre. The plant discharges into the Oso Bay, which is attached to Corpus Christi Bay.

The power blocks are fairly unencumbered by surrounding facilities. The best choice for the cooling towers appears to be along the intake canal since this affords the efficient use of the existing intake canal for returning the water to the existing circulating water pumps.

The Barney Davis site is approximately 1.5 miles south of Waldron U.S. Navy Airfield, 5.5 miles south of Corpus Christi Naval Air Station, 5 miles south of State Route 358, and 15 miles south of Interstate Route 37. The area surrounding the site appears not to be heavily populated, with fish hatcheries on the northwest being one of the closest identifiable features. *Based on this preliminary analysis, it appears as though cooling tower plume abatement design measures may not be a requirement at the Barney Davis site*.

Big Bend Station, Units 1, 2, 3, and 4

Big Bend Station comprises four coal-fired steam plants. Units 1, 2, and 3 each have nominal 446 MW coal-fired subcritical steam generators. Units 1 and 2 each have a turbine generator with one double-flow LP cylinder with 31-inch last-stage blades. Unit 3 has a turbine with one double-flow LP cylinder with 33.5-inch last-stage blades. Unit 4 has a nominal 486 MW coal-fired steam generator with a turbine that has two double-flow LP cylinders with 26-inch last-stage blades. Unit 1 was placed in service in October 1970, Unit 2 in April 1973, Unit 3 in June 1976, and Unit 4 in February 1985.

The site is located on the lower Hillsborough Bay near Tampa Bay, Florida. The four units appear to share a common seawater intake canal north of the plants and discharge back into the bay south of the plants.

The power blocks are surrounded by the intake canal and bay on the north and south, the coal handling and storage facilities on the west, and other support facilities on the east side so that there is virtually no vacant area immediately adjacent to the power blocks. The best available vacant space appears to be on the strip of land on the north side of the intake canal. The length of this strip of land appears to be sufficient to accommodate the use of inline towers for all four units without having to place any in parallel rows.

The Big Bend site is approximately 1.5 miles north of the Apollo Beach marina, 6 miles southeast of McDill Air Force Base, 1 mile west of the Tamlani Trail highway, and 3 miles west of Interstate Route 75. *Based on this preliminary analysis, it appears as though cooling tower plume abatement design measures may not be a requirement at the Big Bend site.*

Figure 2-1
Aerial Photograph, Vicinity of Surry Site, with Proposed Cooling Towers Superimposed

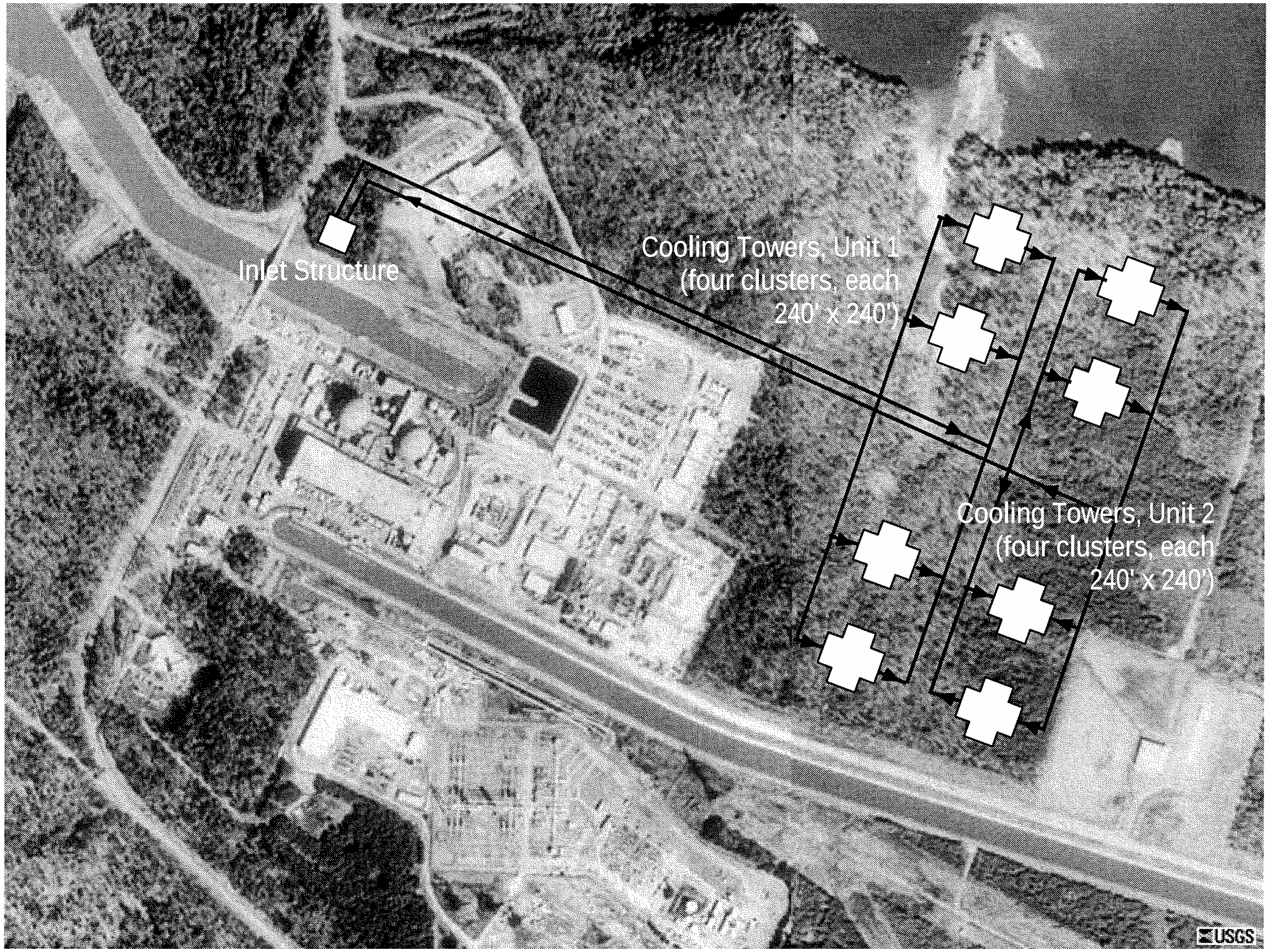


Figure 2-2
Map, Vicinity of Surry Site

27 km NW of Newport News, Virginia, United States 01 Jul 1972

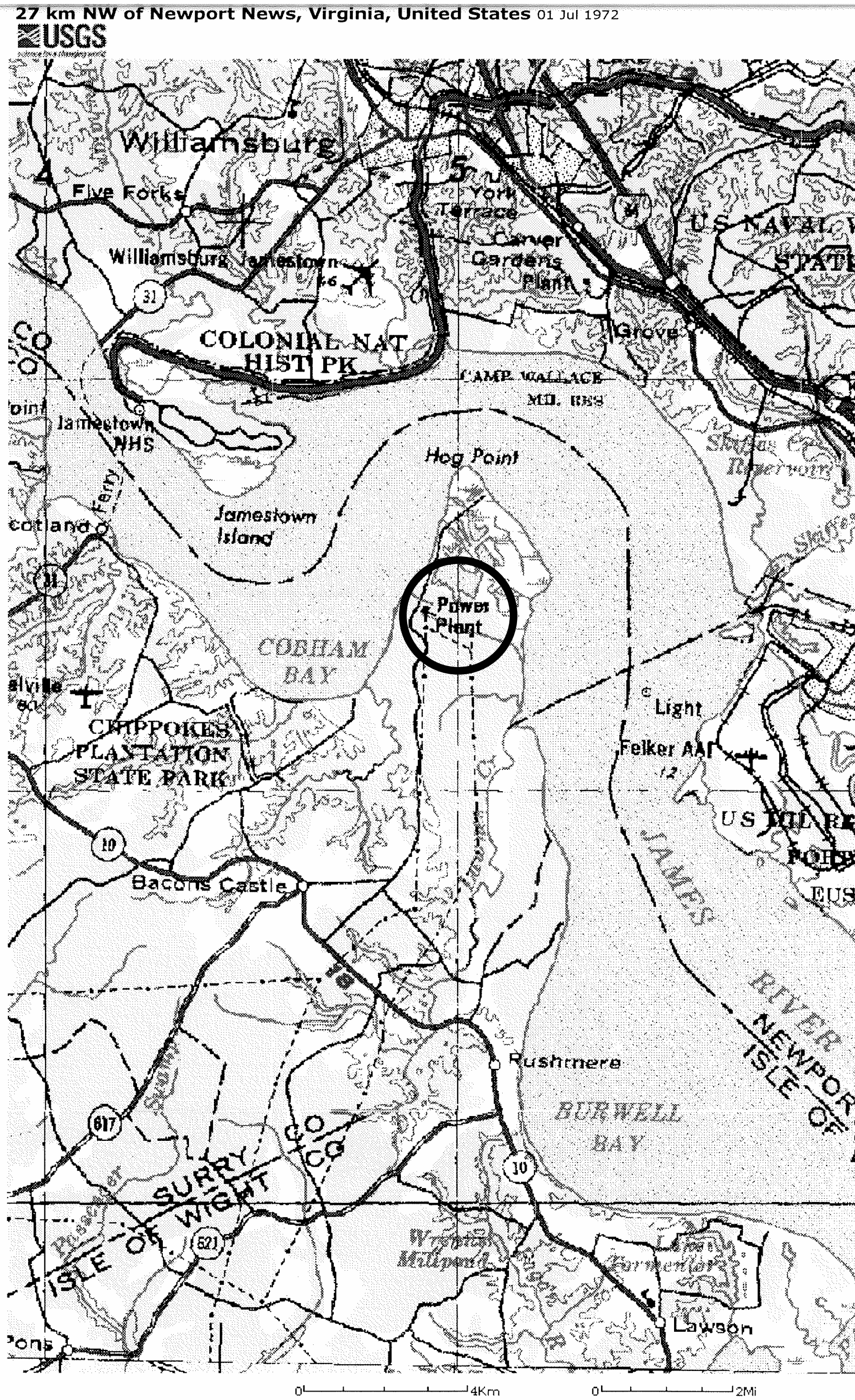


Image courtesy of the US Geological Survey.

Figure 2-3
Aerial Photograph, Vicinity of Hudson Site, with Proposed Cooling Towers Superimposed

Figure 2-4
Map, Vicinity of Hudson Site

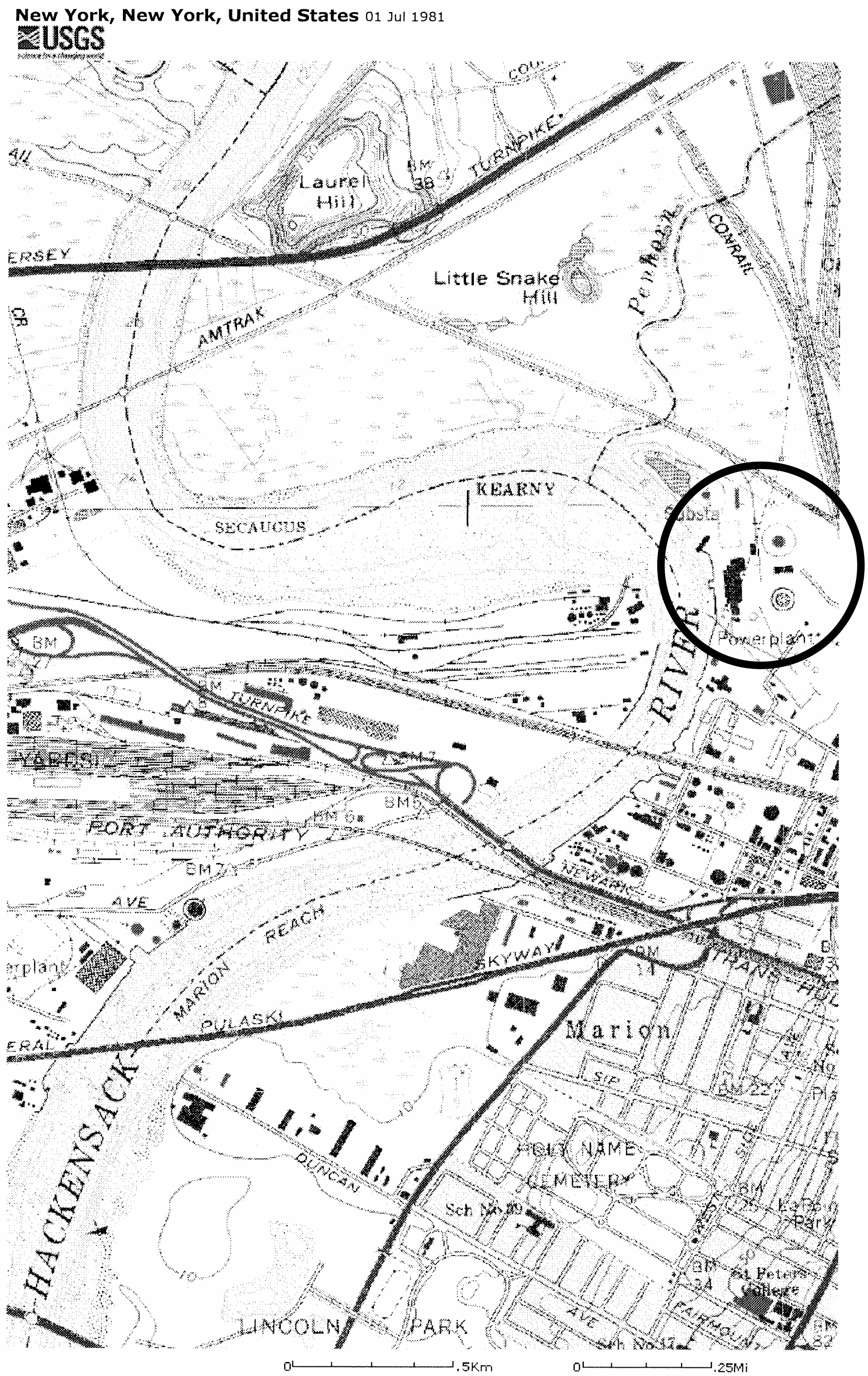


Image courtesy of the US Geological Survey.

