CHAPTER 9

ALTERNATIVES TO THE PROPOSED ACTION

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

LIST OF TABLES

LIST OF FIGURES

CHAPTER 9

ALTERNATIVES TO THE PROPOSED ACTION

9.0 ALTERNATIVES TO THE PROPOSED ACTION

The proposed action is U.S. Nuclear Regulatory Commission (NRC) issuance of a combined license (COL) to Tennessee Valley Authority (TVA) to construct and operate Bellefonte Nuclear Plant, Units 3 & 4 (BLN). The TVA objective is to obtain a license for the construction and operation of a baseload generating facility. If TVA receives a COL and decides to construct these units, this would also enable TVA to make use of a site that it has already acquired, and for which TVA had previously held an NRC construction permit.

Chapter 9 describes the alternatives to construction and operation of new nuclear units at the BLN site and alternative plant and transmission systems. These energy alternatives to the proposed action discussed herein were among those bounded by the TVA Integrated Resource Plan (IRP) Environmental Impact Statement (EIS) (Subsection 9.2.5, Reference 4). A transmission system sufficient to support operation of the two units at the BLN site is already in place, and has previously been energized (but is currently de-energized). The descriptions provide sufficient detail for the reader to evaluate the impacts of these alternative generation options or plant and transmission systems relative to those of the proposed action.

The chapter is divided into four sections:

- No-Action Alternative (Section 9.1)
- Energy Alternatives (Section 9.2)
- Alternative Sites (Section 9.3)
- Alternative Plant and Transmission Systems (Section 9.4)

Chapter 9 uses the terms “service area” and “region of interest” (ROI). For BLN, the service area is the seven-state TVA service area defined in Section 8.1. The ROI for BLN, which is used in the alternative site analysis, is the same as the TVA service area.

9.1 NO-ACTION ALTERNATIVE

Section 9.1 discusses the alternative to the BLN project that involves taking no action. The no-action alternative, for NRC purposes, is the denial of the COL for the BLN site. The result of this denial would be that TVA could not construct or operate the BLN and would lose the benefit of using an existing asset with substantially developed infrastructure (i.e. transmission, switchyard, cooling towers, intakes and discharges). The consideration of the no-action alternative conforms to Regulatory Guide 4.2.

Under the no-action alternative, the environmental impacts associated with the BLN project would not occur and electrical generation from the BLN project would not be available. In such an event, TVA would have two options: 1) it could take no action to satisfy the need for power identified in Section 8.4; or 2) it could implement one or more alternatives to satisfy the need for power identified in Section 8.4.

The first option, doing nothing to satisfy the demand for power, is not reasonable. TVA would not be able to maintain an adequate reserve margin, would fail in its public service obligations to provide sufficient power within its service territory, and would jeopardize its commitment to provide capacity to other electric suppliers within Southeastern Electric Reliability Corporation (SERC) by not maintaining an adequate reserve margin.

With the second option, TVA would satisfy the need for power by implementing one or more alternatives that do not involve operation of BLN. In this case, TVA would take actions or combinations of actions to address a deficiency in power supply by selecting and implementing alternative actions as described in its IRP (Subsection 9.2.5, Reference 4). These include:

- Demand Side Management (DSM) - These utility programs consist of planning, implementing, and monitoring activities that are designed to encourage consumers to modify their level and pattern of electricity usage. TVA already has active DSM programs in place and continues to pursue additional opportunities in this area. However, TVA records show DSM capable of reducing only a small fraction of the needed additional capacity, as discussed in Subsection 9.2.1.3. To avoid rolling blackouts or similar cutbacks with the no-action alternative, substantial reductions in customer electrical use would be necessary.

- Alternatives to Generating Capacity - TVA may choose not to pursue construction of new generation capacity with the no-action alternative, and attempt to meet the need for power with purchases from other electricity providers. With the recognition of factors shaping decisions in the marketplace, along with current information on relative environmental impacts, a reasonable evaluation of alternatives involving no new generation capacity is possible. This evaluation is discussed in greater detail in Subsection 9.2.1.

- Construct Alternative Generation - The required generating capacity could be provided by the construction of generating facilities other than the BLN project. The new capacity could be constructed at the BLN site, other existing generating facility sites, or at other unspecified "greenfield" sites. A comparison of the environmental impacts from alternative energy sources is provided in Subsection 9.2.2. A comparison of the environmental impacts from new nuclear generating capacity is discussed in the alternative site analysis in Section 9.3.

- Combination - It is possible that some combination of the above approaches, as described in TVA's IRP EIS (Subsection 9.2.5, Reference 4), would be taken to provide the equivalent of the generating capacity with the no-action alternative. For example, the proposed capacity could be met by a certain amount of new coal-fired capacity, combined with power purchased from outside the relevant service area. Combinations of alternative energy sources are considered in greater detail in Subsection 9.2.3.3.

9.2 ENERGY ALTERNATIVES

This section provides the analysis of the environmental impacts associated with alternatives to the BLN project.

The BLN project is a nuclear-powered electrical generation facility, to be used in a base loaded manner. Two Westinghouse AP1000 pressurized water reactors are proposed as Bellefonte Nuclear Plant Units 3 and 4 (BLN). Power generated by the facility would be expected to be baseload capable. TVA assumed a target value of 2234 megawatts (MW) for the net electrical output from the facility. This is a bounding value and is the basis for the alternatives analyzed in this section.

The options considered as alternative to this proposal are consistent with, and bounded by, the suite of actions included in TVA's comprehensive analysis (Reference 4) of energy supply options to meet anticipated need for power in the power service area of TVA through the year 2020. The resulting Integrated Resource Plan (IRP - Energy Vision 2020 Environmental Impact Statement) was developed to provide TVA's roadmap or guide for addressing those energy needs with a flexible energy supply plan.

In that review, TVA considered a broad range of supply-side and customer service options, using multiple evaluation criteria, considering future uncertainties, and seeking public input. TVA created an extensive list of generating options (7-6A, 6B, 6C, and 6D of the IRP) to meet new peaking, intermediate, baseload, and storage power supply needs. These options included traditional technologies (such as coal plants, nuclear plants, and combustion turbines), as well as potential renewable and advanced combustion facilities; options to create greater flexibility (Figure 7-6E of the IRP) in planning (such as purchasing of competitively priced power from other suppliers, buying options on future power delivery, and entering business partnering arrangements). Overall TVA considered over 100 supply-side resource options. The IRP also considered over 60 customer service options for demand-side management (i.e., energy efficiency and load management). The resource integration plan evaluated over 2000 strategies using various mixes of supply-side and customer service options. From an extensive series of iterative evaluations, seven strategies emerged that met demand for power and offered TVA low-cost, lower debt, improved environmental and economic development performance, as well as providing hedges against key uncertainties, namely load growth, natural gas prices, possible environmental regulations for air and water, and nuclear performance. These strategies involving both supply and demand side management options were further evaluated in the IRP EIS.

TVA's preferred option identified in that Final EIS was a portfolio of options drawn from the seven key strategy alternatives. The IRP has provided TVA with a flexible energy supply plan that has subsequently helped guide the strategic actions necessary for TVA to develop needed capacity and to serve its customers efficiently in providing reliable power to the TVA Power Service Area.

Practical alternatives to the BLN project (i.e., construction and operation at the Bellefonte site of two Westinghouse AP1000 nuclear reactors with a net electrical output of 2234 MW) that do not require new generating capacity are discussed in Subsection 9.2.1, and those that do require development of new capacity are discussed in Subsection 9.2.2. As discussed in Subsection 9.2.2, some of the alternatives that require new generating capacity were eliminated from further consideration based upon their lack of availability in the region, overall feasibility, inability to supply baseload power, or environmental consequences. The alternatives that were not so eliminated are discussed in further detail in Subsection 9.2.3. The practical alternatives to the BLN project for energy sources discussed in Subsection 9.2.3 constitute reasonable, practical energy options that are also bounded and drawn from among the suite of options evaluated in the TVA IRP.

9.2.1 ALTERNATIVES THAT DO NOT REQUIRE NEW GENERATING CAPACITY

This subsection provides assessments of the practical means of supplying alternative power without constructing new generating capacity. The assessments include the economic and technical bases of the alternative power sources and meets the projected demand for electrical energy identified in Section 8.4. There are several areas of pertinent information which set the context of discussion.

First, in order to understand and assess practicable alternatives, the administrative structure of the current generating supply system in the relevant regional grid and the applicant's relationship to this structure in terms of current and projected power supply are discussed.

- The North American Electric Reliability Corporation (NERC) was formed in 1968 with a mission to ensure that the bulk electric system in North America is reliable, adequate, and secure.
- The Southeastern Electric Reliability Corporation (SERC) is the local Regional Reliability Council (RRC) to the location of BLN, and is one of eight RRCs within NERC. SERC is the largest NERC region in terms of total generation (221,246 MW in 2006) and total load, and covers an area of approximately 560,000 square miles (sq. mi.) in sixteen states.
- COL applicant TVA is a member and a geographic subregion of SERC. TVA had 32,008 MW summer peak generating capacity, or 14 percent of the SERC total, in 2006. The project at BLN would add 2234 MW of generating capacity.

Second, data are also needed on the projected regional system reserve margins published on the relevant electric utilities and other generators. Reserve margin is the amount of unused available capability of an electric power system or area at peak load, as a percentage of the total capability of that system or area. NUREG-1555 suggests a six-year projection beginning with the first year of commercial operation of the project. The first year of commercial operation of BLN is planned in 2017 (Table 1.1-1). The six-year period to consider is then from 2017 - 2022 inclusive. TVA's reserve margin projections and need for capacity are demonstrated in Section 8.4.

The electric power industry has not determined what percentage level is adequate for the electric generating capacity margins to guarantee electricity at all times and under varying conditions. Under the traditional regulated regime, capacity margin calculations were considered as part of long-term planning to ensure that enough capacity was available under typical adverse events. In the aftermath of partial deregulation, a number of investor-owned utilities have divested their generating assets, and are no longer responsible for capacity planning as in the past. Capacity additions, therefore, may or may not keep pace with the growth in demand. There is no guarantee to the validity of these estimates that far in the future.

Third, data are required for the projected peak loads of the electric utilities in the area being served, load duration curve, and baseload for the same six-year period. These data are provided in Section 8.4.

Fourth, data on the transmission intertie capability within the relevant region's plant and between the systems first identified in this list during the initial years of plant operation are needed.

- SERC is currently (2007) divided into five geographic subregions that are identified as Entergy, Gateway, Southern, TVA, and VACAR (the Virginia-Carolinas Area). The five subregions transmit power freely between themselves, and numerous interconnections between SERC and its neighboring RRCs. BLN is part of the TVA subregion and would distribute its generation through the Widows Creek and East Point substations after any necessary reconductoring and equipment upgrades.

Fifth, a listing is needed of the plants in the relevant service area scheduled for retirement between the date of COL Application through the sixth year of commercial operation of the BLN. The relevant service area is the TVA seven-state customer service area. This includes existing nuclear power plants within the relevant region that are near the end of their license and are candidates for license renewal. Other power plants with the potential for reactivation or extended operation should also be considered. Factors to be considered include the expected plant generating capacity, projected availability factor, environmental impacts, and operating costs (including capital costs required to put the unit back on line).

- TVA currently has no firm plans for retiring any of its generating units. TVA is adding environmental controls and maintaining existing generating units as necessary to keep them operational and in compliance with environmental requirements (Reference 3). TVA plans to consider license renewal at the appropriate time.

Finally, information is also needed on the potential for energy conservation within the relevant service area.

- Conservation technologies and measures have proven to be popular with utilities, public utility commissions, and members of the public. Energy conservation is viewed as a way of providing economical service while avoiding construction of more electric generating facilities. TVA already actively pursues energy savings in this area. Additional discussion is provided in Subsection 9.2.1.3, "Demand Side Management."

9.2.1.1 Power Purchases from Other Sources

If available, purchased power from other sources could provide all or some of the baseload replacement power, and obviate the need to construct BLN. The TVA service area does not limit power purchase analysis, so purchased power can be generated at any location and transmitted to the TVA system, provided that it is technically and economically viable (Reference 4). TVA regularly reviews purchased supply options through its Bulk Power Trading Group, with this group having already entered into several long-term purchase contracts to obtain firm capacity. Power covered by these contracts is already included in current and future capacity estimates. Therefore, TVA does not consider this power available to satisfy the alternative of purchased power.

If power to replace the capacity of BLN were to be purchased from a domestic source, the generating technology likely would be one of those described in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (probably coal, natural gas, or nuclear). The descriptions of the environmental impacts of other technologies in this chapter are representative of the environmental impacts associated with the purchased electrical power alternative to construction of BLN. Under the purchased power alternative, the environmental impacts of imported power would still occur, but would be located elsewhere.

Electricity trading has existed between the U.S. and Canada or Mexico for many years, and numerous transmission ties exist. Electricity trading between the U.S. and Mexico has been quite small; however, electricity trading between the U.S. and Canada is considerably greater and involves exchanges along almost the entire border separating the countries. In 2003, American utilities negotiated a net import of approximately 30.39 terrawatt-hour (TWh) of electricity. For comparison, the expected BLN annual production of electricity is 19.6 TWh. Based on the quantity of electricity traded between the U.S. and Canada in the past, a regulatory and political structure that supports current and future electricity trading between the two countries, and the available transmission infrastructure and generating capacity for continued trading, this source of electricity is considered as a potentially feasible source of future electricity trading.

Projected capacity margins -- essentially the amount of existing and planned generating capacity available for planned maintenance, unplanned electrical outages, and unforeseen growth in demand -- are similar in both the U.S. and Canada, from which most imported power originates.

Canada's mix of generating technologies is considerably different from that of the U.S., with hydroelectric power constituting 60 percent, nuclear power providing about 9.2 percent, and fossil fuel fired (combined coal, oil, and gas) providing 27 percent.

As Canada is engaged in substantial conservation efforts and has adequate generating capacity, it appears unlikely that a major power plant construction effort would have to be undertaken in Canada to meet expected American needs in the next 20 years. Similarly, transmission lines are in place within and between the two countries, and any construction of new lines should be a modest effort at best. If TVA were to purchase power from Canada, there would be environmental impacts in Canada due to the generation of electricity there. These impacts would primarily be from the operation of the hydroelectric and fossil fuel facilities. As explained later in Subsection 9.2.2, these impacts would be greater than the impacts from BLN.

Because use of contracted power is already included in current and future capacity estimates, purchasing power from other generators is not considered a reasonable or environmentally preferable alternative to the proposed baseload generation capacity of this project.

9.2.1.2 Repowering, Reactivating, Uprating, or Extending Service Life of Existing Plants

Electric utilities in general have given considerable attention to the issue of repowering generating facilities. Repowering is the process by which utilities update or change the technology of existing plants to realize gains in efficiency or output not possible at the time of the plant's construction. Typically, candidates for repowering would be fueled by coal or natural gas, and the environmental impacts are bounded by the coal- and natural gas-fired alternatives evaluated in Subsection 9.2.2. TVA currently has no existing plants available for repowering, nor does it have any plans at this time to reactivate any once-operating, but now closed, generating facilities.

License renewal and power uprates of nuclear plants could be a potential alternative source of electricity. TVA is the owner and operator of the Browns Ferry, Sequoyah, and Watts Bar nuclear plants. The power uprate and licensing status of these plants is shown in Table 9.2-1 (Reference 2). The need for power analysis in Chapter 8 reflects the additional electricity that would be provided by any approved or planned power uprates and 20-year license renewal of these current plant licenses. Extending the life of existing plants (whether nuclear or fossil fuel) would result in the continued environmental impact attributable to operation of the plants. As explained in Subsection 9.2.3, operation of fossil fuel plants is not environmentally preferable to BLN.

After completing an environmental review and a detailed feasibility, financial, and engineering study, TVA has resumed construction activities and plans to complete the construction of Watts Bar-2, located near Spring City, Tennessee. Work on Watts Bar-2 was estimated to be about 60 percent complete at the time of construction reactivation, and current plans are to begin commercial operation in 2012. The need for power analysis in Chapter 8 reflects the additional electricity that would be provided by Watts Bar-2.

In addition to the above nuclear power plants, TVA has two partially completed units at the Bellefonte site. As described in Section 1.1, TVA received construction permits for Bellefonte Units 1 and 2 in 1974. The history of withdrawal of the construction permits for Bellefonte Units 1 and 2 in 2006 is documented in Section 1.1. In the time since the construction permits were withdrawn, some investment recovery activities have taken place and several components have been removed or partially dismantled and sold. Asset recovery activities have ceased, and TVA is now taking preliminary steps to consider whether Bellefonte Units 1 and 2 should once again be regarded as a potential baseload generating option, due in large part to the change in power generation economics since 2005.

In August 2008, TVA submitted a letter to the NRC requesting reinstatement of the construction permits for Bellefonte Units 1 and 2. If such permits are reinstated, TVA will place the units in deferred status pursuant to the NRC's Policy Statement on Deferred Plants, 52 Fed. Reg. 38077 (October 14, 1987). Among other things, TVA would then conduct a licensing assessment in which it would seek to establish, with some relative degree of certainty, the regulatory framework that would be used should TVA decide to complete the units.

In arriving at this framework, TVA anticipates communicating with the NRC to establish the key regulatory assumptions underlying the potential completion of the units as well as the regulatory framework for completing any subsequent construction and licensing activities. TVA considers this framework as critical to determining the viability of this potential alternative, because the cost and schedule for completion could vary dramatically depending on the final determination of how the regulatory requirements are to be met. In addition to the licensing assessment, TVA would also conduct engineering, design, and equipment reviews. Using the sum of this information, TVA would be in a position to best determine whether completing the units would constitute a viable generating alternative. Bellefonte Units 1 and 2 are described in Subsection 9.2.2.12.

In summary, TVA has no firm plans to retire existing generating plants, and has taken or will take actions to extend the licenses of its operating nuclear units and to uprate existing units to the extent reasonable to do so. It is also completing construction of another nuclear unit, and it has taken these plans into account in determining that there is a need for additional power. Furthermore, continued operation of fossil fuel plants has environmental impacts on air quality that would exceed those associated with new nuclear generation. Therefore, reactivating or extending the service life of existing fossil plants is not a reasonable alternative as a means of satisfying TVA's need for additional power. Completion of the partially constructed Bellefonte Units 1 and 2 is discussed as an alternative for providing new generating capacity in Subsection 9.2.2, although this option is not considered a viable alternative at this time.

9.2.1.3 Demand Side Management

Demand-side management (DSM) programs consist of planning, implementing, and monitoring activities of electric utilities to encourage consumers to modify their level and pattern of electricity usage. This can reduce customers' demand for energy through conservation, efficiency, and load management so that the need for additional generation capacity is eliminated or reduced. Those environmental impacts that result from the construction of the BLN are avoided if DSM were sufficient to reduce the need for additional power.

These programs are in response to the rising cost of energy and the rising cost of building new electric generating units. A wide variety of conservation technologies are considered as alternatives to generating electricity at current nuclear plants. These technologies include hardware, such as more efficient motors in consumer appliances, commercial establishments, or manufacturing processes; more energy-efficient light bulbs; and improved heating, ventilation, and air conditioning (HVAC) systems. Structures consume less energy when weatherized with better insulation, weather stripping, and storm windows. Conservation measures on the utility side include the installation of more efficient equipment, as it retrofits its power plants and improves distribution and transmission technologies. An average of 6.2 percent of an American utility's power is lost before reaching customers.

Conservation technologies and measures have proven to be popular with some utilities, public utility commissions, and members of the public. Energy conservation is viewed as a way of providing economical service while reducing the need to construct more electric generating facilities. Using integrated planning processes such as TVA's conservation technologies and measures are considered as potential new resources in the utility's portfolio of capabilities.

Treating energy conservation measures as resource options received a major stimulus in the passage of the Energy Policy Act of 2005 (EPACT), which amended the Public Utility Regulatory Policies Act of 1978. This now requires each utility to employ up-to-date integrated resource planning as a forecasting tool in cooperation with state regulators and the public. A major barrier to implementing conservation technologies was the degree to which utilities could recover their costs and earn a profit while reducing growth in electric sales as opposed to selling more power. This barrier was removed under EPACT by ensuring that conservation investments were at least as profitable to utilities as investments in energy generation facilities. Additional discussion is provided in Subsection 8.2.2.

In May 2007, TVA's Board of Directors approved a new Strategic Plan. The current-day priorities for the portion of TVA's mission related to energy production focus on improving reliability, managing demand, and reducing environmental impacts. In partnership with customers and others, TVA's new strategic direction includes enhancing efforts to improve energy-efficiency, energy conservation and peak demand reduction over the next five years. Specific targets and elements to implement these efforts are under development. As the goals and program unfold over the next few years, the anticipated reduction in peak demand will be reflected in power supply planning for the TVA system. These enhanced efforts are expected to reduce some of the forecasted demand on the TVA system. These reductions should occur primarily in peak demand, but could have some affect on the demand for baseload, which would be taken into account in future planning for the BLN. What can be and is actually achieved by enhanced efforts remains to be determined. DSM forecasts are current as of February 2007 and do not include changes that may result from TVA's 2007 Strategic Plan approved May 31, 2007.

DSM programs have been part of TVA's energy program since the 1970s. As described, TVA issued a formal integrated resource plan in 1995 (Reference 4). This plan was the subject of a detailed FEIS. DSM options were compared to other resource options in this FEIS based upon a number of criteria including environmental effects. TVA continues to maintain a number of residential and commercial programs to reduce both peak demands and daily energy consumption, and continues to pursue additional opportunities for DSM. TVA and the distributors of TVA power market energy-efficiency programs and tools under the Energy Right® brand, their registered trademark name.

Current DSM programs by TVA include:

- New homes plan.
- New manufactured home plan.
- Heat pump plan.
- Water heater plan.

Tools available for all customers through this initiative include:

- Dare to Compare – Compare electric vs. natural gas systems.
- Energy Calculator – Calculate the energy use and cost of systems and appliances.
- Energy Depot Comparison Tool – Compare energy use, cost, and paybacks for replacing your existing heating and air-conditioning system or water heater with a range of new systems.
- Home Energy Estimator – Compute energy costs under different scenarios.
- Personalized Energy Profile Report – Understand your overall energy use and identify actions to reduce your energy bill with this online report.

- Energy Advisor – Have your energy questions answered via e-mail by an online energy advisor.

- Energy Library – Read about a range of residential or business energy topics and review the most frequently asked questions and answers on energy use.

These initiatives have accounted for estimated reductions in power demand of 57.4 MW in 2004 and an additional 45.4 MW in 2005, and they have contributed to a cumulative demand reduction of 450 MW since 1996. The relevant service area definition is applicable only to the present demand-side management analysis. Redirecting demand outside TVA's service area would not relieve demand within the relevant service area. In response to the Energy Policy Act of 2005, TVA has also recently estimated (Reference 5) the benefits and impacts of a "smart metering" program that would shave peak demand (and thereby slow the need to construct new peaking facilities), but would result in a minor increase in baseload demand. Over the next few years it is anticipated that in concert with distributors TVA would implement this load management program.

Additional measures available in other areas include:

- Various forms of 'time of day rate' programs that allow customers to purchase power more cheaply at the times of day when the supplier costs are lower.

- 'Load shedding' of pre-enrolled high wattage loads during peak usage times, enabling utilities to prepurchase committed load reductions from customers at a small monthly fee, are now available for homeowners (i.e., on a minutes-per-hour shutoff of air conditioning) as well as industrial customers (interruptible rate).

These reduction measures offer the cleanest resource options in contrast to utility generated emissions, but must be properly utilized to avoid significant environmental impacts. Subsection 8.3.14 of the GEIS indicates that indoor air quality is considered the potential impacts of greatest concern from demand reduction technologies. Radon, formaldehyde, and combustion products from cigarette smoking and furnaces are the substances that appear to be the sources of most problems.

Current research indicates that indoor air quality is highly site specific, and the levels of contamination existing before weatherization appear to be a major factor in determining post-weatherization pollution levels. Mitigation measures are available and should always be considered to correct problems. Weatherization programs by themselves are not a primary cause of indoor air pollution problems.

Another category of environmental impact of electrical energy conservation programs is the resource recovery, processing, and manufacturing stages associated with producing conservation equipment or material, as well as impacts of disposing of the equipment or material. At this time, little assessment has been performed for these stages. Resources used in producing conservation technologies are common to many manufacturing processes, and large amounts of resources would not be required. Disposal of these resources should involve normal procedures, and some benefits are likely over the long term as troublesome components of current technologies, such as chlorofluorocarbons that require special handling, are eliminated from the waste stream, and replaced by components that are more benign.

Energy savings attributable to TVA's DSM activities are part of its long-range plan (Reference 4) for meeting projected demand, and therefore are not available as offsets for the generating capacity of BLN. Although DSM programs are an important part of TVA's energy portfolio, TVA concludes that additional DSM, by itself, would not be sufficient to replace the capacity of BLN. Additional energy savings are anticipated as a result of TVA's new Strategic Plan. However, because the implementing details of that plan are under development, the amount of the savings is uncertain. Furthermore, it is anticipated that the savings will largely relate to peak load, with relatively little impact on base load power needs.

9.2.1.4 Combination of Alternatives

Even though individual alternatives might not be sufficient on their own to replace the BLN generating capacity because of the small size of the resource or lack of cost-effective opportunities, it is conceivable that a combination of alternatives might be cost-effective. All the considered alternative energy sources are consistent with TVA's IRP EIS (Reference 4). BLN is projected to have a capacity of 2234 MW. Furthermore, any reasonable combination of alternatives for satisfying the need for baseload power is likely to include generation of significant amounts of power from fossil fuel plants (either through the purchase power option or life extension of existing plants), with some contribution from additional DSM. As discussed in Subsection 9.2.3, operation of fossil fuel plants has significantly greater impacts of air quality than BLN. Therefore, reasonable combinations of purchase power, life extension, and additional DSM would not be environmentally preferable to BLN.

9.2.2 ALTERNATIVES REQUIRING NEW GENERATING CAPACITY

This subsection discusses alternatives requiring new generating capacity that could substitute for the capacity expected from the new nuclear technology option (e.g. Westinghouse AP1000 reactors) considered for the BLN site. This subsection, as a starting point, considers (1) alternatives not yet commercially available, (2) fossil fuel-fired generation, (3) partially completed nuclear units, and (4) alternatives uniquely available within the region to be served by the BLN.

While the need for power is discussed in this report, for the purposes of this evaluation, it is presumed that there would be a demand for the power at the time a COL application is submitted to the NRC. For the future period considered, numerous uncertainties arise from the expected available technology levels, operational and environmental performance, and related costs. It is presumed similar to Subsection 9.2.1 that sufficient knowledge is available at this time to make reasonable comparisons of the alternatives.

NUREG-1437 represents a useful spectrum of alternative source analyses. The focus of NUREG-1437 is on the environmental effects of extended operation of a wide variety of permitted and/or licensed nuclear plants, including such types as Bellefonte Nuclear Plant Units 1 and 2. In NUREG-1437, the NRC also calculated alternatives, using commonly known generation technologies, and researched various states' energy plans to identify alternative generation sources typically being considered. Although NUREG-1437 is specific to license renewal, the document's alternatives analyses can be applied to determine if the alternative technology represents a reasonable alternative to the proposed action and satisfies the intent and requirements of 10 CFR Part 52 regarding a COL application.

In satisfying National Environmental Policy Act (NEPA) requirements, the NRC considered these reasonable alternatives, documented in NUREG-1437:

- Wind power.
- Solar power.
- Hydropower.
- Geothermal energy.
- Biomass-derived fuels.
- Municipal solid waste.
- Petroleum liquids.
- Fuel cells.
- Pulverized coal.
- Integrated Gasification Combined Cycle (IGCC).
- Natural gas.
- Possible combinations of the above.

Where applicable, TVA has identified the significance of the impacts associated with each issue as SMALL, MODERATE, or LARGE. This characterization is consistent with the criteria that NRC established in Footnote 3 of 10 CFR Part 51, Appendix B, Table B-1, as follows:

> SMALL - Environmental impacts are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission's regulations are considered small.
>
> MODERATE - Environmental impacts are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.
>
> LARGE - Environmental impacts are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

The alternative technologies considered in this analysis are consistent with national policy goals for energy use, and are not prohibited by federal, state, or local regulations. The alternative energy sources considered are consistent with the broad suite of options evaluated in the TVA IRP EIS (Reference 4).

Each of the alternatives are assessed and discussed in the subsequent subsections relative to the following criteria:

- The alternative energy conversion technology is developed, proven, and available in the applicable region during the BLN lifetime.
- The alternative energy source provides baseload generating capacity and availability equal to the project.
- The alternative energy source does not result in environmental impacts in excess of a nuclear plant, and the costs of an alternative energy source do not exceed the costs that make it economically impractical.

Based on one or more of these criteria, several of the alternative energy sources are considered technically or economically infeasible after a preliminary review and were not considered further. Alternatives that were considered technically and economically feasible were assessed in detail in Subsection 9.2.3.

9.2.2.1 Wind

Wind power systems produce power intermittently, depending upon when the wind is blowing at sufficient velocity and duration. Despite advances in technology and reliability, capacity factors for wind power systems remain relatively low (25 to 45 percent) compared to the 90 to 95 percent industry average for a baseload plant such as a nuclear plant. Therefore, wind power alone is not capable of producing baseload power, and is not a reasonable alternative by itself to BLN.

Estimates of the wind resource are expressed in wind power classes ranging from class 1 (low) to class 7 (high), with each class representing a range of mean wind power density or equivalent mean speed at specified heights above the ground. Areas designated class 4 or greater are suitable with advanced wind turbine technology under development today. Power class 3 areas may be suitable for future technology. Class 2 areas are marginal and class 1 areas are unsuitable for wind energy development.

The generation capability is low within the overall TVA region, which is rated at class 1 or 2 wind power ratings. Several ridge crests are the exception; TVA is already using potential wind generation sites such as their Buffalo Mountain, TN facility (29 MW). These remote mountain ridge-top locations require access roads and power transmission infrastructure at additional cost. Hilly terrain increases the complexity of installation and the overall costs of wind energy due to turbulence. This decreases the usable energy and capacity factor available from the wind. Reduced capacity factors increase overall cost per kilowatt-hour of energy generated.

TVA acknowledges that approximately 800 MW of wind capacity energy is available within 5 mi. of the TVA service area. Because the average capacity factor for wind energy systems in that area is about 25 percent, the 800 MW of wind capacity is equivalent to only 267 MW of fossil-fuel-fired capacity. This is considered generation on a commercial level. On a homeowner level, TVA'a policy is to purchase even small amounts (minimum output of 500 watts [W]) on a dual-metering option with credit back, but the total goal for this entire program is only 5 MW.

Aesthetic concerns exist from recreation and scenic value of ridgetops to the public, so resistance to wind power generation in the Southeast has been strong. Wind farms are responsible for the deaths of some birds and bats, but when put into the perspective of other causes of avian mortality, the impact is quite low. Also, wind energy is at a minimum in the Southeast in the summer months contrasting with summer-peaking utility generation history. Consequently, wind generation requires redundant power generation resources to meet seasonal peak loads.

Renewable energy sources such as wind turbines have environmental impacts of their own that are of concern. For example, it would take 1440 large wind turbines, 2.5 MW each, placed upon about 240 mi. of ridgeline at a cost of approximately $4.2 billion to equal the energy from one 1200 MW nuclear unit. Wind power costs have declined to as little as $0.03 per kilowatt-hours (kWh) to $0.05/kWh, after installation costs of $1000/kW to $2000/kW. Large-scale systems (greater than 100 kW) achieve the lowest cost when multiple units are installed at one location.

Although considered a viable component of TVA's generation mix, due to the limited availability of areas having suitable wind speeds, daily and seasonal variability of wind in the region, and aesthetic impacts, wind generation is not a reasonable alternative for baseload power in the Southeast.

9.2.2.2 Solar Technologies

There are currently two practical methods to produce electricity from solar energy: photovoltaic and solar thermal power. Photovoltaics ("solar cells") convert sunlight directly into electricity using semiconducting materials. Solar thermal power systems convert sunlight into electricity using heat as an intermediate step. These systems generate electricity from this heat with various methods. For this discussion, the different methodologies of nonphotovoltaic systems are grouped together.

Some solar thermal systems can also be equipped with a thermal storage tank to store heated transfer fluid. These solar thermal plants can then dispatch electric power on demand using this stored heat.

Solar technologies produce more electricity with more intense and direct sunlight. Cloudy days can significantly reduce output. To work effectively, solar installations require consistent levels of sunlight (solar insolation). The lands with the best solar resources are usually arid or semi-arid. While photovoltaic systems use both diffuse and direct radiation, solar thermal power plants can only use the direct component of the sunlight. This makes solar thermal power less suitable for areas like the Southeastern U.S. with high humidity and frequent cloud cover, both of which diffuse solar energy and reduce its intensity. In addition, the average annual amount of solar energy reaching the ground needs to be 64 kWh per square foot per day (kWh/ft^2/day) or higher for solar thermal power systems. The Southeast receives an average of 0.3 to 0.4 kWh/ft^2 per day of solar radiation.

Like wind, capacity factors are too low to meet baseload requirements. Average annual capacity factors for solar power systems are relatively low (24 percent for photovoltaics and 30 to 32 percent for solar thermal power) compared to 90 to 95 percent for a baseload plant such as a nuclear plant.

Land use requirements (and associated construction and ecological impacts) are also much greater for solar technologies than for a nuclear plant. The area of land required depends on the available solar insolation and type of plant, but is about 8 ac/MW for photovoltaic systems and 3.8 ac/MW for solar thermal power plants.

Assuming capacity factors of 24 percent for photovoltaics and 32 percent for solar thermal power, facilities having a 2234 MW net capacity are estimated to require 74,467 ac. (116 sq. mi.), if powered by photovoltaic cells, and 26,529 ac. (41 sq. mi.), if powered by solar thermal power. Construction of a nuclear plant the size of BLN is expected to require about 500 ac. of which about 310 ac. would be required for permanent facilities. This is equivalent to 0.14 ac/MW. Based on the comparison of the amount of land needed, the solar alternative would require a large site, which would result in a LARGE environmental impact.

Solar-powered technologies (photovoltaic cells and solar thermal power) do not currently compete with conventional technologies in grid-connected applications due to higher capital costs per kilowatt of capacity. Capital costs for photovoltaic installations range from $3000/kW to $4000/kW and capital costs for solar thermal installations range from $2000/kW to $3000/kW. Recent estimates indicate that in areas with good solar insolation, the levelized cost of electricity produced by photovoltaic cells is $0.18/kWh to $0.23/kWh, and electricity from solar thermal systems can be produced for a cost of $0.09/kWh to $0.12/kWh. Solar energy costs are expected to be much higher in areas like the Southeast that have lower solar insolation. Therefore, solar energy costs are not competitive with the cost of generation of baseload power from other sources, such as nuclear, fossil-fueled plants, and hydroelectric.

TVA currently has a demonstration program, Green Power Switch Generation Partners, that pays participating consumers for energy generated by renewable resource technologies such as solar voltaic. Under the Public Utility Regulatory Policy Act (PURPA), as amended by the Energy Policy Act of 2005, TVA recently completed an assessment (Reference 6) of the likely level of participation in solar power and its impacts as a source of net-metered, distributed generation within the TVA Power Service Area. That study concluded that based upon the economics and limitations noted for solar power, TVA could reasonably expect a maximum of only about 5 MW of such generation.

Although a minor contributor to the overall TVA generation mix through the Green Power Switch Generation Partners program, solar power is not a reasonable alternative to the BLN, because solar energy, due to its intermittent nature, cannot be relied upon for baseload power and because solar power is not cost-competitive and has LARGE land-use impacts.

9.2.2.3 Hydroelectric Power

Hydroelectric power (hydro) is a fully commercialized technology. It is a clean, domestic, and renewable energy source, and can provide recreation and flood control. Downsides include potential losses in fish migrations, water quality, natural habitat, and historical land sites. Hydroelectric output is also vulnerable to drought.

In 2004, hydro generated about 4 percent of America's electricity, or 78,000 MW. The National Hydropower Association estimates more than 18,000 MW of potential additional power could be available mainly through the conversion of non-generating dams and the improvement of generating dams.

Hydropower sources are an integral part of TVA's generation fleet. TVA operates 29 conventional hydroelectric dams, contributing approximately 10 percent of TVA's generated power. These hydropower units are typically dispatched to meet peak and intermediate load needs. Their availability is also highly dependent upon availability of water and the necessity to control waterflow to meet broad multi-purpose goals as established in TVA's Reservoir Operations Policy (ROS) EIS (Reference 7). TVA currently has an active effort underway to gain megawatt capacity through modernization of the aging hydropower system. The availability of these capacity additions is already embedded in the assessment of need for power in Section 8.0.

Hydropower's percentage of U.S. generating capacity is expected to decline because new traditional (utility size) hydroelectric facilities have become difficult to site because of public concern over flooding, destruction of natural habitat, and destruction of natural river courses. This situation has also been illustrated with the more recent proposals to build large dams in the Tennessee River Valley (e.g., Tellico and Columbia). The Idaho National Laboratory Hydro Resource Assessment attempted to standardize an estimate of all potential US undeveloped hydropower with a uniform set of possible site-specific environmental attribute factors. A gross engineering estimate indicates the undeveloped hydropower potential in the TVA service area is as much as 1180 MW. The influence of the various environmental attributes on the reality of successfully developing hydropower sites reduces this value to an estimated 510 MW.

Land use for a new large-scale hydropower facility is estimated to be quite large. NUREG-1437 estimates land use of 1 million ac. (1600 sq. mi.) per 1000 MW generated by hydropower. Based on this estimate, a 2234 MW project would require flooding more than 3574 sq. mi. resulting in a LARGE impact on land use.

Hydro capacity factors are too low to meet baseload requirements. Average annual capacity factors for hydro generation are 40 to 50 percent, compared to 90 to 95 percent for a baseload plant such as a nuclear plant. Recent estimates indicate that capital costs for a hydropower facility range from $1700/kW to $2300/kW capacity (Determining the average capital cost is difficult due to the many various types of hydropower sites (high-low heads and/or high-low flows) and the myriad of possible environmental requirements). The levelized cost of electricity produced from new hydropower facilities is estimated at a total cost of $0.04/kWh.