Figure 2-5
Aerial Photograph, Vicinity of Barney Davis Site, with Proposed Cooling Towers Superimposed

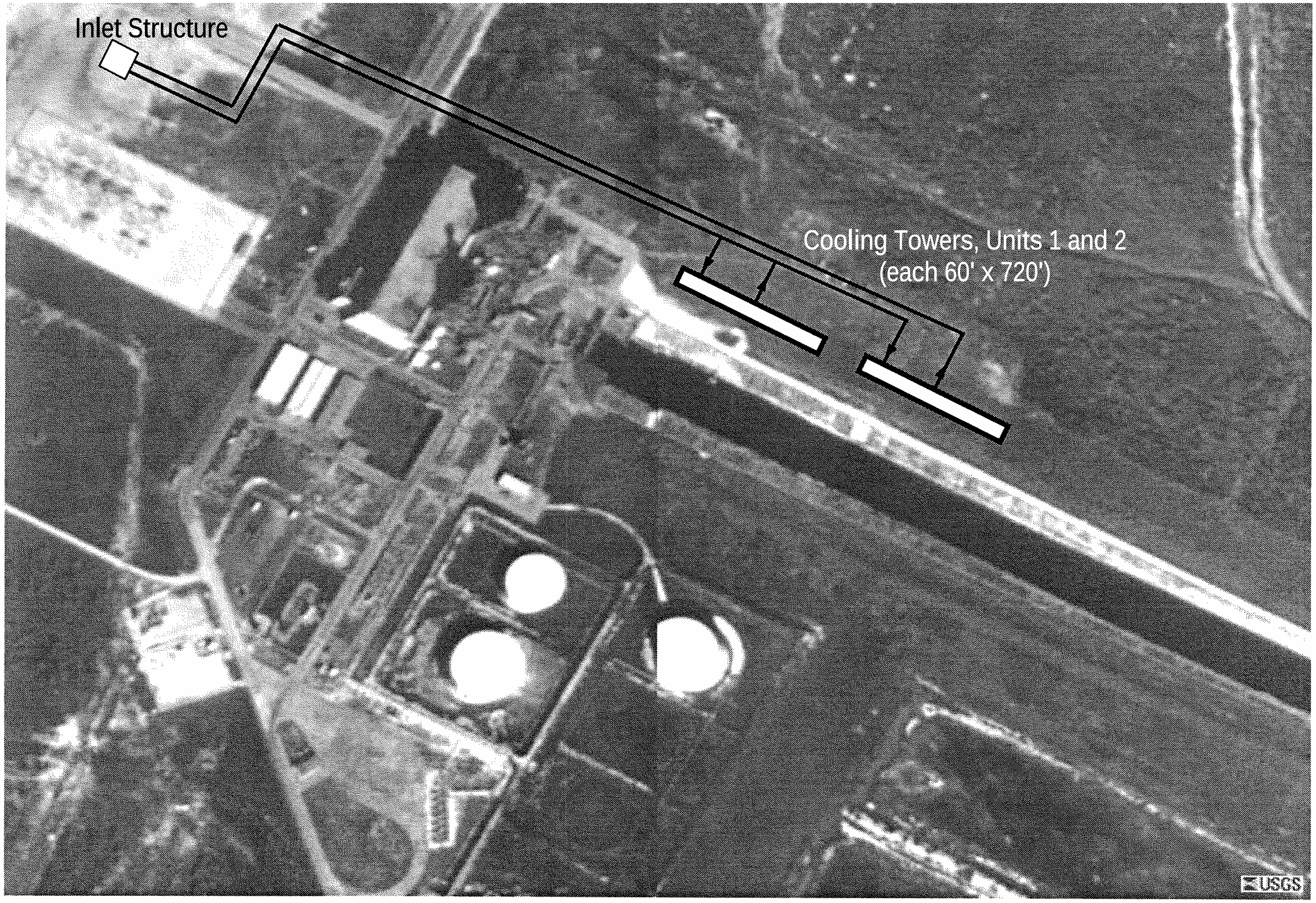


Figure 2-6
Map, Vicinity of Barney Davis Site

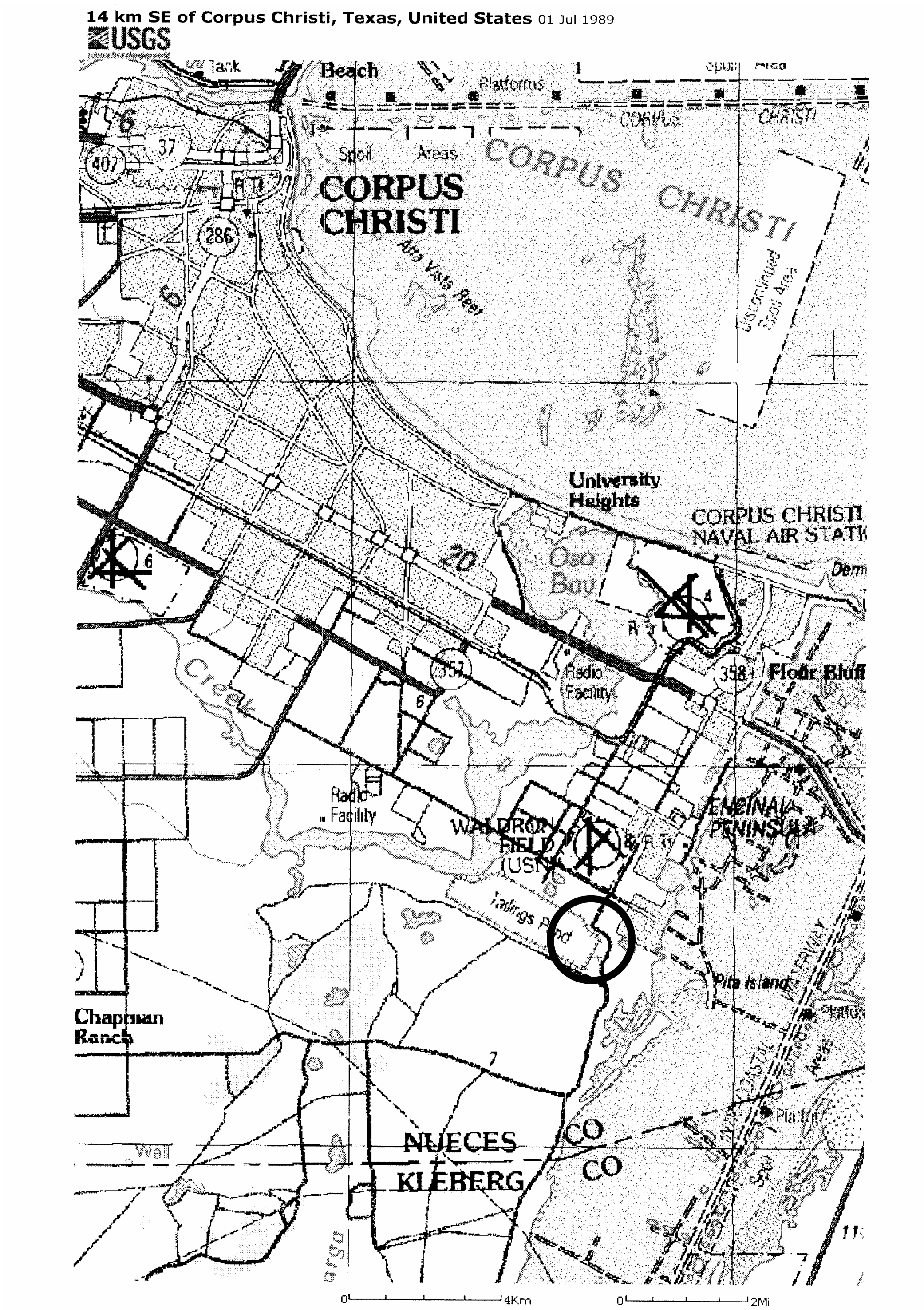


Image courtesy of the US Geological Survey.

Figure 2-7
Aerial Photograph, Vicinity of Big Bend Site, with Proposed Cooling Towers Superimposed

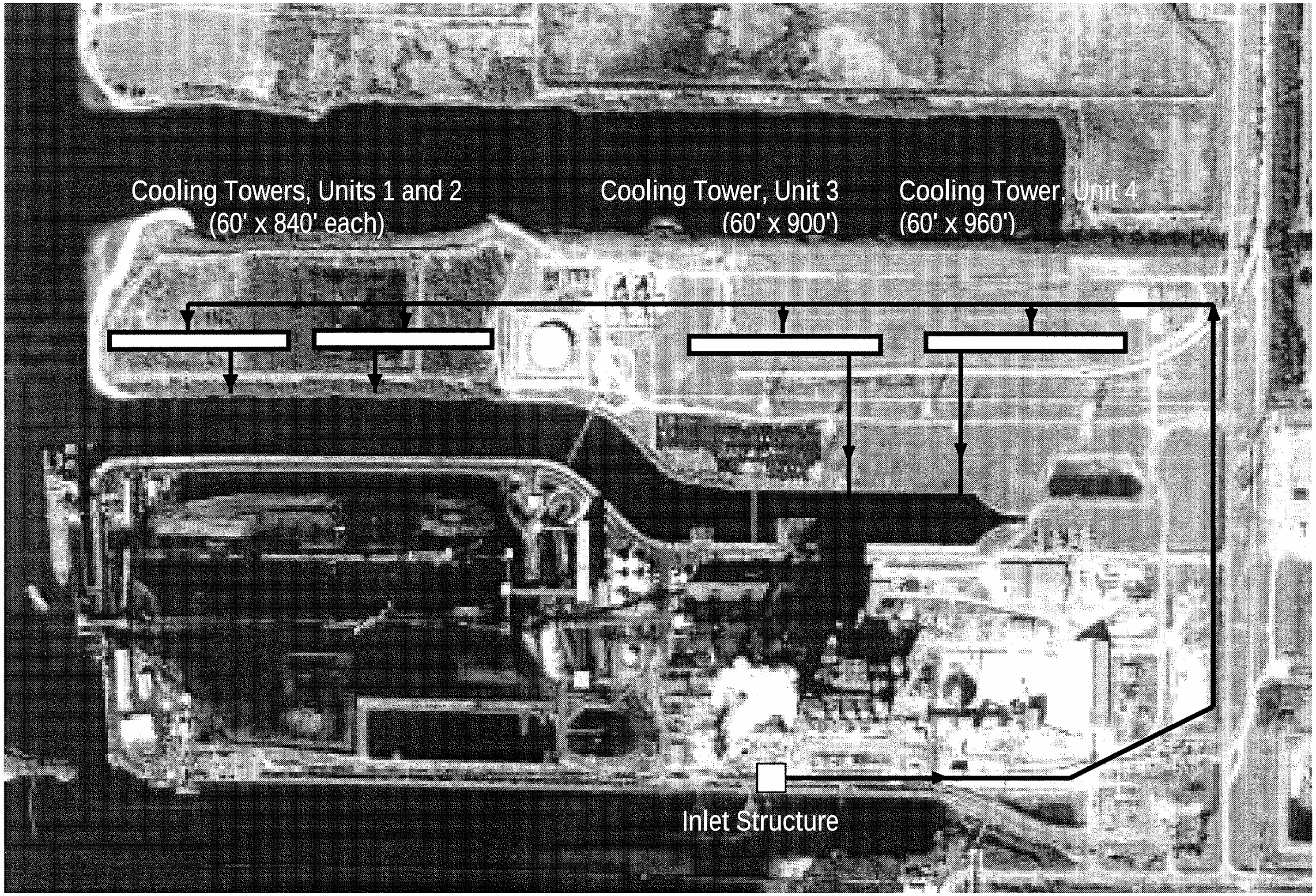


Figure 2-8
Map, Vicinity of Big Bend Site

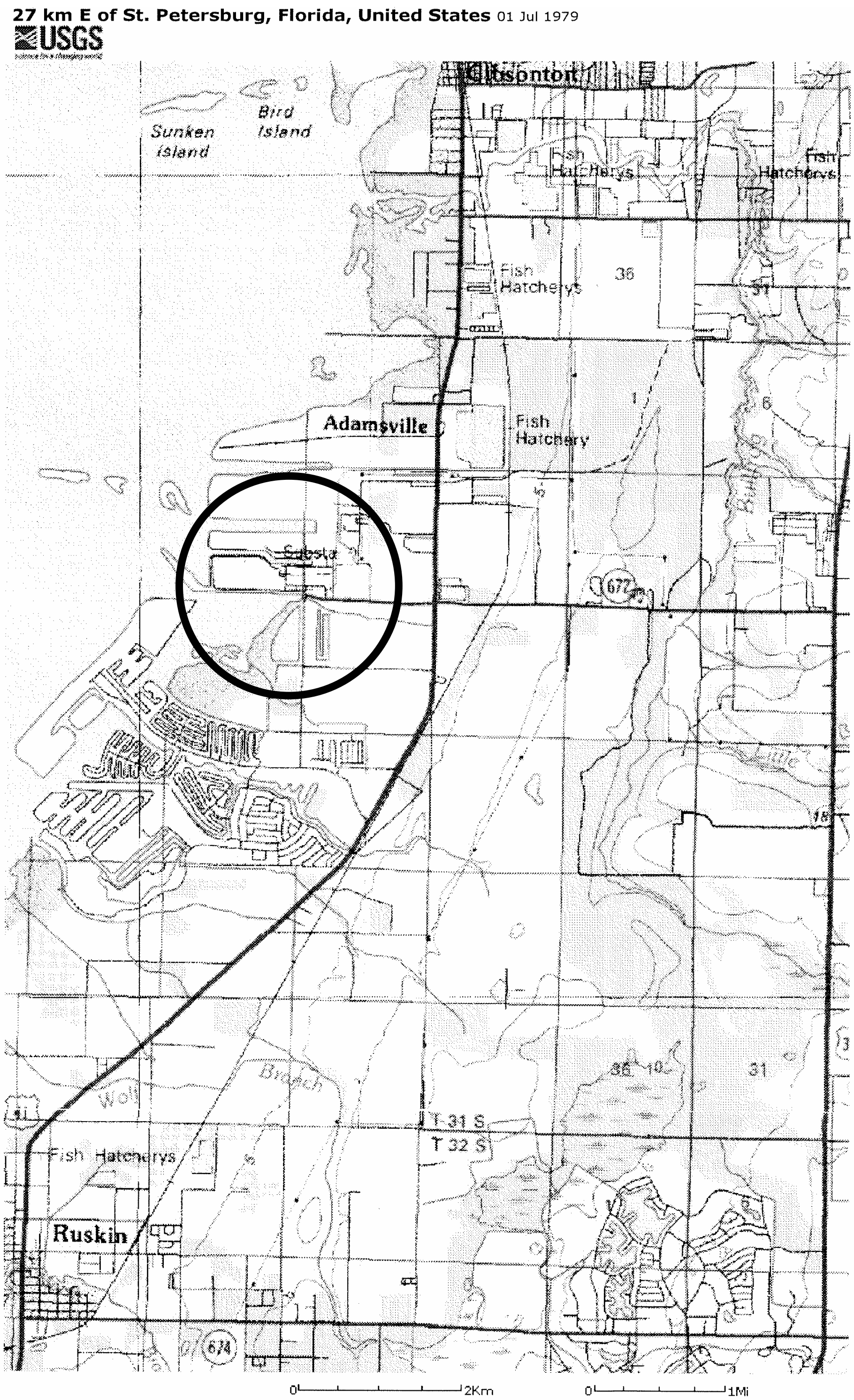


Image courtesy of the US Geological Survey.

3. METHODOLOGY

3.1 TECHNICAL CONSIDERATIONS

Evaluation of the retrofit of evaporative cooling towers to existing power plants was based on certain assumptions. For this study, the retrofit design was configured to minimize the impact on the existing steam turbine and condenser. This minimizes capital costs and the potential for lengthy plant outages, both of which would add a significant cost penalty to the retrofit. The design approach taken maintains intact the major part of the plant circulating water system, including the circulating water pumps and intake structure, piping from the pumps to the condenser, the condenser itself, and much of the discharge piping from the condenser.

If new pumps with higher discharge pressure were employed to replace the existing circulating water pumps, the system pressure might be higher than the pressure capability of the condenser, which would necessitate expensive modifications or replacement of the condenser. The original circulating water flow and condenser range (temperature rise) were maintained to keep tube velocity at the original design value to minimize fouling. This has the added effect of minimizing the impact of the cooling tower retrofit on condensing backpressure, and thus on turbine generator output. The penalty in added auxiliary load caused by higher than optimum circulating water flow rate is minimized by the fact that modern cooling tower designs have a spray deck height that is significantly lower than previous generations of cooling tower designs. Typical once-through circulating water system designs utilize a condenser temperature rise of between 12 °F and 15 °F, whereas cooling-tower-based systems use a temperature rise of about 20 °F or higher.

The modifications to the plant involve interception of the condenser discharge piping at an appropriate location and installation of a wet pit with vertical booster pumps. These booster pumps provide the added head required to lift the water up to the cooling tower spray deck, and to compensate for added piping pressure losses and for any differential in elevation between the new pumping station and the cooling towers. Two schematic diagrams showing a typical plant configuration pre- and post-retrofit are presented as Figure 3-1 and Figure 3-2.