Although a contributor to the current total generation mix of TVA (Reference 4), development of new hydropower sites in the Tennessee River Valley or Power Service Area is not considered a reasonable alternative to address the need for baseload power, because of the low capacity factors of hydroelectric plants in the TVA service area, the LARGE land-use impacts, and limited availability of feasible new hydroelectric sites.

9.2.2.4 Geothermal

Geothermal energy is a developed technology for power generation. To produce electric power with geothermal energy, underground high-temperature reservoirs of steam or hot water are tapped by wells and the escaping steam rotates turbines to generate electricity. Typically, water is then returned to the ground to recharge the reservoir.

Geothermal energy can achieve average capacity factors of 89 to 97 percent and can be used for baseload power where this type of energy source is available. The major challenge for the geothermal development lies in the area of geothermal resource mapping. Power plant development is limited to those locations where the quantity, quality, and reliability have been proven from intensive geological exploration, drilling, testing, and production. In the U. S., high-temperature hydrothermal reservoirs are located in the western states, Alaska and Hawaii. Water at 360 °F or higher is required to generate geothermal electricity. There are no known high-temperature geothermal sites in the Southeast.

Due to the lack of high-temperature geothermal reservoirs, geothermal power is not a reasonable alternative for baseload power in the relevant service area.

9.2.2.5 Biomass Related Fuels

Biomass combustion is a current significant energy source for electrical generation. Supplying almost 850 gigawatt hours (GWh) (2.9 quadrillion British thermal units [Btu] [quads]) of energy in 2003 (including municipal solid waste), it has surpassed hydropower as the largest domestic source of renewable energy. Biomass fired facilities generate electricity using commercially available equipment and well-established technology. This energy is dispatchable on demand because it is combustion based.

Energy crops such as switchgrass could be grown to ensure a reliable supply of biomass feedstocks for generation of electricity. Detrimental environmental impacts can result from converting large tracts of land to production of energy crops. These include changes to wildlife habitat and biodiversity, reduced soil fertility, increased erosion, and reduced water quality. The net environmental impacts vary due to many factors, including previous land use, the particular energy crop, and how the crop is managed. Displacing natural land cover with energy crops would likely have negative impacts.

Biomass is the largest renewable energy resource in the Tennessee Valley. Approximately 11 million tons (T.) of wood waste (mill residue, forest residue, and urban wood waste) is generated each year. Also, studies project that approximately 10 million T. of switchgrass, a native, high-yielding grass, could be grown annually as an energy crop in the TVA service area. Combined, these could produce an energy equivalent of approximately 900 MW in the TVA service territory. The energy content of dry biomass ranges from 7000 Btu per pound (Btu/lb) for straws to 8500 Btu/lb for wood. However, the cost of switchgrass and other energy crops currently is almost twice the cost of coal on an energy basis. Furthermore, the lack of adequate infrastructure, along with transportation and handling costs, are primary obstacles when considering the economic and technical feasibility of this renewable energy source.

Most of the biomass fueled generation facilities in the U.S. use steam turbine conversion technology, and can accept a wide variety of biomass fuels. However, at the scale appropriate for biomass (the largest biomass power plants are 40 to 50 MW in size), the technology is expensive and inefficient. Biomass is much less dense than coal, requiring a greater volume of fuel to be handled per megawatt. Greater areas of biomass storage and additional handling are required to accommodate the lower-density materials. Therefore, the technology is relegated to more cost effective applications where there is a readily available supply of low-, zero-, or negative-cost delivered feedstocks.

The levelized cost of electricity from a new biomass power plant only generating electricity for sale lies in the range of $0.052/kWh to $0.067/kWh.

Construction of a biomass-fired plant would have an environmental impact that would be similar to that for a coal-fired plant, although facilities using wood waste and agricultural residues for fuel would be built on smaller scales. Like coal-fired plants, biomass-fired plants require areas for fuel storage, processing, and waste (i.e., ash) disposal. Additionally, operation of biomass-fired plants has environmental impacts, including potential impacts on the aquatic environment and air.

Another option for using biomass feedstocks to generate electricity is cofiring with coal. TVA, for example, estimated in 2000 that it would save $1.5 million per year in fuel costs cofiring with biomass at its Colbert plant. Generating electricity through cofiring biomass feedstocks with coal, however, is not problem free, as blending coal and biomass can cause ash fouling and slagging problems.

The NRC has evaluated other biomass-derived fuels for the purposes of alternative energy source analysis. These included burning crops, converting crops to a liquid fuel such as ethanol, and gasifying crops (including wood waste). The NRC concluded that none of these technologies had progressed to the point of being competitive on a large scale or of being reliable enough to replace a baseload plant. This conclusion applies to this analysis. The other biomass-derived fuels do not represent an acceptable alternative to the BLN project.

Due to the small scale of biomass generating plants, high cost, and lack of an obvious environmental advantage, biomass energy is not a reasonable alternative for baseload power.

9.2.2.6 Municipal Solid Waste

Municipal solid waste (MSW) can be used to fuel electrical generation similar to biomass or coal. MSW would be delivered to the plant by collection trucks and shredded or processed to ease handling. After removal of recyclable material, the remaining waste would be fed into a combustion chamber to be burned. The resulting heat of combustion is used to produce steam, which turns a steam turbine to generate electricity.

Specialized waste separation and handling equipment increases initial capital costs over other technologies. Recent estimates indicate that capital costs for MSW plants range from $2500/kW to $4600/kW. The levelized cost of electricity produced from MSW plants is $0.035/kWh to $0.153/kWh.

The decision to burn MSW to generate energy is usually driven by the need for an alternative to landfills, rather than by energy considerations. MSW power plants reduce the need for landfill capacity because disposal of ash created by MSW combustion requires less volume and land area as compared to unprocessed MSW. Many landfills are unlikely to begin converting waste to energy due to obstacles to MSW power generation, primarily environmental regulations and public opposition to siting MSW facilities near feedstock supplies (i.e., people).

MSW power plants also concentrate the toxins from the feedstock within the smaller ash volume. Current regulations require MSW ash sampling on a regular basis to determine its hazardous status. Hazardous ash must be managed and disposed of as hazardous waste. Depending on state and local restrictions, nonhazardous ash may be disposed of in a MSW landfill or recycled for use in roads, parking lots, or daily covering for sanitary landfills.

The construction and operational (i.e., aquatic environment, air, and waste disposal) impacts for a MSW plant are similar to a conventional fossil fuel fired unit. Some of these impacts would be small, but still greater than the proposed action.

Due to the high costs and lack of obvious environmental advantages, other than reducing landfill volume, burning municipal solid waste to generate electricity is not a reasonable alternative for baseload power.

9.2.2.7 Petroleum Liquids

Petroleum liquids in this discussion include distillate fuel oil, residual fuel oil, jet fuel, kerosene, petroleum coke converted to liquid petroleum, and waste oil. The high cost of this fuel group has prompted a steady decline in its use for electricity generation in recent decades and no new petroleum-liquids-fired units have been constructed in the United States since 1981. From a peak of 17 percent of total U.S. net electricity generation in 1978, petroleum liquids accounted for about 3 percent of net electricity generated in 2005. With the combination of the decline of domestic petroleum production since 1970, rising import quantities, increasing global prices, plus competition from the transportation sector and petrochemical industry, the downward trend for using petroleum to generate electricity is likely to continue.

Comparing costs in dollars per MWh ($/MWh) (dollars per million Btu [$/MBtu]) (September 2006), coal was $0.50/MWh ($1.72/MBtu), natural gas was $1.82/MWh ($6.22/MBtu), and petroleum liquids were $2.39/MWh ($8.14/MBtu).

TVA has 72 combustion turbine generators located at six sites across the relevant service area. They run on natural gas or fuel oil and are designed to start quickly during peak demand periods. Their total generation of 4644 MW comprises about 15 percent of the available 31,924 MW generation (2006) but is the last choice of generating capacity because of the high price of fuel oil or natural gas.

While capital costs for new petroleum-fired plants are similar to those of new natural-gas-fired plants, operation is more expensive due to the high cost of petroleum. Future increases in petroleum prices are expected to make petroleum-fired generation increasingly more expensive.

Also, construction and operation of a petroleum-fired plant would have identifiable environmental impacts. For example, NUREG-1437 estimates that construction of a 1000-MW petroleum-fired plant would require about 120 ac. Assuming a 95 percent capacity factor, a petroleum-fired power plant with a net output of 2234 MW would require about 282 ac. Additionally, operation of petroleum-fired plants would have environmental impacts (including impacts on the aquatic environment and air) that would be similar to those from a coal-fired plant (Reference 1).

Petroleum-fired generation is not a reasonable alternative for baseload power, based on the high cost of the fuel, combined with concerns related to availability, energy independence, and lack of obvious environmental advantage.

9.2.2.8 Fuel Cells

Fuel cell power plants are approaching utility scale, with over 800 large stationary fuel cell systems built and operated worldwide, but the total global stationary fuel cell electricity generating capacity is small compared to conventional generation.

Fuel cells operate similarly to batteries but do not lose their charge. Instead, fuel cells rely on a supply of hydrogen, which is broken into free protons and electrons within the fuel cell. There are several types of fuel cells, using different materials and operating at different temperatures. Stationary fuel cells can be connected to the electricity grid, and smaller cells are envisioned for use in the transportation sector. Although the costs of fuel cells have been reduced since their inception, they currently remain too high for widespread market penetration.

Phosphoric acid fuel cells, which operate at relatively low temperatures, are currently being used in several applications with efficiency rates of 37 to 42 percent. An advantage of this cell type is that relatively impure hydrogen is tolerated, broadening the source of potential fuels. The major disadvantage is the high cost of the platinum catalyst.

Molten carbonate fuel cells, which use nickel in place of more costly metals, can achieve a 50 percent efficiency rate and are operating experimentally as power plants. Solid oxide fuel cells, also currently being developed, use ceramic materials, operate at relatively high temperatures, and can achieve similar efficiencies of around 50 percent. They have applications in the electric power sector, providing exhaust to turn gas turbines, and could have future uses in the transportation sector.

Although at up to 60 percent efficient at converting fuel to power, fuel cells are still not cost effective when compared with other generation technologies, both renewable and fossil fuel fired. Mobile and stationary fuel cell achievements and costs vary by process, and show increasing annual improvement, but the cost per kilowatt-hour is not yet competitive with current utility delivered prices. Recent (2005) data indicate that the levelized cost of electricity produced by commercial fuel cells is in the range of approximately $0.12/kWh to $1.30/kWh. The capital cost for General Electric's latest prototype system is estimated at $724/kW, versus available systems' costs of $3000/kW to $4000/kW.

The costs of fuel cells must be reduced significantly before they can become competitive in U.S. markets, and an inexpensive, plentiful source of hydrogen fuel must also be found. If those hurdles can be met, fuel cells offer several advantages over current generation technologies. They are small, quiet, and clean, and because no combustion is involved, their only byproduct is water.

This technology has not matured sufficiently to support production for a baseload facility. TVA has concluded that, due to the cost and production limitations, fuel cell technology is not a reasonable alternative for baseload capacity.

9.2.2.9 Pulverized Coal

Pulverized-coal-fired steam electric plants provide the majority of electric generating capacity in the United States, accounting for about 50 percent of the electricity generated and about 32 percent of summer electric generating capacity in 2005. In the Southeast (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee), pulverized-coal-fired plants provide about 53 percent of the electricity generated and about 36 percent of its summer electric generating capacity. The environmental impacts of constructing a typical pulverized-coal-fired steam plant are well known. Conventional pulverized coal-fired boilers have been sized to take advantage of the economies of scale, at over 300 MW.

Both primary technologies for generating electrical energy from pulverized coal were evaluated: conventional pulverized coal boiler and fluidized bed combustion.

In conventional pulverized-coal-fired plants, pulverized coal is blown into a combustion chamber of a boiler and ignited. The released heat converts water in the boiler into steam. This high-pressure steam is applied in a steam turbine to produce electricity. Flue gas is cleaned of significant fractions of major pollutants such as oxides of nitrogen (NO_X), oxides of sulfur SO_X, and particulates.

Fluidized bed combustion (FBC) is an advanced electric power generation process. The FBC method is similar overall to conventional pulverized-coal-fired boilers, but differs in the combustion process and content. FBC reduces the formation of gaseous pollutants by better controlling coal combustion parameters and by injecting a sorbent (such as crushed limestone) into the combustion chamber along with the fuel. Crushed fuel mixed with the sorbent is fluidized on jets of air in the combustion chamber. Sulfur released from the fuel as sulfur dioxide (SO_2) is captured by the sorbent in the bed to form a solid compound that is removed with the ash. The resultant by-product is a dry, benign solid that is potentially a marketable byproduct for agricultural and construction applications. More than 90 percent of the sulfur in the fuel is captured in this process. NO_X formation in FBC power plants is lower than that for conventional pulverized coal boilers because the operating temperature range is below the temperature at which thermal NO_X is formed.

FBC units are currently limited to a maximum size of approximately 265 MW. Although a multi-unit facility could be built, this would not be able to benefit from the economies of scale associated with a 2234 MW project. Also, the lower operating temperature of the FBC system lowers efficiency levels as compared to conventional pulverized coal boilers. Due to the limited size of available units, and lower thermal efficiency, FBC is not a cost-effective alternative for the proposed project.

To improve the thermal efficiency of the FBC technology, a new type of FBC boiler is being proposed that encases the entire boiler inside a large pressure vessel. Burning coal in a pressurized fluidized bed combustion (PFBC) boiler results in a high-pressure stream of combustion gases that can spin a gas turbine to make electricity, then boil water for a steam turbine. It is estimated that efficiencies for PFBC systems would eventually exceed 50 percent. The PFBC technology is currently in the demonstration phase in most of the world and is not a feasible alternative for the BLN project at this time. Barriers in commercial deployment opportunities of second-generation PFBC systems arise due to slow progress in hot gas filter development, high turbine costs, and complex plant integration. With the current state of technology development and projections for the future, it remains uncertain whether advanced PFBC systems can achieve U.S. Department of Energy's (DOE's) goal of 20 to 25 percent reductions in electricity cost as well as capital cost reductions relative to current pulverized coal plants.

For the purposes of comparison, the pulverized-coal-fired alternative is defined as consisting of four conventional boiler units, each with a net capacity of 530 MW for a combined capacity of 2120 MW. This configuration was chosen to be equivalent to the natural-gas-fired alternative described below. This equivalency makes impact characteristics most comparable, facilitating impact analysis. Although this provides less capacity than two AP1000 units, it ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other methods, such as purchasing power. Table 9.2-2 shows the amounts of the 2120 MW coal-fired plant emissions. Table 9.2-3 presents the assumed basic operational characteristics of the coal-fired units. The emission control technology and percent-control assumptions are based upon alternatives that the Environmental Protection Agency (EPA) has identified as being available for minimizing emissions. For the purposes of analysis, it is assumed that coal and limestone (calcium oxide) would be delivered by rail.

Recent estimates indicate that capital costs for conventional pulverized-coal-fired power plants range from $1094/kW to $1350/kW. The levelized cost of electricity produced from pulverized-coal-fired power plants is $0.033/kWh to $0.041/kWh.

The U.S. has abundant low-cost coal reserves, and the price of coal for electric generation should increase at a relatively slow rate. Pulverized-coal-fired plants are likely to continue as a reliable energy source well into the future, assuming environmental constraints do not cause the gradual substitution of other fuels. Even with recent environmental regulation, new coal capacity is expected to be an affordable technology for reliable, near-term development.

Based on the well-known technology, fuel availability, and generally understood environmental impacts associated with constructing and operating a coal-fired power generation plant, it is considered a competitive alternative and is therefore examined further in Subsection 9.2.3.

9.2.2.10 Integrated Gasification Combined Cycle (IGCC)

Integrated Gasification Combined Cycle (IGCC) is an emerging, advanced technology that combines modern coal gasification technology with both gas turbine and steam turbine power generation. Compared to conventional pulverized coal plants, the technology is substantially cleaner because major pollutants can be removed from the gas stream prior to combustion.

The IGCC process generates much less solid waste than the pulverized-coal-fired alternative. The largest solid waste stream produced by IGCC installations is slag, a sand-like marketable byproduct. Slag production is a function of the fuel ash content. The other large-volume byproduct produced by IGCC plants is sulfur, which is extracted during the gasification process and can be marketed rather than placed in a landfill. IGCC units do not produce ash or scrubber wastes.

Today's IGCC technology still needs operating experience for widespread expansion into commercial-scale, utility applications. Each major component of IGCC has been broadly utilized in industrial and power generation applications. But the joining of coal gasification with a combined cycle power block to produce commercial electricity as a primary output is relatively new. This has been demonstrated at only a handful of facilities around the world, including five in the U.S. Experience has been gained with the chemical processes of gasification and the impact of coal properties on the IGCC areas of design, efficiency, economics, etc. System reliability is still relatively low, as compared to conventional pulverized-coal-fired power plants. There are problems with the process integration between gasification and power production as well.

Overall, experience with IGCC still shows generation costs more expensive than comparably sized pulverized coal plants, due in part to the coal gasifier and other specialized equipment. Recent data indicate that capital costs for coal-fired IGCC power plants are near $1200/kW, and have production costs of electricity near $0.043/ kWh.

As described in the TVA IRP EIS (Reference 4) and analyzed in a subsequent site-specific EIS (Reference 5), TVA considered the conversion of the Bellefonte site to an IGCC facility. An IGCC facility is not a reasonable alternative to the BLN project, because IGCC technology currently is not cost-effective and requires further research to achieve an acceptable level of reliability.

9.2.2.11 Natural Gas

Natural-gas-fired generation using combined-cycle turbines is a technology that is available and economical. Current estimates indicate that capital costs for natural-gas-fired power plants average $575/kW.

Electrical generation with natural gas has a higher cost due to fuel costs rather than capital costs. For example, one study calculated that if the fuel prices increase 100 percent, this would result in a 16 percent increase in the cost of nuclear generation, 55 percent for coal, and 79 percent for natural gas. The average annual variable cost of TVA gas combustion turbines range between $0.103/kwh and $0.152/kwh.

Existing manufacturers' standard-sized units include a natural-gas-fired combined-cycle plant of 530 MW net capacity, consisting of two 184 MW natural gas turbines (e.g., General Electric Frame 7FA) and 182 MW of heat recovery capacity. TVA assumed four 530 MW units, having a total capacity of 2120 MW, as the natural-gas-fired alternative at the BLN project site. Although this provides less capacity than two AP1000 units, it ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other methods, such as purchasing power. Table 9.2-4 shows the amounts of the 2120 MW natural-gas-fired plant emissions. Table 9.2-5 presents the assumed basic operational characteristics of the natural-gas-fired units. For the purposes of analysis, TVA has assumed that there would be sufficient gas availability.

Based on the well-known technology, fuel availability, and generally understood environmental impacts associated with constructing and operating a natural-gas-fired power generation plant, it is considered a competitive alternative and is therefore examined further in Subsection 9.2.3.

9.2.2.12 Partially Completed Nuclear Power Plant

Nuclear generation accounts for approximately 30 percent of the electricity generated by TVA, 20 percent of all the electricity generated in the United States, and 16 percent of the electricity generated worldwide. TVA's nuclear power supply comes from its three nuclear plants: Browns Ferry (BFN, 3 units), near Athens, Alabama; Sequoyah (SQN, 2 units), in Soddy-Daisy, Tennessee; and Watts Bar (WBN, 1 unit in operation, 1 under construction), near Spring City, Tennessee. These plants represent about 6900 MW of TVA's electric capacity, and produce enough electricity to power more than three million homes in the Tennessee Valley. Sixty-nine of the 104 fully licensed U.S. nuclear power plants are pressurized-water reactors (PWRs), including TVA's Sequoyah and Watts Bar nuclear plants.

In addition to the units at Watts Bar and Sequoyah nuclear plants, TVA has two partially completed pressurized water reactor units at the BLN site. As described in the Bellefonte Units 1 and 2 FSAR, these units are 205 Babcock & Wilcox (B&W) designed reactors with a design net output of 1230 MWe each. The designation "205" refers to the number of fuel assemblies in the reactor core. The operating B&W plants in the United States are "177" plants. However, the 205 design is essentially a B&W 177 design plant with a larger core, and therefore not a unique design to NRC. A standard Safety Analysis Report (B-SAR-205) describing the B&W 205 design is on file with the NRC. The uranium fuel cycle described in Chapter 5 of this ER for Units 3 and 4 would also be applicable to Units 1 and 2, as would be the availability of uranium for nuclear fuel as described in Subsection 10.2.2.4.

The existing components of Units 1 and 2 are illustrated in Figure 2.1-1, and noted in the Building Legend as items 3, 6, 7, 10, 12, 15, 19, and 24. The transmission lines built to support Units 1 and 2 are in place. As described in Subsection 2.2.2, both 500-kV and161-kV lines run into and out of the BLN site (illustrated in Figure 1.1-5). Construction power for Units 1 and 2 would be supplied by the existing 161-kV line.

As described in Section 1.1, TVA was issued construction permits for Bellefonte Units 1 and 2 by the Atomic Energy Commission in December 1974. Construction of Units 1 and 2 continued until the mid-1980s when forecasted load growth began to decrease. Given the additional generating capabilities from TVA's completed generating facilities, the diminished demand for electrical power, and financial considerations, including the goal of holding electric rates constant, TVA decided to defer completion of the Bellefonte units. At that time, Unit 1 was approximately 90 percent complete, and Unit 2 was approximately 58 percent complete.

In 2005, TVA determined that completing Units 1 and 2 would not be a cost-effective generating option and could no longer be economically justified. However, it was recognized that, if Units 1 and 2 are not completed and operated, some of the existing Unit 1 and Unit 2 equipment and structures (e.g., cooling towers, intake structure, transmission switchyards) could be used to support a new facility, and that their use could reduce new construction costs associated with an advanced technology nuclear plant to be licensed utilizing the improved combined licensing process described in 10 CFR Part 52. This proposed plant, which utilizes the Westinghouse AP1000 Design Certification Document, was eventually designated as Bellefonte Units 3 and 4.

In 2006, TVA requested that the NRC withdraw the construction permits for Units 1 and 2, and submitted a Site Redress Plan to the NRC along with the withdrawal request. The permits were withdrawn by the NRC in 2006. However, TVA has maintained the site's National Pollutant Discharge Elimination System permit, Air Permit for Synthetic Minor Source Operation for two 7000-kW diesel generators, and the applicable Resource Conservation and Recovery Act permit.

Since TVA made the decision to request withdrawal of the BLN Units 1 and 2 construction permits, the cost per kilowatt of installed capacity among generation alternatives has continued to increase. In addition, the worldwide decrease in the number of suppliers available for providing necessary reactor components and the significant expression of interest in developing new nuclear generation capacity in the past 2 years creates potential additional cost and schedule impacts on new construction. Also, many major Unit 1 and 2 structures, systems, and components are near completion, including the containment buildings, cooling towers, circulation water buildings, most major and minor Unit 1 systems, and some Unit 2 systems. In terms of commodities, these structures, systems, and components represent considerable amounts of installed concrete, steel, piping, and cable, all of which have significantly increased in cost over the past few years. For the reasons listed above, in a letter dated August 26, 2008, TVA asked the NRC to reinstate the construction permits for Units 1 and 2. If the permits are reinstated, TVA intends to place the units in deferred plant status.

In the time since the construction permits were withdrawn, some investment recovery activities have taken place at the site; however these activities were halted in November 2007. If NRC reinstates the construction permits for Bellefonte Units 1 and 2 in a deferred status, TVA anticipates conducting minor refurbishment of the Construction Administration Building (CAB), as well as reinstituting certain preventive maintenance, testing, and monitoring activities at the site.

Environmental studies conducted over the years addressing the completion of Units 1 and 2 include TVA's 1974 Final Environmental Statement (Reference 9), the AEC's 1974 Final Environmental Statement (Reference 10), and the Final Environmental Impact Statement on the BLN Conversion Project (Reference 5), as well as the U.S. Department of Energy's Final Environmental Impact Statement on the Production of Tritium in a Commercial Light Water Reactor (Reference 11).

In view of the above, TVA has determined that it is prudent and worthwhile to examine the viability of adding Bellefonte Units 1 and 2 as a baseload generation source. However, determination of the viability of completing Units 1 and 2 will depend, in part, on the results of a licensing assessment that will be performed. TVA has requested that the original construction permits for these units be reinstated to allow TVA to establish, with some relative degree of certainty, the regulatory framework that would be applied should TVA decide to complete the units. The viability of this completion option will not be known until completion of the licensing assessment as well as a review of the engineering, design, and equipment that would be required to complete the units, as well as consideration of intangible factors such as the desirability of the resulting technology.

Should NRC reinstate the construction permits in a deferred status, TVA would resume preservation and maintenance activities as appropriate under NRC regulations and Generic Letter 87-15, "Policy Statement on Deferred Plants." TVA would maintain the units in the same deferred status as when TVA elected to withdraw the construction permits.

In making the subject request for reinstatement of the construction permits, TVA has not indicated any preference or prejudgment in favor of completing the existing Bellefonte units. Should NRC reinstate the construction permits, any future decision to resume Units 1 and 2 construction and completion activities would require approval by the TVA Board. TVA's Board would take into account the full range of engineering, construction, environmental, and regulatory/licensing considerations associated with such a project, including the associated cost and need for power considerations. In addition, should the TVA Board later decide to move forward with the completion of Bellefonte Units 1 and 2, TVA would follow the notice of resumption of construction directions included in the NRC's Deferred Plant Policy.

In summary, TVA has requested that the construction permits for Bellefonte Units 1 and 2 be reinstated to enable TVA to evaluate whether completion of Units 1 and 2 is a viable option. Pending completion of this evaluation, there is no basis for concluding that completion of Units 1 and 2 is a reasonable alternative to the BLN project. Therefore, this alternative is not considered further.

9.2.3 ASSESSMENT OF REASONABLE ALTERNATIVE ENERGY SOURCES AND SYSTEMS

In its IRP EIS (Reference 4), TVA identified a broad suite of strategies to address power supply needs for the future. Subsection 9.2.2, discussed the pertinent options addressing the particular need for power to be addressed by the BLN project. Subsection 9.2.3 further evaluates the environmental effects from the reasonable alternatives to the BLN project. For the reasons discussed, these alternatives are: coal and natural-gas-fired generation. The environmental impacts discussed in this section and summarized in Table 9.2-6 are general in nature and representative of the alternate energy sources.

9.2.3.1 Pulverized-Coal-Fired Generation

The NRC analysis of environmental impacts from coal-fired generation alternatives in NUREG-1437 was reviewed and found to be reasonable. Construction impacts could be substantial, due in part to the large land area required (which can result in natural habitat loss). NRC pointed out that siting a new coal-fired plant where an existing nuclear plant is located would reduce many construction impacts. NRC identified major adverse impacts from operations as human health concerns associated with air emissions, waste generation, and losses of aquatic biota due to cooling water withdrawals and discharges.

The pulverized-coal-fired alternative was defined as consisting of four conventional boiler units, each with a net capacity of 530 MW for a combined capacity of 2120 MW. This coal-fired alternative discussed in Subsection 9.2.2.9 would be located at the BLN site. Table 9.2-3 presents the assumed basic operational characteristics of the coal-fired units.

In a pulverized-coal-fired generation system, pieces of coal are crushed between balls or cylindrical rollers. The raw coal is then fed into the pulverizer along with air heated to about 650°F from the boiler. As the coal is crushed by the rolling action, the hot air both dries it and moves the usable fine coal powder to a burner in the boiler where it is combusted.

The overall impacts associated with the construction and operation of the coal-fired alternative using closed-cycle cooling are summarized in Table 9.2-6 and are discussed in the following subsections.

9.2.3.1.1 Air Quality

The air quality impacts of coal-fired generation vary considerably from those of nuclear generation due to emissions of sulfur oxides (SO_X), nitrogen oxides (NO_X), particulates, carbon monoxide, hazardous air pollutants such as mercury, and naturally occurring radioactive materials. Estimated emissions for sulfur dioxide (SO_2), NO_X, particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM-10), and carbon monoxide are shown here. The emissions are for new pulverized-coal-fired plants meeting applicable regulatory requirements with a capacity sufficient to substitute for the BLN project.

As Subsection 9.2.2.9 indicates, it was assumed a plant design that would minimize air emissions through a combination of boiler technology and post combustion pollutant removal. TVA estimates the 2120-MW coal-fired alternative emissions to be as follows:

- SO_2 = 6140 tons per year (Tpy)
- NO_X = 1923 Tpy
- CO = 1923 Tpy
- PM = 325 Tpy
- PM-10 = 75 Tpy

A new coal-fired generating plant would need to meet the new source review requirements in Title I of the Clean Air Act (42 USC 7491). The plant would need an operating permit issued under Title V of the Clean Air Act. The plant would also need to comply with the new source performance standards for new generating plants in 40 CFR Part 60, Subpart Da. The standards establish limits for particulate matter and opacity (40 CFR 60.42a), SO_2 (40 CFR 60.43a), and NO_X (40 CFR 60.44a).

EPA has various regulatory requirements for visibility protection in 40 CFR Part 51, Subpart P, including a specific requirement for review of any new major stationary source in an area designated as attainment or unclassified under the Clean Air Act.

Section 169A of the Clean Air Act establishes a national goal of preventing future and remedying existing impairment of visibility in mandatory Class I Federal areas (e.g., national parks and wilderness areas) when impairment results from air pollution caused by human activities. In addition, EPA issued a new regional haze rule in 1999 (64 FR 35714). The rule specifies that State agencies must establish goals for reasonable progress toward achieving natural visibility conditions for each mandatory Class I Federal area located within a state. The reasonable progress goals must provide for an improvement in visibility for the most-impaired days over the period of the implementation plan and ensure no degradation in visibility for the least-impaired days over the same period (40 CFR 51.308(d)(1)). If a new coal-fired power plant were located close to a mandatory Class I area, additional air pollution control requirements could be imposed.

In 1998, EPA issued a rule requiring 22 eastern states, including Alabama, to revise their state implementation plans (SIP) to reduce NO_X emissions. Emissions of NO_X contribute to violations of the national ambient air quality standard for ozone (40 CFR 50.9). The total amount of NO_X that can be emitted by each of the 22 states in the year 2007 ozone season (May 1 through September 30, 2007) is specified in 40 CFR 51.121(e). For Alabama, the amount is 172,619 T. These requirements are met through a system of marketable NO_x emission allowances. Any new coal-fired power plant sited in Alabama would be subject to these limitations.

A new coal-fired power plant would be subject to the requirements in Title IV of the Clean Air Act. Title IV was enacted to reduce emissions of SO_2 and NO_X, the two principal precursors of acid rain, by restricting emissions of these pollutants from power plants. Title IV caps aggregate annual power plant SO_2 emissions and imposes control on SO_2 emissions through a system of marketable allowances. EPA issues an allowance for each ton of SO_2 that a unit is allowed to emit: New units do not receive allowances but are required to have allowances to cover their SO_2 emissions. Owners of new units must therefore acquire allowances from owners of other power plants by purchase or reduce SO_2 emissions at other power plants they own. Allowances can be banked for use in future years. Thus, a new coal-fired power plant would not add to net regional SO_2 emissions, although it might do so locally. Regardless, SO_2 emissions would be greater for the coal alternative than the BLN project alternative because a nuclear power plant releases almost no SO_2 during normal operations. Section 407 of the Clean Air Act establishes technology-based emission limitations for NO_X emissions; the market-based allowance system used for SO_2 emissions is not used for NO_X emissions under the acid rain program.

EPA issued the Clean Air Interstate Rule (CAIR) in 2005. CAIR provides a Federal framework requiring certain states to reduce emissions of SO_2 and NO_X. EPA anticipates that states would achieve this reduction primarily by limiting emissions from the power generation sector. CAIR covers 28 eastern states and the District of Columbia, including Alabama. Any new fossil fuel fired power plant sited in Alabama would be subject to the CAIR limitations. CAIR is implemented through a system of marketable emission allowances.

In 2005, EPA issued a final rule limiting mercury emissions from coal-fired power plants. Emissions are capped at specified, nationwide levels. A first-phase cap of 38 Tpy becomes effective in 2010 and a second-phase cap of 15 Tpy becomes effective in 2018. Plant owners must demonstrate compliance with the standard by holding one “allowance” for each ounce of mercury emitted in any given year. Allowances are transferable among regulated plants. Any new coal-fired power plant sited in Alabama would be subject to this rule. The new facility would also have to meet regulatory levels under the latest EPA regulations.

Coal contains uranium and thorium. Uranium concentrations are generally in the range of 1 to 10 ppm. Thorium concentrations are generally about 2.5 times greater than uranium concentrations. One estimate is that a 1000-MW (e) coal-fired plant had an annual release of approximately 5.2 T of uranium and 12.8 T of thorium in 1982. The population dose equivalent from the uranium and thorium releases and daughter products produced by the decay of these isotopes has been calculated to be significantly higher than that from nuclear power plants.

A coal-fired plant would also have unregulated carbon dioxide emissions that could contribute to global warming. Pulverized-coal-fired plants sufficient to substitute for the power that would be generated by the BLN project would be estimated to emit approximately 22 million Tpy of carbon dioxide.

During the construction of a coal-fired plant, temporary fugitive dust would be generated. Exhaust emissions would come from vehicles and motorized equipment used during the construction process. In addition, coal-handling equipment would introduce fugitive particulate emissions.

The NRC GEIS analysis did not quantify emissions from coal-fired power plants but implied that air quality impacts would be substantial. The GEIS also mentioned global warming from unregulated carbon dioxide emissions and acid rain from SO_X and NO_X emissions as potential impacts. Adverse human health impacts, such as cancer and emphysema, have been associated with the products of coal combustion at sufficiently high concentrations.

Overall, the air quality impacts associated with the 2120 MW coal alternative would be MODERATE. The impacts would be clearly noticeable, but would not destabilize air quality.

9.2.3.1.2 Waste Management

Coal combustion generates waste in the form of ash, and equipment for controlling air pollution generates additional ash, spent selective catalytic reduction (SCR) catalyst, and scrubber sludge. Scrubbers and SCRs are state-of-the-art controls for SO_2 and NO_x, respectively.

This coal-fired alternative facility, using coal having an ash content of 8.45 percent, would annually consume approximately 7,694,000 T of coal. Particulate control equipment would collect most (99.9 percent) of this ash, approximately 649,000 Tpy.

Other amounts of waste include:

- 1,137,000 Tpy of flue gas desulfurization sludge (gypsum).
- 1160 Tpy of raw water treatment sludges and
- 726 Tpy of general water treatment sludges.

Portions of the ash and gypsum may be recycled. These by-product and waste streams are classified as non-hazardous, as determined by the Resource Conservation and Recovery Act (RCRA).

Provision would be made to store fly ash, bottom ash, and scrubber by-products on-site indefinitely. If permitted, it might be possible to inject ash into underground mine works in the future. Market potential and economic benefit may also exist by selling the ash and scrubber by-products to wallboard manufacturers and for other uses. Water treatment sludges would be disposed at a State-approved landfill, either on-site or off-site. Spent SCR catalyst would be regenerated or disposed off-site. Waste impacts to groundwater and surface water could extend beyond the operating life of the plant if leachate and runoff from the waste storage area occurred. Disposal of the waste could noticeably affect land use and groundwater quality, but with appropriate management and monitoring, it would not destabilize any resources. After closure of the waste site and revegetation, the land could be available for other uses.

In May 2000, EPA issued a 'Notice of Regulatory Determination on Wastes from the Combustion of Fossil Fuels" (65 FR 32214). EPA concluded that some form of national regulation is warranted to address coal combustion waste products.

Accordingly, EPA announced its intention to issue regulations for disposal of coal combustion waste under subtitle D of RCRA.

Debris would be generated during construction activities on the coal-fired alternative units. Such debris would be disposed of in landfills.

For the preceding reasons, the appropriate characterization of impacts from waste generated from coal-fired alternative is MODERATE; the impacts would be clearly noticeable but would not destabilize any important resource.

9.2.3.1.3 Other Impacts

Land - In the NRC GEIS, the staff estimated that approximately 1700 ac. would be needed for a 1000-MW coal-fired plant. This indicates that a 2120-MWe coal-fired plant would require approximately 3604 ac. This area includes land for a barge unloading facility, the coal pile, a limestone pile, ash and scrubber solids disposal area, and plant buildings and structures, but it does not include land for an associated coal mine, access road, and railroad spur. Transmission lines already exist at BLN.

In the GEIS, the staff estimated that approximately 22,000 ac. would be affected for mining the coal and disposing of the waste to support a 1000 MW coal plant during its operational life. A replacement 2120-MWe coal-fired plant to substitute for the BLN project could potentially affect approximately 46,640 ac. of land.

Construction of the alternative would permanently change the land use at the site, but the BLN site has already been devoted to an industrial use for almost three decades. No significant impacts to plant site soils are anticipated because of the use of erosion control practices during and following construction.

The impact of the coal-fired alternative on land use is considered SMALL, similar to the proposed project.

Ecology - The coal-fired generation alternative would introduce construction impacts and new incremental operational impacts. Even assuming siting at a previously disturbed area, the impacts would alter the ecology. Ecological impacts to a plant site and utility easements could include impacts on threatened or endangered species, wildlife habitat loss, reduced wildlife reproduction, habitat fragmentation, and a local reduction in biological diversity. Use of cooling makeup water from a nearby surface water body could have adverse aquatic resource impacts. If needed, maintenance of a transmission line and a rail spur would have ecological impacts. There could be impacts to terrestrial ecology from cooling tower drift. Most of these impacts would be avoided, however, if a previously disturbed site such as BLN is used. Overall, the ecological impacts would be considered SMALL, similar to the proposed project.

Water Use and Quality - Construction of each unit (including access roads) would affect surface water hydrology, but sites could be chosen to avoid extensive site excavation, filling, or grading. New construction would disturb the land surface, which may temporarily affect surface water quality. Potential water quality impacts would consist of suspended solids from disturbed soils, biochemical oxygen demand, nutrient loading from disturbed vegetation, and oil and grease from construction equipment. New construction activities that disturb 1 ac. or more would require a National Pollutant Discharge Elimination System (NPDES) permit for stormwater discharges from the site to ensure the implementation of best management practices and to minimize impacts to surface waters during construction. To minimize the impacts of stormwater flow erosion during construction, on-site retention areas (stormwater detention ponds) would be designed to detain stormwater from the 25-year, 24-hour rainfall event. Runoff detention ponds would be designed to detain runoff within the containment areas to allow for settling and to reduce peak discharges. Best management practices would also be required during construction to minimize water quality impacts. Construction would cause no significant consumption of surface water resources. Sanitary wastewater would most likely be routed to a publicly owned treatment works, if available. If a sanitary waste treatment system was not available, one would be constructed.

During operation, a fraction of the plant intake water requirement for each unit would be for cooling tower makeup water flow. Consumptive water use through evaporation would be small. This amount of water consumption would be taken from the local reservoir with a negligible impact on water availability downstream or in the vicinity of the plant. Cooling water for the main condensers and miscellaneous components would be recirculated through the cooling towers, with the blowdown (i.e.; the fraction of circulated water that is discharged to prevent the buildup of dissolved salts and minerals) and other plant operational wastewater streams subsequently being discharged through diffusers.

A biocide would be used to protect the cooling water system from biological growths. Cooling tower blowdown is expected to be several times larger than any other wastewater stream, but it would not contain any detectable amounts of priority pollutants. Plant process wastewater streams would include demineralizer regeneration wastes, steam cycle blowdown, and service water/pre-treatment waste and chemical drains. Plant wastewater outfalls would also require a NPDES permit, with established treatment standards and discharge limits. To prevent leachate in stormwater runoff from entering the surficial aquifer, the coal storage area and the runoff basin would be lined with low-permeability materials. Runoff streams from the coal pile, fly ash and bottom ash piles, and gypsum storage area would be collected in the lined recycle basin for reuse (which would be sized to exceed capacity requirements for the 25 year, 24 hour storm event), with no direct discharge to the surface water.

Overall, water use and quality impacts can be considered SMALL, similar to the BLN project.

Human Health - Coal-fired power generation introduces worker risks from coal and limestone mining, worker and public risks from coal and lime/limestone transportation, worker and public risks from disposal of coal combustion wastes, and public risks from inhalation of stack emissions.

Emission impacts can be widespread and health risks are difficult to quantify. The coal alternative also introduces the risk of coal-pile fires and attendant inhalation risks. The staff stated in the NRC GEIS that there could be human health impacts (cancer and emphysema) from inhalation of toxins and particulates from a coal-fired plant, but did not identify the significance of these impacts. In addition, the discharges of uranium and thorium from coal-fired plants can potentially produce radiological doses in excess of those arising from nuclear power plant operations.

Regulatory agencies, including EPA and State agencies, set air emission standards and requirements to protect human health and the environment. These agencies also impose site-specific emission limits as needed to meet the health standards. EPA has recently concluded that certain segments of the U.S. population (e.g., the developing fetus and subsistence fish-eating populations) are believed to be at potential risk of adverse health impacts because of mercury exposures from sources such as coal-fired power plants. However, in the absence of more quantitative data, and with the limits imposed for the regulated constituents of air emissions, human health impacts from radiological doses and inhaling toxins and particulates generated by burning coal at a newly constructed coal-fired plant are considered SMALL.

Socioeconomics – During the four-year construction period of the coal-fired Big Stone Plant 2 near Milbank, South Dakota, this single 630 MW plant is estimated to employ an average of 625 construction workers, with a peak workforce of 1500. Once online, it would likely employ 30 to 40 operational workers at the site. The 2120-MW coal-fired alternative, if constructed on a staggered timeline, would be expected to employ proportionally more workers, with an average of 2100 construction workers and a peak workforce of less than 3000. The peak number of workers would noticeably affect the local workforce for most sites, but the jobs would be temporary and many of the workers would commute from surrounding areas. The influx of workers could noticeably affect local school systems and other social services.

New construction could have a negative impact on availability and cost of housing.

The coal-fired units would increase the in-lieu-of payments made by TVA. For these reasons, the nontransportation socioeconomic impacts for new pulverized-coal-fired plants would be noticeable, but depending on how TVA's in-lieu-of tax payments are distributed and the timing of the distributions, the beneficial impact of these payments would be expected to vary over time.

For transportation related to commuting of plant operating personnel for the coal-fired alternative, the impacts are similar to constructing the proposed BLN nuclear units. Transportation impacts would be temporary, noticeable, but not destabilizing during plant construction.

The NRC GEIS states that socioeconomic impacts at a rural site would be greater than at an urban site, because more of the peak construction workforce would need to move to the area to work.

Coal and lime/limestone would likely be delivered by rail to each power plant, although barge delivery is feasible for a site located on a navigable body of water, such as the BLN site. Barge delivery of coal and lime/limestone would likely have minor socioeconomic impacts.

Socioeconomic impacts associated with constructing and operating the 2120-MW coal-fired alternative would be considered SMALL (Adverse) to LARGE (Beneficial), similar to the BLN project.

Aesthetics - The coal-fired power block could be as much as 200 ft. tall and could be visible off-site during daylight hours. The exhaust stack could be as high as 650 ft. Also present are 100 ft. high mechanical towers or 600 ft. high natural draft towers, if required. The stack and cooling towers would likely be highly visible in daylight hours for distances greater than 10 mi. These structures would also be visible at night because of outside lighting. The Federal Aviation Administration (FAA) generally requires that structures exceeding an overall height of 200 ft. above ground level have markings and/or lighting so as not to impair aviation safety. Visual impacts of a new coal-fired plant could be mitigated by landscaping and color selection for buildings that is consistent with the environment. Visual impact at night could be mitigated by reduced use of lighting, provided the lighting meets FAA requirements, and appropriate use of shielding. Overall, the addition of the coal-fired unit would likely have some aesthetic impact. There could be a significant aesthetic impact if construction of a new rail spur were needed.

Coal-fired generation would introduce mechanical sources of noise that could be audible off-site. Sources contributing to total noise produced by plant operation are classified as continuous or intermittent. Continuous sources include the mechanical equipment associated with normal plant operations. Intermittent sources include the equipment related to coal handling, solid waste disposal, transportation related to coal and lime/limestone delivery, use of outside loudspeakers, and the commuting of plant employees. The noise impacts of a coal-fired plant would be slightly greater than those of expected operation of the BLN project. Noise impacts associated with rail delivery of coal and lime/limestone would be most significant for residents living in the vicinity of the facility and along the rail route. Although noise from passing trains significantly raises noise levels near the rail line, the short duration of the noise reduces the impact. Nevertheless, given the frequency of train transport and the fact that many people are likely to be within hearing distance of the rail route, the impacts of noise on residents in the vicinity of the facility and the rail line would be noticeable. Noise associated with barge transportation of coal and lime/limestone would be minimal. Noise and light from the pulverized-coal-fired power plants could be detectable off-site. Aesthetic impacts at the plant site would be mitigated if the plant were located in an industrial area adjacent to other industrial facilities.

Overall, the aesthetic impacts associated with new pulverized-coal-fired power plants can be considered SMALL, but greater than the BLN.

Historic and Archaeological Resources - The potential impacts of new plant construction on historic and archaeological resources have been discussed and evaluated for the proposed BLN nuclear site in Subsections 2.5.3 and 4.1.3. Historic and archaeological resource impacts can generally be effectively managed and as such are considered SMALL.

Environmental Justice - Environmental justice impacts would depend upon the nearby population distribution. Environmental justice impacts have been discussed and evaluated for the proposed BLN nuclear site in Subsections 2.5.3 and 4.1.3. Overall, environmental justice impacts are considered SMALL, similar to the BLN project.

9.2.3.1.4 Design Alternatives

The BLN project location lends itself to coal delivery by rail. Subsection 9.4.1 analyzes alternative designs for the BLN Units 3 and 4 heat dissipation systems. Based on this analysis, TVA assumed that cooling towers would be used for the coal-fired alternative. Use of cooling towers would minimize impingement, entrainment, and thermal impacts; consumptive water use through evaporation would be a SMALL impact, and 100 ft. high mechanical towers or 600 ft. high natural draft towers would introduce a visual impact.

The environmental impacts of constructing and operating the coal-fired alternative using a once through cooling system are more severe than a closed cycle system due to thermal and aquatic disturbance. Per the discussion in Subsection 9.4.1.2.1, a completely open system was not considered feasible based on insufficient flows in the reservoir to meet thermal standards for limited number of days. The cooling towers and infrastructure are already constructed and, therefore, an open cycle system would not result in less land use. There are no impacts to terrestrial ecology from the closed system's cooling tower drift. Increased water withdrawal for an open system may have possible greater impacts to aquatic ecology.

9.2.3.1.5 Conclusion for Pulverized Coal-Fired Generation

A pulverized coal-fired plant is not environmentally preferable to BLN, due primarily to the impacts on air quality, land use, and waste disposal.

9.2.3.2 Natural Gas Generation

TVA has reviewed the NRC analysis of environmental impacts from natural-gas-fired generation alternatives in NUREG-1437 (Reference 1) that focused on combined-cycle plants and found it to be reasonable. Subsection 9.2.2.11 presents TVA's reasons for defining the natural-gas-fired generation alternative as a combined-cycle plant to substitute for the proposed project.

TVA assumed four 530 MW units, having a total capacity of 2120 MW, as the natural-gas-fired alternative at the BLN site. Although this provides less capacity than two AP1000 units, it ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other methods, such as purchasing power. The natural-gas-fired alternative defined by TVA in Subsection 9.2.2.11 would be located at the BLN site. Table 9.2-5 describes assumed basic operational characteristics of the natural-gas-fired units.

Construction of a natural gas pipeline from the plant location to a supply point where a firm supply of gas is available would be needed. There is currently no gas pipeline to the BLN site. It is anticipated that the environmental impacts of constructing a gas pipeline to the BLN site would be similar to those associated with constructing a new transmission line right-of-way. As discussed in Reference 5, soil impacts for construction of the natural gas pipeline are considered moderate because of the disturbance to the topsoil along its route. The gas pipeline corridor may impact limited areas of wetlands, but those impacts would be temporary and insignificant. Per Reference 5, the pipeline would have a light negative impact on geologic setting, land use, terrestrial ecology, and aesthetics and recreation.

The overall impacts associated with the construction and operation of the natural-gas-fired alternative using a closed-cycle cooling system are summarized in Table 9.2-6 and are discussed in the following subsections.

9.2.3.2.1 Air Quality

Natural gas is a relatively clean-burning fuel. Also, because the heat recovery steam generator does not receive supplemental fuel, the combined-cycle operation is highly efficient (60 percent versus 33 percent for the coal-fired alternative). The natural-gas-fired alternative would release similar types of emissions, but in lesser quantities than the coal-fired alternative, and in much larger quantities than the nuclear alternative.

Emission control technology for natural-gas-fired turbines focuses on the reduction of NO_X emissions. TVA estimates the 2120 MW natural-gas-fired alternative emissions to be as follows:

- SO_2 = 168 Tpy
- NO_X = 1785 Tpy
- CO = 743 Tpy
- PM = 94 Tpy (all particulates are PM-2.5)

A new natural-gas-fired generating plant would need to meet the new source review requirements in Title I, Part C of the Clean Air Act and an operating permit issued under Title V. A new natural-gas-fired power plant would also be subject to the new source performance standards for such units at 40 CFR Part 60, Subparts Da and GG. These regulations establish emission limits for particulates, opacity, SO_2, and NO_X.

The EPA has various regulatory requirements for visibility protection in 40 CFR Part 51, Subpart P, including a specific requirement for review of any new major stationary source in an area designated as attainment or unclassified under the Clean Air Act.

Section 169A of the Clean Air Act establishes a national goal of preventing future impairment and remedying existing impairment of visibility in mandatory Class I Federal areas when the impairment results from air pollution caused by human activities. In addition, EPA issued a new regional haze rule in 1999. The rule specifies that for each mandatory Class I Federal area located within a state, the State must establish goals that provide for reasonable progress towards achieving natural visibility conditions. The reasonable progress goals must provide for an improvement in visibility for the most-impaired days over the period of the implementation plan and ensure no degradation in visibility for the least-impaired days over the same period (40 CFR 51.308(d)(1)). If a new natural-gas-fired power plant were located close to a mandatory Class I area, additional air pollution control requirements could be imposed.

In 1998, EPA issued a rule requiring 22 eastern states, including Alabama, to revise their SIPs to reduce NO_X emissions. NO_X emissions contribute to violations of the national ambient air quality standard for ozone (40 CFR 50.9). The total amount of NO_X, that can be emitted by each of the 22 states in the year 2007 ozone season (May 1 through September 30) is set out at 40 CFR 51.121 (e). For Alabama, the amount is 172,619 T. Any new natural gas combined-cycle plant sited in Alabama would be subject to these limitations. Compliance is determined through a system of tradeable NO_x emission allowances.

EPA issued the CAIR in 2005 (EPA 2005a). CAIR provides a Federal framework requiring certain states to reduce emissions of SO_2 and NO_X. EPA anticipates that states would achieve this reduction primarily by limiting emissions from the power generation sector. CAIR covers 28 eastern states and the District of Columbia, including Alabama. Any new fossil fuel fired power plant sited in Alabama would be subject to the CAIR limitations. Compliance is determined through a system of tradeable emission allowances.

A natural-gas-fired power plant would also have unregulated carbon dioxide emissions that could contribute to global warming. TVA estimates that the natural-gas-fired alternative would emit approximately 5.8 million Tpy of carbon dioxide.

The combustion turbine portion of the combined-cycle plant would be subject to EPA's National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines at 40 CFR Part 63, Subpart YYYY, if the site is a major source of hazardous air pollutants. Major sources have the potential to emit 10 Tpy or more of any single hazardous air pollutant (such as carbon monoxide) or 25 Tpy or more of any combination of hazardous air pollutants (40 CFR 63.6085(b)).

Construction activities would result in temporary fugitive dust. Exhaust emissions would also come from vehicles and motorized equipment used during the construction process.

Overall, the air quality impacts of new natural-gas-fired plants sized to substitute for the proposed project capacity are considered SMALL to MODERATE, however are substantially greater than nuclear generation as indicated in Table 9.2-6.

9.2.3.2.2 Waste Management

In the NRC GEIS, the staff concluded that waste generation from natural-gas-fired technology would be minimal. The only significant solid waste generated at a new natural-gas-fired plant would be spent SCR catalyst. The SCR catalyst is used to control NO_X emissions. The spent catalyst would be regenerated or disposed off-site. Other than spent SCR catalyst, waste generation at an operating natural-gas-fired plant would be largely limited to typical office wastes; impacts would be so minor that they would not noticeably alter any important resource attribute. Construction-related debris would be generated during construction activities.

Overall, the solid waste impacts associated with natural-gas-fired alternative would likely be SMALL.

9.2.3.2.3 Other Impacts

Land Use – The 1000 MW natural-gas-fired plant would require approximately 110 ac. A 2120 MW natural-gas-fired alternative to the proposed project would then require approximately 233 ac. Additional land would be affected for construction of a natural gas pipeline to serve the plant. For any new natural-gas-fired plant, additional land would be required for natural gas wells and collection stations. In the NRC GEIS, the staff estimated that a 1000 MW plant would require approximately 3600 ac. of additional land. A 2120 MW natural-gas-fired alternative to the proposed project would then require approximately 7632 ac. of additional land.

Overall, land-use impacts for construction and operation of the natural-gas-fired alternative plant are considered SMALL.

Ecology - Ecological impacts would depend on the nature of the land converted for the plant and new gas pipelines that are required. Construction of a gas pipeline to serve the plant would be expected to have temporary ecological impacts. Ecological impacts to a plant site and utility easements could include impacts on threatened or endangered species, wildlife habitat loss, reduced wildlife reproduction, habitat fragmentation, and a local reduction in biological diversity. Intake and discharge of makeup water for the cooling system could adversely affect aquatic resources. There could be impacts to terrestrial ecology from cooling tower drift. With proper project management (e.g., use of Best Management Practices), the ecological impacts are considered SMALL.

Water Use and Quality - Construction would be expected to increase erosion and stormwater runoff of suspended solids above existing levels, but this would be temporary and mitigated by the use of best management practices. Completion of a retention pond for the treatment of stormwater runoff early in the construction phase would significantly reduce potential increased solids loading to local surface drainage waterways. Application of best management practices to control erosion during construction should mitigate construction impacts of pipelines (natural gas supply, potable water supply, process water supply, and wastewater discharge).

Wastewater discharges would be regulated by the State or by EPA. Approximately 90 percent of the wastewater discharge flow would be cooling tower blowdown. Other sources of wastewater include steam cycle blowdown, water from inlet fogging, demineralizer rinse water, and miscellaneous low-volume wastewater. This water would be treated on-site as necessary to meet regulatory requirements before being discharged to local waters.

Stormwater runoff during plant operation would be drained to a retention pond to allow sediments to settle out prior to discharge to local waterways. Rainwater that fell in secondary containment around oil-containing equipment would drain to an oil/water separator where the oil would be removed for disposal and the water would subsequently drain to the process water pond. Excavation and grading associated with construction of the plant or any of the ancillary features, such as backup power, process and potable water pipelines, wastewater discharge pipelines, and natural gas pipelines, would not be expected to cause adverse impacts to groundwater. Excavations that penetrated the water table might require temporary construction dewatering.

Any groundwater drawdown impacts associated with construction dewatering would be temporary. The long-term impact of these activities should be negligible because of the limited depth and relatively small area of disturbance. Structural damage to aquifer areas resulting from pipeline construction would not be anticipated because aquifers are not generally located within excavation depth.

The impact on the surface water would depend on the discharge volume and the characteristics of the receiving body of water. Intake from and discharge to any surface body of water would be regulated by the State or EPA.

Water quality impacts from sedimentation during construction of a natural-gas-fired plant were characterized in the NRC GEIS as small. NRC staff also noted in the GEIS that operational water quality impacts would be similar to, or less than, those from other generating technologies.

Overall, water use and quality impacts would be considered SMALL.

Human Health - Potential accidents related to plant operations include the possible rupture of natural gas pipelines both on-site and off-site, and the possible release of ammonia. Ammonia is used in the SCR process for control of NO_X emissions. Both events are considered very low probability.

In the GEIS, the staff identified cancer and emphysema as potential health risks from natural-gas-fired plants. NO_X emissions contribute to ozone formation, which in turn contributes to health risks. NO_X emissions from any plant would be regulated by the State or EPA. For a plant sited in Alabama, NO_X emissions would be regulated by the Alabama Department of Environmental Management. Human health impacts are not expected to be detectable or would be minor such that they would neither destabilize nor noticeably alter any important attribute of the resource. Overall, the impacts on human health of newly constructed natural-gas-fired plants are considered SMALL.

Socioeconomics – For a single 400-MW facility, construction would take approximately 31 months. Up to 17 full-time jobs would be created at the site to support operations of the new plant. Construction personnel on-site would peak at about 400. A 1500-MW gas-fueled plant would require 1350 job-years of employment during the construction phase. Assuming a 3-year construction duration, this would correlate to approximately 450 temporary jobs during construction. The study estimated that 78 permanent jobs are required to operate the plant. It is roughly estimated that a 2120-MW natural-gas-fired alternative would create 100 permanent jobs and 500 jobs during construction.

During construction, the communities immediately surrounding each plant site would experience demands on housing and public services that could have noticeable impacts. These impacts would be tempered by construction workers commuting to the sites from cities that are more distant. After construction, the communities would be affected by the loss of jobs. The new natural gas combined-cycle plants would increase TVA's in-lieu-of-tax payments and, depending on how these are distributed, could help address socioeconomic impacts. Jobs related to pipeline construction would not be centralized at one location for any significant period of time and, therefore, would have no important impact on the local economy or on community and government services.

In the NRC GEIS, the staff concluded that socioeconomic impacts from constructing a natural gas-fired plant would not be very noticeable and that the small operational workforce would have the lowest socioeconomic impacts of any nonrenewable technology. Compared to the coal-fired and nuclear alternatives, the smaller size of the construction workforce, the shorter construction time frame, and the smaller size of the operations workforce would lessen socioeconomic impacts.

For transportation related to commuting of plant operating personnel for the natural gas-fired alternative, the impacts are considered negligible. Impacts related to the commuting of plant construction personnel would be noticeable, temporary, but not destabilizing.

Overall, socioeconomic impacts resulting from construction and operation of natural-gas-fired plants can be considered SMALL.

Aesthetics - The natural-gas-fired plants would alter the visual landscape character at each location. The tallest structures would be the 150 ft. high auxiliary boiler and two heat recovery steam generator stacks, as well as the 100 ft. high steam turbine building. Some portion of these structures would likely be visible for 1 mi. or more.

Cooling tower plumes from the 500-ft. natural draft cooling towers would also be visible. The natural draft towers would likely be highly visible in daylight hours for distances greater than 10 mi. There would be more lighting visible across the night landscape, and sky brightness would increase somewhat. Noise from the plant may be detectable off-site, depending on the location.

The gas pipeline compressors also would be visible. Aesthetic impacts would be mitigated if the plant were located in an industrial area adjacent to other power plants. Overall, the aesthetic impacts associated with replacement natural-gas-fired plants are categorized as SMALL, with site-specific factors determining the final categorization.

Historic and Archaeological Resources - The potential impacts of new plant construction on historic and archaeological resources would be similar to those for construction of two nuclear units, which have been discussed and evaluated for the BLN site in Subsections 2.5.3 and 4.1.3. Impacts to cultural resources can be effectively managed under current laws and regulations and kept SMALL.

Environmental Justice - Environmental justice impacts would depend upon the sites chosen for the natural-gas-fired power plants and the nearby population distribution. Similar to the discussion and evaluation for nuclear construction at the BLN site in Subsections 2.5.3 and 4.1.3, the impacts on minority populations resulting from the construction and operation of natural-gas-fired power plants would not be disproportionate.

Overall, environmental justice impacts would be considered SMALL.

9.2.3.2.4 Design Alternatives

The environmental impacts of constructing and operating a natural-gas-fired generating plant using a once-through cooling system are more severe than a closed cycle system due to thermal and aquatic disturbance. Per the discussion in Subsection 9.4.1.2.1, a completely open system was not considered feasible based on insufficient flows in the reservoir to meet thermal standards for a limited number of days. The cooling towers and infrastructure are already constructed and, therefore, an open cycle system would not result in less land use.

However, several environmental differences between the closed-cycle and once-through cooling systems are noted here. No additional land is required because cooling towers already exist. There are no impacts to terrestrial ecology from cooling tower drift. Increased water withdrawal, associated with once-through cooling systems, may have possible greater impacts to aquatic ecology.

9.2.3.2.5 Conclusion for Gas-Fired Generation

A gas-fired power plant is not environmentally preferable to BLN, due primarily to impacts on air quality.

9.2.3.3 Combination of Alternatives

This subsection reviews possible combinations of alternatives that could generate replacement baseload power in lieu of the BLN project. Section 8.3 provides the TVA capacity plan by fuel type for years 2008, 2014, and 2020. ER Section 8.3 indicates no long-term fuel availability problems are anticipated that would limit the capability of resources included in the capacity plan.

As stated in the beginning of Section 9.2, the BLN project has a capacity of 2234 MW of electrical generation, and is expected to supply baseload power to the grid. TVA expects to use this power to meet the electrical supply needs of their dedicated customer base as a public power provider.

As a stand-alone technology, wind energy (Subsection 9.2.2.1) is not a feasible alternative for baseload power, because of its intermittent capacity and current level of cost effectiveness. Solar power (Subsection 9.2.2.2) has a similar problem with intermittent capacity and cost at the magnitude required. As shown above, fossil and/or carbon fuel fired combustion technologies can produce baseload capacity generation, but not at environmental impact levels smaller or equal to the proposed project. These include biomass-derived fuels (Subsection 9.2.2.5), municipal solid waste (Subsection 9.2.2.6), petroleum liquids (Subsection 9.2.2.7), pulverized coal (Subsection 9.2.2.9), integrated gasification combined cycle (IGCC) (Subsection 9.2.2.10), and natural gas (Subsection 9.2.2.11). Only coal and natural gas are in full commercial use at this time for electrical generation because of the high cost and lack of clear environmental advantages of other technologies, and these technologies are not as environmentally preferable.

A combinatorial analysis is necessary for all combinations of multiples to correctly assess the best combination of alternative sources of power. This would consider optimum size, local applicability of technology, effective combination methods, etc., to arrive at the best solution(s). For the renewal of licenses pursuant to 10 CFR Part 54, the NRC has already determined that comprehensive consideration of all possible combinations would be too unwieldy given the purposes of the alternative analysis. However, the analysis of combinations of alternatives should be sufficiently complete to aid the Commission in its analysis of alternative sources of energy pursuant to NEPA. The following text provides the basis for an evaluation of a reasonable number of combinations of alternative energy sources to the BLN project.

TVA reviewed combinations that due to technological maturity, economics, and other factors, could be reasonable alternatives to the proposed project. Although some alternatives may not by themselves provide the capacity needed, a mix of these alternatives could be sufficient. Several representative and bounding sets of these combination alternatives are addressed below out of the large number of possible combinations.

9.2.3.3.1 Determination of Alternatives

A possible alternative combination is a baseload capable source coupled with a renewable non-baseload capable source. TVA expects the BLN project to be baseload capable in its capacity planning, providing power in a predictable, consistent manner; any alternative combination would require the same behavior. This combination allows the full dependability of a consistent baseload supply, but could reduce environmental impacts. For this portion of this analysis, wind and solar are considered as renewable sources of power able to supplement the baseload capable source.

Any combination of alternative sources that includes a variable renewable source of energy (offering all or part of the BLN project capacity) must be combined with a 100 percent load capacity fossil fuel fired source. This allows the fossil-fuel-fired portion to manage as much as the entire load during times when the output of the renewable source of energy is reduced or unavailable. When available, the output of the renewable source displaces the baseload supply, and the output of the fossil-fuel-fired portion can be reduced to accommodate the increase in renewable generation. For example, if the renewable resource is wind, when the wind blows and wind driven power becomes available, the fossil-fuel-fired power output can be reduced, so that the sum of the two sources continues to match the baseload capacity expected. The result is that the overall performance of the combination meets the demand of TVA with the same dependability as a fossil-fuel-fired plant.

Both coal- and natural-gas-fired generation were evaluated above (Subsections 9.2.3.1 and 9.2.3.2) and were shown to have environmental impacts that are greater than the BLN project. Of the two, natural-gas-fired generation has a smaller environmental impact. In addition, natural gas is a better effective partner to a variable source because it can better tolerate the ramping up and down of the power level. Even cleaner burning technologies for coal do not approach the small environmental impact of natural gas. For this reason, in the environmental comparison portion of this alternative study, natural gas is used as the fossil fuel for baseload capacity.

This review examines the reduction in environmental impacts from a natural-gas-fired facility when generation from the facility is displaced by the renewable resource. The impacts of natural gas considered are those shown in Subsection 9.2.3.2. Also, the renewable part of the alternative combination is any combination of renewable technologies that could produce power equal to or less than the BLN project, when that resource is available.

In the economic comparison portion of this review, coal was chosen to be used in combination with the renewable power source. Coal was chosen as a fuel over natural gas because coal-fired power plants can generate electricity at a lower cost than natural gas plants. The economic comparison is based on generation costs for coal and natural gas identified in Subsections 9.2.2.9 and 9.2.2.11.

9.2.3.3.2 Environmental Impacts

The overall environmental impacts associated with the construction and operation of the natural-gas-fired alternative using a closed-cycle cooling system are summarized in Table 9.2-6 and are discussed in Subsection 9.2.3.2 referencing TVA IRP EIS (Reference 4). Depending on the amount of renewable output included in the combination alternative, the level of environmental impacts of the natural-gas-fired portion would be comparatively lower. If 100 percent of the power level of the natural-gas-fired portion was not available from the renewable alternative, then there remains some level of environmental impact associated with the natural gas portion. When 100 percent of the load is carried by the renewable portion, the environmental impact of the operation of the natural-gas-fired portion is eliminated.

A determination of the types of environmental impacts that a combination of these alternatives would have can be made from the statistics previously evaluated.

The environmental impacts associated with a natural-gas-fired facility and equivalent renewable facilities are summarized in Table 9.2-6. The natural-gas-fired facility alone has impacts that are greater than the project. Some of the environmental impacts of the renewable energy sources are equal to or greater than those of the BLN project. Therefore, the combination of a natural-gas-fired plant and wind or solar facilities would have environmental impacts that are equal to or greater than those of a nuclear facility.

The environmental impacts from a natural-gas-fired plant are SMALL. Land-use impacts from wind and/or solar facilities could be SMALL to LARGE, and the aesthetic impacts of wind could be SMALL to MODERATE, depending upon the size of the facilities (the smaller the size of the wind/solar facilities, the larger the air impacts from the gas-fired plant). The environmental impacts from the use of wind and/or solar facilities in combination with a natural-gas-fired facility would be SMALL, except for land use and aesthetic impacts from wind and solar facilities which range from SMALL to LARGE, and the air impacts from the gas-fired facility which would range from SMALL to MODERATE. In comparison, the environmental impacts of a new nuclear plant at BLN would be SMALL. Therefore, a combination of alternatives would not be environmental preferable to BLN.

At best, the combination of wind and/or solar facilities, and a natural-gas-fired facility is not environmentally preferable to the BLN project, and should not be considered further.

9.2.3.3.3 Economic Comparison

For the combination alternative to pass an economic comparison, the cost of the generation using all generation pairing levels of the combination are considered. That is, 100 percent wind power, or 100 percent coal power, or 90 percent wind and 10 percent coal, etc., must be shown to cost less to generate electricity as compared to the BLN project. Also in consideration is the fact that coal or other plants cost more per MW to operate when not running at 100 percent capacity, because the capital and fixed operating costs are loaded across fewer MWh, increasing the cost per MWh.

Various studies (Subsection 10.4.2.1.1) show a wide range of electricity generation costs for varying power sources. The levelized cost of electricity generation calculated by these studies is based on various factors, such as choices for discount rate, construction duration, plant lifespan, capacity factor, cost of debt and equity and the split between debt and equity financing, depreciation time, tax rates, and premium for uncertainty (Subsection 10.4.2.1.2). One reason for the difference in reported generation costs between the various studies is the choice of which combinations of these factors are included in their calculations. In some instances, this results in calculated nuclear generation costs that are within the range of costs associated with natural gas and coal-fired plants. The 2005 Organization for Economic Co-operation and Development (OECD) study of projected electricity generating costs (Reference 13), reported a levelized cost of nuclear generation between $0.021 and $0.031/kWh at the 5 percent discount rate, while costs for coal and natural gas plants ranged from $0.025 to $0.050/kWh and $0.037 to $0.060/kWh, respectively. A 2004 National Institute of Nuclear Investigations study of the overall costs of generating electricity (Reference 14) provided costs of $0.0227/kWh for nuclear, $0.0328/kWh for coal, and $0.0353/kWh for natural gas at a 5 percent discount rate. A 2004 University of Chicago study (Reference 15) lists a range for nuclear generation costs of $0.047 to $0.071/kWh, compared to $0.033 to $0.041/kWh and $0.035 to $0.045/kWh for coal and natural gas plants, respectively. Solar ranges from $0.09/kWh to $0.23/kWh, and wind from $0.03/kWh to $0.05/kWh, although as discussed in Subsection 9.2.2.1, the wind generation capability within the overall TVA region is low, and there is not enough wind to generate output equal to that generated by the BLN project. To support timely decision making, TVA updates such information as there are changes in market conditions or technological costs. Considering the above information, a range of $0.036 to $0.083/kWh has been selected as a reasonable and conservative estimate of the levelized cost of generation for the BLN project, as discussed in Subsection 10.4.2.1.2.

The project costs associated with electricity generation at BLN are anticipated to fall within the range that makes it economically competitive with other forms of electricity generation.

9.2.3.3.4 Summary

Although other combinations of the various alternatives are not discussed here, the lower capacity factors, higher environmental impacts, immature technologies, and a lack of cost competitiveness have not been found to assemble into a viable, competitive alternative combination that is either environmentally equivalent or preferable.

Wind and solar generation in combination with fossil-fuel-fired facilities could be used to generate baseload power and would serve the equivalent purpose of the proposed project. However, wind and solar generation in combination with fossil-fuel-fired facilities would have equivalent or greater environmental impacts as compared to a new nuclear facility at the BLN site. Also, wind and solar generation in combination with fossil-fuel-fired facilities would have higher electrical generating costs as compared to a new nuclear facility at the BLN site. Therefore, wind and solar generation in combination with fossil-fuel-fired facilities are not preferable to the proposed project.

9.2.4 CONCLUSION

As shown in detail in Table 9.2-6, based on environmental impacts, the analyses demonstrate that either a coal-fired or a natural-gas-fired plant would entail a appreciably greater environmental impact on air quality than would the proposed project. Furthermore, each of these types of plants would entail a significantly greater relative environmental impact on air quality than would the proposed project. In addition, a combination of either of these two types of generation with renewable sources of energy such as wind or solar is possible, but to achieve a smaller impact on the air qualify, a moderate to large impact on land would be required. Therefore, TVA concludes that neither a coal-fired, nor natural-gas-fired plant, nor a combination of alternatives would be environmentally preferable to the proposed project. Also, these alternatives would have higher economic costs, and therefore are not economically preferable to the proposed project.

9.2.5 REFERENCES

1. U.S. Nuclear Regulatory Commission, NUREG-1437, Volume 1, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants,” May 1996, Website, www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1437/v1/index.html, accessed November 2006.

2. U.S. Nuclear Regulatory Commission, NUREG-1350, Volume 18, "2006 – 2007 Information Digest," August 2006.

3. U.S. Nuclear Regulatory Commission, NUREG-1437, Supplement 21, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Regarding Browns Ferry Nuclear Plant, Units 1, 2, and 3,” June 2005, Website, www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1437/supplement21/index.html, accessed November 2006.

4. Tennessee Valley Authority, “Integrated Resource Plan, Environmental Impact Statement,” TVA, Knoxville, TN, 1995.

5. Tennessee Valley Authority, “Final Environmental Impact Statement for the Bellefonte Conversion Project,” TVA Knoxville, TN, 1997.

6. Tennessee Valley Authority, Public Utilities Regulatory Policies Act (PURPA) “Service and Rate-Making Standards - Final Environmental Assessment and Finding of No Significant Impact,” Knoxville, TN, 2007.

7. Tennessee Valley Authority, “Reservoir Operations Policy - Environmental Impact Statement,” Knoxville, TN, 2001.

8. U.S. Environmental Protection Agency, AP 42, Fifth Edition, "Compilation of Air Pollutant Emission Factors", Volume 1, "Stationary Point and Area Sources", Section 1.1, "Bituminous and Subbituminous Coal Combustion," Website, http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

9. Tennessee Valley Authority, *Final Environmental Statement - Bellefonte Nuclear Plant, Units 1 and 2*, May 1974.

10. Atomic Energy Commission, *Final Environmental Statement Related to Construction of Bellefonte Nuclear Plant Units 1 and 2*, June 1974.

11. U.S. Department of Energy, *Final Environmental Impact Statement for the Production of Tritium in a Commercial Light Water Reactor*, DOE/EIS-0288, March 1999.

12. U.S. Department of Agriculture, Forest Products Laboratory, Techline Fuel Value Calculator, Website, http://www.fpl.fs.fed.us/documnts/techline/fuel-value-calculator.pdf, accessed March 2008.

13. Nuclear Energy Agency, Organization for Economic Co-operation and Development (OECD), and International Energy Agency, Projected Costs of Generating Electricity: 2005 Update, Website, http://213.253.134.43/oecd/pdfs/browseit/6605011E.PDF (Note: electronic version cannot be printed; paper version is available for purchase), accessed June 5, 2007.

14. National Institute of Nuclear Investigations, Mexico, Palacios & others, "Levelized Costs for Nuclear, Gas and Coal for Electricity, Under the Mexican Scenario," 2004.

15. The University of Chicago, The Economic Future of Nuclear Power: A Study Conducted at The University of Chicago, August 2004, Website, http://nuclear.energy.gov/np2010/reports/NuclIndustryStudy-Summary.pdf, accessed June 5, 2007.

TABLE 9.2-1
TVA NUCLEAR PLANT STATUS

Plant	Full Power Operating License Issued	License Extension Applied For	Current License Expiration	Power Uprate Status		
				% Uprate	MWt	Date Approved
Browns Ferry 1	1973	Y	2033	5	165	03/06/07
Browns Ferry 2	1974	Y	2034	5	164	09/08/98
Browns Ferry 3	1976	Y	2036	5	164	09/08/98
Sequoyah 1	1980	N	2020	1.3	44	04/30/02
Sequoyah 2	1981	N	2021	1.3	44	04/30/02
Watts Bar 1	1996	N	2035	1.4	48	01/19/01
Watts Bar 2 (not operating)	na[a]	na	40-year initial period	na	na	na
Bellefonte 1	na	na	na	na	na	na
Bellefonte 2	na	na	na	na	na	na

a) na = Not applicable.