The retrofit design is based on the use of mechanical draft evaporative cooling towers of modern counter flow design, using film type fill. The cooling tower for each plant is comprised of a series of cells constructed of pultruded fiberglass for the linear arrays used at Hudson, Barney Davis, and Big Bend. Each cell is 66 feet square, with a deck height of 40 feet, and equipped with a 250 hp 1,800 rpm totally enclosed, fan cooled, motor driving the fan through a speed-reducing gearbox. Each cell is equipped with high-efficiency drift eliminators, to limit drift to 0.0005 percent or less. The clustered cell arrangement used at Surry utilizes a concrete structure. Cell dimensions, fan horsepower, and other details of construction are similar to those in the fiberglass cells used at the other sites.

Figure 3-3 provides an illustration (plan view) of the cooling tower cell arrays for each of the four sites evaluated. These cell arrays were chosen to efficiently use available land. The tower views are all presented at the same scale.

Figure 3-1
Existing Once-Through Cooling Schematic

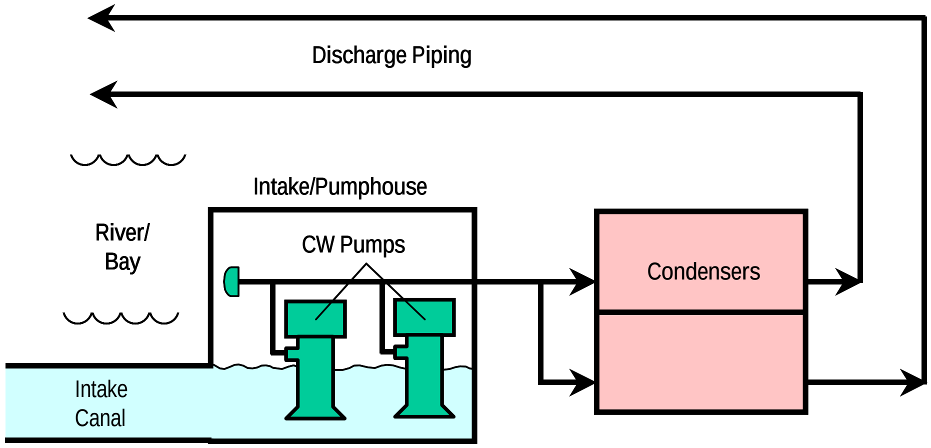


Figure 3-2
Proposed Retrofit Cooling Tower Schematic

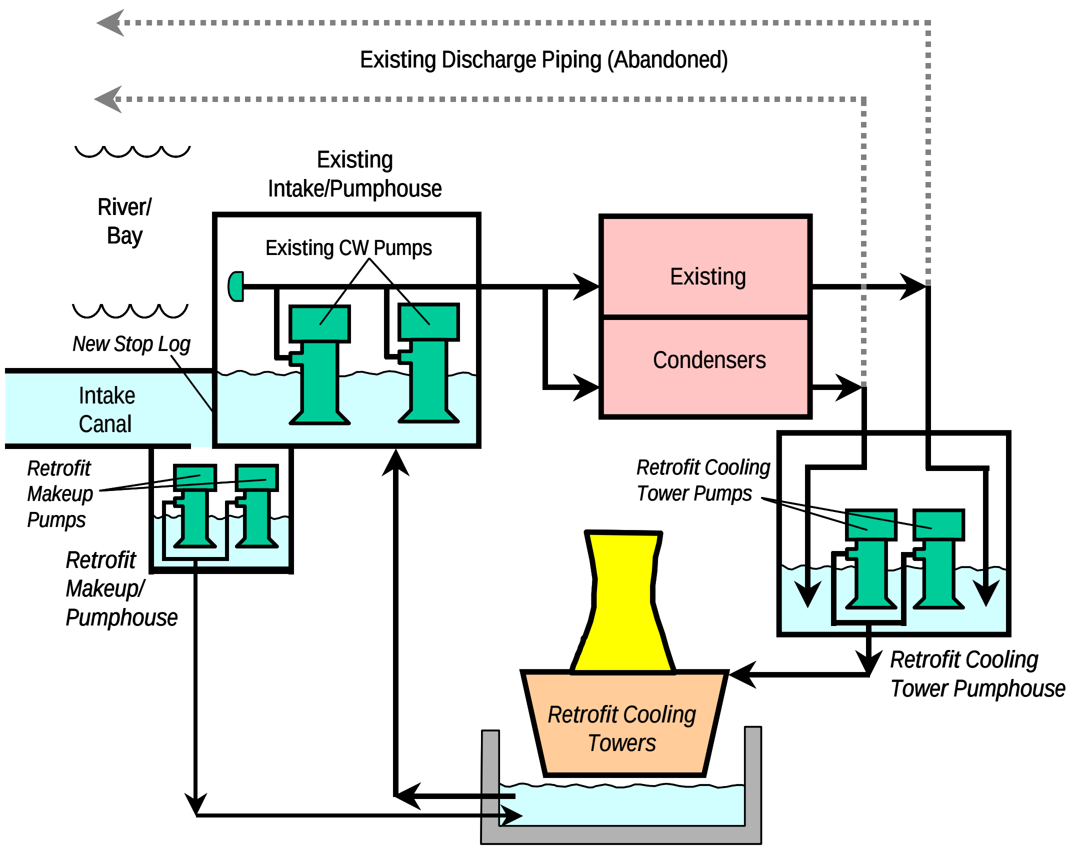
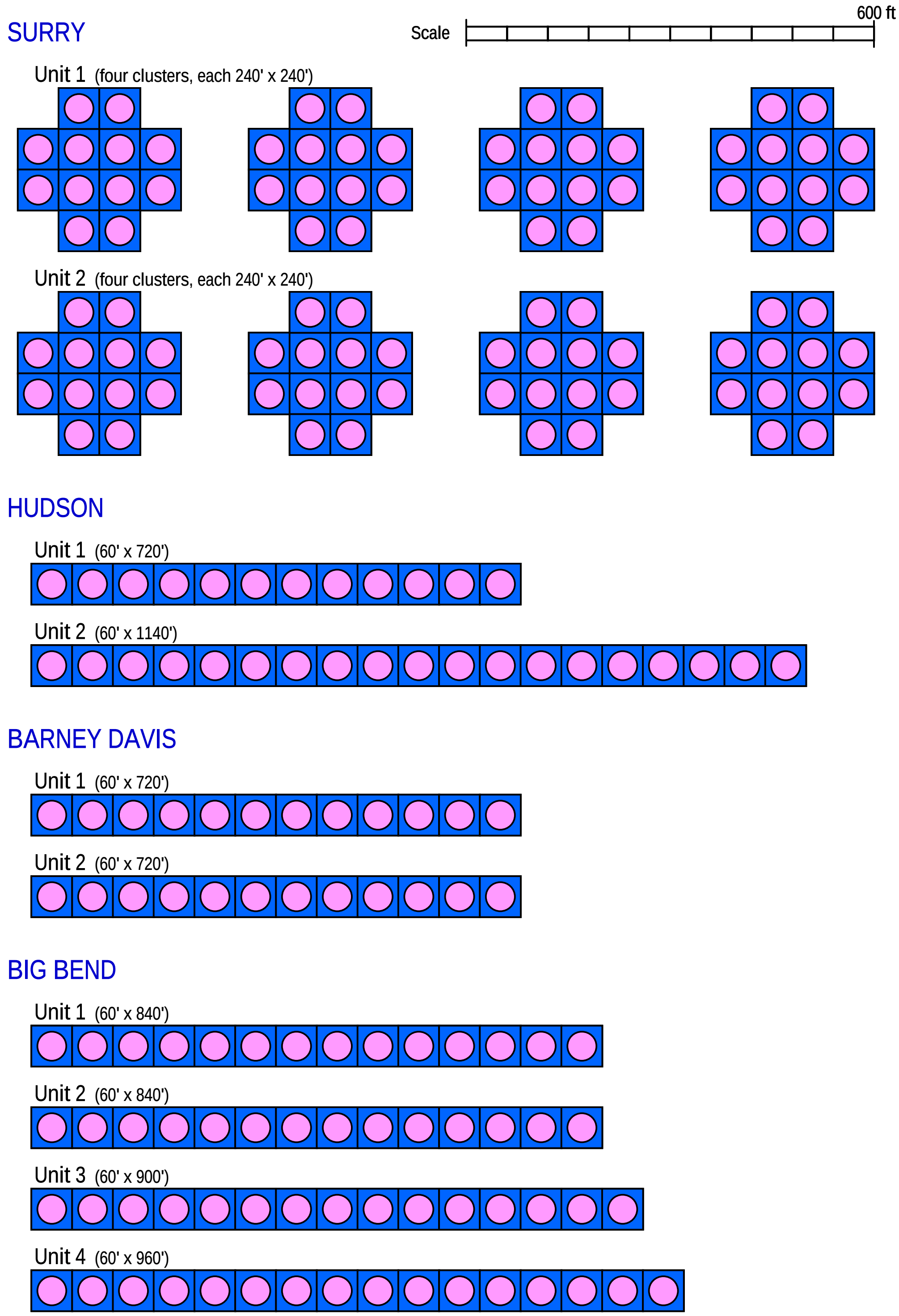


Figure 3-3
Cooling Tower Cell Arrays (Plan View)



The need for plume abatement was evaluated for each of the four plants evaluated herein. Of the four plants, only the Hudson plant was deemed to require plume abatement design measures, based on its proximity to a road and its general location in a heavily urban setting.

The cooling tower for the Hudson plant application is equipped with a plume abatement feature, which comprises a finned tube coil mounted on top of the fan deck. The hot circulating water returning from the condenser passes through the coils first, and is cooled approximately 4 °F before exiting the coil and being routed to the spray nozzles above the fill. The fin tube coils are mounted to provide a parallel flow path with respect to the air that flows through the fill. The air streams mix in the fan exhaust; the mixed dry and humid air has a lower dewpoint, resulting in reduction in visibility of the plume and mitigation of the potential for local fogging and icing of nearby surfaces and structures. The other three plants evaluated in this study are not provided with plume abatement design features, based on the specific layout and location of each plant. If cooling tower retrofit becomes a reality for any of these plants, a more detailed study must be undertaken to thoroughly evaluate local conditions. The plume abatement feature is regulated by valves and dampers, and is only used when ambient conditions warrant. This type of plume abatement feature adds significantly to the cost of a cooling tower, potentially doubling the cost of the tower.

To accommodate the short time period available to perform the study and the lack of detailed information regarding the plant design conditions, the following simplifications or assumptions were made:

- The circulating water (CW) temperature rise across the condenser was assumed to be 15 °F. From our experience, this value is typical for many of the plants. Since the condenser temperature rise is equal to the range for the cooling tower, the cooling tower range is thus also set at 15 °F.
- Where plant data on the circulating water flow to the condenser was not available (only Surry data were), the flow was calculated using the assumed condenser rise of 15 °F, an assumed steam flow to the condenser of approximately 65 percent of the plant rated steam flow at the throttle, and a steam condensing enthalpy of 1000 Btu/lb. The percentage (65 percent) of plant rated steam flow to the condenser is based on previous experience with steam cycles using regenerative feedwater heating. The other 35 percent of the throttle steam flow is extracted from the steam turbine at various locations for feedwater heating and deaeration.
- The condenser backpressure was determined by using an assumed terminal temperature difference of 5 °F for the nuclear unit and 8 °F for the fossil units. The assumed terminal temperature differences were considered from experience to be typical values for condenser design.
- Seasonal average temperatures (cooling water and ambient wet bulb) were used to evaluate the impact of differences in condenser backpressure due to the introduction of a cooling tower into the circulating water system. Cooling water temperatures were based on available data from observation and recording stations for sites close to the plants. Likewise, the mean ambient wet bulb temperature data came from airports near the sites that record annual

weather data. Monthly averages for at least the last 5 years of data were calculated and then combined into spring, summer, fall, and winter seasonal averages. Time did not permit a more detailed or exhaustive study of this type of data.

- The return cooling water temperatures from the cooling towers at various seasonal average mean wet bulb temperatures were estimated using a tower manufacturer's performance curve for the specified design duty and range. Although the sites had different design wet bulb temperatures (74, 77, 78, and 79 °F), a performance curve based on a design wet bulb temperature of 77 °F was used for all sites in determining the return water temperatures for the various seasonal temperature conditions. This approach was suggested by the tower manufacturer since the effect of the tower design wet bulb temperature is minimal. The site design wet bulb temperature was selected using standard air conditioning design values for temperatures that are exceeded no more than 2 percent of the total hours during a normal summer.
- Curves for LP turbine exhaust pressure correction to the plant output or heat rate were matched to turbines with a similar number of LP flow paths and last-stage blade length, as listed later in Table 3-2 (page 3-7). However, because of the lack of plant data for each unit, predictions of the loss of generation capability due to variations in condenser backpressure (due to the introduction of cooling towers) may not be exact, but are typical for plants with a similar type of LP turbine.
- The cooling towers were located on the best available vacant area on each site and as close as possible to the power blocks. Vacant areas were determined from USGS site aerial maps that were not necessarily current nor detailed enough to verify all obstacles to installation of towers or piping. Piping lengths were estimated using the assumed tower locations and routings that avoided existing facilities as best as could be determined from the aerial maps.
- Cooling tower blowdown is required to maintain the required quality of the recirculated water and was assumed to be at a flow that would result in a doubling of the concentration of total dissolved solids in the original feedwater. Blowdown containing twice the amount of total dissolved solids of the makeup water is considered typical for seawater cooling tower applications. Based on experience at other sites, treatment of blowdown, other than addition of chemicals to remove chlorine (if used for biological growth control), is not required. Therefore, no treatment plant or extensive equipment is expected for processing the cooling tower blowdown before discharge. Specific site conditions or local restrictions may require more extensive treatment.

A summary of cooling water temperatures (pre- and post-retrofit) is presented in Table 3-1. Although cooling water temperatures increase by 10 °F to 20 °F by adding the cooling towers, this increase does not appear to impact electricity generation to a significant extent (i.e., the annual energy penalty is less than 2 percent) at three of the four plant sites evaluated. Cooling tower retrofit impacts on steam cycle performance, such as reduced generating output, were estimated by using manufacturer's steam turbine performance characteristics for machines that have the same configuration as found in each of the cases evaluated.

Table 3-1
Seasonal Average Temperatures

	Surry	Hudson	Barney Davis	Big Bend
Seasonal Avg. Ambient Mean Wet Bulb Temp, ºF				
Spring	58	46	66	65
Summer	77	66	77	76
Fall	62	52	68	69
Winter	42	31	54	56
Seasonal Avg. River/Bay Water Temp, ºF				
Spring	60	51	74	75
Summer	83	75	86	84
Fall	67	58	74	78
Winter	41	36	56	66
Seasonal Avg. CT Return Cold Water Temp, ºF				
Spring	72	65	77	77
Summer	85	77	85	84
Fall	75	68	78	79
Winter	62	58	70	71

Based on available data, it was judged that the steam turbines installed in three of the plants evaluated (Surry, Barney Davis, and Big Bend) do not have sufficiently large last-stage blading to effectively expand the steam to backpressures consistent with condensing temperatures typically achieved with once-through cooling. In theory, reducing cooling water temperature reduces condensing backpressure and increases power output. However, in three of the specific cases evaluated here, the steam turbine generator cannot effectively utilize the reduced condensing backpressure. Only one of the four plants evaluated, Hudson Generating Station, appears to use a turbine design that can effectively utilize lower cooling water temperatures achieved with once-through cooling. A cooling tower retrofit at this plant would increase condensing backpressure (relative to once-through cooling), and thus reduce generation output. This is discussed further in Section 4.1, Discussion of Technical Results.

Principal design parameters for each plant evaluated are summarized in Table 3-2. The condenser and cooling tower design parameters selected for each plant evaluated in this study are presented in Table 3-3.