TABLE 9.2-2
AIR EMISSIONS FROM THE 2120 MW COAL-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual Coal Consumption	$4\text{ units}\times\frac{562\text{ MW}}{\text{unit}}\times\frac{10,000\text{ Btu}}{\text{kWh}}\times\frac{1000\text{ kW}}{\text{MW}}\times\frac{\text{lb}}{10,878\text{ Btu}}\times\frac{\text{ton}}{2000\text{ lb}}\times 0.85\times\frac{8760\text{ hr}}{\text{year}}$	7,694,000 Tpy
SO_X	$\frac{38\times 0.84\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2000\text{ lb}}\times(1-95/100)\times\frac{7,694,000\text{ tons}}{\text{year}}$	6140 Tpy
NO_X	$\frac{10\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2000\text{ lb}}\times(1-95/100)\times\frac{7,694,000\text{ tons}}{\text{year}}$	1923 Tpy
CO	$\frac{0.5\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2000\text{ lb}}\times\frac{7,694,000\text{ tons}}{\text{year}}$	1923 Tpy
PM (particulate matter)	$\frac{10\times 8.45\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2000\text{ lb}}\times(1-99.9/100)\times\frac{7,694,000\text{ tons}}{\text{year}}$	325 Tpy
PM-10 (particulate matter less than 10 microns in diameter)	$\frac{2.3\times 8.45\text{ lb}}{\text{ton}}\times\frac{\text{ton}}{2000\text{ lb}}\times(1-99.9/100)\times\frac{7,694,000\text{ tons}}{\text{year}}$	75 Tpy
Note: the calculation in this table is done only in English units		

TABLE 9.2-3 (Sheet 1 of 2)
COAL-FIRED ALTERNATIVE

Characteristic	Basis
Unit size = 530 MW ISO rating net (note a)	Assumed
Unit size = 562 MW ISO rating gross (note a)	Calculated based on 6 percent on-site power
Number of units = 4	Assumed
Boiler type = tangentially fired, dry-bottom	Minimizes NO_X emissions
Fuel type = bituminous, pulverized coal	Typical for coal used in Alabama
Fuel heating value = 10,878 Btu/lb	2004 value for coal used in Alabama
Fuel ash content by weight = 8.45 percent	2004 value for coal used in Alabama
Fuel sulfur content by weight = 0.84 percent	2004 value for coal used in Alabama
Uncontrolled NO_X emission = 10 lb/T	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS
Uncontrolled SO_x emission = 38lb/T	Typical for pulverized coal, tangentially fired, dry bottom, NSPS (adjust for fuel sulfur content)
Uncontrolled CO emission = 0.5 lb/T	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS
Heat rate = 10,000 Btu/kWh	Typical for coal-fired, single-cycle steam turbines
Capacity factor = 0.85	Typical for large coal-fired units
Fuel consumption = 7,694,000 Tpy	Calculated from the above values
NO_X control = low NO_X burners, overfire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NO_X emissions
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions
SO_X control = Wet scrubber – limestone (95 percent removal efficiency)	Best available for minimizing SO_X emissions
Uncontrolled PM = 10 lb/ton Uncontrolled PM-10 = 2.3 lb/ton	Typical for pulverized coal, dry bottom (Reference 8, Table 1.1-4).

TABLE 9.2-3 (Sheet 2 of 2)
COAL-FIRED ALTERNATIVE

Note a - The difference between “net” and “gross” is electricity consumed on-site

Btu = British thermal unit

ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity and 14.696 pounds of atmospheric pressure per square inch

Heat Rate (a measure of efficiency) = the reciprocal of thermal efficiency, units of Btu/kWh.

kWh = kilowatt hour

NSPS = New Source Performance Standard

lb = pound

MW = megawatt

NO_X = nitrogen oxides

SO_X = oxides of sulfur

Tpy = U S Short ton per year

lb/T = pound per U S Short ton

TABLE 9.2-4
AIR EMISSIONS FROM THE 2120 MW NATURAL GAS-FIRED ALTERNATIVE

Parameter	Calculation	Result
Annual Gas Consumption	$4\text{ units} \times \frac{551\text{ MW}}{\text{unit}} \times \frac{6040\text{ Btu}}{\text{kWh}} \times \frac{1000\text{ kW}}{\text{MW}} \times 0.85 \times \frac{\text{cf}}{1025\text{Btu}} \times \frac{8760\text{ hr}}{\text{year}}$	96,704,725,229 cf/yr
Annual Btu Input	$\frac{96{,}704{,}725{,}229\text{ cf}}{\text{yr}} \times \frac{1025\text{Btu}}{\text{cf}} \times \frac{\text{MMBtu}}{1{,}000{,}000\text{ Btu}}$	99,122,343 MMBtu/yr
SO_X	$\frac{0.0034\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2000\text{ lb}} \times \frac{99{,}122{,}343\text{ MMBtu}}{\text{yr}}$	169 Tpy
NO_X	$\frac{0.036\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2000\text{ lb}} \times \frac{99{,}122{,}343\text{ MMBtu}}{\text{yr}}$	1784 Tpy
CO	$\frac{0.015\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2000\text{ lb}} \times \frac{99{,}122{,}343\text{ MMBtu}}{\text{yr}}$	743 Tpy
PM (particulate matter)	$\frac{0.0019\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2000\text{ lb}} \times \frac{99{,}122{,}343\text{ MMBtu}}{\text{yr}}$	94 Tpy
PM-2.5	94 Tpy (all PM is PM-2.5)	94 Tpy

Note: the calculation in this table is done only in English units

PM-2.5 = particulates having diameter of 2.5 microns or less

TABLE 9.2-5 (Sheet 1 of 2)
NATURAL GAS-FIRED ALTERNATIVE

Characteristic	Basis
Unit size = 530 MW ISO rating net (note a)	Assumed
Unit size = 551 MW ISO rating gross (note a)	Calculated based on 4 percent on-site power
Number of units = 4	Assumed
Fuel type = natural gas	Assumed
Fuel heating value = 1025 Btu/ft^3	USDA TechLine Fuel Value Calculator (Reference 12)
Fuel consumption = 96,704,725,229 ft^3/yr	Calculated from above values
Fuel SO_X content = 0.0034 lb/MMBtu	
NO_X control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_X emissions
Fuel NO_X content = 0.036 lb/MMBtu (GE value of 15.5 g/GJ)	Typical for large GE units
Fuel CO content = 0.015 lb/MMBtu	Typical for large SCR-controlled natural gas-fired units
Fuel PM-2.5 content = 0.0019 lb/MMBtu (note b)	
Heat rate = 6040 Btu/kWh	
Capacity factor = 0.85	Assumed based on performance of modern plants

Note a - The difference between "net" and "gross" is electricity consumed on-site.

Note b - All particulate matter is PM-2.5.

Btu = British thermal unit

ft^3 = cubic foot

ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity and 14.696 pounds of atmospheric pressure per square inch

kWh = kilowatt hour

TABLE 9.2-5 (Sheet 2 of 2)
NATURAL GAS-FIRED ALTERNATIVE

MM = million

MW = megawatt

NO_X = nitrogen oxides

PM-2.5 = particulates having diameter of 2.5 microns or less

TABLE 9.2-6
COMPARISON OF ENVIRONMENTAL IMPACTS OF ALTERNATIVE ENERGY SOURCES TO A NEW NUCLEAR UNIT

Category	Nuclear	Coal	Natural Gas	Combinations
Air Quality	SMALL	MODERATE	SMALL to MODERATE[(a)]	SMALL to MODERATE[(a)]
Waste Management	SMALL	MODERATE	SMALL	SMALL
Land Use	SMALL	SMALL	SMALL	SMALL to LARGE
Water Use and Quality	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	SMALL	SMALL
Ecology (including threatened and endangered species)	SMALL	SMALL	SMALL	SMALL to MEDIUM
Socioeconomic	SMALL to LARGE (Adverse) to LARGE (Beneficial)	SMALL (Adverse) to LARGE (Beneficial)	SMALL (Adverse) to LARGE (Beneficial)	SMALL (Adverse) to LARGE (Beneficial)
Aesthetics	SMALL	SMALL to MODERATE[(b)]	SMALL	SMALL to MODERATE
Historic and Cultural Resources	SMALL	SMALL	SMALL	SMALL
Environmental Justice	SMALL	SMALL	SMALL	SMALL

a) Impacts would be SMALL to MODERATE, but substantially greater than nuclear generation.

b) Coal deliveries by rail would add visual and noise impacts associated with unit-train traffic.

9.3 ALTERNATIVE SITES

This section identifies and evaluates a set of alternatives to the Tennessee Valley Authority (TVA) BLN site. The objective of this evaluation is to verify that a reasonable suite of candidate sites have been considered, and that there is no "obviously superior" site for the eventual construction and operation of a new nuclear plant. The siting process considered the potential use of brownfield sites previously developed and permitted for nuclear generation but not completed; operating nuclear power plant sites within the TVA power service area as well as an undeveloped greenfield site.

The applicant of record for this combined license (COL) is the TVA, who would be the sole owner and operator of the BLN project. As part of its function as an independent, multipurpose federal corporation established under the TVA Act, TVA provides reliable, low-cost electricity throughout its power service area. The selection of preferred sites for particular facilities, including the present BLN site, involves the balancing of engineering, environmental and economic factors related to the sequence of development of the TVA power system.

9.3.1 THE SITE-COMPARISON PROCESS

As required by National Environmental Policy Act (NEPA) and Part 51.45 of Title 10 of the Code of Federal Regulations (10 CFR 51.45) alternatives must be considered. The Electric Power Research Institute (EPRI) Siting Guide (Reference 1) is used as a general guideline. This document is the industry standard for site selection and ESP (Early Site Permit) preparation, and is additionally appropriate to use with the COL application. As stated in the siting guide, the objective of site comparison is "to identify and rank a relatively small number of candidate sites for a more detailed study, with the goal of selecting a preferred site from among candidate sites.

However, the Nuclear Regulatory Commission (NRC) "has noted that a full-scale, systematic siting process may not be necessary to justify selection of an existing site…" For example, guidance provided to NRC staff on their review of alternative site analyses (NUREG-1555, Section 9.3, III (8)) states, in part (emphasis added):

> "*Recognize that there will be special cases in which the proposed site was not selected on the basis of a systematic site-selection process. Examples include facilities proposed to be constructed on the site of an existing nuclear power facility previously found acceptable on the basis of a NEPA review and/or demonstrated to be environmentally satisfactory on the basis of operating experience…"*

The rationale behind this guidance is that "existing nuclear power facility sites have previously been reviewed by NRC and found to satisfy the principle that no obviously superior site existed at the time of original licensing.

Based upon a combination of factors discussed in Subsection 9.3.3, the BLN site was ultimately identified for the proposed development of a COLA and siting of the AP1000 units. The economically and environmentally preferable use of existing assets with some existing infrastructure, or those previously permitted for construction by the NRC arose as a primary consideration for alternative sites within the region of interest (ROI). As a part of the site comparison process, additional issues such as environmental impacts, land use, transmission, proximity to population centers, and economical viability are considered. A greenfield site is also discussed.

9.3.2 DATA DEVELOPMENT AND EVALUATION

This subsection discusses the process by which TVA defines its ROI, and conducted screening and selection of candidate areas, potential sites, and candidate sites. Additionally, this subsection discusses the generic issues for the evaluation and comparison of alternative candidate sites with the BLN site.

9.3.2.1 Region of Interest

TVA sells electricity in bulk to the residents of its power service area through locally owned distributors. Most business and industrial customers are also serviced in this manner, but a few (approximately 60) are directly served customers of TVA. The geographical scope of TVA's ROI is the seven-state area comprising TVA's defined service area. It consists of the Tennessee River watershed, the Cumberland River watershed, and surrounding environs with environmental diversity ranging from riparian habitat along rivers and lakes to rugged mountain ranges to lowlands. The Tennessee River watershed covers approximately 41,000 sq. mi. and includes 129 counties within much of Tennessee and parts of Alabama, Kentucky, Georgia, Mississippi, North Carolina and Virginia. The larger TVA service area covers 81,000 sq. mi. and includes 201 counties in the same seven states. This choice reflects the power region mandated to be served by TVA under the TVA Act as amended (1959), the area in which TVA has transmission capability adequate to distribute the power where needed, and the region for which analyses have established a need for power (Section 8.4), thereby indicating a need for the BLN facility. No potentially desirable TVA candidate areas are excluded; a description of the screening methodology employed by TVA is provided in Subsection 9.3.2.2.

The broad diversity of environmental and current large size of the customer service area indicate the ROI is adequately extensive and would not be improved by an increase in geographical area. Additionally, all of the identified candidate sites meet threshold criteria (see discussion below). The ROI currently includes a diverse mix of power generation including hydroelectric, coal-fired, nuclear, combustion turbine, pumped storage, solar, wind, and methane.

9.3.2.2 Identification and Screening of Potential Sites within the ROI

One of the earliest, integral, and most critical components of planning for future energy facilities has been the identification and selection of suitable locations for their construction and operation. As well as providing a basis for selection of the most preferable sites, a systematic screening process eliminated many potentially unsuitable locations before detailed, expensive, and time-consuming investigations were committed. The more favorable potential sites have undergone detailed investigations to determine both their basic engineering and environmental feasibility.

Historically and on an ongoing basis, particularly through the 1960s, 1970s, and into the 1980s, TVA conducted initial high-level screening assessments of numerous (more than 200) sites for generation across the TVA service area. Broadly based interdisciplinary TVA teams reflecting power planning, transmission, environmental, and financial interests conducted these efforts. At various points, these studies identified 24 sites that warranted further detailed investigations, including further study of physical characteristics such as: studies of foundation conditions, site archaeology, meteorology and hydrology. As discussed in Subsection 9.3.2.2, of these, nine were subsequently selected for purchase as inventory. Over time, as TVA has had to make decisions in response to the growing need for power generation, the suitability of the most attractive sites has been re-evaluated (including addition to, restart, or completion of existing or partially-completed nuclear assets) as to their continued viability for the purpose of operating nuclear power generation facilities. In addition, TVA considered the potential use of the three sites where it has existing operating plants. TVA has documented these site comparisons and decisions in a series of environmental review documents made publicly available under the requirements of NEPA. These include:

1. Final Environmental Statement – Bellefonte Nuclear Plant Units 1 and 2 (Reference 2).

2. Final Environmental Statement – Hartsville Nuclear Plants (Reference 3).

3. Environmental Report – Phipps Bend Nuclear Plant Units 1 and 2 (Reference 4).

4. Final Environmental Statement – Yellow Creek Nuclear Plant Units 1 and 2 (Reference 5).

5. Final Environmental Impact Statement – Coal Gasification Project (Reference 6).

This iterative approach has reduced the list of appropriate sites down to the current set of candidate sites (BLN and alternatives –Yellow Creek, Phipps Bend, Hartsville and Murphy Hill) for the proposed project. Each of the documents for BLN, Hartsville (HVN), Phipps Bend (PBN), and Yellow Creek (YCN) were submitted to the NRC, or its predecessor, the Atomic Energy Commission (AEC) as part of the permitting process for the respective plants. (For simplicity, the name NRC is used throughout the remainder of this Section 9.3 when referring to either agency). Each of these plants received a construction permit from the NRC after that agency's review found the sites acceptable for construction of the nuclear plants planned at that time for the sites. The initial site studies referenced were extensive in evaluating and describing the respective sites. The process leading to selection of those sites as superior sites among potential sites is discussed below. Additionally, the information pertinent to analyzing differences between the sites has been updated and is discussed under Subsection 9.3.3 comparing the sites as well as validating their continued viability as licensable.

Among sites previously considered, nine preferable locations for meeting TVA's power supply needs and meeting the criteria for the site-screening process described below were identified and purchased as "inventory" for nuclear generation sites. TVA constructed multi-unit nuclear generation facilities at three of these sites: Browns Ferry Nuclear Plant near Athens, Alabama, Sequoyah Nuclear Plant near Chattanooga, Tennessee, and Watts Bar Nuclear Plant near Spring City, Tennessee. TVA additionally obtained construction permits from the NRC to build nuclear units at the BLN, YCN, HVN, and PBN sites. As described in Subsection 9.3.2.4, site preparation and construction of nuclear units proceeded by varying degrees at each of these sites. Due to the slowing of demand for power, TVA subsequently halted construction at these latter sites and, as described in Subsection 9.3.3, conveyed portions of three sites (HVN, PBN, and YCN) to other governmental entities for potential industrial development. In addition to the permitted sites, TVA also purchased and, to date, has maintained two additional greenfield sites in its inventory of potential nuclear sites: Murphy Hill (MH) and Saltillo. All of these nine sites met, and the four permitted sites, for which TVA did not complete nuclear units, continue to meet the NRC criteria for acceptable candidate sites. For the Saltillo site, however, there are substantive unanswered questions regarding the acceptability of the underlying foundation conditions that would need to be addressed before it could be considered an acceptable site for the present decisions. Additionally, the site selection analysis in the TVA EIS for YCN site concluded that the Saltillo site was not superior to the YCN site. Accordingly, Saltillo was relegated to the second (lesser) tier and is not considered further.

The remaining eight sites are discussed in the comparisons of Subsection 9.3.3.

Further screening occurred in the preparation of TVA and NRC environmental impact statements (EISs) pertinent to selection of Watts Bar and Sequoyah Nuclear plants, and Yellow Creek, Phipps Bend, and Hartsville as the prime sites for nuclear generation. In each review alternative sites were rejected in favor of the preferred alternative. These other potential sites were eliminated from further consideration. The criteria considered in these evaluations are identified below.

1. The site characteristics identified in the earlier EISs.

2. The selected sites received evaluations under NEPA (from both TVA and the NRC) that included comparisons for environmental impacts and engineering feasibility as nuclear plant sites with the alternative sites.

3. The selected sites were determined to be licensable and received construction permits for nuclear units from the NRC that resulted from the licensing process.

4. The sites were subsequently disturbed during site preparation and construction and are now considered brownfield (e.g., many construction-related impacts have already occurred).

5. The updated site information as discussed in Subsection 9.3.3 indicates the selected sites are still viable, although TVA may have to re-purchase some property previously conveyed for industrial uses. They meet NRC criteria for candidate sites and continue to constitute a reasonable suite of alternatives representing the best available sites in the TVA power service area. Environmental evaluations of these sites, including any newly acquired land purchases outside the original site boundaries, are performed to demonstrate they still meet NRC criteria.

Although a greenfield site is not considered environmentally preferable for a number of reasons, TVA has considered the Murphy Hill greenfield site among the present candidate sites. MH was initially acquired by TVA as a preferred generation site. A greenfield site is generally not considered environmentally preferable for the following reasons:

1. A large land area would typically need to be acquired and disturbed to build the new plant, potentially causing large land use change, as well as impacts to ecological resources and aesthetic impacts.

2. New transmission lines and corridors would be necessary to tie in to the existing grid. Cumulative impacts from construction and maintenance of additional transmission corridors would occur.

3. Local transportation routes and access roads may need to be built or upgraded.

4. Cumulative impacts to terrestrial and aquatic resources would be greater than those incurred from development of an existing brownfield or partially developed site.

5. Aesthetic impacts from construction and operation of a nuclear generating plant at a greenfield site would be similar to or greater than those at an existing brownfield site.

6. Site development costs for a greenfield site are substantial, especially with regard to building the required infrastructure and conducting the site characterization studies.

The need to obtain land, including easements, from third parties, as well as the considerable size of property that would need to be obtained, would also make greenfield sites, other than the MH site that TVA already owns, even less favorable. This consideration also holds true for existing nuclear facilities for which additional land must be obtained. The MH greenfield site was chosen and evaluated as a site that is representative of other greenfield sites that TVA has previously evaluated. Based on known information, no other sites were determined to be environmentally preferable to MH. In summary, the environmental impacts of construction and operation of a nuclear power generation facility at a greenfield site would be similar to or greater than those at a brownfield or partially developed site. Therefore, a greenfield site would not be obviously superior to the proposed brownfield, or other partially developed locations among the candidate sites. This issue is further discussed in Subsection 9.3.2.4.3 and 9.3.2.5, as well as specifically evaluated for the candidate greenfield site, Murphy Hill, in subsections of the Section 9.3 Alternative Site Review.

9.3.2.3 Methodology for Identification and Screening of Potential Sites

During the initial identification, review, and screening of potential sites for generating facilities within the power service area (present ROI), TVA used a cyclical analysis of various engineering, environmental, land use, cultural, and institutional data. The screening process was designed to address the interface between environmental and engineering concerns. The iterative nature and development of this process is described in the following paragraphs. Four general criteria were used to guide potential site identification.

1. The identification of potential site areas, which exhibited a suitable combination of engineering, environmental, land use, cultural, and institutional characteristics for power plant siting.

2. The identification of potential site areas of a developable size (1000 ac. or more).

3. The identification of a manageable number of potential sites.

4. The identification of a relatively even distribution of potential sites along the Tennessee River corridor and within the defined TVA service area that meet projected supply and load requirements.

For the purposes of identifying an adequate number of sites that address TVA load requirements across the region (to meet the fourth objective identified above), the TVA service region (the ROI for the present considerations) was divided into five system study areas that roughly coincided with the concentration of load centers in the region. This division does not represent a real physical division in the power service area because all these areas are strongly interconnected with transmission lines. One purpose of this approach was to identify superior sites within each area that would reduce the need for construction of additional transmission to meet load requirements. This concern remains valid today, but load growth across the TVA service areas, as well as improved transmission system characteristics and ability for load balancing, now further reduces that concern. The suite of candidate sites currently under consideration represents superior sites identified in this process (excluding those sites at which TVA has already developed nuclear generation).

The following criteria included in the process for preliminary site screening and used to judge the superior sites as candidate sites:

1. Map reconnaissance, aerial survey, and field reconnaissance.

2. Land use and ownership assessment.

3. Proximity to existing transmission lines.

4. Site access by rail, highway, and barge.

5. Proximity to population centers.

6. Seismology.

7. Availability of cooling water and/makeup water, and water use compatibility.

8. Topography of the site.

9. Flooding conditions.

10. Foundation conditions.

11. Proximity to, and impact upon, significant recreational, wildlife, or cultural areas.

For these early siting considerations, TVA developed an “optimization” model approach that segmented the Tennessee Valley and surrounding power service area into a fine geographical grid, termed "cells." The model identified cells in the study areas representing the coincidence of the best engineering, environmental, land use, cultural, and institutional characteristics in the database. An engineering “attractiveness” model and a "vulnerability" model based on environmental and land use considerations were used to identify those sites with the highest engineering attractiveness and the lowest environmental/land use impact. The "Attractiveness - Vulnerability" interface allowed for a systematic iterative consideration of levels of vulnerability for resources or decrease in engineering attractiveness. From the consideration of engineering feasibility, environmental impact, and economics, and after assessing the merits of each site, TVA selected the sites for development or purchase for inventory which were judged to offer more favorable overall characteristics with the least environmental impact from development as a nuclear facility.

9.3.2.4 Description of Potential Sites

The four brownfield site locations, three operating nuclear plants, and the greenfield site described below are illustrated on Figure 9.3-1.

9.3.2.4.1 Operating Plants

The three operating TVA nuclear plants within the ROI are Browns Ferry (BFN), Sequoyah (SQN) and Watts Bar (WBN). BFN is on the north shore of Wheeler Reservoir in north Alabama. It was TVA's first nuclear power plant, beginning commercial operations in 1974. Unit 1 had been idle since 1985, but resumed operations in 2007. The three operating units at BFN are boiling water reactors. SQN is located in East Tennessee 18 mi. north of Chattanooga on the banks of Chickamauga Reservoir. Unit 1 began commercial operation in 1981, with Unit 2 coming on line the following year. Both units are pressurized water nuclear reactors. WBN is located just south of Watts Bar Reservoir on the Tennessee River near Spring City in East Tennessee. WBN is currently a single-unit pressurized water nuclear reactor in commercial operation since 1996. In 2007, TVA announced it plans to complete construction of WBN Unit 2, and the project is expected to take about five years. When completed, the unit will supply enough electricity to serve about 650,000 homes. More than 2,000 contract workers will be needed at the height of construction, and about 250 permanent new jobs will be created at the site.

In addition to site-specific characteristics that may exclude acceptability as candidate sites, there are both advantages and disadvantages offered by co-locating new nuclear units at existing nuclear generating facilities.

Advantages of co-location include:

- Depending on available capacities, infrastructure and support facilities may sometimes be able to also support new units
- Adequate land to site additional units may be available
- Many sites have already gone through the alternatives review process required by NEPA and were the subject of environmental screening in an earlier selection process

- Environmental impacts of existing plants are known, and impacts of a new facility should be similar to those of the operating facility (although this may be a disadvantage if some impacts are compounded by the addition of new facilities and increased beyond acceptable limits)

- Site information characterizing and determining site suitability is available

- Adequate transmission infrastructure may be available

- Local acceptance of such a facility may be greater

- Site development, construction, installation, operation and maintenance costs may be lower.

Disadvantages include:

- Cumulative impacts to natural resources or human populations or communities may be greater

- Although adding capacity at an existing nuclear site may address an overall system capacity need, co-location may not address system balancing needs, and create the need to construct more transmission infrastructure than would otherwise be needed by a stand-alone facility located elsewhere on TVA's system

- Operation of the existing nuclear facility may be adversely impacted, especially during the construction period

As a part of TVA's energy resource planning processes, TVA has at various times evaluated the potential for new generation at existing nuclear plant sites. When considered for co-location, the three operating TVA nuclear generating plants in the relevant service area display, to varying degrees, both the advantages and disadvantages noted above. For each of the three sites where TVA currently operates nuclear units, those aspects that were a deciding factor in TVA's considerations regarding their potential for co-location are discussed below. The reasons primarily focus upon: potential thermal issues and their interactive impacts to the operation of units already operating at the site; unavailability of adequate land without potential for substantive impacts to rapidly growing residential communities; or large scale changes underway on-site that will entail the need for additional operational monitoring to confirm impact predictions and reduce uncertainty (i.e., a timing issue). For these reasons, TVA has concluded that co-location at its operating nuclear plants is not an acceptable alternative for the AP1000 units currently under consideration.

Browns Ferry Nuclear Plant Site

The Browns Ferry site on Wheeler Reservoir in Alabama has two substantive limitations regarding its potential for co-locating additional units. Although BFN has an excellent record regarding compliance with its NPDES-stipulated thermal limits, the AP1000 units, even operating in closed cycle mode, would increase thermal loading to Wheeler Reservoir. This cumulative addition could exacerbate the existing challenges to managing the three BFN units in compliance with thermal limits, especially during low flow or drought conditions, and could require substantive modification to plant intake and cooling system infrastructure producing associated additional construction impacts and costs. In recent experience, TVA has already derated or taken existing BFN units out of service to maintain thermal compliance. These occurrences have not only substantive financial consequences, but could reduce TVA's ability to provide reliable power. Additionally, the Browns Ferry site is approximately 850 ac. with three operating nuclear units. There is not sufficient property to accommodate additional units and additional property would have to be acquired.

Because of these site issues, TVA has decided that co-locating the AP1000 units at BFN is not advantageous and does not consider this a viable alternative for purposes of this report.

Watts Bar Nuclear Plant Site

The WBN site is approximately 1100 acres with one operating nuclear unit. TVA has recently decided to complete the partially completed WBN Unit 2. Any delay in completing WBN Unit 2 would likely result in overlapping construction of the AP1000 units. This would unnecessarily affect not only project management resources, but produce greater strain on plant operations, local community services and infrastructure. It also is anticipated that once WBN Unit 2 is completed and operating, the discharge of the combined total thermal discharges to the river will more often approach allowable NPDES thermal limits. Co-locating the two AP1000 units at the site would exacerbate this thermal loading situation and potentially affect the operation of WBN Units 1 and 2. Because of these site issues, TVA has decided that co-locating the AP1000 units at WBN is not advantageous and does not consider this a viable alternative for purposes of this report.

Sequoyah Nuclear Plant Site

The 629-ac. SQN site has two operating units. The site is not large enough to accommodate additional units and additional land would have to be obtained. Because residential communities in close proximity to SQN have grown significantly, it would be difficult and costly to expand the site and doing so would significantly disrupt the nearby residential communities. As in the case of BFN and WBN, the SQN site has a small thermal discharge margin that would be exacerbated by co-locating the AP1000 sites there. Because of these site issues, TVA has determined that co-locating the AP1000 units at SQN is not advantageous and does not consider this a viable alternative for purposes of this report.

Based on decisions made by TVA regarding their existing operational facilities and described in this subsection, no further discussion is provided for the consideration of existing operational sites as potential sites for the proposed project.

9.3.2.4.2 Brownfield Sites

Brownfield sites considered include BLN, HVN, PBN, and YCN. For each of the four brownfield sites, construction permits were applied for and obtained under the regulations and evaluation procedures of the period. Although nuclear plant construction was never completed at any of these sites, they offer many of the operating nuclear site advantages mentioned previously. An added incentive for TVA would be making use of unused assets. A description of the four sites follows.

The former Bellefonte Nuclear Plant site is located on Guntersville Reservoir near the towns of Hollywood and Scottsboro, Alabama. The site is relatively flat, with the exception of lands next to the reservoir, which form low cliffs. The site is surrounded by water on three sides, and a portion of the site is forested. Construction activities at BLN were deferred in 1988. The candidate site is reviewed at length in the ER, and figures throughout Chapter 2 illustrate various aspects of this site. A generalized view of the BLN site, including the construction right-of-way (ROW), is provided in Figure 9.3-2.

The former Hartsville Nuclear Plant site is situated on the north shore of Old Hickory Reservoir at Cumberland River mile 284 in Smith and Trousdale counties, Tennessee. The site is located on the 100-year floodplain of the Cumberland River, adjacent to dissected highlands. The HVN site nuclear units were cancelled in 1982 and 1984, respectively. Located within the 6-mi. radius of the site is the town of Hartsville to the west-northwest with a population of 2395.The site location and 6-mi. vicinity is presented in Figures 9.3-3 and 9.3-4.

The former Phipps Bend Nuclear Plant site is located at river mile 120 on the Holston River in Hawkins County, Tennessee. It is located in an area of moderately high ridges with flood plains along the bank of the river; the region is dominated by a broken pattern of open valleys interrupted by steep, forested ridges. Site elevation varies from 1100 to 1260 ft. msl. Within the 6-mi. radius of the site are the towns of Church Hill to the northeast, with a population of 5916 and Surgoinsville to the west, with a population of 1484. Transient populations in the area are primarily associated with camping and other activities associated with the Holston River. Construction of the units for PBN was cancelled in 1982. Figures 9.3-5 and 9.3-6 illustrate the site location and the 6-mi. vicinity, respectively.

The former Yellow Creek Nuclear Plant located at river mile 5 on the Yellow Creek embayment of Pickwick Lake. The area consists of a moderately dissected plateau in a transition zone between coastal plain environments and narrow, steep-sided valleys. Site elevation ranges from 500 to 600 ft. msl. There are no towns within the 6-mi. radius; Iuka, with a population of 3059 lies approximately 9 mi. to the north. The YCN site is located in an area that is rural in character and is used predominantly for forest and agricultural purposes. Recreational use of the reservoir accounts for the majority of the transient population in this area. Construction at YCN was cancelled in 1984. The site location is illustrated in Figure 9.3-7, and the 6-mi. vicinity map is shown in Figure 9.3-8.

The HVN, PBN, and YCN sites, or portions thereof, were sold for industrial development. Because the NRC has previously approved each site for the construction of a nuclear generating plant, they are included as potential sites for this comparison. TVA would need to reacquire portions of the industrial parks with some degree of impact to the existing industrial uses on developed areas of the sites.

Transportation corridors to all four of the sites were constructed to facilitate construction of the nuclear plants. Additional information on the current status of these sites is provided in the following paragraphs.

The Yellow Creek site in Tishomingo County, Mississippi, consisted of approximately 1149 ac., of which 13 ac. have been retained by TVA. The remaining 1136 ac. were transferred to the Tishomingo County Board of Supervisors and are now part of the Tri-State Commerce Park. This 3500-ac. industrial park, of which the former TVA property is a portion, is contiguous with the former TVA property on two sides; i.e., to the north and east. Most of the former TVA land at this site has been developed, with only a few parcels not currently in use. Other than the development on the former TVA property, the remainder of the industrial park is basically undeveloped with no current users. Industries in the portions of the park which were part of the former TVA site include aerospace-related firms, millwork, and fiberglass manufacturing. Employment is about 300. A new announcement of another fiberglass-related manufacturer was made recently, with an expected employment of 120. Other than the development on the former TVA property, the remainder of the industrial park is basically undeveloped with no current users. TVA would need to reacquire at least a portion of the former YCN site, as well as additional industrial park property. Siting of a two-unit nuclear plant at YCN could involve the acquisition of both currently developed and undeveloped portions of the industrial park with some potential disruption of existing industrial uses. Based on examination of topographic and aerial photographic information, the physical and ecological conditions of the undeveloped portions of the industrial park are expected to be very similar to the portions of the peninsula evaluated in the earlier TVA EIS for the YCN site. A combination of developed and undeveloped portions of the industrial park would provide an adequate amount of property to site and operate a two unit nuclear facility with potentially minor to moderate effects on the existing uses of the industrial park.

The Phipps Bend site in Hawkins County, Tennessee, consisted of approximately 1284 ac., of which TVA has retained 102 ac. for transmission facilities. The remainder was sold and is now the Phipps Bend Industrial Park. The undeveloped portion of the park adjacent to the retained 102 ac. of TVA property is about 300 ac. In order to construct and operate a two-unit nuclear plant at the PBN site, TVA would need to reacquire portions of the industrial park with some degree of impact to existing industrial uses of the site.

The Hartsville site is in Tennessee, largely in Trousdale County, with a small portion in adjacent Smith County. The site is approximately 1931 ac., of which 554 ac. are now the PowerCom Industrial Center. TVA has retained 1377 ac., which include a transmission ROW. The original plans for the HVN site included construction and operation of four nuclear generating units. TVA currently owns enough of the HVN site to construct two nuclear units. The TVA property, which wraps around most of the PowerCom property, has various structures that could be used for industrial or commercial purposes as well as land with development potential. About 400 ac. of the PowerCom property is currently available for industrial use. Buildings and facilities for industrial or commercial use have been constructed at two locations on the Power Com site. One of these locations, called Village One, has several buildings, with a total of 242,000 square feet, of which 84,000 square feet are occupied. This location is in the northwest corner of the Industrial Center, near the western edge of the original nuclear site. The other location, Village Two, is located in the southwest corner of the original site. Village Two also has several buildings, with a total of 248,000 square feet. Of this, 96,000 square feet are currently used by TVA for storage purposes and 4,000 square feet are used by the state of Tennessee. The remaining 148,000 square feet are vacant. Other developments on the site are from the earlier TVA nuclear construction. Given the location of Village One and Village Two, adequate acreage would still be available for nuclear power construction and operation.

The NRC granted the construction permits for the BLN in 1974. In 1988, TVA deferred completion of the plant, with Unit 1 at 90 percent complete and Unit 2 at approximately 57 percent complete. The NRC approved TVA's request to terminate the construction permits for this unfinished plant in September 2006. Existing environmental permits at the site have been maintained. TVA has retained ownership of the entire site. Several major plant components on-site remain potentially usable, including water intake and discharge facilities, cooling towers, and transmission switchyards and corridors. The construction access routes remain complete for this facility.

Each of the original environmental documents (References 2, 3, 4, and 5) supported the NRC licensing process for the respective plants (except MH). Each plant received a construction permit after the NRC review found the sites acceptable for construction of the nuclear plants planned at that time for the sites. These brownfield sites were fully evaluated in all environmental effect areas to qualify for the construction permit issued. These referenced reports formed the basis of the information used in the evaluation and comparison of the required studies of physical characteristics mentioned above. Additional information was obtained to update or supplement these reports where necessary for this process including to facilitate evaluation of proposed actions such as the BLN fossil fuel evaluation and the HVN, PBN, and YCN land transfers.

9.3.2.4.3 Greenfield Sites

A greenfield site is useful as a bounding comparison for identifying on-site impacts. This concept has been used by the NRC in other licensing activities, where the NRC has developed generic characteristics of a greenfield site for comparison during license renewal. Some of the issues identified for greenfield sites in NUREG-1437, *Generic Environmental Impact Statement (GEIS) for License Renewal,* can correlate with the issues the applicant faces in determining the superiority of the proposed site.

The Murphy Hill site consists of approximately 1200 ac. located in northeast Marshall County, Alabama, on the southern bank of Guntersville Reservoir at Tennessee River mile 370. Most of the site is forested with the remainder a combination of pastureland or cultivated fields. No development has occurred on this site to date and it is currently designated by TVA for natural resource conservation purposes. This classification focuses on the enhancement of natural resources for human use and appreciation (i.e., informal recreation). There are two small towns located within the 6-mi. radius of the site. To the west-northwest, Grant supports a population of 665 and Langston to the northeast houses 254 people. Figures 9.3-9 and 9.3.10 illustrate the site and the 6-mi. vicinity.

9.3.2.4.4 Summary of Screening Process

TVA evaluated and selected these five sites as candidate sites in their ROI for potential siting of a new nuclear facility. Each candidate site meets the eight minimum NUREG-1555 criteria for site selection. The TVA site-comparison process resulted in the choice of BLN as the proposed site for further study.

This completes the description of the comparison process and the method used to select the candidate sites for analysis. The remainder of this section compares the BLN project site and the alternative sites on the expected environmental effects, then on economic, technical, and other benefits and costs. These comparisons include effects from both plant construction and operation. They include both supporting and adverse information where available. Sufficient data are provided to aid the NRC in its development of an independent analysis as outlined in NUREG-1555. The original data that were used in the site-comparison process for each site, as well as updated information, are used in the alternate site evaluation (ASE), including results of site-specific field investigations. The comparison of data is given in text and appropriately summarized in Tables 9.3-1 and 9.3-2.

9.3.2.5 Generic Issues for Alternative Sites

Several issues were identified for which the potential impacts of construction and operation of new nuclear power plants would be sufficiently similar among the proposed and alternative sites that detailed site-specific evaluation of the potential impacts would not contribute to the determination that one or more of the alternative sites are obviously superior to the proposed site. Some issues such as land use and ownership show sufficient variation among the sites that a site-specifc discussion is warranted; whereas others, such as air quality can be considered more generically. As discussed below, these non-differentating aspects may include either, or both, construction and operational impacts.

Air Quality:

Air quality impacts of construction and operation of a new nuclear unit would likely be similar at the BLN site and the alternative sites. The construction impacts would include dust from disturbed land, roads, and construction activities and emissions from construction equipment. These impacts would be similar to the impacts associated with any large construction project. A discussion of measures that TVA would take to mitigate air quality impacts at the proposed BLN site is provided in Chapter 4. The same or similar measures would be taken if a new nuclear unit were to be constructed at any of the alternative sites.

For purposes of the evaluation of alternative sites, it is reasonable to assume that the air quality impacts of emissions from vehicles used for construction worker transportation likely would be similar at all sites and temporary.