Table 3-2
Plant Design Bases

	Surry 1	Surry 2	Hudson 1	Hudson 2	Barney Davis 1	Barney Davis 2	Big Bend 1	Big Bend 2	Big Bend 3	Big Bend 4
Gross MW_e	848	848	455	660	353	351	446	446	446	486
Fuel Type	Nuclear	Nuclear	Gas	Coal	Gas	Gas	Coal	Coal	Coal	Coal
Boiler	PWR	PWR	Supercritical	Supercritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical
Steam Press, psig	733	733	3500	3500	2000	2000	2400	2400	2400	24000
Steam Temp, ºF	511	511	1000	1000	1000	1000	1000	1000	1000	1000
Reheat Temp, ºF	483	483	1025/1050	1025/1050	1000	1000	1000	1000	1000	1000
Steam Flow, million lb/h	10	10	2.5	3.9	2.4	2.4	2.9	2.9	3.1	3.3
Turbine Manufacturer/ LP Configuration	Westing-house/ TC4F44	Westing-house/ TC4F44	Westing-house/ TC4F28	Westing-house/ TC6F28	Westing-house/ TC2F28	GE/ TC2F30	Westing-house/ TC2F31	Westing-house/ TC2F31	GE/ TC2F33.5	GE/ TC4F26
Commercial Operation Date	12/72	5/73	12/64	12/68	5/74	6/76	10/70	4/73	6/76	2/85
Circulating Water Source	Brackish	Brackish	Brackish	Brackish	Seawater	Seawater	Seawater	Seawater	Seawater	Seawater

Table 3-3
Condenser and Cooling Tower Design Parameters

	Surry 1	Surry 2	Hudson 1	Hudson 2	Barney Davis 1	Barney Davis 2	Big Bend 1	Big Bend 2	Big Bend 3	Big Bend 4
Condenser/CT Duty, MMBtu/h	6,300	6,300	1,630	2,570	1,600	1,600	1,910	1,910	2,020	2,150
Assumed Condenser/ CT Range, ºF	15	15	15	15	15	15	15	15	15	15
Assumed Condenser Terminal Temperature Difference, ºF	5	5	8	8	8	8	8	8	8	8
CW Flow, gpm	840,000	840,000	220,000	340,000	214,000	214,000	256,000	256,000	270,000	288,000
CT Design Wet Bulb, ºF	77	77	74	74	79	79	78	78	78	78
CT Design Approach, ºF	8	8	8	8	8	8	8	8	8	8

3.2 COST ESTIMATING AND ECONOMIC CONSIDERATIONS

3.2.1 COST ESTIMATING

Separate cost estimates have been developed for each power plant unit and with total costs calculated for each site. The cost estimates are for a completed retrofit for each facility, with all-new construction and normally supplied services, including indirect costs and contingencies.

The format of each estimate has been arranged to show major cost components and their relative importance. Cost components are not arranged in any particular order of importance. Equipment costs are broken out separately and contain bulk material items. Labor costs cover site craft personnel and associated contractor markups, employee benefits, and supporting supervision, administration, and home office support. Union labor or equivalent prevailing wage rates are implied. No attempt has been made to convert or adjust labor costs for particular areas of the country.

Vendor quotes have been incorporated for major items such as cooling towers, circulating water pipes, and cooling tower pumps on a generic basis due to the lack of specific site design information. Lengths of circulating water piping were scaled from the design sketches superimposed on the aerial photos presented in Section 2. Labor costs associated with these items have been made based on experience with similar items at other sites. Allowances for costs of other items such as demolition, foundations and structures, instruments and controls, electrical, and chemical treatment were made from prior similar estimates.

Allowances for indirect costs have been included in each of the estimates based upon percentage factors. These include temporary construction services and facilities, engineering, construction management, and other professional services, owner costs, and a contingency. An allowance of 20 percent for contingencies has been included since these are existing sites and many interferences are expected. No allowances for escalation or for funds used during construction (AFDC) have been included, as there are no schedule dates considered in this study.

Costs are presented at 2002 levels in thousands of dollars for each category and also dollars per kilowatt. The overall accuracy of the estimates is expected to be ±40 percent due to the conceptual nature of the design, in accordance with the Association for the Advancement of Cost Engineering International (AACEI) guidelines. Variances beyond these ranges are possible but not likely.

3.2.2 ECONOMIC CONSIDERATIONS

Separate estimates of changes in operating and maintenance (O&M) costs caused by conversion to cooling towers at each plant have been prepared. An attempt has been made to include all major cost components for each plant.

For most of the plants it is expected that existing personnel can absorb some of the added duties that will be required to operate and maintain the new cooling system equipment. The skill level, average salaries, burdens, and overhead rates are used to estimate the cost of additional personnel that would be required (see Appendix B).

Supplies have been estimated mostly for the chemicals required for treatment of the makeup water, treatment of the cooling towers and basins, and treatment of blowdown flows prior to their discharge. The costs are similar to those needed in a new fossil plant on a per kilowatt basis.

Maintenance costs have been estimated on a percentage basis of new construction costs. The percentage chosen is an average of the various components involved. For instance, the cooling towers will have a higher percentage of maintenance than the circulating water piping. The costs will vary by year and thus an average value is shown.

The worksheets in Appendix A show the estimated power quantities and costs of the new cooling tower equipment and related systems. Allowances have been made for motor sizes, capacity factors of the existing plant, and the interchange rate for the region. These are new auxiliary loads for the existing plants.

An additional calculation has been made to account for the expected change in plant efficiency due to different cooling water temperatures during the year and their resulting impact on the condenser and turbine operations. The values shown are the average energy penalty over four different seasons of the year.

O&M costs have been grouped into two categories: fixed and variable annual costs. The way that the O&M costs were assigned to each category is described in the worksheets provided in Appendix B.

4. RESULTS

4.1 DISCUSSION OF RESULTS

The results of the study indicate that cooling tower retrofits are technically feasible at three of the four plants evaluated: Surry Nuclear Power Plant, Big Bend, and Barney Davis. The addition of cooling towers at the Hudson plant is considered feasible on a provisional basis; serious issues remain that require evaluation. These issues relate to availability of land to locate the cooling towers and route the large-diameter circulating water piping. The requirement for plume abatement at this site exacerbates the space issues, since the plume abatement requirement imposes restrictions on the cooling tower cell array configuration. Towers with plume abatement features added cannot be spaced as closely as towers without this feature.

From an economic perspective, the addition of cooling towers to the evaluated plants poses a significant added cost, both as one-time capital costs and an ongoing increase in the cost of production of electricity. The added costs range from an estimated $128/kW$_e$ for the Surry plant to $65/kW$_e$ at the Hudson plant. The cost of adding cooling towers to nuclear units is significantly higher, on a unit basis, compared to a fossil plant. This is due to the much higher heat rejection to the condenser in a nuclear unit relative to that of a fossil unit, which rejects a significant amount of waste heat to the atmosphere via the stack. Table 4-1 compares the heat rejection at Surry with a typical fossil unit. Note that the heat transfer to the condenser for each of the Surry nuclear units is more than 1½ times greater per kilowatt of electricity produced.

Table 4-1
Energy Flow Comparison

Plant	Surry Power Station (Nuclear)	Typical Fossil Unit
Efficiency	33.3%	37.5%
Energy Input, MW$_t$	2,550	1,133
Heat to Condenser, MW$_t$	1,650	510
Heat to Stack, MW$_t$	0	149.5
Energy at Generator Terminals, MW$_e$	900	422
Auxiliary Load, MW$_e$	50	24.5
Net Plant Output, MW$_e$	850	397.5
Condenser Heat Rejection/ Net Electric Generation, MW$_t$/MW$_e$	2.0	1.28

The annual energy penalty caused by the installation of cooling towers at these four existing plants (see Table 4-2) is estimated to be between 1.1 and 2.1 percent of the power plant output. This loss in salable power (annual energy penalty) is due to increases in condensing backpressure and auxiliary load (cooling tower boost pumps and fans).

Table 4-2
Evaluation Results – Plant Output Effects

	Surry 1	Surry 2	Hudson 1	Hudson 2	Barney Davis 1	Barney Davis 2	Big Bend 1	Big Bend 2	Big Bend 3	Big Bend 4
Gross MW_e	848	848	455	660	353	353	446	446	446	486
Generation Capability Impact, MW:										
Spring	--	--	0.5	0.8	0.1	.01	--	--	--	1.0
Summer	0.8	0.8	0.5	0.8	--	--	--	--	--	--
Fall	--	--	0.5	0.8	0.2	0.2	--	--	--	0.5
Winter	--	--	0.5	0.7	--	--	--	--	--	0.5
Yearly Average	0.2	0.2	0.5	0.78	0.08	0.08	0	0	0	0.5
Auxiliary Load Impact, MW:										
Cooling Tower Pumps	7.46	7.46	1.91	2.98	1.91	1.91	2.57	2.57	2.73	2.90
Cooling Tower Fans	9.94	9.94	2.49	3.98	2.49	2.49	2.90	2.90	3.15	3.31
Makeup Water Pumps	0.21	0.21	0.06	0.10	0.06	0.06	0.08	0.08	0.08	0.08
Miscellaneous	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Net Impact on Salable Power, Loss in MW	17.86	17.86	5.01	7.89	4.59	4.59	5.60	5.60	6.01	6.84
Net Impact on Salable Power, Loss in %	2.1	2.1	1.1	1.2	1.3	1.3	1.3	1.3	1.3	1.4

The auxiliary power requirements for booster pumps and cooling tower fans associated with the cooling tower retrofits are significant in all four of the cases evaluated accounting for 90 to 100 percent of the estimated annual energy penalty.

In contrast, decreased plant generation output due to condenser/turbine effects of the new cooling systems is smaller than originally anticipated. Surry's capacity decrement due to the new cooling temperatures (and not new plant auxiliary loads) is only 0.002 percent or 200 kW per unit. The losses at Barney Davis and Big Bend are equally small. The Hudson plant can anticipate a loss of almost 0.7 percent, or 7,500 kW_e for both units combined. However, the decrease in net plant generation output due to increased auxiliary load is much more significant, and ranges from about 1 percent for the fossil units to about 2 percent for the nuclear units (Surry).

Decreases in the performance of the steam turbines because of the change from once-through cooling to recirculated cooling water were a minor contributor to the overall energy penalty due to the factors listed below.

- First, it appears that most of the plants evaluated (except Hudson) were designed with relatively high turbine exhaust velocities. Operation on a cooling tower would shift the condensing backpressure up, and exhaust velocity down. The reduction in exhaust velocity results in lower exhaust power losses, which tends to mitigate, but not completely compensate for, any reduction in generation output caused by the higher backpressure.

- Second, the cooling tower retrofits were designed with the same condenser temperature rise (nominally 15 °F). This tends to maintain low condensing backpressures, relative to units operating with higher temperature rises.

- Third, the cooling water temperatures for the original once-through cooling water systems tend to be high; cooling water from an evaporative tower designed with a typical design basis approach (difference in temperature between cold water temperature leaving the tower and the ambient wet bulb temperature) was relatively close to the once-through cooling water temperature during the summer months. During winter, spring, and fall the differences in cold water temperatures available to the plant condensers tend to diverge (between once-through vs. cooling tower cases of each plant). However, the Surry, Barney Davis, and Big Bend plants are not significantly impacted by increased cooling water temperatures over the range of temperatures encountered in the study due to turbine characteristics referred to above.

Technical parameters describing the retrofit cooling towers and circulating water piping for each unit that was evaluated are presented in Table 4-3.

4.2 CAPITAL COST AND OPERATING COST RESULTS

From an economic perspective, the retrofit of cooling towers to the evaluated plants poses a significant added cost, both as one-time capital costs and an ongoing increase in the cost of production of electricity.

Table 4-3
Evaluation Results – Technical Parameters

	Surry 1	Surry 2	Hudson 1	Hudson 2	Barney Davis 1	Barney Davis 2	Big Bend 1	Big Bend 2	Big Bend 3	Big Bend 4
CW Pipe Diameter, in.	144	144	108	120	108	108	120	120	120	120
Length of CW Pipe, ft	12,000	12,000	4,000	4,000	4,000	4,000	7,000	7,000	7,000	7,000
Total CT Pump Flow, gpm	840,000	840,000	220,000	340,000	214,000	214,000	256,000	256,000	270,000	288,000
CT Pump Head, ft	35	35	35	35	35	35	40	40	40	40
Total CT Pump Horsepower, bhp	9,000	9,000	2,300	3,600	2,300	2,300	3,100	3,100	3,300	3,500
CT Makeup Water Flow, gpm	20,000	20,000	6,000	9,000	6,000	6,000	7,000	7,000	7,000	7,000
CT Makeup Water Pump Horsepower, bhp	250	250	75	125	75	75	100	100	100	100
Number of Modular 60 ft x 66 ft CT Cells	4 clusters of 12	4 clusters of 12	12	19	12	12	14	14	15	16
CT Total Fan, bhp	12,000	12,000	3,000	4,800	3,000	3,000	3,500	3,500	3,800	4,000
Plume Abatement	No	No	Yes	Yes	No	No	No	No	No	No
Cell Arrangement	Cluster	Cluster	Inline	Inline	Inline	Inline	Inline	Inline	Inline	Inline
CT Plan Area, L (ft) x W (ft)	4 clusters at 250 x 250	4 clusters at 250 x 250	726 x 66	1150 x 66	726 x 66	726 x 66	847 x 66	847 x 66	908 x 66	968 x 66

A summary of the results of the assessment of capital costs and other economic considerations is shown on Table 4-4.

Table 4-4
Summary of Capital and Operating Costs – All Plants

Plant Name	Unit No.	Capital Costs, $/kW	Fixed Oper. Costs, $/MW	Variable Oper. Costs[1], $/MWh	Annual Energy Penalty[2], %
Surry Nuclear Plant	1	$128	$655	$0.885	2.1
	2	$128	$655	$0.885	2.1
	Total	$128	$655	$0.885	2.1
Big Bend	1	$75	$411	$0.617	1.3
	2	$75	$411	$0.617	1.3
	3	$77	$418	$0.642	1.3
	4	$72	$391	$0.636	1.4
	Total	$75	$407	$0.628	1.3
Barney Davis	1	$67	$371	$0.623	1.3
	2	$67	$373	$0.625	1.3
	Total	$67	$372	$0.624	1.3
Hudson	1	$68	$371	$0.540	1.1
	2	$65	$347	$0.558	1.2
	Total	$66	$357	$0.551	1.2

Notes:

1 Includes cost of added electric power consumption for new pumps and cooling tower fans.

2 Energy penalty shown includes condenser backpressure effect on generation and the reduction in salable power due to increased auxiliary load.

Detailed capital cost estimates for each unit and plant are contained in Appendix A. The total cost per plant ranges from $23 million to $108 million or from $65 per kW to $128 per kW. As expected, the Surry Nuclear Plant has the highest cost due to its large (848 MW) size per unit and high rate of heat rejection. However, two additional factors contributed to the high cost of this plant: the use of clustered cooling towers to minimize the required land space and distance of the towers from the plant, and, secondly, the long runs of circulating water pipes to the available open areas for the towers.

The costs to retrofit cooling towers at the fossil units are relatively close to each other at $65 to $77 per kW. The installed cost of both the cooling towers and the circulating water pipe account for approximately 60 percent of the direct costs. The foundations and structures account for almost another 20 percent of direct costs.

The Hudson site cost estimate includes plume abatement technology and costs due to its location. This factor increases the cost of the towers by about 100 percent or an additional $12 million of direct costs. This had the effect of increasing the total capital cost of the installation by 22.5 percent. The Barney Davis, Surry, and Big Bend sites were not determined to need plume abatement due to their location.

The detailed calculations for annual O&M costs associated with cooling towers for each unit and plant are contained in Appendix B. Operating costs for each of the nuclear units is expected to increase about $5.8 million per year. About 60 percent of this increase is for new auxiliary power requirements to run pumps and fans. The remaining 40 percent is for additional operators and supplies. About 90 percent of the O&M costs are considered variable costs.

Operating costs for each of the fossil units is expected to increase by about $1.5 to $2.0 million per year. About 50 percent of the new costs are for new plant auxiliary loads for fans and pumping. About 90 percent of the fossil O&M costs are for variable costs.

If construction of the retrofit cooling tower system would require an extended outage, costs could increase significantly. However, it is the opinion of the Parsons engineering staff that construction and startup of new cooling tower systems at the Surry and Barney Davis sites would not result in extended outages. With proper planning and coordination with other planned outages, cutover from the older cooling systems to the new cooling towers could be accomplished without loss of generating time. This has been the experience with other plants. Therefore, the analysis shows no cost penalty for extended outages at this time.

The situation is less certain at the Hudson and Big Bend sites. The configuration of the existing site for each of these two cases makes it difficult to assess the need for extended construction outages without more detailed site information and study.

The data presented in Appendix B of this report reflect no outage. However, should it be determined upon further review and a more detailed analysis of system locations, that an extraordinary outage will be required as part of a cooling tower retrofit, the following loss of revenues can be expected <u>per plant</u> (i.e., all units) per month:

- Surry… $30 million per month
- Hudson… $16 million per month
- Barney Davis… $11 million per month
- Big Bend… $28 million per month

To determine these losses in revenues, a conservative assumption of $0.030/kWh was used as the value of the lost power generation each plant would suffer as a result of an extended cooling tower retrofit outage. The calculation was also based on each plant's peak net summer power output.

5. CONCLUSIONS

The conclusions reached from this study based on assumptions about, and analysis of, four "real world" power plants indicate that the retrofit of evaporative cooling towers to an electric generating plant, fossil or nuclear, imposes a significant burden in terms of capital costs ($65 to $128 per kW) and loss of net generation output (1.1 to 2.1 percent of plant electricity generation). The capital cost expenditure reflects the cost of the cooling towers, circulating water piping, and related ancillary items such as added circulating water booster and makeup pumps. The loss of salable power is due to the added auxiliary electrical load, and for certain plants, a decrement in electric generation caused by operation at higher condensing backpressures.

Operating costs are estimated to increase about $5.8 million per year for the nuclear unit studied and about $1.5 to $2.0 million per year for the fossil energy units studied. More than half of the increase in operating costs is for new auxiliary power requirements to run new pumps and cooling tower fans.

The loss of revenue due to an extended outage to accommodate a cooling tower retrofit is a potential issue. In the current study, two plants (Surry and Barney Davis) appear to be able to avoid an extension to a normal annual outage to enable the changeover to be accomplished; the other two plants (Hudson and Big Bend) have more restrictive site arrangements and may require outage extensions.

When considering a recirculating wet cooling tower retrofit to an existing once-through cooled facility, there are several significant site-specific issues and assumptions that must be fully analyzed a priori. Among these issues are effect on turbine performance, increased plant parasitic power losses, land space consideration, tower size and type, permitting restrictions, tower plume and noise abatement, and tower drift loss control.

A series of these assumptions was made to facilitate the analysis of a prospective cooling tower retrofit at the four power plant sites documented in this study. These assumptions were based on the collective experience of the Parsons engineering staff, drawing on a large number of power plant design experiences spanning the last several decades. Changes to these assumptions will affect the detailed performance and cost data presented herein, but will most likely not affect the validity of the conclusions expressed. The effect of deviations from each assumption is briefly discussed below:

<u>Cooling Water Temperature Rise</u>

The assumption made in this study was to maintain the original temperature rise of 15 °F. If the cooling tower retrofit were to be based on a value of 20 °F, for example (a value typically used in new power plant cooling tower installations), the capital cost of the cooling tower might decrease somewhat, but generation output might also be diminished. A more detailed study, beyond the scope of the present effort, is required to select the optimum design value.

Steam Flow to Condenser

A typical value for the fraction of throttle steam flow passed to the condenser after expansion in the steam turbine of 65 percent was assumed. Variations of plus or minus 10 percent in this flow rate are not expected to change any of the results of this study. Larger changes would require evaluation on an individual plant basis.

Seasonal Average Temperatures for Cooling Water and Ambient Wet Bulb Temperatures

The use of seasonal average temperatures instead of monthly averages is not expected to impact the results developed by this study.

Steam Turbine Exhaust Pressure Correction

The steam turbine exhaust physical design parameters coupled with condensing steam flow rates have a significant impact on steam turbine generator electric output and plant efficiency. The estimate of performance impacts due to cooling tower retrofits presented in this report is based on the assumption that the reported turbine configuration is correct for each plant. Changes in turbine configuration used in this study to alternate configurations (number of low-pressure flow paths and/or last-stage blade lengths) could have a significant impact on the predicted change in generation output.

Cooling Tower Siting

For this study, the cooling towers were sited on the closest available open land near the steam turbine generator building. If these lands were not suitable or available, and the towers were located further away, piping costs would increase.

Cooling Tower Blowdown

The report assumes that extensive and/or expensive treatment of cooling tower blowdown is not required. If specific site conditions mandate high degrees of treatment for the blowdown, the capital and operating costs of the retrofit will increase, but are not expected to increase to a level that will compromise the overall economics of the cooling tower retrofit.

Overall, any requirement to retrofit closed circuit cooling towers to plants that now utilize once-through cooling could have significant operational and financial impacts. If the motivation for this change is due to water intake concerns, other engineering solutions that modify the inlet designs should be investigated.

APPENDIX A

CAPITAL COST ESTIMATE

APPENDIX A – CAPITAL COST ESTIMATE

Parsons Corporation

Client:__ U.S. DOE NETL — **Date:** 1/31/2002

Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Surry Nuclear Power Plant - Unit #1 - 848 MW 848 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	$50	$450	$500	1
2	Foundations & Structures	$2,940	$6,860	$9,800	12
3	Cooling Towers (clustered)	$28,800	$9,600	$38,400	45
4	Mechanical Equipment	$3,300	$660	$3,960	5
5	Piping Systems	$8,294	$12,442	$20,736	24
6	Instruments & Controls	$500	$500	$1,000	1
7	Accessory Electrical Systems	$2,500	$2,500	$5,000	6
8	Chemical Treatment	$500	$500	$1,000	1
9	Miscellaneous	$500	$500	$1,000	1
10	Open	$0	$0	$0	0
11	Open	$0	$0	$0	0
12	Open	$0	$0	$0	0
13	Open	$0	$0	$0	0
14	Open	$0	$0	$0	0
	SUBTOTAL DIRECT COST	$47,384	$34,012	$81,396	96
INDIRECT COSTS					0
	Temporary Construction Services and Facilities			1,628	2
	ENGINEERING, CM, PROFESSIONAL SERVICES			6,512	8
	OWNER COSTS			814	1
	SUBTOTAL INDIRECT COST			8,954	11
	CONTINGENCY @ _20_____%			18,070	21
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0 0
	TOTAL COST			108,419	128

Accuracy =+/- 40% Page 1

Parsons Corporation
Client:__ U.S. DOE NETL | **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits | **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Surry Nuclear Power Plant - Unit # 2 - 848 MW 848 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	50	450	500	1
2	Foundations & Structures	$2,940	$6,860	9,800	12
3	Cooling Towers (clustered)	$28,800	$9,600	38,400	45
4	Mechanical Equipment	$3,300	$660	3,960	5
5	Piping Systems	$8,294	$12,442	20,736	24
6	Instruments & Controls	500	500	1,000	1
7	Accessory Electrical Systems	2,500	2,500	5,000	6
8	Chemical Treatment	500	500	1,000	1
9	Miscellaneous	500	500	1,000	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	47,384	34,012	81,396	96
INDIRECT COSTS					0
	Temporary Construction Servicesand Facilities			1,628	2
	ENGINEERING+B44, CM, PROFESSIONAL SERVICES			6,512	8
	OWNER COSTS			814	1
	SUBTOTAL INDIRECT COST			8,954	11
	CONTINGENCY @ _20_____%			18,070	21
	ESCALATION @____0___% PER YEAR			0	
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			108,419	128

Accuracy =+/- 40% Page 2

Parsons Corporation
Client:__ U.S. DOE NETL — **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

CAPITAL COST ESTIMATE — 2002 Dollars X 1000 — Conceptual

Surry Nuclear Power Plant — 1,696 MW
Both Units #1 & #2 - 848 MW Each

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	100	900	1,000	1
2	Foundations & Structures	5,880	13,720	19,600	12
3	Cooling Towers (clustered)	57,600	19,200	76,800	45
4	Mechanical Equipment	6,600	1,320	7,920	5
5	Piping Systems	16,589	24,883	41,472	24
6	Instruments & Controls	1,000	1,000	2,000	1
7	Accessory Electrical Systems	5,000	5,000	10,000	6
8	Chemical Treatment	1,000	1,000	2,000	1
9	Miscellaneous	1,000	1,000	2,000	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	94,769	68,023	162,792	96
INDIRECT COSTS					0
	Temporary Construction Servicesand Facilities			3,256	2
	ENGINEERING, CM, PROFESSIONAL SERVICES			13,023	8
	OWNER COSTS			1,628	1
	SUBTOTAL INDIRECT COST			17,907	11
	CONTINGENCY @ _20_____%			36,140	21
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			216,839	128

Accuracy =+/- 40% — Page 3

Parsons Corporation
Client:_ U.S. DOE NETL **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Big Bend Coal Fired Power Plant - Unit #1 - 446 MW 446 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	25	225	250	1
2	Foundations & Structures	1,170	2,730	3,900	9
3	Cooling Towers	4,200	1,400	5,600	13
4	Mechanical Equipment	1,190	238	1,428	3
5	Piping Systems	$4,032	$6,048	10,080	23
6	Instruments & Controls	250	250	500	1
7	Accessory Electrical Systems	1,250	1,250	2,500	6
8	Chemical Treatment	250	250	500	1
9	Miscellaneous	250	250	500	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	12,617	12,641	25,258	57
INDIRECT COSTS					0
	Temporary Construction Services and Facilities			505	1
	ENGINEERING, CM, PROFESSIONAL SERVICES			2,021	5
	OWNER COSTS			253	1
	SUBTOTAL INDIRECT COST			2,778	6
	CONTINGENCY @ _20_____%			5,607	13
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0 0
	TOTAL COST			33,644	75

Accuracy =+/- 40% Page 1

Parsons Corporation
Client:__ U.S. DOE NETL — **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Big Bend Coal Fired Power Plant - Unit #2 - 446 MW 446 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	25	225	250	1
2	Foundations & Structures	1,170	2,730	3,900	9
3	Cooling Towers	4,200	1,400	5,600	13
4	Mechanical Equipment	1,190	238	1,428	3
5	Piping Systems	$4,032	$6,048	10,080	23
6	Instruments & Controls	250	250	500	1
7	Accessory Electrical Systems	1,250	1,250	2,500	6
8	Chemical Treatment	250	250	500	1
9	Miscellaneous	250	250	500	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	12,617	12,641	25,258	57
INDIRECT COSTS					0
	Temporary Construction Servicesand Facilities			505	1
	ENGINEERING+B44, CM, PROFESSIONAL SERVICES			2,021	5
	OWNER COSTS			253	1
	SUBTOTAL INDIRECT COST			2,778	6
	CONTINGENCY @ _20_____%			5,607	13
	ESCALATION @____0___% PER YEAR			0	
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			33,644	75

Accuracy =+/- 40% — Page 2

Parsons Corporation
Client:__ U.S. DOE NETL — **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Big Bend Coal Fired Power Plant - Unit #3 - 446 MW 446 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	25	225	250	1
2	Foundations & Structures	1,200	2,800	4,000	9
3	Cooling Towers	4,500	1,500	6,000	13
4	Mechanical Equipment	1,190	238	1,428	3
5	Piping Systems	$4,032	$6,048	10,080	23
6	Instruments & Controls	250	250	500	1
7	Accessory Electrical Systems	1,250	1,250	2,500	6
8	Chemical Treatment	250	250	500	1
9	Miscellaneous	250	250	500	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	12,947	12,811	25,758	58
INDIRECT COSTS					0
	Temporary Construction Services and Facilities			515	1
	ENGINEERING, CM, PROFESSIONAL SERVICES			2,061	5
	OWNER COSTS			258	1
	SUBTOTAL INDIRECT COST			2,833	6
	CONTINGENCY @ _20_____%			5,718	13
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			34,310	77

Accuracy =+/- 40% Page 3

Parsons Corporation
Client:__ U.S. DOE NETL   **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits   **Proj. No.** 50802

CAPITAL COST ESTIMATE   2002 Dollars X 1000   Conceptual

Big Bend Coal Fired Power Plant - Unit #4 - 486 MW   486   MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	25	225	250	1
2	Foundations & Structures	1,230	2,870	4,100	8
3	Cooling Towers	4,800	1,600	6,400	13
4	Mechanical Equipment	1,190	238	1,428	3
5	Piping Systems	$4,032	$6,048	10,080	21
6	Instruments & Controls	250	250	500	1
7	Accessory Electrical Systems	1,250	1,250	2,500	5
8	Chemical Treatment	250	250	500	1
9	Miscellaneous	250	250	500	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	13,277	12,981	26,258	54
INDIRECT COSTS					0
	Temporary Construction Servicesand Facilities			525	1
	ENGINEERING+B44, CM, PROFESSIONAL SERVICES			2,101	4
	OWNER COSTS			263	1
	SUBTOTAL INDIRECT COST			2,888	6
	CONTINGENCY @ _20_____%			5,829	12
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			34,976	72

Accuracy =+/- 40%   Page 4

Parsons Corporation
Client:_ U.S. DOE NETL — **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Big Bend Coal Fired Power Plants - 1,824 MW
Unit #1, #2, #3 @ 446 MW & #4 @ 486 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	100	900	1,000	1
2	Foundations & Structures	4,770	11,130	15,900	9
3	Cooling Towers	17,700	5,900	23,600	13
4	Mechanical Equipment	4,760	952	5,712	3
5	Piping Systems	16,128	24,192	40,320	22
6	Instruments & Controls	1,000	1,000	2,000	1
7	Accessory Electrical Systems	5,000	5,000	10,000	5
8	Chemical Treatment	1,000	1,000	2,000	1
9	Miscellaneous	1,000	1,000	2,000	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	51,458	51,074	102,532	56
INDIRECT COSTS					0
	Temporary Construction Servicesand Facilities			2,051	1
	ENGINEERING, CM, PROFESSIONAL SERVICES			8,203	4
	OWNER COSTS			1,025	1
	SUBTOTAL INDIRECT COST			11,279	6
	CONTINGENCY @ _20_____%			22,762	12
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			136,573	75

Accuracy =+/- 40% — Page 5

Parsons Corporation
Client:___ U.S. DOE NETL | **Date:** 1/31/2002
Project: _ Proposed Section 316b Cooling Tower Retrofits | **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Barney Davis Gas Fired Power Plant - Unit #1 - 353 MW 353 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	20	180	200	1
2	Foundations & Structures	960	2,240	3,200	9
3	Cooling Towers	3,600	1,200	4,800	14
4	Mechanical Equipment	920	184	1,104	3
5	Piping Systems	2,074	3,110	5,184	15
6	Instruments & Controls	200	200	400	1
7	Accessory Electrical Systems	1,000	1,000	2,000	6
8	Chemical Treatment	200	200	400	1
9	Miscellaneous	200	200	400	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	9,174	8,514	17,688	50
INDIRECT COSTS					0
	Temporary Construction Services and Facilities			354	1
	ENGINEERING, CM, PROFESSIONAL SERVICES			1,415	4
	OWNER COSTS			177	1
	SUBTOTAL INDIRECT COST			1,946	6
	CONTINGENCY @ _20_____%			3,927	11
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0 0
	TOTAL COST			23,560	67

Accuracy =+/- 40% Page 1

Parsons Corporation
Client:___ U.S. DOE NETL — **Date:** 1/31/2002
Project: _ Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