Impacts of operation of a new nuclear plant on air quality are related primarily to the operation of standby generators and cooling towers. The operation of standby generators is independent of the site. Similarly, the quantity of cooling tower drift is generally a function of cooling tower design, not the site. The assumption is made that TVA would comply with all regulations related to emissions from generators. Cooling towers would use current technology to minimize drift. Based on identified limiting meteorological parameters at the sites, aspects of drift are addressed for each of the alternative sites.

The physical impacts of construction would be similar at all of the alternative sites classified as brownfields. People who work or live around the alternative sites could be exposed to noise, fugitive dust, and gaseous emissions from construction activities. Construction workers and personnel working on-site could be the most impacted. Air pollution emissions are expected to be controlled by applicable best management practices and federal, state, and local regulations. All brownfield sites are categorized industrial. The greenfield site is currently designated by TVA for natural resource management.

During station operation, standby diesel generators used for auxiliary power would have air pollution emissions. It is expected that these generators would see limited use and, if used, would be used for only short time periods. None of the candidate sites are located in air quality regions designated as in non-attainment for parameters potentially affected by plant emissions. Applicable federal, state, and local air pollution requirements would apply to all fuel-burning engines. At the site boundary, the annual average exposure from gaseous emission sources is anticipated not to exceed applicable regulations during normal operations. The impacts of station operations on air quality are expected to be minimal. As with construction impacts, potential off-site receptors are generally located well away from the site boundaries.

Terrestrial Ecology

Terrestrial ecological impacts that may result from operation of a new nuclear unit at the alternative sites include those associated with cooling towers, transmission system structures, and maintenance of transmission line ROWs. Conclusions in NUREG-1437, *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), are used to assess terrestrial impacts resulting from the operation of cooling towers. The GEIS evaluated terrestrial ecological impacts resulting from operation of existing nuclear power plants. Because the types of terrestrial ecological impacts resulting from operation of a new nuclear unit would be similar to those of existing nuclear power plants, the GEIS is useful for this analysis. For impacts resulting from transmission line operation and transmission line ROW maintenance, the assumption is made in the GEIS that any existing transmission lines at the alternative sites would not have the capacity to carry the power that would be generated by a new nuclear unit. Therefore, it is also assumed that any transmission system upgrades would require the addition of new lines that would result in expansions of the existing ROWs and that such expansions could consist of doubling current corridor widths. Given these assumptions, conclusions in the GEIS are used for impacts resulting from transmission line operation and transmission line right-of-way maintenance to help bound the potential impacts at candidate sites that are already connected to the grid.

Cooling Towers

The impacts of cooling tower drift and bird collisions for existing power plants were evaluated in NUREG-1437 and found to be of minor significance for all plants, including those with various numbers and types of cooling towers. It is assumed for the purpose of comparing the alternative sites, that the impacts of cooling tower drift and bird collisions with cooling towers resulting from operation of a new nuclear unit at any of the alternative sites would be minor.

For both natural and mechanical draft cooling towers, the anticipated noise level from cooling tower operation is anticipated to be 55 decibels on the A scale (dBA) at 1000 ft. The noise level for dry cooling towers is somewhat higher. This noise level is well below the 80- to 85-dBA threshold at which birds and small mammals are startled or frightened. Thus, noise from operating cooling towers at any of the alternative sites would not be likely to disturb wildlife beyond 1000 ft. from the source.

Further, impacts within this distance would be considered negligible because no important terrestrial species are known to occur on any of the alternative sites. Consequently, it is assumed that the impacts of cooling tower noise on wildlife would be minimal at all the alternative sites.

Descriptions of terrestrial species at the candidate and alternative sites are provided in the specific sections for construction and operational impacts on ecosystems.

Transmission Lines

The impacts associated with transmission line operation consist of bird collisions with transmission lines and electromagnetic field (EMF) effects on flora and fauna The impacts associated with ROW maintenance activities are loss of habitat due to cutting and herbicide application, and similar impacts where ROWs cross floodplains and wetlands. Bird collisions with transmission lines are of minor significance at operating nuclear power plants, including transmission line ROWs with variable numbers of power lines. Thus, although additional transmission lines could be required for a new nuclear unit at the alternative sites, these would likely present few new opportunities for bird collisions. The additional number of bird collisions, if any, would not be expected to cause a measurable reduction in local bird populations. Consequently, the incremental number of bird collisions posed by the addition of new transmission lines for a new nuclear unit would be negligible at all the alternative sites.

EMFs are unlike other agents that have an adverse impact (e.g., toxic chemicals and ionizing radiation) in that dramatic acute effects cannot be demonstrated and long-term effects, if they exist, are subtle. A review of biological and physical studies of EMFs did not reveal consistent evidence linking harmful effects with field exposures. The impacts of EMFs on terrestrial flora and fauna are of small significance at operating nuclear power plants, including transmission systems with variable numbers of power lines.

Since 1997, more than a dozen studies have been published that looked at cancer in animals that were exposed to EMFs for all or most of their lives. These studies have found no evidence that EMFs cause any specific types of cancer in rats or mice. Therefore, the incremental EMF impact posed by addition of new transmission lines for a new nuclear unit would be negligible at all the alternative sites. Existing roads providing access to the existing transmission line ROWs at the alternative sites would likely be sufficient for use in any expanded ROWs, and no new roads would be required. It is anticipated that the same vegetation management practices currently employed to maintain the existing ROWs at the alternative sites would be applied to any ROWs associated with a new nuclear unit. Thus, vegetation management would occur along the same ROWs, but over twice the area, assuming that ROWs would have to be expanded in order to bound potential impacts. Transmission line ROW management activities (cutting and herbicide application) and related impacts on floodplains and wetlands in transmission line ROWs are of minor significance at operating nuclear power plants, including those with transmission line ROWs of variable widths.

Aquatic Ecology

Aquatic ecological impacts that may result from construction and operation of a new nuclear unit at the alternative sites include those associated with cooling water intake, consumption, and water discharge. Ten operational impacts of cooling water systems on aquatic ecology (including issues concerning gas supersaturation, water quality, nuisance organisms, and others) determined to be applicable to current operating nuclear power plants were evaluated in NUREG-1437. These impacts were found to be minimal for all currently operating plants and, based on the nature of these ecological effects, it is expected that they would also be minimal for the next generation of nuclear plants.

However, other potential impacts of water intake and discharge systems on aquatic ecosystems at nuclear power plants are site-specific and depend on factors related to specific features of the design and construction of these systems. Therefore, impingement and entrainment of fish and shellfish and these impacts are discussed separately for each of the alternative sites.

Historic and Cultural Resources

The candidate and alternative sites do not appear to present significant issues concerning historic and cultural resources. Because of some dissimilarity among the sites, the cultural resources of each of the alternative sites are addressed in the site-specific discussions.

Environmental Justice

Because of the importance of the site-specific factors, environmental justice is discussed for the candidate and each alternative site.

Nonradiological Health Impacts

Nonradiological health impacts from construction of a new nuclear unit on the construction workers at the alternative sites would be similar to those evaluated in Section 4.5. They include occupational injuries, noise, odor, vehicle exhaust, and dust. Applicable federal and state regulations on air quality and noise would be complied with during the plant construction phase. None of the alternative sites has site characteristics that would be expected to lead to fewer or more construction accidents than would be expected for any of the other alternative sites. Occupational health impacts to operational employees would likely be the same for all the alternative sites. Thermophilic microorganisms would not be a concern at the alternative sites using either a wet or hybrid wet/dry cooling process. Health impacts to workers from occupational injuries, noise, and electric fields would be similar. None of the alternative sites has site characteristics that would be expected to lead to fewer or more operational accidents than would be expected for any of the other alternative sites. Noise and electric fields would be monitored and controlled in accordance with TVA standards implementing Occupational Safety and Health Administration requirements.

Radiological Impacts of Normal Operations

Exposure pathways for gaseous and liquid effluents from a new nuclear unit on the proposed BLN site or an alternative site would be similar. Gaseous effluent pathways include external exposure to the airborne plume, external exposure to contaminated ground, inhalation of airborne activity, and ingestion of contaminated agricultural products. Liquid effluent pathways include ingestion of aquatic foods, ingestion of drinking water, external exposure to shoreline sediments, and external exposure to water through boating and swimming.

Section 5.4 discusses the estimates of doses to the maximally exposed individual and the general population for a new nuclear plant at the proposed BLN site for both liquid effluent and gaseous-effluent pathways. The estimated doses to the maximally exposed individual were well within the design objectives of 10 CFR Part 50, Appendix I. The same bounding liquid and gaseous effluent releases would be used to evaluate doses to the maximally exposed individual and the population at each alternative site. Even with differences in pathways, atmospheric and water dispersion factors, and population, doses estimated to the maximally exposed individual for the alternative sites would be expected to be well within the regulatory limits.

Postulated Accidents

In Section 7.1, the staff considered a suite of design-basis accidents for a new nuclear unit at the proposed BLN site. The evaluation involved calculation of doses for specified periods at the exclusion area and low-population zone boundaries, and comparison of those doses with doses based on regulatory limits and guidelines. Similar analyses have not been conducted for the alternative sites. Had such evaluations been conducted, the differences in the results would only have been due to meteorological conditions and the distances to the site boundaries. The release characteristics would have been the same at all sites.

For the BLN site, the local topography and meteorology result in doses for each accident sequence considered that are well below the corresponding regulatory limits and guidelines. The general climatological conditions at the proposed site are sufficiently similar to the conditions at the alternative sites, such that it is highly unlikely that differences in local meteorological conditions would be sufficient to cause doses from design-basis accidents for a new nuclear unit at any of the alternative sites to exceed regulatory limits or guidelines.

9.3.3 ALTERNATIVE SITE REVIEW

The alternative sites chosen from within the ROI are compared with the BLN (the proposed site). This comparison is performed to determine whether any alternative sites are obviously superior to the proposed site. Then, this analysis can be extended to consider economic, technological, and institutional factors among the environmentally preferred sites, to see if any are obviously superior in these perspectives. Portions of the studies, data, and conclusions of the initial evaluations of each candidate site are used to support this comparison. The sites are evaluated in each area of comparison and given a numerical rating scale of 1 to 5 (least suitable to most suitable). No weighting factors were applied to these criteria. The conclusion is drawn from a summary table of these ratings.

The alternative site analysis is documented as follows:

- 9.3.3.1 Safety Criteria
  - Geologic Evaluation
  - Cooling System Suitability
  - Plant Safety Evaluation
  - Accident Effects Evaluation
  - Operational Effects Evaluation
  - Transportation Safety Evaluation
- 9.3.3.2 Environmental Criteria

9.3.3.1 Safety Criteria

Geologic Evaluation:

Although nuclear plants are designed to withstand a certain earthquake hazard, the prediction of earthquake timing and severity is subject to many uncertainties. Consequently, the objective of this criterion is to avoid proximity to seismological hazards. Sites with the least seismic risk are rated the highest.

The Modified Mercalli (MM) Scale is one measure of the intensity of an earthquake. The scale quantifies the effects of an earthquake on the Earth's surface, humans, objects of nature, and fabricated structures on a scale of 1 through 12, with 1 denoting the weakest earthquake and 12 denoting one that causes the greatest destruction. The lower degrees of the MM scale generally deal with the manner in which the earthquake is felt by people. The higher numbers of the scale are based on observed structural damage. This value is translated into a peak ground acceleration (PGA) value to measure the maximum force experienced. The PGA is measured in terms of percent of “g,” the acceleration due to gravity. As an exclusionary criterion, the maximum level of ground motion specified by EPRI is PGA 0.30 g (30 percent g) at a probability of exceedance (PE) of 2 percent in 50 years, translating to once in 2500 years.

For purposes of candidate site comparison based on vibratory ground motion, the PGA with a 2 percent probability of exceedance in 50 years (USGS 2008 seismic hazard maps) and the bedrock conditions were evaluated for the BLN, HVN, PBN, YCN, and MH sites. Sources of information for the bedrock evaluation were the original FE[I]Ss for the brownfield nuclear sites and Geologic Survey of Alabama data (1984) for the MH site. Each of these sites has a PGA of less than 0.30 g, with the PGAs ranging from 0.11 g to 0.20 g. Each of these sites is situated on rock (mostly limestone); however, PBN is on somewhat softer rock.

A comparison of the two factors equally influencing rankings for these criteria (i.e., ground motion and bedrock foundation) are shown in Table 9.3-X1. Each of the five sites is acceptable and, with the exception of PBN, ranked equally with regard to bedrock foundation. However, the differences between the peak ground acceleration were enough to warrant differentiation between the five sites, which is reflected in the overall ratings for the sites.

The HVN site lies within the Nashville Dome tectonic province. The design criteria for a plant at that site would be governed by a reoccurrence of a major earthquake in the Reelfoot Tectonic Structure west of the Nashville Dome. Analysis of a major earthquake in the Reelfoot Structure shows that the maximum intensity felt at the HVN site would be MM VII. The maximum acceleration for intensities of this level was estimated to be 0.14 g for safe shutdown earthquakes. More recent information using USGS Seismic Hazard maps (USGS data set accessed 2008) indicated the value to be 0.11 g.

The BLN, PBN, and MH sites lie within the Southern Appalachian Tectonic Province. For the eastern area sites in this province, the maximum earthquake was the 1897 Giles County, Virginia, earthquake, which had a reported intensity of MM VIII. The maximum acceleration for intensities of this level was estimated at 0.18 g for safe shutdown earthquakes. More recent detailed information for BLN, PBN, and MH from the USGS Seismic Hazard maps indicates the values to be 0.16, 0.17, and 0.14 g, respectively.

The YCN site lies within an area that is affected by earthquakes along the Reelfoot Tectonic structure at distances of 90 to 140 mi. from the site. Intensities varying with location from a MM VIII to a MM IX should be employed for the safe shutdown earthquake for this area. The maximum acceleration for intensities of this level was estimated at 0.18 g for safe shutdown earthquakes. Review of the more recent USGS Seismic Hazard map data indicates a value of 0.20 g for the YCN site.

Table 9.3-1 is used as a consolidated table of comparisons for the TVA ASE. It includes the ratings for the geologic evaluation. As the difference between the peak ground acceleration is negligible between the five sites, all are rated equally with respect to foundation conditions.

Cooling System Suitability

Cooling system requirements are important siting considerations for new power generating facilities. The objective of this subsection is to rate the candidate sites with respect to their ability to satisfy specific cooling system requirements. The AP1000 plant chosen for the site needs no external ultimate heat sink postaccident other than the surrounding atmosphere.

The evaluation of adequacy of water supply is based upon comparisons between the design basis water consumption rate for the facility and 1) the site-specific average flow (when regulated or on reservoirs) for each site; and 2) low flow conditions of the water body. A common assumption noted in the EPRI Siting Guide (Reference 1) is that states typically do not permit more than 10 percent of the "dependable flow" to be withdrawn for consumptive use. For reservoirs and lakes, the comparison considers the type of reservoir (capacity, and ability to maintain reservoir levels) as well as historic average and low flow rates. The BLN, YCN, and MH sites are located on large, high-volume reservoirs in which flow-through is regulated by both upstream and downstream dams. HVN and PBN are located on riverine stretches of rivers in which flow is also highly regulated by upstream and downstream dams.

In light of existing water quality standards, which limit increases in downstream temperature maximums and increases above ambient upstream temperature, the supply of available cooling water has become less important in plant siting because these standards tend to force the use of some form of auxiliary cooling. Heat exhausted by the same design plant (i.e., AP1000) at different site locations would be generally of uniform temperature, and makeup water for the auxiliary cooling systems would remain essentially unchanged between sites. Sites with larger amounts of available cooling water are, however, rated higher due to reduced risk of low flow considerations.

The factors equally affecting the individual site ratings for this criterion are 1) average flow (pertinent because all sites are on either reservoirs or regulated reaches of rivers), and 2) whether or not the low-flow characteristics could potentially constitute an infrequent operational limitation. Low and average flow characteristics and overall ratings for the cooling water suitability analysis are presented in Table 9.3-X2 and discussed below, along with the sources of information and calculation assumptions used to estimate the flow rates.

The BLN site is located on Guntersville Reservoir of the Tennessee River System. Flow at the site is regulated upstream by TVA's Nickajack Dam (dam closure on December 14, 1967) and downstream by TVA's Guntersville Dam (dam closure on January 16, 1939). Flow statistics were computed by the Environmental Protection Agency's DFLOW program using TVA's water records of total flow (turbine and spill) from Nickajack Dam from 1968 through 2007. Based on the information obtained through these sources of information, the Tennessee River flows past the BLN site at an average rate of approximately 37,000 cfs, with 7Q10 and 3Q20 low-flow values of 5780 cfs and 2050 cfs, respectively. (It is noted that the flow data used in this evaluation is for comparison between alternative sites only, and differs from the BLN site evaluation flow data due to period of time during which the data was acquired and the data analysis methodology used to compute the flow data.)

The HVN site is located on Old Hickory Reservoir of the Cumberland River System. Flow at the site is regulated upstream by Cordell Hull Dam and Center Hill Dam and downstream by Old Hickory Dam (all U.S. Army Corps of Engineers' dams). Flow statistics were computed by the Environmental Protection Agency's DFLOW program using TVA's water records of total flow (turbine and spill) from Cordell Hull Dam and Center Hill Dam from 1971 through 2007. Based on the information obtained through these sources, the Cumberland River reach (Old Hickory Reservoir) flows past the HVN site at an average rate of approximately 18,000 cfs, with 7Q10 and 3Q20 low-flow values of 1870 cfs and 980 cfs, respectively.

The PBN site is located on the Holston River of the Tennessee River System. Flow at the site is regulated upstream by TVA's Fort Patrick Henry Dam (dam closure on October 27, 1953). Flow statistics were computed by the Environmental Protection Agency's DFLOW program using the USGS water records of flow measured at the "Holston River at Surgoinsville, TN" stream gauge from 1954 through 1998 (the gauge was removed from service in 1998). Based on the information obtained through these sources, the Holston River flows past the PBN site at an average rate of approximately 3900 cfs, with 7Q10 and 3Q20 low-flow values of 925 cfs and 768 cfs, respectively.

The YCN site is located on Pickwick Reservoir of the Tennessee River System. Flow at the site is regulated upstream by TVA's Wilson Dam (dam closure on April 14, 1924) and downstream by TVA's Pickwick Dam (dam closure on February 8, 1938). Flow statistics were computed by the Environmental Protection Agency's DFLOW program using TVA's water records of total flow (turbine and spill) from Wilson Dam from 1938 through 2007. Based on the information obtained through these sources, the Tennessee River (Pickwick Reservoir) flows past the YCN site at an average rate of approximately 53,000 cfs, with 7Q10 and 3Q20 low-flow values of 7700 cfs and 3740 cfs, respectively.

The MH site is located on Guntersville Reservoir of the Tennessee River System. Flow at the site is regulated upstream by TVA's Nickajack Dam (dam closure on December 14, 1967) and downstream by TVA's Guntersville Dam (dam closure on January 16, 1939). Flow statistics were computed by the Environmental Protection Agency's DFLOW program using TVA's water records of total flow (turbine and spill) from Nickajack Dam from 1968 through 2007. Based on the information obtained through these sources, the Tennessee River (Guntersville Reservoir) flows past the MH site at an average rate of approximately 37,000 cfs, with 7Q10 and 3Q20 low-flow values of 5830 cfs and 2070 cfs, respectively.

Because the average regulated flow rate past each site is adequate to provide required cooling system supply, the sites are rated equally on the Average Flow Rating factor. Three of the sites are situated on large reservoirs and two are located on regulated reaches of rivers (i.e., flow is also controlled by releases from upstream and downstream reservoirs). This situation generally reduces the utility and value of comparing low-flow statistics between sites, because of a greater capacity to flexibly manage flow under extreme conditions to meet multi-purpose objectives for the reservoir system. Comparison of estimated consumptive flow withdrawal for two operating AP1000 units to the most extreme low-flow characteristics indicates that the needed consumptive withdrawals are 10 percent or less for each site. Although acceptable at 10 percent of the 3Q20 flow for the Holston River, PBN would have the most operational challenges under extreme low-flow conditions, and therefore receives a lower scoring for the Low Flow Rating factor (Table 9.3-X2). This situation is, however, ameliorated by flexibility that multi-purpose reservoirs, integrated river management, and regulated flows provide to respond to low-flow conditions.

Table 9.3-1 includes the ratings for the cooling system suitability analysis. As the flow rate past each site is more than adequate to provide required cooling system supply, the BLN, HVN, YCN, and MH sites receive the highest rating; PBN is rated lower because of the operational challenges under extreme low-flow conditions.

Plant Safety Evaluation - Flooding Potential

This section reviews the flooding potential of the sites. Sites that were issued construction permits met the desired exclusionary and avoidance siting criteria. These criteria exclude potential sites within major wetlands and areas lower than the elevation of probable maximum flood (PMF). The PMF is the flood that can be expected from the most severe meteorologic and hydrologic conditions that are reasonably possible for an area. PMF values are typically used in the design of major dams and nuclear power plants.

The BLN site grade, at 628.6 ft. msl, is approximately 6 ft. above the PMF 622.5 ft. The PBN site grade, at 1180 ft. msl, is 0.4 ft. above the PMF 1179.6 ft. The HVN site grade, at 538 ft. msl, is 17.1 ft. above the PMF and maximum wave of 520.9 ft. The YCN site grade, at 530 ft. msl, is 84 ft. above the PMF and maximum wave of 446 ft. The MH greenfield site is approximately 2 ft. above the PMF; no maximum wave height data are available for the greenfield site.

Table 9.3-1 includes the ratings for the flooding potential analysis. As all sites are above the PMF, and satisfied the desired exclusionary and avoidance siting criteria, they were rated equally with respect to flooding potential.

Accident Effects Evaluation

To evaluate sites with respect to the effects of design-related accidents, three site characteristics relevant to these effects are considered: population, emergency planning considerations, and atmospheric dispersion. Each is evaluated and assigned a set of ratings.

For population, it is assumed that sites that were issued construction permits met requirements of 10 CFR 100.21 regarding population, specific exclusion areas, having a low population zone outside the exclusion area, and sufficient distance to high population centers. This criterion gives preference to a local site population density that is low (i.e., mean densities less than 500 people per square mile.). The ranking was based on distances to nearby population centers and population totals within a 50-mi. site radius. Sites further from population centers and having a lower local population are rated higher.

The BLN site is 39 mi. from Huntsville, Alabama, and the population within a 50-mi. radius is estimated to be 1 million people. The nearest town is Hollywood, Alabama, which has a population of approximately 900.

The HVN site is 43 mi. from Nashville, Tennessee, and the population within a 50-mi. radius is estimated to be 1.5 million people. The nearest town is Hartsville, Tennessee, which has a population of approximately 2500.

The PBN site is 65 mi. from Knoxville, Tennessee, and the population within a 50-mi. radius is estimated to be 900,000 people. The nearest town is Surgoinsville, Tennessee, which has a population of approximately 1800.

The YCN site is 30 – 40 mi. from the Florence – Muscle Shoals – Sheffield – Tuscumbia urban complex located east-southeast of this site, with a combined population of approximately 67,000. The estimated population within a 50-mi. radius is estimated to be 440,000.

The MH site is about 30 mi. from Huntsville, Alabama, and the population within a 50-mi. radius is estimated to be about 945,000. The nearest town is Grant, Alabama, which has a population of about 700.

Table 9.3-1 includes the ratings for the population evaluation. On the basis of lower population numbers, YCN is rated slightly higher than the other sites. Based upon similarity of population characteristics, these remaining sites are rated equally with respect to population and accident effects.

In an evaluation of emergency planning considerations, the four brownfield sites have relatively similar population densities with similar expected population growth rates, and close access to major U.S. highways. There is a prison under construction on a portion of the HVN site, which could complicate emergency planning. Although the ramifications of a nearby prison population are not fully certain at this time, the HVN site is therefore ranked lower than the other brownfield sites for emergency planning considerations. The greenfield site at Murphy Hill is rated lower for emergency planning due to the less updated system of access roads and more limited access from major U.S. highways.

For atmospheric dispersion, meteorological conditions at a site are monitored and evaluated as part of determining suitability for siting of nuclear plants. The observation of temperature and wind conditions over time provides input into statistical models. The models can be used to help predict probable atmospheric dispersion of releases. Topographic conditions also influence extreme weather and temperature variations. Sites with better meteorological conditions are rated higher (e.g., limiting conditions affecting the transport and dispersion of plant emission would have a lower rating).

Assessment of the meteorological conditions at the PBN, HVN, and YCN sites did not indicate any limiting conditions. The meteorology of the PBN, BLN, and MH sites provide a limited range of atmospheric conditions for transport and dispersion of plant emissions due to their valley locations and prevailing wind directions.

Table 9.3-1 includes the ratings for the evaluation of atmospheric dispersion. Development at some of the brownfield sites affects final EAB analysis due to recent industrial growth at these sites. The HVN and YCN sites are rated slightly higher than BLN, PBN, and MH with respect to meteorological conditions.

<u>Operational Effects Evaluation</u>

The impacts of severe accidents at each site would be similar. Since the site does not affect the design of the plant, the frequency and source term of severe accidents would be similar at each site. Furthermore, the differences in population are not sufficiently significant to affect the overall risk, which would be SMALL at each site.

Although the release pathways would be somewhat different at each site, the radiological impacts of normal operation at each site would be similar. The doses would be required to be maintained within regulatory limits, which will ensure that the impacts are SMALL.

Transportation of radioactive materials is in accordance with 10 CFR 51.52 (a), or has been generically evaluated by the NRC as discussed in Subsections 3.8.2.3 and 3.8.2.5. New fuel assemblies are transported from the fabrication plant to the proposed site by truck. The environmental impact of transportation of fuel to the site, with respect to normal conditions of transport and possible accidents in transport, are bounded by those described in Summary Table

S-4 of 10 CFR 51.52 or have been generically evaluated by the NRC. Truck shipments do not exceed 73,000 lbs. and comply with the applicable federal or state gross vehicle weight restrictions. Traffic density is less than one truck per day.

The environmental impact of transportation of spent fuel from the site, with respect to normal conditions of transport and possible accidents in transport, are bounded by those described in Summary Table S-4 of 10 CFR 51.52. Spent fuel assemblies are maintained in the spent fuel pool while short half-life isotopes decay. After a minimum of 5 years, the fuel may be removed from the pool and packaged for off-site transport. Packaging of the fuel for off-site shipment complies with applicable U.S. Department of Transportation (DOT) and NRC regulations for transportation of radioactive material. Irradiated fuel is shipped off-site by truck or rail. The heat per irradiated cask in transit does not exceed 250,000 BTU/hr. The cumulative dose to exposed population does not exceed four man-rem per reactor year to transportation workers and three man-rem per reactor year to the general public. Truck shipments do not exceed 73,000 lbs. and comply with the applicable federal or state gross vehicle weight restrictions. Traffic density is less than one truck per day. Rail shipments do not exceed 100 T. per cask per rail car. Rail traffic density is less than three shipments per month.

Packaging of waste for off-site shipment complies with DOT and NRC regulations for transportation of radioactive material as described in Subsection 3.8.1. The environmental impact of transportation of waste from the site, with respect to normal conditions of transport and possible accidents in transport, are bounded by those described in Summary Table S-4 of 10 CFR 51.52. The mode of transportation of low-level radioactive waste can be either truck or rail.

Table S-3 of 10 CFR 51.51 provides estimates of the environmental effects due to the Uranium Fuel Cycle (UFC).The environmental effects of the UFC due to the operation of the proposed plant are assessed, and an analysis of the radiological effect from radon-222 (Rn-222) and technetium-99 (Tc-99) is included. In NUREG-1437, the NRC staff provides a detailed analysis of the environmental effects from the UFC. Although NUREG-1437 is specific to license renewal, the information is relevant because the LWR design considered here uses the same type of fuel.

All sites considered would be bounded by the analysis for operational effects of transportation and the uranium fuel cycle, and all are therefore assigned the same rating. No further comparison is made of these considerations at this time.

Transportation Safety Evaluation - Cooling Tower Drift

Operating plant cooling systems have the potential to create fog and ice hazards for local transportation routes. Sites with high frequencies of naturally occurring fog and ice events could be more adversely affected by cooling tower operations; sites with lower frequencies are rated higher.

Meteorological conditions at a site are monitored and evaluated as part of determining suitability for siting of nuclear plants. The observation of temperature and wind conditions over time provides input into statistical models. The models can be used to help estimate the effects of cooling tower drift. Topographic conditions also influence extreme weather and temperature variations. Sites with better meteorological conditions are rated higher.

Assessment of the meteorological conditions at the PBN, HVN, and YCN sites did not indicate any limiting conditions. The meteorology of the BLN and MH sites provide a more limited range of atmospheric dispersion conditions for cooling tower drift. This may contribute to an increased severity and duration of ice and fog events.

Table 9.3-1 includes the ratings for the transportation safety evaluation. The HVN, PBN, and YCN sites are rated slightly better with respect to meteorological conditions.

9.3.3.2 Environmental Criteria

Proximity to Natural Areas

The four Bellefonte site alternatives were reviewed (1) to identify natural areas in the proximity of each site, and (2) to prioritize the sites according to their environmental superiority. In the case of natural areas, the environmentally superior ranking would be based on the number, proximity, and sensitivity of natural areas to the site alternatives.

The PBN and MH sites have no natural areas within 3 mi. of the sites and are, therefore, rated higher.

The BLN site has three TVA-designated Small Wild Areas within approximately 3 mi. of the site: Bell Island, Coon Gulf, and Section Bluff are all TVA Small Wild Areas. The site has historically been used for hunting, but this activity is no longer permitted.

The HVN site has been used for hunting in cooperation with the Tennessee Wildlife Resource Agency (TWRA), but the site has been deleted as a hunting area in the new 2007 – 2008 TWRA Hunting Guide. This site is also immediately adjacent to the Cumberland River No. 2 State Mussel Sanctuary and is approximately 2 mi. from Old Hickory Wildlife Management Area.

The YCN site is adjacent to the Tennessee-Tombigbee Waterway. Within 1 mi. of the YCN site are Sandstone Outcrops Protection Planning Site, Pickwick Lake Bluffs, Cooper Falls TVA Habitat Protection Area, Mississippi Wildlife and Recreation Land, and JP Coleman State Park. Other natural areas within a 3-mi. radius include Divide Section Wildlife Management Area and Lauderdale County State Wildlife Management Area. This site is rated lowest due to proximity to several natural areas.

Based on proximity to natural areas, YCN is rated lowest, and the PBN and MH sites are rated higher.

Construction-Related Effects on Aquatic Ecology

Many factors can be involved in the disruption of important aquatic species and their habitats. The objective of this subsection is to evaluate the candidate sites with respect to potential construction-related effects on important freshwater or marine species and their habitats.

Regulatory Guide 4.7 (RG 4.7), *General Site Suitability Criteria for Nuclear Power Stations*, defines important plant and animal species if one or more of the following conditions apply:

- Species is commercially or recreationally valuable.
- Species is officially listed as endangered or threatened.
- Species presence ensures the well-being of another species indicated by either of the two bulleted items above.
- Species is a critical component of the structure and function of a valuable ecosystem.
- Species is a biological indicator of radionuclides in the environment.

Of particular concern are potential effects to habitat areas used by important species. These areas include those used in the following ways:

- Breeding and nursery.
- Nesting and spawning.
- Wintering.
- Feeding.

The following siting criteria were used to evaluate the candidate sites:

- Exclusionary – Designated critical habitat of endangered species.
- Avoidance – Areas where threatened and endangered species are known to occur.
- Suitability – Areas where limited potential effects are expected.

The candidate sites were evaluated with respect to information available on important species and habitats. Information on important species was obtained from previous environmental studies. During this evaluation, no information was identified that indicated any of the sites met the exclusionary and avoidance criteria cited above. Therefore, the suitability of a site was evaluated according to the number of areas where limited potential effects are expected, as directly correlated to the number of important aquatic resources that may occur at the site.

Aquatic resources for the proposed BLN site and potential impacts are described at length in Sections 2.4, 4.3, and 5.3.

Aquatic habitats that could be impacted by the proposed development on the HVN site are the Cumberland River (Old Hickory Reservoir), and several streams and constructed ponds present on the site. Aquatic communities in adjacent areas of Old Hickory Reservoir may be impacted by activities undertaken in riparian zones that change the topography of the shoreline, reduce the usefulness of shoreline areas for spawning and feeding, or alter shoreline vegetation, particularly the loss of a wooded shoreline.

The bank along the Cumberland River is almost entirely wooded, with sparse understory vegetation in areas immediately adjacent to the river. Most areas on top of the riverbank, and adjacent to formerly cleared areas are very dense, woody, old field habitats, except for small areas where access points and structures were constructed in association with the canceled nuclear plant.

TVA biologists collected monthly experimental gill net and electrofishing samples near the site from September 1992 through January 1993. Thirty-five species, none of which are protected species, were collected. Gizzard and threadfin shad comprised the largest group of fish in the sample; game fish that are more abundant were bluegill, largemouth bass, and sauger. Several mussel species federally listed as endangered have historically been collected from the Cumberland River near this site.

Important aquatic species potentially found at the HVN site include the dirty darters, which are considered in need of management by the TWRA and have been reported from Dixon Creek adjacent to the HVN site. Several federally listed mussel species were identified in previous surveys and were expected to be found in the Cumberland River near the proposed industrial park. Surveys by divers in January 2001 in the Cumberland River, in the vicinity of the site revealed that a once-thriving population of endangered mussels could no longer be found.

TVA employs an Index of Biotic Integrity to assess environmental quality of free-flowing streams and some tailwater areas in the Tennessee River system, by applying ecologically based metrics to resident aquatic communities. TVA has a “fixed station” site at Holston River mile (HRM) 118, just downstream of the PBN site. This site was sampled yearly from 1990 to 1997 (with the exception of 1995), and has been sampled every other year beginning in 2001. This locality has consistently rated in the fair/good or good categories during recent sampling (2001 – 2007). This river supports a good warmwater fishery including largemouth, smallmouth, and spotted bass.

Several state- and federal-listed aquatic species are known from Hawkins County, Tennessee. The spotfin chub (federally listed as Threatened) is routinely collected at the HRM 118 IBI site and is likely present in the Holston River adjacent to the PBN site. None of the eight federally listed mussel species reported from Hawkins County have been collected from the main stem of the Holston River in the vicinity of the Phipps Bend site. No state- or federal-listed aquatic species are known to occur on the Phipps Bend site itself. The Cumberland bean mussel and purple bean mussel are reported from Beech Creek, a tributary to the Holston River that enters the river at approximately river mile 109, but are not known to occur in the main stem Holston River.

TVA monitored Pickwick Reservoir near the YCN site annually from 1991 through 1994 to establish baseline data on the reservoir’s ecological health under a range of weather and flow conditions. Pickwick is now evaluated every other year. The overall ecological condition in Pickwick Reservoir rated good in 2004, with the highest score to date. The inflow rating, which is based on fish and benthos, also was the highest to date in 2004 and contributed to the overall higher score for the reservoir. Pickwick has scored about the same every year — either high fair or good — depending primarily on chlorophyll concentrations, which are affected by reservoir flows, and conditions in the Bear Creek embayment, which generally rate lower than at other monitoring locations on the reservoir.

Several state- and federal-listed aquatic species are known from Tishomingo County, Mississippi. However, due to the impoundment of Yellow Creek during the creation of Pickwick Reservoir and habitat alterations in streams on the Yellow Creek site, none of these species are currently known to occupy areas on or adjacent to the Yellow Creek site.

TVA monitored Guntersville Reservoir annually from 1991 through 1994 to establish baseline data on the reservoir's ecological health under a range of weather and flow conditions. Guntersville is now evaluated every other year. The ecological health condition of Guntersville Reservoir has rated good consistently since TVA's monitoring program began, and 2004 was no exception. As in past years, ecological health indicator scores for the reservoir were among the highest observed for all TVA reservoirs.

Several state- and federal-listed aquatic species are known from Marshall County, Alabama. However, due to the impoundment of the Tennessee River during the creation of Guntersville Reservoir, none of these species are currently known to occupy areas on or adjacent to the Murphy Hill site.

The candidate and alternate sites have been evaluated for the presence and available habitat of federal- or state-protected or endangered species. It was noted that although habitat could exist for species on all five sites, no protected species currently inhabit these areas.

Table 9.3-1 includes the ratings for the evaluation of construction-related effects on aquatic ecology. Based on the information reviewed, all sites are rated equally.

Construction-Related Effects on Terrestrial Ecology

Many factors can be involved in disruption of important terrestrial species and their habitats. The objective of this subsection is to evaluate the candidate sites with respect to potential construction-related effects on important terrestrial species and their habitats.

See the previous discussion of RG 4.7 and the definition of important plant and animal species.

Terrestrial resources for the proposed BLN site and potential impacts are described at length in Sections 2.4, 4.3, and 5.3.

Distinct groups of terrestrial wildlife are found in association with the vegetation types occurring on the HVN site. Common amphibians and reptiles often found in old field habitats include American toad, upland chorus frog, and black racer. Birds found in this type of habitat include song sparrow, eastern towhee, eastern wild turkey, and black vulture. Resident mammals include eastern cottontail rabbit, white-tailed deer, and coyote. Amphibians and reptiles commonly found in riparian habitats include bullfrog, green frog, red-spotted newt, and northern water snake. Birds found in this type of habitat include Carolina wren, eastern phoebe, barred owl, and American woodcock. Mammals include beaver, muskrat, raccoon, and white-tailed deer. Seeps and damp rock outcrops with small pools of water are found on the site. These areas provide suitable habitat for frogs and salamanders and are likely used as a water source by a variety of wildlife species.

Amphibians and reptiles at HVN found in upland woodlands include spring peeper, gray tree frog, eastern box turtle, and gray rat snake. Birds commonly found in this type of habitat include red-tailed hawk, American crow, eastern tufted titmouse, and Carolina chickadee. Mammals common to the area include eastern gray squirrel, white-footed mouse, woodland vole, and eastern chipmunk.

Several species of game animals occur on the HVN project area. The heavily modified habitats, which are abundant on the site, provide suitable habitat for white-tailed deer and eastern wild turkey. These species are quite common in the project area. Other game species such as beaver, eastern gray squirrel, eastern cottontail rabbit, American woodcock, and northern bobwhite quail are also found on the site. Ponds and wetlands on the area provide resting and foraging habitat for waterfowl including wood duck, Canada goose, mallard, and hooded merganser.