CAPITAL COST ESTIMATE — 2002 Dollars X 1000 — Conceptual

Barney Davis Gas Fired Power Plant - Unit #2 - 351 MW — 351 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	20	180	200	1
2	Foundations & Structures	960	2,240	3,200	9
3	Cooling Towers	3,600	1,200	4,800	14
4	Mechanical Equipment	920	184	1,104	3
5	Piping Systems	2,074	3,110	5,184	15
6	Instruments & Controls	200	200	400	1
7	Accessory Electrical Systems	1,000	1,000	2,000	6
8	Chemical Treatment	200	200	400	1
9	Miscellaneous	200	200	400	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	9,174	8,514	17,688	50
INDIRECT COSTS					0
	Temporary Construction Servicesand Facilities			354	1
	ENGINEERING+B44, CM, PROFESSIONAL SERVICES			1,415	4
	OWNER COSTS			177	1
	SUBTOTAL INDIRECT COST			1,946	6
	CONTINGENCY @ _20_____%			3,927	11
	ESCALATION @____0___% PER YEAR			0	
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			23,560	67

Accuracy =+/- 40% — Page 2

Parsons Corporation
Client:___ U.S. DOE NETL — **Date:** 1/31/2002
Project: _ Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

CAPITAL COST ESTIMATE — 2002 Dollars X 1000 — Conceptual

Barney Davis Gas Fired Power Plants - Unit #1 @ 353 MW & #2 @ 351 MW — 704 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	40	360	400	1
2	Foundations & Structures	1,920	4,480	6,400	9
3	Cooling Towers	7,200	2,400	9,600	14
4	Mechanical Equipment	1,840	368	2,208	3
5	Piping Systems	4,147	6,221	10,368	15
6	Instruments & Controls	400	400	800	1
7	Accessory Electrical Systems	2,000	2,000	4,000	6
8	Chemical Treatment	400	400	800	1
9	Miscellaneous	400	400	800	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	18,347	17,029	35,376	50
INDIRECT COSTS					0
	Temporary Construction Servicesand Facilities			708	1
	ENGINEERING, CM, PROFESSIONAL SERVICES			2,830	4
	OWNER COSTS			354	1
	SUBTOTAL INDIRECT COST			3,891	6
	CONTINGENCY @ _20_____%			7,853	11
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			47,121	67

Accuracy =+/- 40% — Page 3

Parsons Corporation
Client:_ U.S. DOE NETL **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Hudson Gas Fired Power Plant - Unit #1 - 455 MW 455 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	25	225	250	1
2	Foundations & Structures	1,110	2,590	3,700	8
3	Cooling Towers w/ Plume Abate.	7,200	2,400	9,600	21
4	Mechanical Equipment	920	184	1,104	2
5	Piping Systems	2,074	2,333	4,406	10
6	Instruments & Controls	250	250	500	1
7	Accessory Electrical Systems	1,250	1,250	2,500	5
8	Chemical Treatment	250	250	500	1
9	Miscellaneous	250	250	500	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	13,329	9,732	23,060	51
INDIRECT COSTS					0
	Temporary Construction Services and Facilities			461	1
	ENGINEERING, CM, PROFESSIONAL SERVICES			1,845	4
	OWNER COSTS			231	1
	SUBTOTAL INDIRECT COST			2,537	6
	CONTINGENCY @ _20_____%			5,119	11
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			30,716	68

Accuracy =+/- 40% Page 1

Parsons Corporation
Client:_ U.S. DOE NETL — **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Hudson Coal Fired Power Plant - Unit #2 - 660 MW 660 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	30	300	330	1
2	Foundations & Structures	1,620	3,780	5,400	8
3	Cooling Towers w/ Plume Abate.	11,400	3,800	15,200	23
4	Mechanical Equipment	1,260	252	1,512	2
5	Piping Systems	2,304	2,592	4,896	7
6	Instruments & Controls	300	300	600	1
7	Accessory Electrical Systems	1,500	1,500	3,000	5
8	Chemical Treatment	300	300	600	1
9	Miscellaneous	300	300	600	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	19,014	13,124	32,138	49
INDIRECT COSTS					0
	Temporary Construction Servicesand Facilities			643	1
	ENGINEERING+B44, CM, PROFESSIONAL SERVICES			2,571	4
	OWNER COSTS			321	0
	SUBTOTAL INDIRECT COST			3,535	5
	CONTINGENCY @ _20_____%			7,135	11
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			42,808	65

Accuracy =+/- 40% Page 2

Parsons Corporation
Client:__ U.S. DOE NETL | **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits | **Proj. No.** 50802

CAPITAL COST ESTIMATE 2002 Dollars X 1000 Conceptual

Hudson Power Plants 1,115 MW
- Unit #1 Gas @ 455 MW & #2 Coal @ 660 MW

Acct No.	Item/Description	Equip Cost	Labor Cost	Total Cost	Avg. $/KW
1	Demolition & Sitework	55	525	580	1
2	Foundations & Structures	2,730	6,370	9,100	8
3	Cooling Towers w/ Plume Abate.	18,600	6,200	24,800	22
4	Mechanical Equipment	2,180	436	2,616	2
5	Piping Systems	4,378	4,925	9,302	8
6	Instruments & Controls	550	550	1,100	1
7	Accessory Electrical Systems	2,750	2,750	5,500	5
8	Chemical Treatment	550	550	1,100	1
9	Miscellaneous	550	550	1,100	1
10	Open	0	0	0	0
11	Open	0	0	0	0
12	Open	0	0	0	0
13	Open	0	0	0	0
14	Open	0	0	0	0
	SUBTOTAL DIRECT COST	32,343	22,856	55,198	50
INDIRECT COSTS					
	Temporary Construction Servicesand Facilities			1,104	1
	ENGINEERING, CM, PROFESSIONAL SERVICES			4,416	4
	OWNER COSTS			552	0
	SUBTOTAL INDIRECT COST			6,072	5
	CONTINGENCY @ _20_____%			12,254	11
	ESCALATION @____0___% PER YEAR			0	0
	AFDC __0__% FOR ___0____YEARS			0	0
	TOTAL COST			73,524	66

Accuracy =+/- 40% Page 3

APPENDIX B

O&M COST ESTIMATE

APPENDIX B – O&M COST ESTIMATE

Parsons Corporation
Client:_ U.S. DOE NETL — **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

O & M COST ESTIMATE — 2002 Dollars — Conceptual

Surry Nuclear Power Plant - Unit #1 - 848 MW — 848 MW

A.	**Operators**	**Type**	**No - FTE**	**$/ Yr**	**Burden**	**OH**	**Annual Cost**
		Unskilled	0.2	$20,000	0.5	0.25	$7,500
		Skilled	0.1	$30,000	0.5	0.25	$5,625
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		13,125

B. Supplies — Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr — $1,081,200

C. Maintenance — Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$108,419,472
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$1,084,195

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	4	1,865	0.85	$0.030	$1,666,415
Makeup Water Pumps	1	250	0.85	$0.030	$55,845
Cooling Tower Fans	48	207	0.85	$0.030	$2,220,397
Miscellaneous	1	50	0.85	$0.030	$11,169
			Subtotal		$3,953,826

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	200	0.85	$0.030	$11,169
Percent of Capacity		0.02%			

F. Fixed Annual O & M Costs — $555,222 or $655 per MW
(100% Operators and 50% of Maint)

G. Variable O & M Costs — $5,588,292 or $0.885 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	848,000	0.85	$0.030	$0

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Parsons Corporation

Client:_ U.S. DOE NETL — **Date:** 1/31/2002

Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

O & M COST ESTIMATE — 2002 Dollars — Conceptual

Surry Nuclear Power Plant - Unit # 2 - 848 MW — 848 MW

A.	Operators	Type	No - FTE	$/ Yr	Burden	OH	Annual Cost
		Unskilled	0.2	$20,000	0.5	0.25	$7,500
		Skilled	0.1	$30,000	0.5	0.25	$5,625
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		13,125

B.	**Supplies**	Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr	$1,081,200

C. Maintenance — Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$108,419,472
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$1,084,195

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	4	1,865	0.85	$0.030	$1,666,415
Makeup Water Pumps	1	250	0.85	$0.030	$55,845
Cooling Tower Fans	48	207	0.85	$0.030	$2,220,397
Miscellaneous	1	50	0.85	$0.030	$11,169
			Subtotal		$3,953,826

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	200	0.85	$0.030	$11,169
Percent of Capacity		0.02%			

F. Fixed Annual O & M Costs — $555,222 or $655 per MW
(100% Operators and 1/2 of Maint)

G. Variable O & M Costs — $5,588,292 or $0.885 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	848,000	0.85	$0.030	$0

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Parsons Corporation
Client:_ U.S. DOE NETL | **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits | **Proj. No.** 50802

O & M COST ESTIMATE 2002 Dollars Conceptual

Surry Nuclear Power Plant 1,696 MW
Both Units #1 & #2 - 848 MW Each

A.	**Operators**	**Type**	**No - FTE**	**$/ Yr**	**Burden**	**OH**	**Annual Cost**
		Unskilled	0.4	$20,000	0.5	0.25	$15,000
		Skilled	0.2	$30,000	0.5	0.25	$11,250
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		26,250

B. Supplies Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr $2,162,400

C. Maintenance Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$216,838,944
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$2,168,389

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	8	1,865	0.85	$0.030	$3,332,830
Makeup Water Pumps	2	250	0.85	$0.030	$111,690
Cooling Tower Fans	96	207	0.85	$0.030	$4,440,794
Miscellaneous	2	50	0.85	$0.030	$22,338
			Subtotal		$7,907,652

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	400	0.85	$0.030	$22,338
Percent of Capacity		0.02%			

F. Fixed Annual O & M Costs $1,110,445 or $655 per MW
(100% Operators and 1/2 of Maint)

G. Variable O & M Costs $11,176,585 or $0.885 per KW
(50% Maint & 100% Supplies 100% Aux Load and 100%Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	1,696,000	0.85	$0.030	$0

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Client: U.S. DOE NETL | **Date:** 1/31/2002
Project Proposed Section 316b Cooling Tower Retrofits | **Proj. No.** 50802

O & M COST ESTIMATE 2002 Dollars Conceptual

Big Bend Coal Fired Power Plant - Unit #1 - 446 MW 446 MW

A.	Operators	Type	No - FTE	$/ Yr	Burden	OH	Annual Cost
		Unskilled	0.25	$20,000	0.5	0.25	$9,375
		Skilled	0.1	$30,000	0.5	0.25	$5,625
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		15,000

B. Supplies Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr $501,750

C. Maintenance Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$33,643,656
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$336,437

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	2	1,285	0.75	$0.030	$506,547
Makeup Water Pumps	1	250	0.75	$0.030	$49,275
Cooling Tower Fans	14	207	0.75	$0.030	$571,196
Miscellaneous	1	50	0.75	$0.030	$9,855
			Subtotal		$1,136,873

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	0	0.75	$0.030	$0
Percent of Capacity		0.00%			

F. Fixed Annual O & M Costs $183,218 or $411 per MW
(100% Operators and 1/2 of Maint)

G. Variable O & M Costs $1,806,841 or $0.617 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	446,000	0.75	$0.030	$0

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Parsons Corporation
Client: U.S. DOE NETL | **Date:** 1/31/2002
Project Proposed Section 316b Cooling Tower Retrofits | **Proj. No.** 50802

O & M COST ESTIMATE 2002 Dollars Conceptual

Big Bend Coal Fired Power Plant - Unit #2 - 446 MW 446 MW

A.	Operators	Type	No - FTE	$/ Yr	Burden	OH	Annual Cost
		Unskilled	0.25	$20,000	0.5	0.25	$9,375
		Skilled	0.1	$30,000	0.5	0.25	$5,625
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		15,000

B.	**Supplies**	Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr	$501,750

C. Maintenance Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$33,643,656
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$336,437

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	2	1,285	0.75	$0.030	$506,547
Makeup Water Pumps	1	250	0.75	$0.030	$49,275
Cooling Tower Fans	14	207	0.75	$0.030	$571,196
Miscellaneous	1	50	0.75	$0.030	$9,855
			Subtotal		$1,136,873

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	0	0.75	$0.030	$0
Percent of Capacity		0.00%			

F. Fixed Annual O & M Costs $183,218 or $411 per MW
(100% Operators and 1/2 of Maint)

G. Variable O & M Costs $1,806,841 or $0.617 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	446,000	0.75	$0.030	$0

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Parsons Corporation
Client: U.S. DOE NETL — **Date:** 1/31/2002
Project Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

O & M COST ESTIMATE — 2002 Dollars — Conceptual

Big Bend Coal Fired Power Plant - Unit #3 - 446 MW — 446 MW

A.	**Operators**	**Type**	**No - FTE**	**$/ Yr**	**Burden**	**OH**	**Annual Cost**
		Unskilled	0.25	$20,000	0.5	0.25	$9,375
		Skilled	0.1	$30,000	0.5	0.25	$5,625
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		15,000

B. **Supplies** Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr — $501,750

C. **Maintenance** Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$34,309,656
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$343,097

D. **Increased Power Requirements (plant auxiliary load)**

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	2	1,365	0.75	$0.030	$538,083
Makeup Water Pumps	1	250	0.75	$0.030	$49,275
Cooling Tower Fans	15	207	0.75	$0.030	$611,996
Miscellaneous	1	50	0.75	$0.030	$9,855
			Subtotal		$1,209,209

E. **Decreased Rating or Net Output of the Plant (at the generator terminals)**

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	0	0.75	$0.030	$0
Percent of Capacity		0.00%			

F. **Fixed Annual O & M Costs** — $186,548 or $418 per MW
(100% Operators and 1/2 of Maint)

G. **Variable O & M Costs** — $1,882,507 or $0.642 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. **Dispatch Penalty - One Time During Construction**

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	446,000	0.75	$0.030	$0

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Parsons Corporation

Client: U.S. DOE NETL | **Date:** 1/31/2002

Project Proposed Section 316b Cooling Tower Retrofits | **Proj. No.** 50802

O & M COST ESTIMATE 2002 Dollars Conceptual

Big Bend Coal Fired Power Plant - Unit #4 - 486 MW 486 MW

A.	**Operators**	**Type**	**No - FTE**	**$/ Yr**	**Burden**	**OH**	**Annual Cost**
		Unskilled	0.25	$20,000	0.5	0.25	$9,375
		Skilled	0.1	$30,000	0.5	0.25	$5,625
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		15,000

B. Supplies Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr $546,750

C. Maintenance Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$34,975,656
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$349,757

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	2	1,450	0.75	$0.030	$571,590
Makeup Water Pumps	1	250	0.75	$0.030	$49,275
Cooling Tower Fans	16	207	0.75	$0.030	$652,795
Miscellaneous	1	50	0.75	$0.030	$9,855
			Subtotal		$1,283,515

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	500	0.75	$0.030	$24,638
Percent of Capacity		0.10%			

F. Fixed Annual O & M Costs $189,878 or $391 per MW
(100% Operators and 1/2 of Maint)

G. Variable O & M Costs $2,029,781 or $0.636 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	446,000	0.75	$0.030	$0

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Parsons Corporation
Client: U.S. DOE NETL — **Date:** 1/31/2002
Project Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

O & M COST ESTIMATE — 2002 Dollars — Conceptual

Big Bend Coal Fired Power Plant - Unit #3 - 446 MW — 1,824 MW
Unit #1, #2, #3 @ 446 MW & #4 @ 486 MW

A.	Operators	Type	No - FTE	$/ Yr	Burden	OH	Annual Cost
		Unskilled	1	$20,000	0.5	0.25	$37,500
		Skilled	0.4	$30,000	0.5	0.25	$22,500
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		60,000

B. Supplies Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr — $2,052,000

C. Maintenance Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$136,572,624
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$1,365,726

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	8	1,346	0.75	$0.030	$2,122,767
Makeup Water Pumps	4	250	0.75	$0.030	$197,100
Cooling Tower Fans	59	207	0.75	$0.030	$2,407,182
Miscellaneous	4	50	0.75	$0.030	$39,420
			Subtotal		$4,766,469

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	500	0.75	$0.030	$24,638
Percent of Capacity		0.03%			

F. Fixed Annual O & M Costs — $742,863 or $407 per MW
(100% Operators and 1/2 of Maint)

G. Variable O & M Costs — $7,525,970 or $0.628 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	1,824,000	0.75	$0.030	$0

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Parsons Corporation

Client:___ U.S. DOE NETL — **Date:** 1/31/2002

Project: _ Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

O & M COST ESTIMATE — 2002 Dollars — Conceptual

Barney Davis Gas Fired Power Plant - Unit #1 - 353 MW — 353 MW

A. Operators

Type	No - FTE	$/ Yr	Burden	OH	Annual Cost
Unskilled	0.2	$20,000	0.5	0.25	$7,500
Skilled	0.1	$30,000	0.5	0.25	$5,625
Supv	0	$40,000	0.5	0.25	$0
Admin	0	$20,000	0.5	0.25	$0
			Subtotal		13,125

B. Supplies Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr — $397,125

C. Maintenance Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$23,560,416
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$235,604

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	2	955	0.75	$0.030	$376,461
Makeup Water Pumps	1	250	0.75	$0.030	$49,275
Cooling Tower Fans	12	207	0.75	$0.030	$489,596
Miscellaneous	1	50	0.75	$0.030	$9,855
			Subtotal		$925,187

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	75	0.75	$0.030	$3,696
Percent of Capacity		0.02%			

F. Fixed Annual O & M Costs — $130,927 or $371 per MW

(100% Operators and 1/2 of Maint)

G. Variable O & M Costs — $1,443,810 or $0.623 per MWh

(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	353,000	0.75	$0.030	$0

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Parsons Corporation
Client:___ U.S. DOE NETL — **Date:** 1/31/2002
Project: _ Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

O & M COST ESTIMATE — 2002 Dollars — Conceptual

Barney Davis Gas Fired Power Plant - Unit #2 - 351 MW — 351 MW

A. Operators

Type	No - FTE	$/ Yr	Burden	OH	Annual Cost
Unskilled	0.2	$20,000	0.5	0.25	$7,500
Skilled	0.1	$30,000	0.5	0.25	$5,625
Supv	0	$40,000	0.5	0.25	$0
Admin	0	$20,000	0.5	0.25	$0
			Subtotal		13,125

B. Supplies — Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr — $394,875

C. Maintenance — Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$23,560,416
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$235,604

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	2	955	0.75	$0.030	$376,461
Makeup Water Pumps	1	250	0.75	$0.030	$49,275
Cooling Tower Fans	12	207	0.75	$0.030	$489,596
Miscellaneous	1	50	0.75	$0.030	$9,855
			Subtotal		$925,187

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	75	0.75	$0.030	$3,696
Percent of Capacity		0.02%			

F. Fixed Annual O & M Costs — $130,927 or $373 per MW
(100% Operators and 1/2 of Maint)

G. Variable O & M Costs — $1,441,560 or $0.625 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	353,000	0.75	$0.030	$0

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Parsons Corporation

Client:___ U.S. DOE NETL — **Date:** 1/31/2002

Project: _ Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

O & M COST ESTIMATE — 2002 Dollars — Conceptual

Barney Davis Gas Fired Power Plants — 704 MW
- Unit #1 @ 353 MW & #2 @ 351 MW

A.	**Operators**	**Type**	**No - FTE**	**$/ Yr**	**Burden**	**OH**	**Annual Cost**
		Unskilled	0.4	$20,000	0.5	0.25	$15,000
		Skilled	0.2	$30,000	0.5	0.25	$11,250
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		26,250

B.	**Supplies**	Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr	$792,000

C. **Maintenance** — Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$47,120,832
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$471,208

D. **Increased Power Requirements (plant auxiliary load)**

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	4	955	0.75	$0.030	$752,922
Makeup Water Pumps	2	250	0.75	$0.030	$98,550
Cooling Tower Fans	24	207	0.75	$0.030	$979,193
Miscellaneous	2	50	0.75	$0.030	$19,710
			Subtotal		$1,850,375

E. **Decreased Rating or Net Output of the Plant (at the generator terminals)**

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	150	0.75	$0.030	$7,391
Percent of Capacity		0.02%			

F. **Fixed Annual O & M Costs** — $261,854 or $372 per MW
(100% Operators and 1/2 of Maint)

G. **Variable O & M Costs** — $2,885,370 or $0.624 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. **Dispatch Penalty - One Time During Construction**

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	704,000	0.75	$0.030	$0

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Parsons Corporation

Client:__ U.S. DOE NETL — **Date:** 1/31/2002

Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

O & M COST ESTIMATE 2002 Dollars Conceptual

Hudson Gas Fired Power Plant - Unit #1 - 455 MW 455 MW

A.	**Operators**	**Type**	**No - FTE**	**$/ Yr**	**Burden**	**OH**	**Annual Cost**
		Unskilled	0.25	$20,000	0.5	0.25	$9,375
		Skilled	0.1	$30,000	0.5	0.25	$5,625
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		15,000

B. Supplies Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr $511,875

C. Maintenance Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$30,716,453
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$307,165

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	2	955	0.75	$0.030	$376,461
Makeup Water Pumps	1	250	0.75	$0.030	$49,275
Cooling Tower Fans	12	207	0.75	$0.030	$489,596
Miscellaneous	1	50	0.75	$0.030	$9,855
			Subtotal		$925,187

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	500	0.75	$0.030	$24,638
Percent of Capacity		0.11%			

F. Fixed Annual O & M Costs $168,582 or $371 per MW

(100% Operators and 1/2 of Maint)

G. Variable O & M Costs $1,615,282 or $0.540 per MWh

(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	455,000	0.75	$0.030	$0

Page 4

Parsons Corporation
Client:__ U.S. DOE NETL **Date:** 1/31/2002
Project: Proposed Section 316b Cooling Tower Retrofits **Proj. No.** 50802

O & M COST ESTIMATE 2002 Dollars Conceptual

Hudson Coal Fired Power Plant - Unit #2 - 660 MW 660 MW

A.	Operators	Type	No - FTE	$/ Yr	Burden	OH	Annual Cost
		Unskilled	0.25	$20,000	0.5	0.25	$9,375
		Skilled	0.1	$30,000	0.5	0.25	$5,625
		Supv	0	$40,000	0.5	0.25	$0
		Admin	0	$20,000	0.5	0.25	$0
					Subtotal		15,000

B. **Supplies** Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr $742,500

C. **Maintenance** Based on the capital cost of added equipment.

Capital Cost of New Equipment (see estimate)	$42,807,816
Annual Percent of Capital Cost	1.0%
Annual Maintenace Costs (both materials & labor)	$428,078

D. **Increased Power Requirements (plant auxiliary load)**

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	2	1,490	0.75	$0.030	$587,358
Makeup Water Pump	1	250	0.75	$0.030	$49,275
Cooling Tower Fans	19	207	0.75	$0.030	$775,194
Miscellaneous	1	50	0.75	$0.030	$9,855
			Subtotal		$1,421,682

E. **Decreased Rating or Net Output of the Plant (at the generator terminals)**

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	800	0.75	$0.030	$39,420
Percent of Capacity		0.12%			

F. **Fixed Annual O & M Costs** $229,039 or $347 per MW
(100% Operators and 1/2 of Maint)

G. **Variable O & M Costs** $2,417,641 or $0.558 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. **Dispatch Penalty - One Time During Construction**

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	455,000	0.75	$0.030	$0

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Parsons Corporation

Client:__ U.S. DOE NETL — **Date:** 1/31/2002

Project: Proposed Section 316b Cooling Tower Retrofits — **Proj. No.** 50802

O & M COST ESTIMATE — 2002 Dollars — Conceptual

Hudson Power Plants — 1,115 MW

- Unit #1 Gas @ 455 MW & #2 Coal @ 660 MW

A. Operators	Type	No - FTE	$/ Yr	Burden	OH	Annual Cost
	Unskilled	0.5	$20,000	0.5	0.25	$18,750
	Skilled	0.2	$30,000	0.5	0.25	$11,250
	Supv	0	$40,000	0.5	0.25	$0
	Admin	0	$20,000	0.5	0.25	$0
				Subtotal		30,000

B. Supplies Makeup & Water Treatment Chemicals @ $1.50/ KW-Yr $1,254,375

C. Maintenance Based on the capital cost of added equipment.

Capital Cost of New E	4	1,539	$73,524,269
Annual Percent of Ca	1	250	1.0%
Annual Maintenace C	48	171	$735,243

D. Increased Power Requirements (plant auxiliary load)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Cooling Tower Pumps	4	1,223	0.75	$0.030	$963,819
Makeup Water Pump:	2	250	0.75	$0.030	$98,550
Cooling Tower Fans	31	207	0.75	$0.030	$1,264,791
Miscellaneous	2	50	0.75	$0.030	$19,710
			Subtotal		$2,346,870

E. Decreased Rating or Net Output of the Plant (at the generator terminals)

Load	Units	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	1	1,300	0.75	$0.030	$64,058
Percent of Capacity		0.12%			

F. Fixed Annual O & M Costs $397,621 or $357 per MW
(100% Operators and 1/2 of Maint)

G. Variable O & M Costs $4,032,924 or $0.551 per MWh
(50% Maint & 100% Supplies & 100% Aux Load and 100% Decreased Rating)

H. Dispatch Penalty - One Time During Construction

Load	Months	Kw/Unit	C.F.	$/Kwh	Annual Cost
Overall Plant	0	1,115,000	0.75	$0.030	$0

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APPENDIX C

JANUARY 22, 2003 ADDENDUM

Addendum to Report

"An Investigation Site-Specific Factors for Retrofitting Recirculating Cooling Towers at Existing Power Plants"

January 22, 2003

Prepared by

The United States Department of Energy
National Energy Technology Laboratory

Executive Summary

Background

This addendum updates a report prepared by Parsons Corporation (Parsons) for the Department of Energy/Office of Fossil Energy's National Energy Technology Laboratory (DOE/NETL). The purpose of the addendum is to provide further information on the critical role that site-specific factors can have on the cost and feasibility of retrofitting cooling towers on thermoelectric power plants that currently employ once-through cooling.

The Parsons report was commissioned during the relatively brief interagency review period for the Environmental Protection Agency's §316(b) Phase II proposed rule for existing power plants. One of the Agency's regulatory options under consideration at that time was to require that over fifty (50) existing thermoelectric power plants retrofit from once-through cooling systems to wet recirculating towers. The Parsons analysis focused on the feasibility of implementing such a requirement on four existing steam-condensing power plants taking into consideration site-specific factors. DOE/NETL used the results of the analysis to provide input to EPA during the proposal's public comment period on the impacts that site-specific factors could have on retrofitting once-through plants with recirculating cooling towers.

The Parsons report was intended to provide a preliminary assessment -- a "30,000-foot view"-- of how site-specific factors might affect the cost of installation of cooling towers and ancillary equipment and any resultant economic and energy impacts on plant operations. Parsons was tasked with completing the study in four weeks and was instructed not to contact the utilities that owned the four plants since the interagency review process was ongoing. Therefore, Parsons was not able to obtain the requisite plant data from the plant operators that would typically be used to generate a detailed site-specific analysis. Nevertheless, while using only publicly available information and aerial photographs, the Parsons study concluded that the retrofit of closed-loop cooling systems at the four existing power plants would impose significant capital cost burdens and loss of net generation output.

Subsequent to the issuance of the Parsons report, DOE/NETL had discussions with each of the four utilities that own the power plants evaluated in the study. These discussions focused on actual site-specific concerns expressed by these utilities. We also sought comment about design parameters selected in the study and input on other issues that would affect the installation and operation of cooling towers at these and similar plants that DOE/NETL was unable to obtain during the interagency review. The subject addendum summarizes the supplementary information that was provided by the four utilities and presents a discussion of the impact of this new information on the cost and feasibility of retrofitting wet cooling towers on the four power plants.

The overall conclusion based on DOE/NETL analysis of the supplemental site-specific information is that cooling towers can be more difficult, and more costly, to retrofit than one would assume based solely on publicly available information. Based on this additional information, we believe that it is critical that EPA recognizes in its rulemaking process that the cost and operational impacts of retrofitting once-through cooling systems must be evaluated on a case-by-case basis. The additional site-specific information also makes it clear that adverse environmental impacts (AEI) beyond those associated with impingement and entrainment and beyond water quality in general, would be caused by a requirement to retrofit to wet cooling towers. The other AEI include endangered species issues, visibility issues, noise pollution, salt corrosion, increased air emissions, and increased waste, and would impact cooling tower retrofit options.

General Issues

Siting

Parsons utilized publicly available aerial photographs to recommend locations for the installation of cooling towers at each of the plants. Additional site-specific information provided by the utilities has shown that most of the locations suggested in the report would not be feasible due to factors unknown at the time of the Parson's study. These factors include the presence of existing landfills, desalinization plants, railroad tracks, and other facilities, as well as commitments to use the targeted location for other purposes. The result of the actual site-specific information is that *three* of the four sites would require a more remote placement of the towers that would result in higher costs and possibly longer outage times.

Plume Abatement

One of the four plants investigated by the Parsons report was deemed to require plume abatement. Additional information provided by the utilities indicates that at least *three* of the four plants would likely require plume abatement due to local factors that were not known at the time of the Parsons study. Plume abatement measures would double the capital cost of the resulting cooling tower and result in other AEI.

Salt Drift

Even with optimum drift control there will be particulate emissions of salt from cooling towers employing salt water. These will have corrosive impacts within the power plant and may have adverse environmental impacts outside the plant boundaries. The consequences of adequately addressing salt emissions from the cooling towers include adding additional cost for salt drift reduction at three of the four plants and recognition of other AEI. At one of the plants it is likely that the State and Federal air quality standards for particulate emissions would be exceeded and a variance for the wet tower would be extremely unlikely.

Noise Abatement

Due to the need to re-site several of the wet towers based on new actual plant-specific information, the new locations close to urban areas would require some amount of noise abatement technologies. These would both increase the original Parsons' cost estimates and create additional AEI.

Local Uses Related to Cooling Water Intake and Discharge

At the nuclear facility that was evaluated the intake canal and pumps are also used for emergency cooling. In addition, at one of the fossil-fuel-fired plants, the discharge canal is used to dilute brine discharge from a desalination plant as well as to provide a warm water sanctuary for manatees, an endangered species. While these site-specific considerations were not included in the initial Parsons study they clearly would limit the practicality of reducing cooling water flow rates at these plants that would result from the installation of a closed-loop system.

Outage Times

The Parsons study assumed conservatively that all of the construction required for retrofitting the cooling tower systems could be performed while the plant is on line, thereby minimizing cost and energy impacts due to plant outages. Based on the input provided by the site operators, it appears that an extended outage would be required by two of the four plants resulting in losses in revenue. The impact of the loss of generating capacity - aside from the loss of revenue attributable to the plant - from these units during retrofit would need to be evaluated based on the historical records and projections of future dispatch for each plant.

Energy Penalty

The Parsons study used nearby wet bulb temperatures that were lower than temperatures actually experienced at some plant sites. This would result in an increase in actual energy penalty. Furthermore, the Parsons study is based on a 2 percentile of maximum wet-bulb incidence rather than the 1 percentile normally used to calculate the impacts on electricity generation during the times of peak summer demand. The 1 percentile of maximum wet-bulb temperature is typically a few degrees higher than the 2 percentile. For a given cooling tower design, an increase in wet-bulb temperature translates directly to increases in condenser temperature, with corresponding increases in turbine back pressure and the resultant energy penalty.

Revenue Loss

In terms of lost revenues, Parsons assumed a conservative replacement cost of electricity based on the average annual price of electricity of $0.03/kWh. However, the greatest loss in energy output from plants with cooling towers would be on the hottest, most humid days of the year when market prices for electricity are far greater than $0.03/kWh. The value of lost revenue could be calculated more accurately by looking at historical records of each plant and the specific price of power in each region, a level of detail that was neither feasible, nor in the scope of the Parsons study. Nevertheless, this lost revenue could be significant in some cases.