The TVA Regional Natural Heritage Program database indicated that three state-listed animal species — Bewick’s wren, Allegheny woodrat, and southeastern shrew — occur in Smith and Trousdale counties. The gray bat, which is on the federal list of endangered species, is also known to occur in Smith County.

The U.S. Fish and Wildife Service (USFWS) list of threatened, endangered and candidate species for Smith and Trousdale counties, Tennessee, consists of 15 plant and animal species, including one mammal species, one bird, ten mollusk and one plant species. The TVA Regional Natural Heritage database identified three terrestrial animal species that may occur on or adjacent to the site. Of the five species potentially present, only the gray bat and bald eagle have been observed near the Hartsville site. No federally listed threatened or endangered species are known to occur on, or immediately adjacent to, the Hartsville site

For the PBN site, the wildlife distributions are similar to those found at Hartsville. The USFWS’ list of threatened, endangered and candidate species for Hawkins County, Tennessee, consists of 12 animal species, including two mammal species, one bird, one fish, and eight mollusk species. The TVA Regional Natural Heritage database identified three federally listed terrestrial animal species that may occur on or adjacent to the Phipps Bend site). Of the three federally listed species potentially present, only the gray bat and bald eagle have been observed near the Phipps Bend site. No federally listed threatened or endangered plant species were known to occur on, or immediately adjacent to, the Phipps Bend site. No important wading bird colonies are reported within 3 mi. of the Phipps Bend site. Two state-listed terrestrial species (barn owl and Virginia rail) have been seen on the Phipps Bend site.

Much of YCN site has been disturbed by previous construction activities, and terrestrial habitat consists primarily of early- to mid-successional vegetation. Relatively undisturbed forest areas are dominated by oak and hickory species mixed with some pines. The surrounding landscape consists of similar forested habitat. There are no records of important wading colonies within 3 mi. of the project site.

The deciduous forested areas provide habitat for bird species such as wild turkey, Carolina chickadee, downy woodpecker, American crow, red-eyed vireo, and tufted titmouse. Other animals likely occurring in this habitat include white-tailed deer, eastern gray squirrel, white-footed mouse, slimy salamander, eastern box turtle, and copperhead.

Birds common in early successional habitats include Carolina wren, eastern bluebird, white-eyed vireo, northern cardinal, and indigo bunting. Common mammals include striped skunk, eastern cottontail rabbit, white-tailed deer, Virginia opossum, and various rodents. Reptiles often found in early successional habitats include racers, black rat snake, and eastern garter snake.

The USFWS' list of threatened, endangered and candidate species list for Tishomingo County, Mississippi, consists of five plant and animal species, including two mammal species, one bird, and two mollusk species. The TVA Regional Natural Heritage database identified three terrestrial animal species that may occur on or adjacent to the Murphy Hill site. Of the five species potentially present, only the gray bat and bald eagle have been observed near the Yellow Creek site. No federally listed threatened or endangered plant species were known to occur on, or immediately adjacent to, the Yellow Creek site. No important wading bird colonies are reported within 3 mi. of the site.

Habitats for terrestrial animals at the Murphy Hill site are similar to conditions at the Bellefonte site. These two sites are located in the same physiographic region, and both sites border Guntersville Reservoir.

The USFWS' list of threatened, endangered and candidate species for Marshall County, Alabama, consists of 15 plant and animal species, including two mammal species, two bird, one turtle, one amphibian, six mollusk, and three plant species. The TVA Regional Natural Heritage database identified three terrestrial animal species that may occur on or adjacent to the Murphy Hill site. Of the five species potentially present, only the gray bat and bald eagle have been observed near the Murphy Hill site. No federally listed threatened or endangered plant species are known to occur on, or immediately adjacent to, the Murphy Hill site.

The alternative sites were evaluated with respect to information available on important species/ habitats, groundcover, and mapped wetlands. Information on important species was obtained from previous environmental studies. During this evaluation, no information was found to indicate that any of the sites met the exclusionary and avoidance criteria; the evaluation was thereby focused on the relative suitability of each site.

For the terrestrial habitats, a common theme of "available wildlife habitats on the site are not of high quality because of former clearing for plant construction" was noted. Little, if any, impact would appear to occur regarding the use of any site in this study. Documents for sites that were issued construction permits indicate that further construction would not substantially disrupt the available habitats.

Table 9.3-1 includes the ratings for the evaluation of construction-related effects on terrestrial ecology. Based on the information reviewed, all sites rated equally in this criterion.

<u>Construction-Related Effects on Wetlands:</u>

Wetlands are recognized as a vital part of the ecosystem. Activities in wetlands are regulated under Section 404 and Section 401 of the Clean Water Act, and Executive Order 11990. Section 404 implementation requires activities in jurisdictional wetlands be authorized through a Nationwide General Permit or Individual Permit issued by the U.S. Army Corps of Engineers (USACE). Section 401 requires water quality certification by the States for projects permitted by the federal government). In Tennessee, activities that may alter aquatic resources, (e.g., wetlands) are also regulated by the Tennessee Department of Environment and Conservation through the Aquatic Resource Alteration Permit program, under the authority of the Tennessee Water Quality Control Act of 1977. Alabama and Mississippi do not have specific regulations regarding wetlands and aquatic resources. However, the Alabama Department of Environmental Management and the Mississippi Department of Environmental Conservation administer Section 401 water quality certifications in their respective states. Executive Order 11990 requires federal agencies to minimize wetland destruction, loss, or degradation, and preserve and enhance natural and beneficial wetland values, while carrying out agency responsibilities.

The objective of this subsection is to evaluate the sites with respect to potential impacts from construction-related dewatering or filling activities on area wetlands.

Information about wetlands at each site was obtained using current aerial photogrammetry at each site, National Wetland Inventory (NWI) data, soil survey data, and hydric soil lists for Alabama, Mississippi, and Tennessee.

For BLN, 40 ac. of scrub-shrub and forested wetlands exist within the proposed site boundary. A wetland delineation conducted by TVA in 2006 identified six additional forested wetlands covering a total of approximately 11 ac. in the vicinity of the proposed construction area. These six wetlands were not shown on NWI maps.

There are approximately 36 ac. of emergent and forested wetlands at the HVN site. Most of these are associated with Corley Branch, Dixon Creek, and the shoreline of Old Hickory Reservoir (Cumberland River). Most of these wetlands are concentrated around the eastern, western, and southern boundaries of the survey area.

There are approximately 3 ac. of emergent, scrub-shrub, and forested wetlands at the MH site. These wetlands are located in the north-central part of the site near the Guntersville Reservoir shoreline.

At the PBN site, there are approximately 11 ac. of emergent and forested wetlands. These wetlands are associated with a large 57-ac. open water complex in the floodplain of the Holston River along the eastern boundary of the survey area.

There are approximately 11 ac. of emergent and forested wetlands at the YCN site. Wetlands are concentrated in the southwestern corner of the site and are generally associated with the Yellow Creek embayment and Tackett Branch.

Table 9.3-1 includes ratings for the wetlands analysis. Stringent environmental laws regulate dewatering or filling of most wetlands. For purposes of this comparison, most potential construction areas are located sufficiently far away that it would be possible to avoid most wetlands. Thus, potential adverse impacts from dewatering or filling are expected to be avoided or minimized such that any potential impacts would be insignificant, and all sites are rated equally.

Operations-Related Effects on Aquatic Ecology

The discussion and evaluation of the operations-related effects on aquatic ecology are primarily related to environmental effects from the operation of condenser cooling water systems. These typically include expected thermal release effects, as well as entrainment and impingement effects.

Thermal Release Effects

The objective of this subsection is to address the relative suitability of the candidate sites with respect to potential thermal release effects on receiving water bodies. The AP1000 plant design needs no external ultimate heat sink. During normal operation, the AP1000, like other types of nuclear power plants, can use this external cooling water. Heat removed by the condenser cooling water system generates the majority of this thermal release. An important consideration in evaluating the suitability of the sites was the proposed design of the condenser cooling water system at each site. Heat rejected by the same plant at different locations would remain virtually unchanged, and makeup water for the auxiliary cooling systems would be essentially the same at each site. The use of closed-cycle cooling is a best available technology for minimizing the amount of water withdrawal required.

The effect of returning unconsumed water (primarily that not evaporated from the cooling towers) to the receiving water body would be primarily a function of 1) the percentage of total flow that heated return water constituted in comparison to average and low flow in the receiving water body, and 2) whether or not the receiving water body is a reservoir, regulated river, or free-flowing river. An additional factor would be the thermal limits imposed by the pertinent NPDES permit. The purpose of such thermal limits at any site is to be protective of aquatic and water resource values; consequently, the flow comparison becomes the primary factor to consider. Because it was determined that no exclusionary or avoidance criteria were exceeded by these thermal discharges, sites with larger amounts of available cooling water are rated higher.

Table 9.3-1 includes the ratings for the thermal discharge analysis. The BLN and alternative sites exhibit acceptable flow characteristics for siting nuclear generation; however, they may be parsed upon their relative ability to assimilate heat and, although a regulatory-defined area, likelihood to affect aquatic resources in the receiving water body. As noted in the above discussion on cooling system suitability, the YCN site has a larger flow rate of dilution cooling water available. Thus, the YCN site is rated more suitable than the other sites with respect to cooling water availability. Similarly, based upon the flow comparisons as discussed under cooling system suitability, PBN is ranked lowest with regard to the potential for creating the most substantive issues for avoiding thermal effects to the receiving water body.

Entrainment and Impingement Effects

When cooling water is pumped from water bodies, two environmental effects of concern can occur. The first effect, entrainment, refers to the removal of small, drifting organisms within the cooling water. Small fish, fish eggs, plankton, and other aquatic/marine organisms experience high mortality rates as they pass through cooling water pumps and heat exchangers. The second effect, impingement, refers to larger organisms that are screened out of the cooling water at the intake structure. Impinged organisms can include large fish, crustaceans, turtles, and other aquatic/marine organisms that are unable to avoid the high intake velocities near the intake structure, and are thereby trapped on the intake screens.

No exclusionary or avoidance criteria apply to entrainment and impingement effects from the operation of condenser cooling water systems, similar to the above discussion on thermal discharges. The objective of this subsection is to address the relative suitability of the candidate sites with respect to potential entrainment and impingement effects.

Concerns about entrainment and impingement losses are resource dependent and vary on a site-to-site basis. Typically, power plants with once-through cooling water systems have higher entrainment and impingement effects than power plants with closed-cycle cooling water systems, such as proposed for the siting of AP1000 units at the alternative sites. Low flow conditions can also increase the potential for entrainment and impingement to occur.

Table 9.3-1 includes the ratings for the entrainment and impingement effects analysis. Three factors were utilized to influence these overall ratings: 1) the presence of endangered species that could be entrained or impinged, 2) relative densities of young fish reported in the references for Table 9.3-X3, and 3) potential for occurrence of low-flow situations exacerbating the potential for increased entrainment/impingement. The candidate sites were evaluated with respect to their relative potential for entrainment and impingement effects from closed-cycle cooling water systems. In general, closed-cycle cooling, which utilizes much less water than open-cycle cooling systems, substantively reduces the potential for entrainment and impingement impacts. Based upon the criteria identified above, and because similar systems would be provided for similar makeup water requirements, the BLN, HVN, and MH sites are overall rated equally on this criterion. Although the impact would also be related to the numbers of juvenile fish actually entrained once a site specific plant were designed and operational, and the relative percentage removed from the reservoir, the YCN site rated slightly lower due to the presence of an extensive number of juvenile fish. PBN is rated lower due to the potential for entraining or impinging the federally listed spotfin chub and the greater potential for low flows to contribute to greater impingement or entrainment at a higher frequency of occurrence.

<u>Operations-Related Effects on Terrestrial Ecology - Cooling Tower Drift</u>

This subsection evaluates the effects of cooling tower drift. In every cooling tower, there is a loss of water to the environment from the evaporative cooling process. This evaporated water leaves the tower in a pure vapor state and presents no threat to the environment. Small unevaporated water droplets are also exhausted through the cooling tower, causing a phenomenon known as drift. These unevaporated water droplets carry minerals, debris, microorganisms, and water treatment chemicals, potentially affecting the environment. High drift losses are typically caused by fouled, inefficient, or damaged drift eliminators, excessive exit velocities, or imbalances in water chemistry.

Minimizing drift losses in a cooling tower reduces the risk of affecting the environment. The principle concern with cooling tower drift effects is related to the downwind deposition of cooling water salts. Salt deposition can adversely affect sensitive plant and animal communities through changes in water and soil chemistry. Information about the important terrestrial and aquatic plant and animal communities, habitats, and wetlands near the candidate sites has already been discussed.

As mentioned in the fog and ice safety subsection above, meteorological conditions at a site are monitored and evaluated as part of determining the suitability of nuclear plant siting. The observation of temperature and wind conditions over time provides input into statistical models. The models can be used to help predict the probable path and dispersion of cooling tower drift. Topographic conditions also influence extreme weather and temperature variations. Sites with better meteorological conditions are rated higher.

Assessment of the meteorological conditions at the PBN, HVN, and YCN sites did not indicate any limiting conditions. The meteorology at the BLN and MH sites tend to display a limited variation in atmospheric conditions that can negatively affect transport and dispersion of cooling tower drift.

Table 9.3-1 includes the ratings for the cooling tower drift effects analysis. The HVN, PBN, and YCN sites are rated slightly higher with respect to meteorological conditions.

9.3.3.3 Socioeconomics Criteria

Construction-Related Effects

During construction of a nuclear power plant, the local population increases from the workers and families who relocate to the area, and the local community grows to support these people. A site is rated on its estimated ability to handle the number of construction workers who would move into the plant site vicinity with their families and the capacity of the communities surrounding the plant site to absorb this temporary (in-migrant) population. Higher ratings are given to the sites better able to accommodate the increases in population.

The number of in-migrant workers is dependent on labor availability within commuting distance of the plant site. If an adequate supply of workers were available within reasonable commuting distance, few (if any) workers would choose to relocate to the site. The issue in siting, therefore, is the potential socioeconomic effects associated with any temporary influx of construction workers who live too far away to commute daily from their residence.

The capacity of communities to absorb an increase in population depends on the availability of sufficient resources such as adequate housing and community services (e.g., schools, hospitals, police, transportation systems, and fire protection) to support the influx without straining existing services. The factors that should be considered in rating sites from the perspective of construction effects includes labor requirements, location of labor pool, number of immigrants, and the economic structure of affected communities. Regardless of the site chosen, construction employment would be the same, with an estimated peak of approximately 3900 workers on-site. Assuming that 50 percent of the workers move to the area from elsewhere, there would be an increase of 1950 workers plus whatever family moved with them. Assuming a family size of four, the population increase would be 7800, about a 10 percent increase, for example, in Jackson County (BLN site).

Both Chattanooga, Tennessee, and Huntsville, Alabama, are within 50 mi. of the BLN site and would likely furnish many of the workers needed; some in-migrants might also locate in those areas. The city of Nashville, Tennessee, and the counties around it on the northeast to southeast sides are within 50 mi. of the HVN site. Around the PBN site, the Kingsport-Bristol-Johnson City area is within 50 mi., as is the smaller Morristown area. The YCN site is within 50 mi. of the Florence/Mussel Shoals/Sheffield/Tuscumbia - Quad Cities (Alabama) area as well as a number of smaller communities in Alabama, Mississippi, and Tennessee. The MH site is within 50 mi. of the Huntsville and Gadsden areas in Alabama. Each of the alternative sites has a reasonably-sized population center (i.e., greater than 25,000) within 50 mi. and, with the exception of Yellow Creek, has an estimated total population within 50 mi. of between 880,000 and 1.4 million.

Previous studies (information reported in the site-specific TVA EISs) and the current discussion herein that is based on the population numbers and cities noted within 50 mi. of each site, indicate that the BLN, HVN, and PBN sites are capable of adequately handling an increase in population due to construction worker influx, and the corresponding demand on housing and related services. Due to the relative size of the current population in the area, the impact at the YCN site could be more substantial than at the other sites. The YCN site could have more difficulty accommodating the increase without special assistance. Although the MH greenfield site is located in a more rural area where housing, infrastructure, transportation routes, and public services are less well developed, its proximity to the Huntsville area and to other smaller urban centers would increase its ability to accommodate a major construction project. As a result, with the exception of YCN, which is rated lower, the other alternative sites are rated the same with respect to construction-related socioeconomic effects as presented in Table 9.3-1.

Highway Access

In reviewing access effects, nuclear plant construction requires dependable highway access for large vehicles. Sites with available access are rated higher. Because construction of nuclear plants was proposed or initiated at four of the sites, transportation access was constructed at each site. Access by highway is available for vehicles of all expected sizes at these sites. It is expected that a sufficient amount of access development be performed to accommodate the number of construction and workers' vehicles.

All four brownfield sites are therefore rated equally with respect to site access. Access to the MH site is more limited and is rated lower accordingly. Table 9.3-1 includes the ratings for the highway access effects analysis.

Operations-Related Effects

The socioeconomic effects of operations relate primarily to the impacts and benefits afforded to local communities as a result of constructing the plant. These benefits tend to be a function of negotiations between the plant owner and local government; they are not indicative of inherent site conditions that affect the relative suitability of sites. As a result, all sites are rated equally on this criterion. Table 9.3-1 includes the ratings for the operations-related effects analysis.

Environmental Justice

The objective of the environmental justice (EJ) evaluation is to ensure that the effects of proposed actions do not result in disproportionate adverse effects to minority and low-income communities. In comparing sites, this principle is evaluated based on whether any disproportionate effects to these communities are significantly different when comparing one site to another.

It was first determined if the proposed action results in significant adverse effects. If not (i.e., no significant health and safety effects are identified), then there are no EJ concerns, regardless of the percentage of minority or low-income populations identified within the surrounding communities of a site.

If significant adverse health or safety effects are expected, then EJ concerns may be relevant to site comparison. However, a significance finding based on EJ considerations would be true only if disproportionate adverse effects on minority or low-income populations are identified at one or more sites, thereby resulting in significant differences between sites.

The next step is to compare population data for minorities and low-income populations among sites. With the 2000 U.S. Census Bureau data factored in, the percentages of minorities and low-income populations are still relatively small among the candidate sites. Table 9.3-2 provides a summary of appropriate EJ information for each candidate site.

In conclusion, no significant differences in EJ effects are expected among the sites under consideration. No significant effects to any human populations are expected to occur at any of the sites under consideration; thus, there are no significant disproportionate effects only on minority or low-income populations. Therefore, no significant differences in EJ effects are expected between the candidate sites, and all receive the same rating.

Based on this analysis, there is no basis for differentiation of sites according to an EJ perspective, despite differences in the percentages of minority and low-income populations found within the surrounding communities of each site. All sites are found to be equally and highly suitable. Table 9.3-1 includes the ratings for the EJ evaluation.

Land Use

Land to be used for new units would already be owned or acquired by TVA and would already be zoned for uses compatible with development of a new unit; existing units are integrated into the surrounding land use patterns. The PBN, BLN, YCN, and HVN sites have all been partially developed for industrial uses. The amount of industrial development varies from site to site. As an instrument of the federal government, TVA properties are not subject to local zoning regulation. For three of the sites (PBN, YCN, and MH) there are currently no local zoning or land use policies with which siting of nuclear generation would conflict. However, for the HVN site, local property within close proximity to the remaining TVA property is zoned for agricultural and light industry use.

Land use would change significantly with use of the MH greenfield site, as no development has occurred there to date.

With respect to BLN, the land had been previously dedicated as the site for Bellefonte Units 1 and 2. The NRC terminated the construction permits for those units in September 2006 at TVA's request. TVA currently owns all of the land at this site, and no further land acquisitions are required. The site is allocated by TVA for industrial use; further information is provided in Section 2.2.

While the construction permits for the HVN and PBN sites have been terminated, completion of a nuclear power plant at these sites would conform to the previously proposed urban and industrial development land use for the site and its vicinity, as designated by local governmental plans, policies, and controls. While portions of both sites have been transferred for other uses, TVA retains control of 1377 ac. at HVN (Figure 9.3-11), while only 102 ac. of the 1284-ac. site is retained at PBN (Figure 9.3-12). In a complex contractual arrangement with the local authorities for the Hawkins County PBN site, TVA does retain control over the original acreage until the entire acreage is purchased. At this time (May 2008) it is uncertain what effect a newly-identified prison under construction on the transferred portion of the HVN site would have on the suitability of that site.

The former YCN site has been transferred to the National Aeronautics and Space Administration (NASA) and subsequently to the State of Mississippi and is currently the site of a commercial complex now managed by Tishomingo County. TVA retains control of only 13 ac. of the 1149-ac. site, as shown in Figure 9.3-13. However, there is a coherent portion of the former site still undeveloped and contiguous with the approximately 2300 acres of predominantly undeveloped industrial park and small private inholdings. The MH site is still controlled by TVA and is currently designated for natural resource management. Figure 9.3-14 illustrates ownership for this site.

Ratings for this criterion are influenced by three factors: current state of disturbance of the site, potential degree of disturbance to current uses by siting a nuclear generation facility, and status of ownership. No land-use or ownership issues are evident for BLN. MH is rated substantively lower due to its greenfield status and the potential for disturbance of its current TVA natural resource management land use designation. Both HVN and YCN are rated slightly lower due to the need for re-acquisition of lands and potential for disturbance of current uses. As noted above, the effect of a prison being constructed at the HVN site is uncertain at this time.

PBN is also rated lower because of the need to re-acquire property and greater potential for affecting use of adjacent industrial sites. None of the sites affects public amenities such as national parks, preserves, or ecologically sensitive areas.

Cultural Resources

The preservation of cultural heritage is important to our understanding of the development of human civilizations. This section provides a description of the cultural resources identified at the alternative sites; BLN-specific information is included in Section 2.5. Sites with increased potential for impacts to these resources would be rated lower than those with no impacts.

Northern middle Tennessee, the region surrounding the HVN site has been an area of human occupation for the last 12,000 years. Prehistoric land use and settlement patterns vary, but short- and long-term habitation sites are generally located on floodplains and alluvial terraces along rivers and tributaries. Specialized campsites tend to be located on older alluvial terraces and in uplands. European interactions with Native Americans associated with the fur trading industry in this area began in the seventeenth and eighteenth centuries, with the latter half of the eighteenth century marked by small skirmishes and ambushes between settlers and Native American groups. By the end of the eighteenth century, land in the Nashville Basin had been granted to veterans of the Revolutionary War. Agriculture dominated the economies of both Smith and Trousdale counties in the nineteenth and well into the twentieth century. Economic activities in

Smith County now center on large industry and mining of the county's rich zinc deposits. Trousdale County remains linked to its agricultural roots, with the city of Hartsville becoming a thriving center for the loose-leaf tobacco market in the twentieth century.

Prior to and during construction of the Hartsville Nuclear Plant, archaeological surveys were conducted within the project location. These surveys identified 40 archaeological resources. Several sites that were to be adversely impacted within the project area were excavated. No historic/architectural sites were recorded in the project area; however, no systematic historic/ architectural survey has ever been conducted. Ten historic properties are listed on the National Register of Historic Places (NRHP) in Smith County, and seven properties are listed in Trousdale County. None of the properties are within the area of potential effect (APE) for the previously proposed project or in the immediate vicinity of the site.

Human occupation of Northern Alabama in the vicinity of Murphy Hill occurred from the Paleo-Indian to the Historic period. In northern Alabama, prehistoric archaeological chronology is generally broken into five broad time periods: Paleo-Indian, Archaic, Gulf Formational, Woodland, and Mississippian. Prehistoric land use and settlement patterns vary during each period, but short- and long-term habitation sites are generally located on floodplains and alluvial terraces along rivers and tributaries. Specialized campsites tend to be located on older alluvial terraces and in the uplands. European interactions with Native Americans in this area began in the seventeenth and eighteenth centuries associated with the fur trading industry. Various excursions and temporary settlements by the British, French, and Spanish occurred prior to this period.

Marshall County was created in 1836. Warrenton, in Brown's Valley near Guntersville, was an early trading post. It was incorporated in 1841 and served briefly as the county seat in the 1840s. Marshall County residents tended to have small farms, with corn and livestock forming the backbone of the relatively self-sufficient agricultural regime. Cotton was grown in areas that were suited to it. Following the Civil War, Alabama was readmitted to the Union in 1868. The effects of the war were not as keenly felt in Marshall County, where the economy was not as dependent on slave labor. Tenancy increased in Marshall County in the early twentieth century as cotton production continued to increase. Cotton production had declined significantly during the 1920s and 1930s as a result of the combined effects of the boll weevil, the lack of cheap labor, and competition from other markets, and a more diversified agricultural economy began to take its place with soybeans, truck farming, and livestock products replacing the corn and cotton regime. By the late twentieth century, poultry raising and processing, feeding mills, and hatcheries were the largest segment of Marshall County's economy.

Prior to the proposed construction of the Murphy Hill Coal Gasification Plant, an archaeological survey was conducted within the project location. This survey resulted in the identification of four archaeological sites. Only one site , a prehistoric burial mound, was recommended eligible for the National Register of Historic Places (NRHP). Subsequent looting of this site necessitated mitigation measures through archaeological excavation. In consultation with the Tennessee State Historic Preservation Officer (TN-SHPO), TVA recommended a determination of no adverse effect based on the results of the 1973 survey and subsequent mitigation measures. The TN-SHPO concurred with these determinations. No systematic historic/architectural survey was conducted for the project area, although known historic/architectural resources existed in the vicinity of the proposed Murphy Hill plant in the 1970s. Thirteen historic properties are listed on the NRHP in Marshall County, none of which are within the APE of the previously proposed project or in the immediate vicinity of the site.

Phipps Bend is located in east Tennessee, an area of human occupation for the last 12,000 years, which spans five broad cultural periods: Paleo-Indian (11,000 – 8,000 BC), Archaic (8000 – 1600 BC), Woodland (1600 BC – AD 1000), Mississippian (AD 1000 – 1700), and Historic (AD 1700 – present). Prehistoric land use and settlement patterns vary during each period, but short- and long-term habitation sites are generally located on floodplains and alluvial terraces along rivers and tributaries. Specialized campsites tend to be located on older alluvial terraces and in the uplands. In East Tennessee, during the seventeenth and eighteenth centuries, Europeans and Native Americans began interacting through the fur trading industry. Euro-American settlement increased in the early nineteenth century as the Cherokee were forced to give up their land. Hawkins County was originally established as a North Carolina county on January 6, 1787. At this time, the county consisted of what are now Hancock, Grainger, Jefferson, Knox, Roane, Meigs, and Hamilton counties. Development around the Hawkins Court House soon became known as the town of Rogersville. In 1858, the East Tennessee and Virginia Railroad used slave labor to lay the first tracks through an area called Bulls Gap, which is located near Rogersville. During the Civil War, the strategic location of the tracks made Bulls Gap the frequent scene of fighting between Union and Confederate forces. After the war, the railroad dominated the economic life of Bulls Gap. From the 1840s through the 1870s, the marble industry was developed in Hawkins County, and the area became famous for its pink and red variegated marble. Marble from Hawkins County was used in the Washington Monument in Washington, D.C., as well as the balustrades and stairways of the Capitol. Today the principal sources of farm income are beef cattle and burley tobacco. In 1791, the town of Rogersville printed Tennessee's first newspaper, *The Knoxville Gazette*.

Prior to construction of the Phipps Bend Nuclear Plant, archaeological surveys were conducted within the project location. These surveys identified 23 archaeological resources. Seven sites that could be adversely impacted within the project area were evaluated. In consultation with the TN-SHPO, TVA recommended four of the seven sites as potentially eligible for NRHP listing and the remaining 19 sites as ineligible for the NRHP. Furthermore, TVA recommended a determination of no adverse effect to the four sites due to avoidance. The TN-SHPO concurred with all of these determinations. It is unknown how many potentially eligible or eligible sites still exist within the project area. No historic/architectural resources were identified prior to construction of the Phipps Bend Nuclear Plant; however, no systematic historic/architectural survey has ever been conducted of the project area. Ten historic properties are listed on the NRHP in Hawkins County, none of which are within the APE for the previously proposed project or in the immediate vicinity of the site.

The proposed plant site contains no sites or structures that are currently NRHP listed. A field survey by TVA revealed no site or structure within the BLN site boundary that is of sufficient significance to be eligible for inclusion in the register.

Northern Mississippi, the location of the YCN site, has been the location of human occupation for more than 12,000 years. The prehistory and history of the area is generally divided into six broad periods: Paleo-Indian (10,000 – 8,000 BC); Archaic (8,000 – 1000 BC); Gulf Formational Period (1100 – 300 BC); Woodland (300 BC – AD 900); Mississippian (AD 1000 – 1700), and Historic (AD 1700 – present). Prehistoric land use and settlement varies during each period, but generally, short- and long-term habitation sites are located on floodplains and alluvial terraces along rivers and tributaries. Specialized campsites tend to be located on older alluvial terraces and in the uplands. The Historic Period is represented by settlement in the region by Europeans, Euro-Americans, and African-Americans and the subsequent removal of Native American tribes. Tishomingo County was formed in 1832 by the state of Mississippi following secession of the land by the Chickasaw. Agriculture was important to the county throughout the nineteenth century and into the early twentieth century. More recently, industry has increased throughout the county.

Prior to and during construction activities on the Yellow Creek Nuclear Plant site, archaeological surveys were conducted within the project location. These surveys resulted in the identification of 227 archaeological resources, of which 76 were determined eligible as a district in the NRHP. Thirty-four of the 76 sites within the project area were investigated for intact subsurface archaeological deposits, and 19 of these were investigated further based on the presence of intact deposits. TVA, in consultation with the Mississippi SHPO, determined that the construction of Yellow Creek Nuclear Plant would have no adverse effect on the archaeological district due to the mitigation measures. No historic/architectural resources have been identified within the project area; however, no systematic historic/architectural survey was conducted for the project area. Seventeen historic properties are listed on the NRHP in Tishimingo County; however, none of the properties were within the project APE for the previously proposed Yellow Creek project or in the immediate vicinity of the site.

The BLN and MH sites were ranked slightly higher due to the small number of sites identified and the protective/avoidance measures already in place. The other sites rated slightly lower due to the extensive number of sites already identified, indicating the potential for new discoveries if systematic surveys are performed.

9.3.3.4 Engineering and Cost-Related Criteria

Water Supply

The purpose of this criterion is to evaluate relative differences in the design and construction factors affecting costs for developing water supply facilities. Sites with local conditions that would require additional engineering costs to develop water supply capability (e.g., reservoirs to address water supply limitations) or reliability issues (e.g., low-flow constraints) or require substantively greater distances of piping or pumping to the site and acquisition of right-of-way to obtain adequate water supply are rated lower than sites with no such requirements.

All of the sites have access to cooling water sources that would provide adequate supply volume and reliability, such that no significant differential costs should be required for purchasing water rights or constructing on-site reservoirs. No groundwater usage would be required for any of the sites under consideration, as the reservoirs provide an adequate water supply. All sites except PBN are rated equally and highest on this criterion for cost of water supply. PBN could experience a greater potential for operational limitations due to low flows (also see discussion under Cooling System Suitability) that could potentially reduce its availability for generation. PBN is accordingly rated slightly lower. Table 9.3-1 includes the ratings for the water supply cost.

Transportation - Highway

Sites are compared with respect to costs for providing access by highway, rail, and barge. Thus, three transportation criteria are considered. The purpose of the first transportation criterion is to rate sites based on the length of additional or new highway construction required to provide car and truck access. Highway access for HVN, BLN, YCN, and PBN were previously upgraded in anticipation of construction. While some additional highway upgrades may be necessary to support construction and operation of new nuclear power plants, no significant differential highway access development costs are expected. All brownfield sites rated equally for this criterion. A lower rating is assigned to the Murphy Hill site due to the lack of upgraded highways in the vicinity of the site.

Transportation – Railroad

The purpose of the second transportation criterion is to rate sites according to the factors affecting relative costs associated with providing rail access. Sites are rated in accordance with whether or not they have adequate existing rail access or would require additional or new rail spur construction to provide rail access. BLN, YCN, and PBN already have rail access but HVN and MH do not. These latter sites rated lower than the other three sites on this criterion.

Transportation – Barge

The purpose of the third transportation criterion is to rate sites according to the relative costs associated with providing barge access. Barge transport can be a comparatively advantageous (on a cost basis) method of transporting components such as reactor vessels, steam generators, or large modular units. The primary site factors affecting the relative costs among sites are whether or not 1) an adequate barge facility exists on-site; 2) an on-site facility exists that can be upgraded sufficiently; 3) a facility exists nearby to the site, but would require offloading components and then transporting by truck a short distance to the site; 4) a barge facility exists at a greater distance from the site (i.e., would require off-loading and long-distance transport of large components); or 5) it would be feasible to construct an on-site or nearby barge facility. Sites are rated from highest to lowest in accordance with these factors affecting costs for providing new barge access or providing alternative means of transport for major components. With the exception of PBN, the water body at each of the sites is sufficient to accommodate barge traffic. BLN and YCN currently have barge unloading facilities adequate to support construction of a nuclear facility. HVN and MH both have barge access that would need some upgrading, probably including some dredging. Direct barge access is not possible at PBN (see below), requiring off-loading and ground transport for a considerable distance.

A barge unloading facility and an access road from the barge facility to the site have been constructed at BLN. The YCN site has an existing adequate barge unloading facility directly across Yellow Creek from the site, but off-loading and ground transport would still be necessary to bring the large components on site. Although barge transport all the way to PBN is not possible (there is no barge lock at the downstream Cherokee Dam), off-loading at Knoxville, TN to other ground-based transport would be a possibility. When originally constructing the dam, TVA did acknowledge the possibility that someday the agency might need to provide for barge navigation into Cherokee Reservoir. However, during original construction at the PBN site, some large components were off-loaded in Knoxville, trucked to above Cherokee Dam (no lock), reloaded on a barge, moved up the reservoir, off-loaded a second time and land transported to the site. This approach required major effort (i.e., temporary closure and rolling roadblock of a U.S. highway for a few days). No factors contributing to substantive additional costs for utilizing the barge facilities at BLN or YCN were identified. Based on the primary site factors identified above, BLN and YCN were given highest ratings on this criterion, with HVN and MH receiving high ratings, and PBN receiving a low rating for the reasons identified. Table 9.3-1 includes the ratings for the highway, rail, and barge costs.

Transmission Access

Transmission facilities must be constructed or adapted to accommodate plant generation. These costs are substantial and increase per linear mile. For this criterion, sites with lower transmission construction costs are rated higher. Preliminary estimates for new transmission lines necessary to connect each site with the existing transmission network are as follows. These estimates are indicative of the comparative differences between the sites rather than the optimum choice for transmission line routing from a particular site. More detailed surveys and analyses would be required to determine an exact route and interconnection for each line.

To accommodate the anticipated generation, the BLN site requires no additional transmission line or ROW. The HVN site would require approximately 40 mi. of 500-kV transmission line to be constructed on 1000 ac. along two transmission corridors, uprates to approximately 120 mi. of existing 500-kV transmission line, and a new 500-kV substation, occupying approximately 70 ac. The PBN site would require rebuilding approximately 33 mi. of 161-kV transmission line on 17 ac. of transmission ROW. Because of the proximity of the MH and BLN sites and the likely tie-in to some of the same existing 500-kV infrastructure, lines and substations, the transmission lines for MH would be roughly equivalent to that constructed earlier and already existing for BLN. Additionally, the presence of existing 500-kV and 161-kV lines crossing the MH site reduce the mileage of ROW needing to be constructed. Supporting operation of two nuclear units at the MH site would still, however, require off-site construction of approximately 50 miles of new 500-kV transmission lines and approximately 5 miles of 161-kV line on a combined total of 1215 ac. The YCN site would require two 500-kV corridors of approximately 120 mi. traversing approximately 3397 ac. of land. Acquisition of approximately 2266 ac. would be required for the new ROW. Approximately 5 mi. of 161-kV line would be required, of which about 1.1 mi. (10 ac.) would require new ROW. The HVN, PBN, MH, and YCN would all require additional assessment for threatened and endangered species, cultural resources, land use, and potential impacts to water resources.

Based on this information, the BLN site is rated more suitable than the other sites with respect to transmission facility proximity. Table 9.3-1 includes the ratings for the transmission access costs.

Site Preparation - Land Use and Ownership Assessment

For this criterion, the current ownership of each proposed site is examined. Between the sites which were previously issued a construction permit, a higher rating is given to a site where TVA now owns and controls all land than is given a site where TVA does not currently own and control all land.

The BLN site is still owned by TVA and remains dedicated for nuclear generation use. Approximately half of the original HVN plant site has been sold and is intended for use as an industrial park. Significant consideration must be given to the proximity of a nuclear plant on the remaining site owned by TVA and an industrial site immediate adjacent to it. The PBN site has been sold and is intended for use as an industrial site. Use of the PBN site would require TVA to reacquire the site from the present owners and halt further industrial development on the site. Ownership of the YCN site has been transferred to the State of Mississippi. The MH site is undeveloped and fully owned by TVA.

The BLN site is rated more suitable than the other four sites with respect to land use and ownership assessment, and the opportunity to utilize existing assets.

Table 9.3-1 includes the ratings for the land use and ownership assessment.

Topographic Modifications

The relative costs associated with site grading and earthmoving necessary to prepare the site for construction of a nuclear power plant varies by topography. Sites are rated from highest to lowest in accordance with estimated grading costs. Because construction was started at each of the four brownfield sites, the topography of the sites has already been altered for the construction of nuclear power plants. The BLN, PBN and HVN sites are rated equally high with regard to need to alter site topography. Acquisition and grading of undeveloped industrial property surrounding the former TVA YCN site would likely necessitate higher costs as well as increase impacts to terrestrial resources. The YCN site is consequently rated lower than the other three brownfield sites. As a greenfield site, MH is rated significantly lower due to the limited disturbances of the site.

Table 9.3-1 includes the ratings for the topography modifications cost.

Flood Protection Cost

The purpose of this criterion is to rate sites with respect to differential costs associated with construction of flood protection structures necessary to address probable maximum floods at the sites under consideration. Sites with the largest differences between site grade elevation and likely flood elevations are rated highest (least likely to incur costs associated with flood protection); sites with plant grade at or near flood level are rated lowest (most likely to incur costs associated with flood protection).

Per the elevation differences noted in the discussion of flooding potential in Plant Safety Evaluation above, YCN is rated highest for this criterion, BLN and HVN rate high, but PBN and MH rate significantly lower. Table 9.3-1 includes the ratings for the flood protection cost.

Cooling Water

For cooling water availability, the cost is similar across all sites. Sufficient water volume exists at all sites to accommodate expected closed cooling water systems, therefore all sites are rated the same. Table 9.3-1 includes the ratings for the cooling water cost.

9.3.3.5 Conclusion

The BLN site was chosen as the preferred site for the reasons described below.

- Alternative greenfield, brownfield, and nuclear sites are not environmentally preferable to the proposed site. Construction and operation of a new nuclear plant at each of the alternative sites would entail environmental impacts that are equal to or greater than those at the BLN site.

- Available facilities and infrastructure (e.g., transmission, intake and discharge structures, cooling towers) allow TVA to maximize assets that are currently underutilized.

- Construction permits for a nuclear plant were issued for each of the four former nuclear plant sites, including BLN, as indicated in the reference documents. There is no reason to believe that they would not also be suitable for an advanced light water nuclear plant. During the initial evaluations, all four brownfield sites were found more desirable than the MH greenfield site described in the reference documents.

- TVA siting program studies do not show appreciable differences in most attributes at the sites considered in this comparison. However, the BLN site has several advantages. BLN is rated second highest with respect to the availability of cooling water, as river flow past the BLN site is approximately three times that of PBN and more than twice the flow past HVN. BLN remains under TVA ownership. A new plant at that site could potentially use any of the remaining buildings and structures, resulting in significant reductions in construction material use, construction costs, and avoid the environmental impacts associated with constructing such infrastructure.

The BLN site has two other advantages. Environmental data were updated to support the Department of Energy EIS produced for potential tritium production at the BLN site, and local support for a nuclear project exists in the immediate area.

The alternative site analysis compared BLN with the other candidate sites to determine if there were any obviously superior sites among the candidate sites. A simultaneous comparison considered the additional economics, technology, and institutional factors among the candidate sites to see if any are obviously superior. Based on the comparison there are no obviously superior sites, so no further analysis is necessary, and BLN remains TVA's preferred site. Table 9.3-1 shows the total rating value of the sites in this comparison.

9.3.4 REFERENCES

1. Electric Power Research Institute, *Site Selection and Evaluation Criteria for an Early Site Permit Application*, EPRI Technical Report 1006878, Palo Alto, California, March 2002.

2. Tennessee Valley Authority, *Final Environmental Statement – Bellefonte Nuclear Plant, Units 1 and 2*, 1974.

3. Tennessee Valley Authority, *Final Environmental Statement – Hartsville Nuclear Plants, Volume 1,* 1975*,*

4. Tennessee Valley Authority, *Environmental Report – Phipps Bend Nuclear Plant, Units 1 and 2*, Revision 6, 1977.

5. Tennessee Valley Authority, *Final Environmental Statement – Yellow Creek Nuclear Plant, Units 1 and 2*, 1978.

6. Tennessee Valley Authority, *Final Environmental Impact Statement – Coal Gasification Project*, 1981.

7. Tennessee Valley Authority, Data Services Branch, *Summary of TVA Larval Fish Investigations*, Knoxville, Tennessee, 1983.

8. Tennessee Valley Authority, *Final Environmental Impact Statement for the Bellefonte Conversion Project*, Vol. 1, 1997.

9. U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, *Draft Environmental Statement, Phipps Bend Nuclear Plant, Units 1 and 2, Tennessee Valley Authority*, Washington, D.C., 1976.

10. Tennessee Valley Authority, Office of Natural Resources, *First Preoperational Assessment of Water Quality and Biological Resources of Guntersville Reservoir in the Vicinity of the Proposed Murphy Hill Coal Gasification Project*, 1983.

11. Winger, P.V., *Comprehensive Summary of the Water Quality, Limnology and Fisheries of the Cumberland River Near the Proposed Hartsville Nuclear Power Plant*, 1975, Tennessee Cooperation Fisheries Research Unit, Tennessee Technical University, Cookeville, Tennessee, 1976.

TABLE 9.3-1 (Sheet 1 of 2)
TVA ASE SUMMARY OF RESULTS

	BLN	HVN	PBN	YCN	MH
Safety & Health Criteria –					
Geologic Evaluation	4	5	3	4	4
Cooling System Suitability	5	5	4	5	5
Plant Safety Evaluation –					
Flooding Potential Evaluation	5	5	5	5	5
Accident Effects Evaluation –					
Population	4	4	4	5	4
Emergency Planning	5	2	5	5	4
Atmospheric Dispersion	4	5	4	5	4
Operational Effects Evaluation	5	5	5	5	5
Transportation Safety Evaluation –					
Cooling Tower Drift	4	5	5	5	4
Environmental Criteria –					
Proximity to Natural Areas	4	3	5	2	5
Construction-Related Effects on Aquatic Ecology	5	5	5	5	5
Construction-Related Effects on Terrestrial Ecology	5	5	5	5	5
Construction-Related Effects on Wetlands	5	5	5	5	5
Operations-Related Effects on Aquatic Ecology					
Thermal Discharge	4	4	3	5	4
Entrainment And Impingement Effects	5	5	4	4	5
Operations-Related Effects on Terrestrial Ecology					
Cooling Tower Drift	4	5	5	5	4
Socioeconomic Criteria –					
Construction-Related Effects	5	5	5	4	5
Highway Access During Construction	5	5	5	5	4
Operations-Related Effects	5	5	5	5	5
Environmental Justice Evaluation	5	5	5	5	5
Land Use	5	4	3	4	3
Cultural Resources	5	4	4	4	5
Engineering and Cost Related Criteria –					
Water Supply Cost	5	5	4	5	5
Transportation –					
Highway Access Cost	5	5	5	5	3
Rail Access Cost	5	3	5	5	2
Barge Access Cost	5	4	1	5	4
Transmission Access Cost	5	3	5	2	3
Site Preparation –					
Land Use And Ownership Assessment	5	3	3	2	2
Topographic Modifications	5	5	5	4	3
Flood Protection Cost	4	4	3	5	3
Cooling Water Cost	5	5	5	5	5
Total	142	133	130	135	125

TABLE 9.3-1 (Sheet 2 of 2)
TVA ASE SUMMARY OF RESULTS

	BLN	HVN	PBN	YCN	MH

1 = Least Suitable 5 = Most Suitable

* = These criteria were based upon an examination of the relative potential for financial impacts from major factors contributing to "cost" associated with that criterion, rather than cost estimates.

TABLE 9.3-2
TVA ASE POPULATION (2000)

Site	County	Total pop. (2006)	White (Pct. (2005)	Black (Pct.) (2005)	Asian (Pct.) (2005)	Hispanic (Pct.) (2005)	Other (Pct.) (2005)	Pct. below poverty (2004)
BLN	Jackson (AL)	53,926	91.1	3.8	0.3	1.6	3.2	15.3
	Marion (TN)	27,942	94.1	4.1	0.0	0.8	1.1	15.0
	Dade (GA)	16,233	96.5	1.2	0.4	1.1	0.8	12.3
	DeKalb (AL)	68,014	87.4	1.8	0.2	9.0	1.6	15.8
	Marshall (AL)	87,185	88.2	1.6	0.3	8.7	1.2	15.8
	Madison (AL)	304,307	69.8	23.5	2.0	2.2	2.5	11.7
	Franklin (TN)	41,319	91.0	5.5	0.6	2.0	0.9	13.5
HVN	Trousdale (TN)	7,811	86.0	10.5	0.3	2.6	0.6	14.5
	Macon (TN)	21,726	96.0	0.6	0.3	2.8	0.3	16.3
	Smith (TN)	18.753	94.1	3.1	0.2	1.7	0.9	13.0
	Wilson (TN)	104.035	89.4	6.8	0.6	2.1	1.1	8.5
	Sumner (TN)	149,416	89.1	6.5	0.8	2.5	1.1	9.6
PBN	Hawkins (TN)	56,850	96.6	1.7	0.3	0.9	0.5	15.7
	Scott (VA)	22,882	98.1	0.8	0.1	0.6	0.4	14.9
	Sullivan (TN)	153,239	95.7	2.1	0.5	0.8	0.9	14.0
	Greene (TN)	65,945	95.3	2.1	0.3	1.6	0.7	15.3
	Hamblen (TN)	61,026	84.8	4.1	0.9	9.3	0.9	15.2
	Grainger (TN)	22,453	97.4	0.6	0.1	1.3	0.6	17.0
	Hancock (TN)	6,713	98.6	0.5	0.1	0.4	0.4	28.5
YCN	Tishomingo (MS)	19,112	93.4	3.6	0.1	2.6	0.3	15.2
	Prentiss (MS)	25,615	84.5	14.0	0.2	0.7	0.6	16.2
	Alcorn (MS)	35,589	86.1	11.4	0.2	1.8	0.5	17.3
	Colbert (AL)	54,766	80.7	16.7	0.3	1.3	1.0	14.7
	Lauderdale (AL)	87,891	87.8	9.7	0.4	1.2	0.9	16.2
	McNairy (TN)	25,722	91.5	6.3	0.2	1.1	0.9	17.5
	Hardin (TN)	26,089	94.1	3.7	0.3	1.2	0.7	19.2
MH	Marshall (AL)	87,185	88.2	1.6	0.3	8.7	1.2	15.8
	DeKalb (AL)	68,014	87.4	1.8	0.2	9.0	1.6	15.8
	Jackson (AL)	53,926	91.1	3.8	0.3	1.6	3.2	15.3
	Madison (AL)	304,307	69.8	23.5	2.0	2.2	2.5	11.7
	Morgan (AL)	115,237	81.3	11.8	0.6	4.7	1.6	14.0
	Blount (AL)	56,436	90.9	1.5	0.2	6.4	1.0	12.4

TABLE 9.3-X1
COMPARATIVE RANKING OF ALTERNATIVE CANDIDATE SITES ON THE BASIS OF GROUND MOTION AND BEDROCK FOUNDATION

Site	USGS (2007 draft) PGA 2% in 50 yrs	Ground Motion Rank	Bedrock Foundation Rank	Overall Rank
BLN	0.16	3	5	4
HVN	0.11	5	5	5
PBN	0.17	3	4	3
YCN	0.20	3	5	4
MH	0.14	4	5	4

TABLE 9.3-X2
AVERAGE AND LOW FLOW CHARACTERISTICS AND RATINGS OF THE ALTERNATIVE SITES

	Low Flow		Average Flow		
Site	7Q10 / 3Q20 (ft^3/s)	Rating	(ft^3/s)	Rating	Overall Rating
BLN	5780 / 2050	5	37,130	5	5
HVN	1870 / 980	4	17,710	5	5
PBN	925 / 768	3	3890	5	4
YCN	7700 / 3740	5	53,080	5	5
MH	5830 / 2070	5	37,440	5	5

TABLE 9.3-X3
DENSITIES OF YOUNG OF YEAR FISH AND STANDING STOCKS OF FISH IN EACH RESERVOIR WHERE ALTERNATIVE SITES ARE LOCATED

Site	Young of Year (YOY) Fish - Years Samples	Annual Average Total Numbers YOY Fish per 1000 m^3 Water Volume	Standing Stock Years Sampled	Standing Stock Densities of Fish (by weight) kg/ha
BLN	1975 - 1983	54,783 (1)	1971 - 1984 and 1985 - 1993	297 and 371, respectively (2)
PBN	1975 - 1976	2103 (1)	1975	5 - 29 (3)
YCN	1975, 1976, 1979, 1980	185,690 (1)	1974, 1975	67.2 (5)
HVN	1974, 1975	6776 (6)	1974, 1975	684 - 118.5 (6)
MH	1982	135,571 (1)	1981 - 1982	333.8 (4)

Sources:

1. Reference 7.
2. Reference 8, page 3-63.
3. Reference 9.
4. Reference 10.
5. Reference 5, Table 2-14.
6. Reference 11.

9.4 ALTERNATIVE PLANT AND TRANSMISSION SYSTEMS

This section discusses alternatives in each of three system areas for Bellefonte Nuclear Plant Units 3 and 4 (BLN). This information is provided to enable a comparison of the environmental impact on each alternative to those of the proposed system.

Subsection 9.4.1 presents alternatives to the plant heat dissipation system. Subsection 9.4.2 evaluates alternatives to the circulating water system. These are presented as alternatives in the areas of intake designs and locations, discharge designs and locations, water supplies, and water treatment. Subsection 9.4.3 presents alternatives to the transmission system. These include alternative corridor routes, and alternatives to the proposed transmission system design, construction, and maintenance practices.

9.4.1 HEAT DISSIPATION SYSTEMS

Background Information

Tennessee Valley Authority (TVA) prepared Bellefonte Units 1 and 2 Environmental Statement for two identical pressurized water reactors to produce 3600 megawatts thermal (MWt) each and submitted it to the U.S. Atomic Energy Commission (AEC) in 1974 (Reference 1). This report considered the following alternative heat dissipation facilities:

a. Once-through Cooling

b. Dry cooling towers

c. Cooling lake

d. Spray canal

e. Mechanical draft cooling towers (MDCT) and

f. Natural draft cooling towers (NDCT)

Considering feasibility, environmental impact, and cost, the NDCTs represented the best balance and were selected as the best heat dissipation facilities for Bellefonte Units 1 and 2.

Final Environmental Statement (FES) related to the construction of Bellefonte Units 1 and 2 of Tennessee Valley Authority (Docket Nos. 50-438 and 50-439) was prepared by the AEC, Directorate of Licensing in June 1974 (Reference 3).

The AEC granted the construction permits for Bellefonte Units 1 and 2, a dual-unit pressurized water reactor plant in 1974. To meet cooling requirements at Bellefonte Units 1 and 2, TVA constructed two closed-cycle natural draft hyperbolic cooling towers. TVA deferred completion of the plant in 1988. At that time, Bellefonte Units 1 and 2 were approximately 90 and 57 percent complete, respectively.

TVA requested extensions of the expiration dates for Construction Permits Nos. CPPR-122 and CPPR-123 for Bellefonte Units 1 and 2 (Reference 4). Because of the passage of time since the issuance of the Final Environmental Statement (FES), the NRC requested additional information from TVA to determine if the conclusions reached in the June 1974 FES remained valid (Reference 5). TVA responded to these questions (Reference 6). Based on TVA's response and the recent environmental impact statements cited, the NRC concluded that, while the impacts are larger if construction resumes, the mitigative actions are commensurate with the larger impacts and, therefore, the conclusions reached in the FES remain valid (Reference 7).

By Reference 8, TVA requested the termination of Bellefonte Units 1 and 2. The NRC approved the TVA's request to terminate the construction permits for the unfinished Bellefonte Units 1 and 2 (Reference 9). However, during the NRC's review, TVA stated that it intends to continue using existing environmental permits at the site, as well as maintaining major plant components, such as water intake and discharge facilities, cooling towers, and transmission switchyards.

If the BLN project proceeds, TVA anticipates using the two existing NDCTs, water intake and discharge facilities constructed on the BLN site, for the AP1000 BLN Units 3 and 4. The existing cooling towers are preferable on the basis of cost and their adequacy to meet the plant's heat load requirements. Construction of any alternative would impose unnessary economic costs and would cause additional environmental impact.

9.4.1.1 Proposed Heat Dissipation System

The purpose of the plant cooling system is to dissipate energy to the environment. The condenser creates the low pressure required to draw steam through and increase the efficiency of the turbines. The lower the pressure of the exhaust steam leaving the low-pressure turbine, the more efficiency is gained. The limiting factor is the temperature of the cooling water.

The various heat dissipation system options differ in how the energy transfer takes place and, therefore, have different environmental impacts. Potential alternatives considered were those generally included in the broad categories of "once-through" and "closed-cycle" systems. The once-through method involves the use of large quantity of cooling water, withdrawn from and returned to a large water source following its circulation through the main condenser. Closed-cycle cooling systems involve substantially less water usage, since the water performing the cooling is continually re-circulated through the main condenser and only makeup water for normal system losses is required. Normal system losses include evaporation, blowdown, and drift. Evaporation occurs as part of the cooling process in wet systems. The purpose of blowdown is to control solids in the water that accumulate due to evaporation, which helps protect surfaces from scaling or corrosion problems. Drift is liquid water that escapes from the heat dissipation system in the form of unevaporated droplets during operation.

TVA performed analyses in this area to prepare for the construction of the original Bellefonte Units 1 and 2. The plant heat removal rates for BLN Units 3 and 4 are nearly identical to those of Bellefonte Units 1 and 2. Most parts of the analyses still apply to the new BLN units. Only the values for closed-cycle or closed-mode systems, in which the cooling water is circulated in a closed-loop system, are presented here from the previous work on combination systems of operation. Once-through cooling systems were not considered feasible, based on insufficient flows in the reservoir to meet thermal standards for about 30 percent of the days and, are excluded (Subsection 9.4.1.2.1).

The analysis of each alternative heat dissipation system considered various factors during construction and operation, for comparison with those of the proposed system. These factors are discussed in the following sections.

Description of the Proposed Cooling System

To meet cooling requirements at Bellefonte Units 1 and 2 and at the same time to provide environmental protection for the waters of Guntersville Reservoir, TVA installed closed-cycle natural draft hyperbolic cooling towers. This type of condenser cooling water system enables the plant to operate with a minimum thermal effect on the Tennessee River since the condenser cooling water system cycles cool water from the cooling towers through the condensers and discharges the warmed water back to the cooling towers in a closed system rather than discharging to the river. The use of the existing NDCTs for BLN does not require additional land and is cost-effective.

This subsection describes the proposed heat dissipation system, and identifies any associated adverse impacts and their expected mitigation.

BLN is provided with two cooling systems that transfer heat to the environment during normal modes of plant operation. These systems are the service water cooling system (SWS) and the circulating water cooling system (CWS). Heat generated during each operational mode can be released by these systems to the atmosphere and to the Guntersville Reservoir. Operation outside of normal modes of plant operation is not covered in this subsection.

The BLN CWS uses one existing NDCT per reactor unit to dissipate heat. It discharges via the blowdown pipe to the outfall structure on the Guntersville Reservoir south of the intake canal as described in Subsection 3.4.2.3.

The SWS has one MDCT per unit, which drains to the blowdown sump as described in Subsection 3.4.2.3 and AP1000 DCD Subsection 9.2.1.2.2. The MDCT uses fans to force convection within the cooling tower. The volumetric flow of air in the tower varies with the mode of operation. SWS water flows and heat loads at different operating modes are provided in DCD table 9.2.1-1. Further evaluation of SWS heat dissipation alternatives is not required because this is the standard AP1000 design as described in DCD Subsection 9.2.1.

The CWS makeup is provided by the raw water system. Water chemistry is maintained in the circulating water in order to maintain a non-corrosive, non-scale-forming condition and limit biological growth in components.

CWS water losses are replaced by makeup flow from the raw water system. Blowdown water is extracted from the cold water basin of each existing NDCT and is returned directly to the Guntersville Reservoir through the discharge system. The normal concentrations of dissolved solids in the circulating water ranges from three to four cycles of concentration. The blowdown rate is determined by the desired level of concentrations of dissolved solids in the circulating water.

The environmental impacts on the proposed heat dissipation system during station operation on the atmosphere and terrestrial ecosystems are discussed in Subsection 5.3.3. These include:

- Heat dissipation to the atmosphere.
- Length and frequency of elevated plumes.
- Frequency and extent of ground level fogging and icing in the site vicinity.
- Solids deposition (i.e., drift deposition) in the site vicinity.
- Cloud formation, cloud shadowing, and additional precipitation.
- Interaction of vapor plume with existing pollutant sources located within 1.25 mi. of the site.
- Ground level humidity increase in the site vicinity.

Environmental impacts from operating existing NDCTs include cloud development and plume shadowing as discussed in Subsection 5.3.3.1.4. NDCT plumes at several power plant sites are observed to cause broken cloud decks to become overcast, make thin clouds thicker, and create separate cloud formations several thousand feet above ground. Localized light drizzle and snow occasionally are noted within a few hundred meters downwind from NDCTs, and some enhancement of small rain showers is noted. Large thunderstorms do not appear to be significantly affected. Regional augmentation of natural precipitation is inconsequential compared to the total annual rainfall in the area. Induced snowfall due to operating NDCTs is observed but is infrequent. BLN existing NDCTs would not significantly alter local meteorology, and no mitigation is warranted.

Salt and solids deposition occurs with the existing NDCT operation. The maximum NDCT sodium salt deposition rate is well below the guidelines to prevent damage to vegetation (See Subsection 5.3.3.1.3). No mitigation is warranted.

Ground level fogging and icing are generally not a problem with large NDCTs. Surface fogging at the BLN site is rare (See Subsection 5.3.3.2). The height of the existing NDCTs and their evaluated plume make it unlikely that fogging would occur. Icing, that is associated with fogging, results during periods of sub-freezing temperatures. However, because fogging is rare, icing events are not expected. No mitigation is warranted.

Potential environmental impacts on the aquatic ecosystems are presented in Subsection 5.3.2.2.

Several potential environmental impacts on the terrestrial ecosystems are possible as described in Subsection 5.3.3.2.

Operation of the existing cooling towers for BLN is preferable on the basis of cost and their adequacy to meet the plant’s heat load requirements. The cooling tower dimensions, layout and airflow rates are provided in Table 5.3-3.

9.4.1.2 Screening of Alternatives to the Proposed Heat Dissipation System

Existing classes of heat dissipation systems include:

- NDCTs.
- Once-through cooling systems.
- Dry cooling towers.
- MDCTs.
- Cooling lake.
- Spray canals.
- Wet / Dry Cooling Towers.

An initial environmental screening of the above alternative designs was done to eliminate those systems that were obviously unsuitable for use in Bellefonte Units 1 and 2. The screening criteria included on-site land and water use; atmospheric, thermal and physical effects, noise levels etc. that might preclude the use of any of the alternatives. Results of cost comparison of the various alternatives heat dissipation systems are presented in Table 9.4-2 and are discussed in the following sections.

It is noted that TVA prepared Bellefonte Units 1 and 2 Environmental Report and submitted to the AEC in 1974. This report considered several heat dissipation systems. Considering feasibility, environmental impact and cost, the NDCT was selected as the best heat dissipation facility. Final Environmental Statement (Reference 3) was prepared by the USAEC, Directorate of Licensing in June 1974. The NRC granted Construction Permit (CP) for Bellefonte Units 1 and 2 in 1974. Based on the CP, two closed-cycle natural draft hyperbolic cooling towers were constructed. National Pollutant Discharge Elimination System (NPDES) Permit # AL 0024635 for the TVA Bellefonte Units 1 and 2 was issued by the Alabama Department of Environmental Management (Reference 10).

TVA requested termination of the construction permits for the Bellefonte Units 1 and 2 (Reference 8). The NRC approved the TVA's request to terminate the construction permits for the unfinished Bellefonte Units 1 and 2 (Reference 9). However, during the NRC's review, as well as in the subsequent TVA request for the reinstatement of the construction permits for Units 1 and 2, TVA stated it intends to continue using existing environmental permits at the site, as well as maintain major plant components such as water intake and discharge facilities, cooling towers and transmission switchyards. TVA has identified use of the existing NDCTs and water intake and discharge facilities for BLN Units 3 and 4 as preferable.

9.4.1.2.1 Once-Through Cooling Systems

Once-through cooling is the process whereby water is drawn from a water body, circulated through the steam condenser where its temperature is raised, and discharged directly into the same water body.

Once-through cooling utilizing a diffuser discharge to the reservoir has been a practical consideration at other plant sites in order to provide the plant with cooler water for lower turbine backpressure and attendant increased plant capability. Because of the adopted thermal standards of 5°F rise and 86°F maximum, the completely open system was not considered feasible for this plant. Assuming the heated effluent is mixed with 75 percent of the river flow, there would have been insufficient flows available in the reservoir to meet thermal standards for a limited number of days based on analysis of the daily flows for 1966-71. In a low-flow year with a relatively hot summer, plant generation might have to be curtailed as much as 43 percent of the days to comply with the thermal standards, if the plant utilized once-through cooling only. Therefore, the temperature rise after mixing could not meet the criteria a sufficient amount of time to justify the once-through cooling system. Some form of auxiliary cooling with a combined-or closed-cycle system was therefore required to assure that the thermal criteria were complied with and that a reliable source of power was provided.

Therefore, it was concluded that once-through cooling was not a feasible option for Bellefonte Units 1 and 2. This conclusion is still valid for BLN Units 3 and 4 since there have not been any significant technology changes in once-through cooling systems.

9.4.1.2.2 Dry Cooling Towers

Dry cooling is an alternative cooling method in which heat is dissipated directly to the atmosphere using a tower. This tower transfers the heat to the air by conduction and convection rather than by evaporation. The condenser coolant is enclosed within a piping network with no direct air to water interface. Heat transfer is then based on the dry bulb temperature of the air and the thermal transport properties of the piping material. Both natural and mechanical draft can be used to move the air. While water loss is less for dry cooling towers than wet cooling towers, some makeup water is typically required.

Because there were no evaporative or drift losses in this type of system, many of the problems of conventional cooling systems were eliminated. For example, there were no problems with blowdown disposal, water availability, chemical treatment, fogging or icing when dry cooling towers were utilized. Although the elimination of such problems is beneficial, dry towers have associated technical obstacles such as high turbine backpressure, and possible freezing in cooling coils during periods of light load and startup.

This is an inherently less efficient process and requires an extensive heat transfer surface area of metal fin tubing within the tower, which could be either mechanical or natural draft. In this system, the temperature of the water leaving the tower could only approach the dry-bulb temperature of air which was invariably higher than the wet-bulb temperature approached by the wet towers.

Because of the high circulating water temperatures, expensive supplemental cooling must be provided for plant auxiliaries dry cooling systems. These systems would dictate severe performance requirements on the turbines, which might have to operate over a wide range of backpressures with a maximum backpressure of from 10 to 14 in. Hg Absolute compared to a more typical maximum backpressure of about 5 in. of Hg Absolute.

Studies showed that there were substantial turbine design challenges associated with the higher-than-normal exhaust pressure of dry cooling tower applications. These included possible overheating of the last-stage bucket; possible flutter damage to the last-stage bucket at high exhaust pressures and low loads; possible water damage due to recirculation from the direct condenser; rapid exhaust temperature changes due to load changes which could cause cycling thermal stresses; distortion of the exhaust hood and bearing supports; and difficulties in providing adequate clearance control.

The dry cooling tower compared to the hybrid wet/dry cooling tower results in a reduction in plant efficiency, especially during periods of high ambient dry bulb temperatures, and the increased land requirements associated with the dry tower system. The dry towers require more fans than the hybrid towers resulting in higher operating costs and the lower efficiency results in an increase in fuel requirements over the life of the plant.

Dry cooling suffers from the inability to maintain design plant output during the hottest periods of the year. Depending on the meteorology at the site and the choice of design point, a plant can experience capacity reductions of up to ten percent to twenty percent on the steam side alone because of increased turbine backpressure.

Because dry cooling relies only on conductive and convective effects, the towers must be much larger than wet cooled towers to achieve similar cooling performance. This would have a negative impact on on-site land requirements. The investment cost for a dry cooling tower is substantially larger than the cost for a wet mechanical draft tower.

The adverse considerations associated with the use of dry cooling tower systems at new facilities was addressed in the preamble to EPA's final rule on NPDES regulations addressing cooling water intake structures for new facilities. The EPA determined that dry cooling is not the best technology available for minimizing adverse environmental impacts, in part, because the technology of dry cooling carries costs that are sufficient to pose a barrier to entry to the marketplace for some projected new facilities, and dry cooling technology has some detrimental effects on electricity production by reducing the energy efficiency of steam turbines. Therefore, dry cooling tower systems should only be considered if water supply is an issue. Because Guntersville Reservoir provides an adequate water source for BLN, it follows that dry cooling tower systems should not be considered for the BLN site.

9.4.1.2.3 Mechanical-Draft Cooling Towers

MDCTs were considered as an alternative method of heat dissipation to closed-cycle NDCTs at Bellefonte Units 1 and 2. These two types of cooling towers operate on the same basic thermodynamic principles, that is, cooling takes place by evaporation and sensible heat transfer. MDCTs have long piping runs that spray the water downward. Large fans pull air across the dropping water to remove the heat. As the water drops downward onto the "fill" or slats in the cooling tower, the drops break up into a finer spray. On colder days, tall plumes could be seen. On warmer days, only small plumes were seen.

The construction of MDCTs for waste heat dissipation at Bellefonte Units 1 and 2 was a technically feasible alternative. For a closed-loop tower system, the main circulating water pumps would circulate water through the condenser and to the towers where the heat is transferred to the air, the flow of which is induced by large fans. Water returning from the towers would flow by gravity back to the circulating water pumps. Makeup water and blowdown is the only intake and discharge from and to the Guntersville Reservoir. The total makeup required is based upon the concentrations of dissolved solids desired in the CWS. The concentrations present in the blowdown flow would meet water quality standards. Slightly increasing the quantity of blowdown and makeup would further reduce the dissolved solids concentration. The temperatures of this blowdown for the MDCT closed-cycle system is shown in Table 9.4-3.

Drift had been estimated by the cooling tower manufacturers to be small. For ecological considerations, MDCTs rank intermediately in water demand of the alternatives considered. The advantages of this alternative over the spray canal alternative were the absence of impingement on Town Creek Embayment and reduced entrainment losses. The entrainment losses were solely a function of the relatively smaller water demand. Thermal discharge effects were approximately the same as for the spray canal, given the same considerations regarding design and location of the discharge device. No significant differences in entrainment losses were expected for MDCTs versus NDCTs.

Atmospheric effects from the operation of the MDCTs would include considerable fogging and possibly some icing within about 4 to 5 mi. of the cooling towers. At BLN, the MDCTs are at a disadvantage when compared to NDCTs in atmospheric effects. The potential effects are more significant than those from the higher plumes of the NDCTs because of their lower emission height. In some cases, the visible plumes from the MDCTs move downwind at near ground level. In general, MDCTs are comparatively short compared to NDCTs. It was estimated that because of this about three times the amount of fogging incidents and 10 times the number of icing incidents would occur if MDCTs were used.

The intensifying effects of these low-level plumes during periods of natural fog were of particular interest. Such fogging conditions would occur about 35 days per year. Most fogging would occur south-southwest of the plant in the direction of the highest frequency of long-plume occurrence. About 17 percent of the time (61 days per year), the plumes would be transported in the south through the southwest sectors with lengths greater than 4 mi. Alabama Highway 40 could experience fogging from 4 to 8 percent of the time, and icing 1.5 to 3 percent of the time. However, the trend of results in these sectors indicated that a fogging potential exists a small percentage of the time near Alabama Highway 35, and icing on this highway might happen one day a year. Also of significance was potential fogging to U.S. Highway 72 in the north-northeast sector 7 percent of the time (26 days per year).

The data indicated that on-site cooling tower-induced icing would occur on about 70 days during the 5-month period from November through March. The duration of the heaviest icing would depend on persistency of the below-freezing temperatures. The direction with the maximum frequency of plume travel would be toward the south-southwest sector. Light to moderate icing would occasionally occur on nearby structures located north-northeast through west-southwest of the cooling towers.

The use of cross-flow MDCTs as an alternative cooling method required four wood-filled cooling tower sections. Each section is approximately 50 ft. wide by 60 ft. high by 720 ft. long with 18 cells per section for a closed-cycle system. The materials of MDCTs were not compatible with the architecture of the powerhouse. The relatively low profile of the MDCTs would not present a very large vertical barrier or landmark on the terrain. The use of MDCTs as an alternative means of cooling would not require the acquisition of additional land beyond that now required for the plant. The towers would occupy about 50 to 100 ac. of the site.

The use of MDCTs would increase noise levels at plant site. This increase would be due to both the fans and the falling water, but the fan noise would be dominant. Predicted noise levels for Browns Ferry plant of six 600-ft. sections of MDCTs were judged "normally acceptable." Based on these predicted levels, MDCTs for Bellefonte Units 1 and 2 were also judged acceptable.

Technology for MDCTs has improved over the last 15 years with the introduction of the polyvinyl chloride (PVC) film fill. This film fill greatly increases performance for all types of wet cooling towers, including NDCTs and MDCTs. Although technology has improved for the MDCTs, upgrades in technology would equally enhance the performance of the existing NDCTs. Therefore, there is no significant technology change that would make MDCTs superior to NDCTs. The parasitic losses alone would make the existing NDCTs superior to MDCTs. In addition, MDCTs would cause an increase in fogging and icing, which could be serious for the particular topography and the road and city locations in the Guntersville Reservoir area. TVA concluded that the use of MDCTs is inferior to NDCTs at BLN for these reasons.

9.4.1.2.4 Cooling Lake

A cooling lake is a shallow reservoir having a large surface area for removing heat from water. The surface area exposed to the air is increased with spray nozzles. A cooling lake is typically used where land is relatively inexpensive, cooling water is scarce or expensive, or where there are strict thermal loading restrictions in place. If a cooling lake is used, water in the lake can be reused, thus reducing the overall water-withdrawal requirement. If the water is discharged to a river, its return to the river may be delayed by routing it through a canal or cooling lake first.

The construction of a cooling lake for waste heat dissipation at Bellefonte Units 1 and 2 was a technically feasible alternative. The cooling lake required a surface area of about 3900 ac. based on a rule of thumb of 1.5 ac. of surface area per megawatt electric of nuclear generation. Impounding the Dry Creek basin and flooding it to an elevation of 630 ft. would create a lake with a surface area of 5650 ac. at a level of 35 ft. above normal reservoir elevation. This was considered sufficient to dissipate the thermal discharges. This required constructing approximately 8 mi. of dikes and clearing 6100 ac. of sparsely populated land. In 1974, it was estimated that approximately 140 occupied structures were to be removed.

The estimated average depth was 20 ft. with this plan. Heat transfer was effective with a 2-unit flow through a time period of 7 days, and a low thermal loading of the surface, about 2.5 ac. per megawatt. The intake temperature above ambient ranged from 0.5 to 4°F. The average surface temperature ranged from 7 to 14°F above ambient. For environmental considerations, the physical and chemical characteristics of effluents did not present a problem. The required makeup from all causes of evaporation was 140 cubic feet per second (cfs). The average inflow from Dry Creek was stated as 31 cfs, so makeup from Guntersville reservoir would be required.

There were no anticipated drift losses with the cooling lake. The cooling lake alternative would consume about the same amount of water as the NDCTs.

For ecological considerations, this alternative required a one-time demand of water above that required for the existing NDCTS. The effect of a cooling lake on the aquatic biota due to impingement and entrainment in the Tennessee River was no greater than for other closed-cycle alternative cooling systems. The aquatic life of the impounded streams and the terrestrial life of the flooded area were affected. Colonization of the lake by certain species required control measures. Trace metals and scaling elements would increase in the system over operation time.

The atmospheric effects were significant. Local effects extend 0.25 mi. inland of the shoreline, and onto bridges. Steam fogging and icing conditions would occur more often due to its heated waters. The maximum effect was the prevailing wind direction of south-southwest. This would create hazardous conditions for a few days per year on both U. S. Highway 72 and the Norfolk Southern Railroad that would cross the lake. Increased fogging and road icing was observed at other cooling lakes.

Another disadvantage was the large amount of land area used. Approximately 7000 ac. in addition to the plant site would be required. The lake area would be 5650 ac. The additional 1350 ac. would be needed to minimize the environmental impact on wildlife and to control flooding.

Considering all of these effects together, TVA concluded that use of a cooling lake was inferior to NDCTs at Bellefonte Units 1 and 2. This conclusion is still valid for BLN Units 3 and 4, because there have not been any significant technology changes in cooling water systems using cooling lakes. A cooling lake is not viable, based on the additional land required for this alternative.

9.4.1.2.5 Spray Canals

Spray canals were considered for waste heat dissipation at Bellefonte Units 1 and 2. A spray canal system approximately 2.5 mi. long and 200 ft. wide was required. During operation, water is sprayed upward at a low level, 15 to 20 ft., as compared to plume release heights of 60 ft. and up to 500 ft. for MDCTs and NDCTs, respectively. The primary disadvantages of spray canals were atmospheric effects, similar to those of MDCTs, when compared with NDCTs. NDCTs have virtually no occurrence of icing or fogging due to the elevation of their plume discharge, and are superior to spray canals in minimizing fogging and icing.

The construction of a spray canal for waste heat dissipation at Bellefonte Units 1 and 2 was a technically feasible cooling alternative. With spray canals, wind speed had far less of an effect on heat transfer in comparison with a cooling lake. Their efficiency is a very strong function of the wet-bulb temperature alone. Because heat transfer coefficients vary as much as 50 percent for wet-bulb variations between 40°F and 80°F, winter use required a minimum size large enough for the low winter wet-bulb temperatures. Hourly wet-bulb temperature variations cause would change in the condenser intake temperature, and thus in the power production efficiency.

For environmental considerations, several physical and chemical characteristics of effluents were considered. Makeup water for operation would be obtained from the Tennessee River. The makeup volume would be dependent on the blowdown concentration factor chosen. The dissolved solids in the blowdown would not exceed acceptable levels.

Temperature of the blowdown for the spray canal system is shown in Table 9.4-3. Holdup time on blowdown was longer for the spray canal system than for cooling towers due to the larger quantity of water in the system. Drift losses were estimated to be small. Any drift volume was usually larger droplets and were carried only a short distance. The channel edge was sloped back to the channel so that a large percentage of water blown by the wind returned to the canal.

The atmospheric effects involved fogging and icing. These effects were largely dependent on the quantity of evaporation of the spray effluent and the absolute humidity deficit of the atmosphere. Therefore, the expected plume lengths were greater than those estimated for cooling towers because of the usually lower ambient temperature and greater amount of moisture within the near-surface layer where most of the effluent was dispersed.