General Conclusions

The Parsons report highlighted the critical importance of site-specific factors such as those discussed above in the final determination of the costs and impacts of retrofitting to recirculating cooling towers in existing power plants. At the plants considered in this study, the incorporation of additional actual and more detailed site-specific information had the impact of increasing cooling tower capital cost estimates by as much as 100 percent. More importantly, other uses or beneficial impacts of the existing cooling water systems suggest that some cooling tower projects that seem workable as a general proposition are impractical at any cost when these site-specific uses are considered.

The opportunity to consult with the utility companies has demonstrated that the issue of retrofitting cooling towers is even more complex than shown in the report. Therefore, DOE/NETL reiterates its strong preference for a site-specific approach to implementation of §316b regulations. In addition, the finding that non-water related adverse environmental impacts will almost certainly result from installation of cooling towers at some, if not most, sites leads us to conclude that all AEI should be considered in a regulation that contemplates measures such as retrofitting cooling towers.

Plant Specific Issues and Responses

Subsequent to the issuance of the Parsons report, DOE/NETL obtained site-specific information from the electric-utility companies that operated the four plants included in the Parsons report that was not available at the time the report was prepared. Input was provided from America Electric Power (AEP) Company Inc., owner of the Barney M. Davis plant, Tampa Electric Company (TECO) Inc., owner of the Big Bend Station, PSEG Fossil LLC, owners of the Hudson Generating Station, and Dominion Virginia Power Inc., owner of the Surry Power Station.

The following presents a discussion of the comments received and DOE/NETL's assessment of those comments that would significantly impact the general conclusions reached in the Parsons report.

Big Bend Station

<u>Siting Issues</u>

The Parsons report sited the "conceptual" cooling tower on land that is unavailable. Part of the "conceptual" cooling tower is located on land that is occupied by a 25 million gallon per day seawater desalination plant that is under construction at the Big Bend power station.

An alternative possibility would be to construct a cooling tower south of the plant at a site currently used for byproduct management operations (beneficial use of waste to produce gypsum). The land is adjacent to the Apollo Beach residential community and proximate to an undeveloped coastal area covered with sensitive vegetation. Major modifications to the design of the cooling tower system, if sited at this location, would likely be required to minimize adverse environmental impacts and accommodate local permitting requirements. These modifications would require significantly higher costs. Furthermore, the existing byproduct management activities would have to be relocated and changed, thus requiring a detailed alternative analysis to minimize the impact on byproduct handling.

Plume Abatement Issues

The Parsons report does not include plume abatement technology in the cost estimate for the closed-loop, wet cooling tower retrofit at the Big Bend Station site. However, the Big Bend site is located adjacent to the Apollo Beach residential community. Although the need for plume abatement technology at the Big Bend Station site would not be determined until the actual permitting process was completed, the inclusion of such technology would likely be needed and would double the cooling towers' capital costs and significantly increase their annual operating and maintenance costs.

Adverse Environmental Impact Issues

The Parsons report does not include several potential adverse environmental impact issues associated with installation of a cooling tower system as defined in their conceptual study. The adverse environmental impacts that would need to be considered, and potential remedies sought include: (1) impact on endangered species such as the manatee that live in warmer waters created from the Big Bend discharge during the winter months; (2) increased air pollution emissions from power production due to loss in power plant efficiency; (3) visibility concerns from cooling tower plume; and (4) increased particulate emissions from cooling tower exhaust.

The Big Bend Station cooling water discharge provides a warm water refuge for manatees in the winter season and the discharge canal has been designated by the State of Florida as a Manatee Sanctuary. This benefit would be lost if the Big Bend Station were to retrofit their once-through cooling system with a recirculating cooling tower system.

The best available location for siting a cooling tower requires relocation of gypsum handling and raises the potential for salt contamination. A careful analysis and design would be required to determine if saleable gypsum can still be produced or if alternative disposition would be required.

Remedies to mitigate or avoid these potential adverse environmental impacts are site-specific and would require a detailed assessment of alternative measures.

Lost Revenue Issues

Big Bend Station currently has a salable byproduct, gypsum, with annual revenue of $2 million. If the chloride level of the gypsum were raised above acceptable limits from exposure to salt drift, these revenues would be lost. Alternative utilization paths for the gypsum would have to be explored. Soil stabilization and trail construction are two potential uses. If alternative beneficial uses cannot be found, gypsum disposal costs would likely be an order of magnitude higher than current gypsum sales resulting in a total annual net revenue loss of about $20 million.

Outage Time

It is likely that tie-in of a cooling tower system would be scheduled concurrent with a major outage for the power plant. Since the cooling tower tie-in would need to accommodate connections with the condenser and the desalination plant, it is likely that the cooling tower tie-in outage would significantly exceed a scheduled outage. Given the substantial congestion amongst above and underground facilities and the complexities associated with new lines and sumps for the desalination plant at the Big Bend Station, DOE/NETL believes that the cooling tower tie-in outage time would require a detailed engineering analysis estimate.

Energy Penalty

The energy penalty estimated in the study for the cooling tower retrofit probably underestimated the actual energy penalty for the following reasons: (1) the temperature rise across the condensers is designed for a 17 degree rise rather than the 15 degree rise assumed in the Parsons report; (2) Big Bend Station rejects 70 percent of the rated steam flow rather than the 65 percent rejection rate assumed in the Parsons report; (3) turbine configurations for 2 of the 4 units at Big Bend Power Station were different than assumed in the Parsons report; and (4) the wet bulb temperature and summer average water temperature at the Big Bend Station are higher than estimated in the Parsons report.

The steam turbine exhaust physical design parameters coupled with condensing steam flow rates have a significant impact on steam turbine generator electric output and plant efficiency. Changes in turbine configuration from those used in the Parsons study could have a significant impact on the predicted change in generation output. Seasonal average values for cooling water and ambient wet bulb temperature do not reflect the extreme hot summer weather, which is coincident with highest demand for power and the highest cost for replacement power. The combination of factors listed above will increase the energy penalty estimated in the Parsons report. A more detailed study, beyond the scope of the "conceptual" estimate, is required to provide a more accurate estimate of energy penalty.

Economic Issues

The desalination plant begins operation this year and was not pictured on the aerial photo used by Parsons. Neglecting the existence of the desalination plant significantly reduces plant cost associated with installation of a cooling tower at the Big Bend Station. The desalination plant is currently configured to dilute brine discharge with water discharged from the once through cooling system. The reduced water discharge associated with a cooling tower would require an alternative strategy to be developed for the disposal of brine concentrate. Tampa Electric Company considered one other option that entailed discharging the brine concentrate via pipeline into the center of Tampa Bay. That study indicated that the plant would not be economically feasible if a mid-bay discharge were included. Since the current rulemaking could result in installation of such a discharge system 5 or more years after the desalination system is in operation and when it's capacity will be more than four times the initial capacity, DOE/NETL is unable to determine the magnitude of the potential cost impact on this project.

In addition to cost increases related to providing dilution for the desalination brine, siting issues associated with the cooling tower in a less convenient location than assumed in the Parsons report would significantly increase capital and operating costs at the power plant. There is also a potential annual loss in revenue of $20 million if gypsum byproduct sales are lost due to higher chloride content of the gypsum from salt drift deposition and more difficult management of gypsum because of encroachment of the cooling tower at the gypsum treatment area.

Revenues lost from extended outage time to tie-in the cooling tower system are expected to be significant. It is not possible to quantify lost revenues without a detailed engineering study.

The capital cost of the cooling tower situated on available land is estimated to be twice the capital cost estimated in the Parsons conceptual estimate. The major reason for this cost increase is the likely need to install plume abatement technology. If a cooling tower system were to be installed at Big Bend Station there would also likely be a need to have an extensive review of adverse environmental impacts that would increase the normal time needed to secure local, State, and Federal permits.

Hudson Generating Station

<u>Siting Issues</u>

Due to local sensitivity to a fatal Conrail train accident that occurred several years ago, it would be politically unacceptable to locate the cooling towers in proximity to the railroad tracks as they are shown in the Parsons design. That is, even a plume abated cooling tower under some conditions of weather could produce a low hanging plume that would obscure the visibility of any trains and its drift could ice the tracks.

In addition, planned modifications to the New Jersey Turnpike will physically interfere with the cooling tower location as proposed in the Parsons report. The SCRs and scrubbers that PSEG is obligated to regulatory agencies to install in 2006 and 2007 would prevent location closer to the powerhouse.

A more suitable location, further away from the power house, would entail considerably higher construction costs and pumping power requirements. This location, toward the North, would be on the other side of the Conrail railroad tracks and in the case of Unit 2, also across Penhorn Creek.

In that location, a full evaluation of the capital costs would require adding expensive bridging and tunneling of large diameter pipes to and from the towers to traverse these barriers. The stream crossings would also be subject to large permitting costs because of the environmental issues involved. This difference is reflected in the site-specific cost estimate PSEG prepared in 1997 (see below), which budgets $35,067,804 for pumps and piping systems, versus the total cost of $11,918,000 estimated for the same items in the Parsons report.

<u>Noise Issues</u>

Because the design is very open, noise abatement features on a wet-dry tower are generally a necessity, particularly if the tower is to be located near an urban environment, as would be the case at Hudson. The capital costs of noise abatement attenuation on cooling towers are usually very significant. The resulting operating costs can also be much greater. This aspect of the application of a wet-dry cooling tower design is neglected in total and thus these costs are not reflected in the Parsons report.

<u>Energy Penalty Issues</u>

PSEG identified several assumptions in the Parsons report that would tend to underestimate the energy penalty associated with the installation of wet-dry cooling towers at the Hudson site.

- The study is based on a circulating cooling water flow that is 20,000 gallons per minute lower than the actual value. This means that the tower size and pumping power needed may have been underestimated by approximately 9 percent in the report.

- The study is based on a 2 percentile of maximum wet bulb incidence rather than the 1 normally used. This means that the lower corresponding wet-bulb temperature (74°F) selected in the study instead of the higher 1percentile wet bulb of 76°F. This change would mean a 2 degrees F increase in condenser temperature, with corresponding increases in turbine back pressure and associated energy penalty.

- The adverse impacts of using brackish water in a cooling tower, as regards lower evaporation potential, lower thermodynamic properties, and extra pumping power requirements due to greater density were not included in the Parsons report.

<u>Salt Drift Issues</u>

Compliance with State and Federal air quality regulations would likely not be possible for particulate emissions (PM) from mechanical draft cooling towers at Hudson Generation Station. Predicted PM emissions due to salt drift from the mechanical draft tower on Unit No. 2 exceed the maximum allowable rate of 30 pounds per hour and thus a variance from these regulations would be required. Due to the urban setting of the site, PSEG believes that obtaining this variance would be difficult or impossible.

Cooling Tower Blowdown Issues

Water quality regulations are strict in New Jersey and require treating the cooling tower blowdown water. Both the temperature and pollutant levels of any returning water must achieve regulatory permit compliance.

PSEG's detailed site-specific study, made in 1997 (see below), estimates that treating the cooling tower blowdown water at Hudson to meet these regulatory requirements would require a $5,508,000 treatment facility. This treatment facility was not included in the Parsons estimate.

Outage Issues

The Parsons report assumes that retrofit work would fit into the normal spring or fall outage timeframe. However, a more likely scenario is that an extended scheduled outage would be required for the final tie-ins, intake modifications, existing CW piping modifications, services, start-up and testing. This outage construction period was estimated by the PSEG engineering study to be from 2 to 3 months for Hudson Station.

Permitting Issues

PSEG has recently obtained licenses and permits for the installation of a new, combined cycle unit with recirculating cooling towers at its Linden Generating Station. Based on this experience, PSEG estimates that it would take at least one year to acquire the four Federal, eight State, one county, and four municipal permits required for the retrofit of Hudson station with closed cycle cooling. This significant permitting effort was not included in the Parsons estimate for the proposed conversion.

Differences in Construction Cost Estimates

In 1997 PSEG obtained turnkey budget pricing from three respected cooling tower manufacturers based on a specification derived from a detailed site-specific engineering study defining the requirements for the potential conversion of Hudson Station to closed-cycle cooling.

- Based on the lowest of those vendor quotes, that turnkey tower cost of $48,580,000 (in 1997 dollars) was approximately twice the corresponding $24,800,000 (in 2002 dollars) tower cost estimated by Parsons.

- The total estimated project cost for the conversion of Hudson units 1 and 2 to wet-dry towers was $168,250,250 (in 1997 dollars), and was more than double the corresponding $73,524,000 (in 2002 dollars) total project cost estimated by Parsons.

- The significant difference in costs between the vendor quotes and PSEG's estimated project cost and the costs estimated by Parsons further highlights the need for site-specific information in determining the economic feasibility of retrofitting once-through power plants with closed-loop systems.

Surry Power Station

Plume Abatement Issues

The Parsons report did not include plume abatement technology in the cost estimate for the closed-loop wet cooling tower retrofit at the Surry Power Station site. However, based on the relatively close proximity of Colonial Williamsburg (8 miles) and Busch Gardens (7.5 miles) to the Surry Power Station, plume abatement technology could be required. Although the need for plume abatement technology at the Surry Power Station site would not be determined until the actual permitting process was completed, the inclusion of such technology would double the cooling towers' capital costs and significantly increase their annual operating and maintenance costs.

Emergency Services Issues

Dominion expressed concern with respect to maintaining the integrity of operation of the Surry Power Station's Emergency Service Water pumps under the proposed wet cooling tower retrofit design. Preserving the integrity and operation of the Surry Power Station's Emergency Service Water pumps is a significant safety issue. Dominion's concern is valid and serves to underscore how the understanding of truly site-specific issues is critically important to the retrofit design process.

Lost Revenue Issues

The Parsons report assumed that lost power could be replaced at an average annual electricity cost of $0.03/kWh. The greatest loss in energy output from plants with cooling towers would be on the hottest, most humid days of the year when market prices are far greater than $0.03/kWh. The value of lost revenue could be calculated more accurately by looking at historical records of each plant and the specific price of power in each region, a level of detail that was neither feasible, nor in the scope of the Parsons study. Nevertheless, this lost revenue could be significant in some cases and also serves to underscore the site-specific nature of retrofitting with cooling towers.

Energy Penalty Issues

Dominion Virginia Power presents data in support of their position that the Parsons study may underestimate the energy penalty that is attributable to the warmer cooling water temperatures associated with the installation of cooling towers at the Surry Power Station site. The issue of lost revenue, from the preceding paragraph, becomes more significant as the actual energy penalty becomes larger.

Barney M. Davis

Salt Drift

There are several research facilities that lease space on the Barney M. Davis property. These facilities are located between 500 to 1000 feet downwind from the site of the proposed cooling towers. Based on this information and considering the corrosivity of the drift, some type of drift abatement might be required. Salt drift control is a site-specific issue and if it should be required at the Barney M. Davis site, it would increase the proposed cooling towers' capital and annual operating and maintenance costs over that which was reported in the Parsons study and cause other AEI.

Capital Cost Issues

AEP Inc. secured a cooling tower budget estimate, using actual Barney M. Davis plant operating conditions, from the Marley Cooling Technologies Company. AEP's cooling tower material and labor costs, using a wet-bulb temperature of 77 ^{o}F, an 8 ^{o}F approach temperature, an 180,000 gallon per minute flow rate, and a 20 ^{o}F condenser range, was between \$5.2 and \$5.5 million per tower. The Parsons material and labor estimate using the same wet-bulb and approach temperatures, but with a 215,000 gallon per minute flow rate and a 15 ^{o}F condenser range, was \$4.8 million. In this manner, the Parsons report may have underestimated the material and labor costs for a wet cooling tower retrofit at the Barney M.Davis plant by between 8 and 15 percent. Cooling water flow rate and the coolant temperature range through the condenser are two site-specific operating parameters that directly affect the proposed cooling towers' costs and the potential energy penalties associated with their retrofit to once-through cooled facilities.