Visible plumes generated by the spray canals would move downwind near ground level with intensifying effects on natural fogging about 35 days per year. Most fogging and icing would occur in the south-southwest direction of the plant. The plume was estimated at 2 mi. or more in length in this sector for 13 percent of the time. Fogging would be encountered from 4 to 8 percent of the time on Alabama State Highway 40, and icing would be experienced about 4 percent of the time (15 days per year). U.S. Highway 72 would experience fogging in several sectors, and icing would occur 1 percent of the time (3.5 days per year).

The aesthetics were reasonable. The operation of a spray canal would increase noise levels at the plant site by a small amount. This increase would be due to motors and the falling water. Normally acceptable noise levels would occur at the site boundary. It was estimated that use of the spray canal scheme did not require additional land.

As indicated above, spray canals produce twice as much fogging and seven times as much icing as NDCTs. Because of the potential ground-level fogging, TVA concluded that the use of a spray canal was inferior to the existing NDCT.

9.4.1.2.6 Wet / Dry Cooling Towers (Hybrid Towers)

A wet / dry cooling tower functions in principle like a wet cooling tower. An additional dry section installed in the upper part of the cooling tower reduces visible plume by heating wet air coming from the lower wet zone. The construction of a wet / dry cooling tower for waste heat dissipation at Bellefonte Units 1 and 2 was a technically feasible alternative.

In a wet / dry cooling tower, efficient wet cooling cold water temperatures are achieved with reduced visible plume similar to dry cooling systems. Fans are located in both the wet section and the dry section of the tower. In the dry section, the fans are located above the wet level in front of the heat exchangers. The hyperbolic shell achieves a natural draft effect that helps reduce power consumption. Lower operating costs are achieved by the application of two-speed motors (Reference 2).

The wet/dry cooling tower is commonly referred to as “hybrid cooling towers.” The hybrid cooling towers take advantage of the high efficiency of the wet cooling tower with the reduced visible plume of the dry cooling tower. When the ambient temperature is low, the cooling tower may be operated as a dry cooling tower without water consumption or plume production. The hybrid cooling tower traditionally uses air-cooled steel coils in tandem with the evaporative section of the cooling tower. New non-metallic heat exchanger technologies may be used to minimize cost and fouling with improved corrosion resistance.

Note that the dry cooling tower portion of the hybrid tower is not as efficient as the wet cooling process or the NDCT process because it requires the movement of a large amount of air through the heat exchangers to achieve the necessary cooling. This results in less net electrical power for distribution. For these reasons, this alternative is not considered environmentally equivalent or preferable to the NDCT.

The BLN site currently contains existing closed-cycle cooling towers, has access to an abundant supply of water, is located in a rural area in a southern state where the winters are mild and the summers are hot and humid.

The advantages of the hybrid systems are that it conserves water where water is limited and expensive, provides for plume abatement and provides for short-term enhancement of the dry air cooled condenser portion of the system during peak loads when the weather is hot, since under these conditions the dry system becomes less efficient and results in a loss of power unless additional cooling is provided.

Given that water conservation is not a primary concern at this location, plume abatement is also not a significant concern. The current existing closed-cycle NDCT system designed for Bellefonte Units 1 and 2 was slightly undersized for the total cooling requirements during the hottest days for which the addition of a dry cooling component from a hybrid system would further complicate and eliminate a majority of the potential benefits of a hybrid system.

As discussed in NUREG 1811, “Environmental Impact Statement for an Early Site Permit (ESP) at North Anna ESP Site,” the noise level for the North Anna Unit 3 wet and dry cooling towers given in the Plant Parameter Envelope (PPE) is 65 dBA at a distance of 1000 ft. Per Subsection 5.3.4.2, the NDCTs at the BLN site have noise emissions as high as 55 dBA at distances of 1000 ft.

Reduced evaporation, makeup water, and blowdown are the benefits of the wet-dry cooling process, thus reducing water-related impacts. However, the disadvantages of dry cooling, as discussed in the EPA preamble to the final NPDES Rule, apply to the dry cooling portion of the heat-dissipation process. The dry cooling process is not as efficient as the wet cooling process, because dry cooling requires the movement of a large amount of air through the heat exchanger to achieve the necessary cooling. This results in a lower net electrical power output for distribution.

Water availability is not a primary issue at the BLN site, and the visual plume would not impact the scenic surroundings of this rural area. TVA concluded that, for the above-cited reasons, the use of wet/dry cooling towers is not viable at BLN.

9.4.1.2.7 Open-Cycle Natural Draft Cooling Towers

Open-cycle NDCTs were considered as an alternative to the proposed closed-cycle cooling towers (closed-cycle NDCTs are discussed above as the proposed heat dissipation system in Subsection 9.4.1.1). The open-cycle natural draft cooling towers uses the river as a water source but augments them with cooling towers, which reduces the temperature of the water going back to the river. This combined system limits the temperature of water returning to the river. In addition to their physical size, the significant differences between the cooling towers are the increased losses of larval and small fish, and the increased capital expenditure for the open-cycle cooling tower. This increased investment cost is due to the additional channels, gates, and diffusers typically required of the open-cycle system.

The flow of water required to achieve the desired change in temperature for the steam condenser is cooled in the NDCT before final release. Release of this heated water into the river has the effect of raising the river temperature based on mixing assumptions. This heat input would cause the river temperature to exceed the maximum allowable value during low flow and/or hot weather, which would result in operational challenges to ensure continued meeting of water quality standards.

Discharging large amounts of hot water would raise the temperature of the receiving water body to an unacceptable level for the local ecosystem. Consideration of the effects of thermophilic microorganisms on public health were important for facilities using cooling ponds, lakes, canals, or small rivers, because use of such water bodies would increase the presence and numbers of thermophilic microorganisms.

For the above reasons, TVA concluded that open-cycle NDCTs were not a feasible option for BLN.

9.4.1.3 Potential Alternatives to the Proposed Heat Dissipation System

This subsection discusses the applicable operating modes for the cooling water alternatives that were determined to be viable for the BLN site, and provides an assessment of the environmental and economic feasibility of each of these alternatives. Based on the results of the screening, the cooling water designs that were determined to be viable for Bellefonte Units 1 and 2 are:

- Natural Draft Wet Cooling Tower (closed-cycle)
- Spray Canal
- Mechanical Draft Wet Cooling Tower

The BLN facility proposed heat dissipation system is presented in Subsection 9.4.1.1. The environmental impact from NDCTs are discussed in Subsection 5.3.3.

The primary differences between MDCTs and NDCTs relative to environmental impacts are the potential for fogging, icing, and salt deposition. These impacts are greater for MDCTs because the plume is lower to the ground. In addition, the MDCTs require slightly more land area than NDCTs. The difference due to land use can be considered minor, but the MDCTs would cause an increase in fogging and icing which could be serious for the particular topography and the road and city locations in the Guntersville Reservoir area. In this light, NDCTs have the advantage at BLN.

The spray canal alternative has the same evaluation as the MDCTs, and does not qualify as well as the NDCTs overall. The dry cooling tower evaluates about the same as the NDCTs, but the dry tower causes generating efficiency to be lower, as does the spray canal. The closed-cycle NDCTs are environmentally preferable to the other feasible alternatives. Based on the above analyses, TVA concluded that closed-cycle NDCTs would provide the most effective method of waste heat dissipation of all the alternatives from an economic and environmental standpoint. These cooling towers are economically and environmentally preferable to the feasible alternatives.

Alternative Systems of Operation

Two systems of operation were considered for the several heat dissipation alternatives: (1) closed-cycle system, in which the cooling water is circulated in a closed-loop system, and (2) combined-cycle system, in which the system can be operated in any of three modes as required.

The three modes in which the combined-cycle system can operate are:

1. Open mode. Operates as a once-through system with heat dissipated to the river.

2. Helper or topping mode. Heated condenser water is circulated through a supplemental cooling facility for initial cooling and then discharged to the river.

3. Closed-mode. Operates in a closed-loop with heat dissipated to atmosphere by, for example, a tower.

The closed-cycle system is adaptable to either MDCTs or NDCTs, cooling lake, or spray canal. The only water discharged to Guntersville Reservoir would be the required blowdown from the cooling system. The closed system would essentially exclude the use of Guntersville Reservoir for heat dissipation but would result in reduction of plant net electrical output and therefore reduced plant efficiency. Figure 9.4-1 shows the schematic arrangement for a closed system.

The combined-cycle system provides the flexibility of using the Guntersville Reservoir for heat dissipation. The open mode would utilize diffusers alone, which increases plant efficiency due to lower condenser cooling water temperature. The helper mode also would allow use of the lower temperature condenser cooling water from the reservoir and would divide the heat dissipation between the reservoir and the heat dissipation device. The combined-cycle system would employ cooling facilities designed for less cooling capability than the facilities selected for a closed system since a closed system requires supplemental cooling 100 percent of the time, and therefore higher cost, more efficient heat dissipation facilities can be justified. Figure 9.4-2 shows the schematic arrangement and operation of the various gates required in the cooling water circuit to accomplish the three modes of combined-cycle operation.

The design of the intake as a skimmer wall (which functions similar to a weir) for combined-cycle system is not considered feasible because of the shallow water depths at the site and the small temperature difference between the upper and lower layer of water exist when meeting the 5°F rise standard.

The cooling tower or spray canal may be utilized as the supplemental heat dissipation device for a combined-cycle system.

The alternative systems investigated for this plant are the schemes as designated below:

Alternative (Scheme)	Heat Dissipation Device	System Type
1A	Spray Canal	Combined (Intake from reservoir)
1B	Spray Canal	Combined (Intake from Town Creek)
2	Spray Canal	Closed
3	Mechanical Draft Cooling Towers	Combined
4	Mechanical Draft Cooling Towers	Closed
5	Natural Draft Cooling Towers	Combined
6	Natural Draft Cooling Towers	Closed

Alternative 6 is the proposed system discussed previously and was used as a base case for economic comparison of the alternatives.

Note: Alternate and scheme are synonymous.

<u>Evaluation of Alternative Heat Dissipation Facilities</u>

Analyses were performed using the following factors as a basis: feasibility, environmental considerations, and economic considerations. The analyses were carried to the extent required to determine the acceptability of each alternative when considering these factors. Details and environmental impacts for the alternatives are discussed and estimates of environmental impacts were made as discussed in Subsection 9.4.1. The results are summarized in Table 9.4-1.

Table 9.4-2 summarizes the present worth cost comparison in 2007 dollars and other differences of the feasible alternatives. The comparison of feasible alternatives shown in this table indicates the relative economic differences in present worth evaluated costs (2007 dollars) which include the capital cost of installing the facilities and the present worth of the operation and maintenance costs. The natural draft closed-cycle cooling tower alternative is used as the base, because it is the alternative with the lowest total evaluated cost. Alternative 4, closed-cycle MDCT system, has the next lower evaluated cost.

All costs shown in Table 9.4-2 are present worth cost difference in 2007 dollars using alternative 6 as a base. The 1979 dollar values from Table 2.6-1 of Reference 11 were converted to 2007 dollars. The dollar values were increased by the Consumer Price Index (CPI) ratio of the April 2007 southern region value of 199.618 to the April 1979 value of 70.3. CPI data were taken from the U.S. Department of Labor Bureau of Labor Statistics.

Based on 1979 dollars, the cost of installing closed-cycle NDCTs was approximately $58 million for the two-unit plant, including conduits, condensers, and site preparation. Based on 2007 dollars, this installation cost would be $165 million. Note that the alternative 6 closed-cycle NDCTs have already been installed for use with BLN Units 1 and 2. The estimated installation cost of the alternatives would be the capital cost noted on Table 9.4-2 plus $165 million.

All alternatives are estimated to be compatible with the construction schedule for the remainder of the plant, except the cooling lake, because of the enormous amount of land that would need to be acquired.

The mechanical draft closed system (alternative 6*),* in addition to having an evaluated cost of some $181.9 million, or $16.9 million more than the NDCTs, would create considerable fogging and icing, the effects of which would be more significant than the potential effects from the higher plumes of the NDCTs. MDCTs are also noisier than any of the other alternatives.

In conclusion, TVA has investigated numerous feasible alternatives for heat dissipation for the Bellefonte Units 1 and 2, and each alternative costs more and offers no significant advantages over the NDCTs. The anticipated environmental impact (physical and chemical characteristics of the tower effluent, local fogging and icing, effects of NDCTs, aesthetics, noise), as a result of installing and operating this system is described in Subsection 5.3.3. Therefore, due to the economic advantage and the smaller overall potential for environmental impacts, TVA installed closed-cycle natural draft hyperbolic cooling towers for heat dissipation at the Bellefonte Units 1 and 2. Because TVA did not complete Bellefonte Units 1 and 2, the present proposal is to use the existing cooling towers for BLN if the AP1000 units are built.

9.4.2 CIRCULATING WATER SYSTEM

The CWS is an integral part of the heat dissipation system discussed in Subsection 9.4.1. The CWS provides the interface between the main condenser and the heat dissipation system.

9.4.2.1 Proposed Circulating Water System

TVA installed closed-cycle natural draft hyperbolic cooling towers to meet cooling requirements at Bellefonte Units 1 and 2 and at the same time to provide environmental protection for the waters of Guntersville Reservoir. This type of condenser cooling water system would enable the plant to operate with a minimum thermal effect on the Tennessee River because the condenser cooling water system cycles cool water from the cooling towers through the condensers and discharges the warmed water back to the cooling towers in a closed system rather than discharging to the river. In the operation of cooling towers a certain portion of the circulating water is continuously lost as a result of evaporation, small leaks, drift, and blowdown. Therefore, makeup water is continuously added to the system. To provide this makeup, water is withdrawn at the head of the channel feeding from the Guntersville Reservoir and discharged to the cold water channel of the towers.

Intake System

The system is described in Subsection 3.4.2.1. Normal water surface of the Guntersville Reservoir varies between elevations about 595 ft. msl (summer) and 593 ft. msl (winter). The water intake pump structure is located at the end of an intake channel in which the maximum water velocity of the cross section is less than 0.0174 feet per second (ft/s) even for a minimum pool elevation of 593 ft. msl. The intake structure has four openings slightly over 10 ft. wide and 36 ft. high. The top of the opening is at elevation 592.75 ft. msl and the bottom at elevation 557 ft. msl. The maximum flow velocity is less than 0.0157 ft/s through each of the openings at a maximum pool elevation of 595 ft. The openings are followed by vertical traveling screens which have 3/8-inch opening mesh. The maximum velocities through clean screens are estimated to be about 0.5 ft/s. The intake water taken from the river passes through 1/32-inch strainers after passing through the traveling screens.

The intake channel that connects the intake structure to the reservoir has side slopes 4 ft. horizontally to 1 ft. vertically with the side slopes intersecting the surface of rock. The distance between the toes of the slopes at the rock surface is 40 ft. To provide assurance that water is always available, a 20-ft. wide trench is excavated 20.5 ft. below the surface of the rock to connect to the original river channel. The depth of water in the intake channel varies from 10 ft. to 12 ft. measured to the surface of the rock and 30.5 ft. to 32.5 ft. to the bottom of the trench. The intake structure is located some 1200 ft. from the existing shoreline (at elevation 595 ft.). TVA originally concluded that the proposed intake resulted in no significant adverse environmental impacts and that a detailed study of alternatives was not warranted. In the process of its review of the draft environmental statement, the AEC staff requested TVA to examine alternative intake designs.

In response to the AEC request, TVA examined several alternatives to the proposed intake arrangement and concluded, on balance, that the originally proposed shoreline intake structure was the best alternative available. Alternative intake designs are discussed in Subsection 9.4.2.2.1.

BLN is designed with one intake system that supplies the necessary raw water to the plant. The intake system consists of an intake canal, which connects the Guntersville Reservoir to the intake structure (Subsection 3.4.2.1). Pumps provide the driving force to the CWS and SWS makeup flow. The flow rates for these pumps vary based on system demand. Flow intake is at the end of a channel 1200 ft. inland from the Guntersville Reservoir shoreline. Intake velocity is low, and the inlet is screened to minimize the intake of material other than water.

Discharge System

BLN is designed with a single discharge system. This system consists of one main blowdown pipe, which travels back to the Guntersville Reservoir where the blowdown is discharged through a multiport diffuser. The discharge system is described in Subsection 3.4.2.2. The primary purpose of the discharge system is to disperse cooling tower blowdown into the Guntersville Reservoir.

Each unit has a blowdown pipe that runs from the NDCT. These lines join to a single blowdown pipe that leads to the outfall structure. Once this pipe reaches the Guntersville Reservoir, the pipe splits into two branches. At the end of each branch is a submerged, multiport diffuser. The diffuser discharge is split into two pipes of different lengths. These pipes are designed to achieve a nominal port exit velocity. The ports are positioned to discharge at an angle that precludes scour problems. The diffuser sections begin approximately 300 ft. offshore.

During each operational mode, the raw water requirements vary, therefore the discharge flow rates and velocities also vary. The maximum blowdown temperature is conservatively assumed as 95°F, and blowdown is not discharged directly into Guntersville Reservoir.

The proposed discharge would not result in any significant environmental impacts, and a detailed study was not required.

Water Supply

The water supply for BLN is from the Guntersville Reservoir. Sufficient volume is provided for maximum system requirements, and intake structure geometry is designed to function under the worst expected river and reservoir conditions.

The water supply portion of the proposed CWS would not result in any significant environmental impacts, and a detailed study was not required.

Water Treatment

The water treatment or circulating water chemistry, for the BLN CWS is maintained by the turbine island chemical feed system. Turbine island chemical equipment injects the required chemicals into the circulating water downstream of the CWS pumps. The chemicals used are divided into six categories based upon function: biocide, algaecide, pH adjuster, corrosion inhibitor, scale inhibitor, and silt dispersant. The pH adjuster, corrosion inhibitor, scale inhibitor, and dispersant are metered into the system continuously or as required to maintain proper concentrations. The biocide application frequency may vary with seasons. The algaecide is applied, as necessary, to control algae formation on the cooling tower.

The water treatment system portion of the proposed CWS would not result in any significant environmental impacts, and a detailed study was not required.

9.4.2.2 Alternatives to the Proposed Circulating Water System

The purpose of this subsection is to identify and analyze reasonable alternatives to the proposed system. The analysis of each alternative system considers various factors during construction and operation, for comparison with those of the proposed system. These factors are covered in separate sections: intake system, discharge system, water supply, and water treatment system.

9.4.2.2.1 Alternatives to the Proposed Intake System

An alternative intake system withdraws makeup water from the same source body, the Guntersville Reservoir or Tennessee River. The layout and geometry of the proposed system was analyzed. In order to avoid recirculation, the intake structure was located upstream of the discharge point. Alternative intake system locations included locations at the shoreline or in an offshore intake structure. An intake located at the shoreline would result in greater impingement and entrainment of aquatic organisms. An offshore intake would extend into the Guntersville Reservoir and interfere with river navigation. In response to the AEC request, TVA had evaluated alternatives 1 through 6 intake designs for Bellefonte Units 1 and 2. These alternatives and evaluations are also applicable to proposed BLN Units 3 and 4. New alternatives 7 and 8 are also considered for BLN Units 3 and 4. These are summarized below:

Alternative 1 - This is the proposed intake design that is discussed in Subsection 9.4.2.1 above and which incorporates an intake structure located approximately 1200 feet from the reservoir shoreline with a 5-foot floating trash boom located at the shoreline to protect the channel from floating debris and Eurasian water milfoil (Figure 9.4 -3). The inlet had been constructed utilizing and expanding a natural embayment. The proposed design has a maximum channel intake velocity of less than 0.0174 ft/s.

Alternative 2 - This is the same as the proposed alternative 1 except that a skimmer wall would be used in lieu of the floating trash boom. The depth of withdrawal for the skimmer wall would be 22 feet below the minimum reservoir water surface. The maximum intake water velocity under the wall would be 0.36 ft/s. Due to the weak thermal stratification of Guntersville Reservoir, the skimmer wall would not be effective in reducing the impact to suspended aquatic life.

Alternative 3 - The intake structure design is the same as for alternatives 1 and 2, but the structure would be located at the shoreline of the reservoir. The reservoir shoreline location for the intake structure was not desirable because it would be vulnerable to damage and blockage from runaway barges and to fire resulting from oil spills. Although the intake structure is not required for plant shutdown due to plant design, plant operation would be interrupted upon a loss of the intake structure. Replacement power costs and intake restoration costs would be prohibitive.

Alternative 4 - This alternative consists of a submerged intake located in the bottom of the original river channel nearest the site shoreline. From the submerged intake, four 60-inch steel pipes would extend to and through a permanent earth dike across the embayment at the shoreline. A valve system was required to permit periodic testing of the pipes. A traveling screen system for the submerged intake to remove trash and debris was not feasible for this system. Therefore, periodic inspection and removal of debris and siltation by underwater divers would be required. At the deepwater intake, the pipes would turn downstream into a concrete intake structure, which would take water from the downstream face. The pumping structure would be located in the embayment. Trash racks would be fitted on the intake openings and the openings would be sized for a maximum velocity through the racks of 0.5 ft/s. A cofferdam extending into the reservoir would be required to construct the deepwater intake and would serve for dewatering the embayment for construction of the pumping structure and the permanent earth dike.

Alternative 5 - This alternative is the same as alternative 4 except that the intake pipes extend to the pumping structure and no permanent earth dike would be required.

Alternative 6 - This alternative is the same as alternative 4 except redundant inlet piping would not be provided and a 60-acre cooling pond would be used as a backup in the event the deepwater intake becomes blocked. This system would consist of dikes to form the pond and a water conduit with a control valve to pass water from the pond to the intake forebay. Should the deepwater intake become blocked, the control valve under the pumping station would open at a predetermined water level in the intake channel permitting the cooling water to circulate from the intake forebay to the plant, from the plant to the cooling pond, and the cooling pond to the intake forebay.

Alternative 7 – Perforated Pipe Intake with Pump Structure

A perforated pipe intake with pump structure would consist of a perforated pipe intake located in the Guntersville Reservoir, piping to a pump structure, the pump structure, and the intake water pumps including piping for backwashing the perforated pipe. Inlet velocities of less than 0.5 ft/s would assure sufficient protection for fish against impingement on the pipes. A thick concrete mat, which anchors the pipes in the reservoir, may be required for stability for the channel in this area. Stiffened and streamlined pipe heads may be required to provide protection from floodwater debris loading. Large diameter pipes would carry water to the pumping structure. The frequency of backwashing the perforated pipes is determined by head loss due to debris loading.

A perforated piped intake with pump structure would require a sweeping flow from the reservoir to sweep fish past the openings in the pipe. With an inlet velocity of less than 0.5 ft/sec, fish entrainment should not occur.

A cellular sheet-pile cofferdam or similar structure would be constructed out from the reservoir so that the anchorage system, concrete mat, perforated pipe, and piping to the pump structure can be built in the dry with no adverse impact on the reservoir water during construction. No adverse impacts on the reservoir are expected based on the above discussion.

The perforated pipe intake with pump structure provides negligible impacts on fish and plankton. Turbidity of the reservoir may increase slightly during backwash operations. It is uncertain if the reservoir has sufficient current to sweep fish and debris past the openings in the perforated pipe. Debris may cause some damage to the intake during flood conditions. The presence of the perforated pipe in the channel may cause localized stream flow alterations, which may affect sediment distribution in the channel bottom. No effective means is available to inspect and repair the perforated pipe intake and no operating experience is available for prediction of such maintenance. Lack of operating experience, possible damage by debris, and lack of inspection and maintenance capability are the primary reasons for not selecting this system and therefore no further evaluation of this alternative is warranted.

Alternative 8 – Infiltration Bed Intake with Pump Structure

An infiltration bed intake with pump structure consists of an infiltration bed, piping to the pump structure, the pump structure, and the intake water pumps including piping for backwashing the infiltration bed. Low intake velocities would minimize impingement of free swimming organisms. Backwashing of the bed forces entrapped sediment and debris up into the reservoir current, allowing it to continue downstream. Water from numerous smaller, perforated pipes in the bed is collected into several large diameter pipes, which carry water to the pumping structure. These pipes would be fully encased in concrete in the reservoir channel. The frequency of backwashing the perforated pipes is determined by head loss due to debris loading.

A cellular sheet-pile cofferdam or similar structure would be constructed away from the reservoir so that the perforated pipe, gravel filter, and piping to the pump structure can be built on land. No adverse impacts on the reservoir are expected based on the above discussion.

The infiltration bed intake with pump structure provides negligible effects on fish and plankton. Heavy sediment load in the reservoir is expected to require frequent backwashing, which causes a significant increase in turbidity downstream of the intake.

Additional scour may also result from use of the large cofferdam. Additional problems include possible scour of the bed by reservoir currents. No operating experience is available with this system and no backwash system has been demonstrated to effectively cleanse such an infiltration bed in a turbid body of water. For the above reasons, this system is not selected. No further evaluation of this alternative is warranted.

Evaluations of Alternative Intake Designs

With a flow velocity of less than 0.0174 ft/s through the intake openings, the losses of aquatic life due to the proposed intake design would result in entrainment of plankton. Impingement of healthy fish was expected to be minor. The use of louvers, bypass devices, and bubble screens was such that they had not demonstrated to be effective in reducing entrainment of suspended aquatic life. This, in addition to the unfavorable economics of such devices precluded the need to conduct a detailed cost/benefit analysis of these devices since they were not be considered feasible alternatives.

Following these additional studies and evaluations as requested by AEC (Reference 2), TVA's selection of a proposed design remained as Alternative 1, the alternative with the least total evaluated cost as shown in the Tables 9.4-4, 9.4-5 and 9.4-6. The costs shown are not the total expected costs as the estimates were carried out to the extent deemed necessary to determine that further evaluations were not warranted. Costs associated with operation and maintenance of these alternative intake designs are expected to be minimal compared to the capital costs associated with their construction, and are not expected to affect the evaluation or conclusion. For example, the costs of using underwater divers to inspect and remove debris for alternatives 4, 5, and 6 are not included in the table. In addition, the evaluation also concluded that the environmental costs for the shoreline intake alternatives are estimated to be $8.5 million (2007 dollars) more than for the alternatives with a deepwater intake. The above tables show that the capital costs of any of the alternatives with a deepwater intake exceed the proposed alternative 1 by nearly $16 million (2007 dollars), while a conservative estimate of the environmental advantage is only about $8.5 million. Therefore, after weighing and balancing the economic and environmental costs along with safety considerations, TVA concluded that the proposed intake design represents the best balance of cost, feasibility, and environmental impact. Although not quantified in the table, maintenance costs for the deepwater alternatives (4, 5, and 6) would be significantly higher due to the need for underwater divers. Since alternatives 2 and 3 are not environmentally desirable, maintenance costs were not evaluated. Although the above evaluation was performed for Bellefonte Units 1 and 2, the results and conclusions are still valid for BLN. No environmentally preferable alternatives to the proposed intake structure were identified. No improvements are apparent where substitution of components or modifications to the size or function of components would improve on the operation of the system for its intended purpose. Since TVA has already constructed the Alternative 1 structures intended for use with Bellefonte Units 1 and 2, and proposes to use them for BLN Units 3 and 4, construction of any other alternative would impose unnecessary economic costs and would cause additional economic impact.

The hydrodynamics of the proposed intake system are planned to generate a smooth continuous source of water to the intake structure. Additional precautions were incorporated into the intake canal so that water would flow under the most limiting combination of river supply and weather conditions expected.

The physical effects of the current water intake system were analyzed. Construction and operation of this system did not result in any effects to groundwater, physical alterations of local streams and wetlands, or effects to downstream water quality as a result of erosion and sedimentation.

Effects of the intake structure for closed-cycle cooling systems on aquatic ecology were considered. Final Environmental Statement (Reference 3) was prepared by the AEC, Directorate of Licensing in June 1974 that evaluated the following:

- Impingement or trapping of fish and shellfish on the intake structure screens
- Entrainment, or drawing into the cooling water stream, of fish and mollusk larvae
- Entrainment of phytoplankton and zooplankton

Studies of intake effects of closed-cycle cooling systems had generally judged these effects to be insignificant because a closed-cycle, recirculating cooling system decreases water use by up to 98 percent from a once-through cooling system (Subsection 5.3.1.2). The aquatic ecosystems were minimally affected by the current water intake system. Problems were minimal from impingement of organisms on the intake screens due to minimal water use and low intake velocities. Subsection 5.3.1.1.1 summarizes why the induced flow fields during BLN intake system operation result in insignificant effects on aquatic biota.

The proposed system's pumping facilities had insignificant environmental impact. No substitution was apparent that would result in an environmentally preferable system as compared to the proposed system. No alternative method of intake defouling, including chemicals, was proposed which was environmentally superior or equivalent.

The proposed alternative intake systems were analyzed. No improvements were apparent where substitution of components or modifications to the size or function of components would improve on the operation of the system for its intended purpose.

In conclusion, TVA had examined several alternatives to the proposed intake arrangement and had concluded that the originally proposed shoreline intake structure was the best alternative available.

TVA prepared Bellefonte Units 1 and 2 Environmental Statement and submitted it to AEC in 1974. The FES (Docket Nos. 50-438 and 50-439) was prepared by the AEC, Directorate of Licensing in June 1974. The staff had reviewed the cooling water intake design and stated (Reference 3)

> "The applicant and the staff have agreed upon a sampling program as outlined in Section 6.2.1.1 (Investigation Related to Location of Cooling Water Intake Openings). This program will provide a basis for estimating the entrainment of ichthyoplankton flowing past the plant. If the fraction of ichthyoplankton entrained is less than 5%, no change in the intake design and location will be necessary. If the fraction is greater than 25%, the applicant will be required to implement an alternate intake scheme to reduce entrainment. If the fraction of entrained ichthyoplankton is between 5-25%, the data will be assessed by the staff and may lead to either additional collection or implementation of an alternate intake scheme to reduce entrainment".

In response to TVA request for extensions of Bellefonte Units 1 and 2 Construction Permits Nos. CPPR-122 and CPPR-123, the staff requested additional information (Reference 5) from TVA to determine if the conclusions reached in the June 1974 FES remained valid. TVA responded to these questions via Reference 6. Based on TVA's response and the recent environmental impact statements cited (Reference 7), the NRC staff concluded that, while the impacts were larger if construction resumes, the mitigative actions are commensurate with the larger impacts and, therefore, the conclusions reached in the FES remained valid.

9.4.2.2.2 Alternatives to the Proposed Discharge System

Discharges of heated effluents have the potential to affect water quality in following five ways:

- Water temperature increases, including altered thermal stratification of lakes
- Temperature effects on sediment transport capacity
- Scouring
- Lowered dissolved oxygen concentrations
- Eutrophication

BLN would use an existing blowdown discharge for the new units. This discharge system consists of a submerged multiport diffuser, which discharges at an angle of 60° to the river channel centerline, as discussed in Subsection 3.4.2.2, and shown in Figure 5.3-3. The diffuser system consists of two diffuser sections with a combined length of 120 ft. situated approximately 300 ft. from the right bank.

Heated water discharges tend to remain at (or move toward) the surface of lakes and rivers. These discharges form a plume of warm water that dissipates with distance from the source by rejecting heat to the atmosphere or mixing with cooler ambient waters. Mixing tends to occur more rapidly in rivers than in lakes because of increased turbulence. Also because of turbulence, rivers do not naturally thermally stratify; as a result, alteration of temperature stratification in rivers by nuclear power plants is not an issue. Effects of thermal discharges to water quality are of small significance if discharges are within thermal effluent limitations designed to ensure protection of water quality and if ongoing discharges have not resulted in adverse effects on the five attributes of water quality identified above.

For alternative discharge locations, consideration is taken of the existing blowdown pipe that runs from the NDCTs to the shoreline. A change in the physical path to the shoreline is difficult as it follows the only existing level path. The submerged, multiport diffuser has already been engineered in geometry and size to accommodate the expected volume and temperature of the plant blowdown under the range of possible river conditions. Any change in the discharge location or geometry does not affect the already small effect expected due to the heat or chemical amounts deposited into the reservoir during normal operation.

A full range of plume characteristics is analyzed and presented for the proposed discharge system (Subsection 5.3.2.1). Alternative exit structures are not environmentally preferred, as they do not decrease the small effect of plume or potential physical scour problems. Due to the distance of the intake from the station discharge, the plume would dissipate before ever reaching the plant intake in the event of a reverse river flow.

The following presents the potential effects of discharging heated water to an aquatic system:

- Thermal discharge effects
- Cold shock
- Effects on movement and distribution of aquatic biota
- Premature emergence of aquatic insects
- Stimulation of nuisance organisms
- Losses from predation
- Parasitism and disease
- Gas super-saturation of low dissolved oxygen in the discharge
- Accumulation of contaminants in sediments or biota

In general, for plants employing cooling tower systems, the impact is minor. The thermal plume discharged by the BLN in particular is so small that adverse impact on biota is not expected as long as the thermal limits set forth in the NPDES permit are met.

In winter, fish attracted to the elevated temperature of the BLN plume may stay an extended time. This may result in accelerated spawning and increased larval mortality from asynchrony with food source development or cold shock of migrant larvae. Drifting benthos, plankton, and larval fish may be affected passing through the thermal plume at the site during the winter. Any resulting effect is considered small due to the plume size considering the total reservoir populations.

Alternatives to a multiport diffuser include the multiple-nozzle jet diffuser, an open pipe with headwall, and a single buoyant jet. The least costly alternative to construct and operate would be the open-end pipe to discharge back to the reservoir. However, the open-pipe discharge and the buoyant jet would not achieve the required degree of mixing to meet the state water quality standards. The multiple nozzle jet diffuser would also be an adequate choice based on technical considerations. However, it holds no environmental advantage over the multiport diffuser, and a significant financial investment would be required to remove the existing diffuser and replace it. Thus TVA proposes to use a submerged multiport diffuser system that already exists for discharging the blowdown to the reservoir. The proposed alternative discharge systems have been analyzed. No improvements are apparent where substitution of components or modifications to the size or function of components would improve on the operation of the system for its intended purpose.

9.4.2.2.3 Alternatives to the Proposed Water Supply

The proposed water supply for the heat dispersion system at BLN is the Tennessee River. No alternative sources of water for this purpose are available. This proposed water supply system is designed so that the bottom of the intake channel is at sufficient depth to allow direct flow from the main river channel to the water intake during all low water levels. No shortages are anticipated. Based on the maximum intake flow for both units in operation, the intake would withdraw less than one percent of the river's flow during minimum river flow conditions (Subsection 5.3.1.1.1).

No restrictions on withdrawal volume are anticipated with this water source. The environmental impact of the use of this water supply is SMALL. No alternative source is identified that is environmentally equivalent or superior.

Groundwater was evaluated and not considered a viable water source alternative because the groundwater would not be able to support the CWS makeup water requirement of 24,059 gallons per minute (gpm) per unit.

9.4.2.2.4 Alternatives to the Proposed Water Treatment System

Table 9.4-8 provides a tabularized evaluation of the alternative water treatment systems.

- Chemical Treatment: Biocide, algaecide, pH adjuster, corrosion inhibitor, scale inhibitor, and silt dispersant
- Mechanical Treatment: Periodic mechanical cleaning of condenser tubing
- Non-chemical Treatment: Ultraviolet light sterilization

This evaluation demonstrates that the mechanical condenser cleaning option poses smaller adverse environmental impacts than the other technically-feasible alternative treatment system—the chemical treatment system. The mechanical cleaning system represents the environmentally-preferred treatment system for the condenser. However the mechanical cleaning process is not practical for the cooling towers due to the large surface area to be cleaned. As discussed in Table 9.4-8, ultraviolet (UV) treatment has not been proven effective on large-scale cooling systems. Therefore, chemical treatment would be necessary. A chemical treatment system would be selected that meets environmental impact limits. Further economic evaluation of the alternative water treatment systems is not warranted.

Water treatment is applied to the CWS water at BLN (Subsection 3.3.2.1). Application typically consists of adjustments to water chemistry using several chemicals: biocide, algaecide, pH adjuster, corrosion inhibitor, scale inhibitor, and silt dispersant. Water quality effects could occur from the concentration and discharge of chemicals added to the recirculating cooling water. These additives are present in the blowdown.

Concentration of dissolved salts in the makeup water resulting from evaporative water losses require the discharge of a certain percentage of the mineral-rich stream (blowdown) and its replacement with fresh water (makeup). The concentration of total dissolved solids in the cooling tower blowdown is monitored to meet the limits of the NPDES permit. Dilution of the low-volume blowdown by the receiving water also reduces water quality effects of contaminants discharged from closed-cycle cooling systems. The number of cycles that water is used before the blowdown is removed is changed to meet the measured contaminant amounts in the system.

Nuclear power plants are required to obtain an NPDES permit to discharge effluents. These permits are renewed every five years by the regulatory agency, either EPA or, more commonly, the state's water quality permitting agency. The periodic NPDES permit renewals provide the opportunity to require modification of power plant discharges or to alter discharge monitoring in response to water quality concerns.

Effects of cooling tower discharges are considered to be of small significance when water quality criteria (e.g., NPDES permits) are complied with. In considering the effects of closed-cycle cooling systems on water quality, the NRC evaluated the same issues that were evaluated for open-cycle systems. Based on review of literature and operational monitoring reports, consultations with utilities and regulatory agencies, and comments on the draft Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants, discharge of cooling tower effluents has not been a problem at existing nuclear plants. Although occasional exceedances of NPDES permits have occurred at operating plants (e.g., minor spills), water quality effects have been localized and temporary. Cumulative water quality impacts are small, because the low-volume discharges are readily dissipated in the receiving water bodies.

A detailed description of treatment system operating procedures, including plant operational and seasonal variations is discussed in Section 3.6. The frequency of treatment for each of the normal modes of operation is described, as well as the quantities and points of addition of the chemical additives. All methods of chemical use are monitored. No substitutions are proposed for the current treatment amounts or methods. The environmental impact on the use of this water treatment is SMALL. As discussed above, mechanical cleaning or UV treatment are not practical or effective water treatment systems for cooling tower applications. No effective alternative treatment is therefore identified that is environmentally equivalent or superior.

9.4.3 TRANSMISSION SYSTEMS

The power transmission system performs the bulk transfer of electrical power between the power plant and a substation near a populated area. The electricity distribution system performs the delivery from the substation to the consumers. In a transmission system, redundant paths and lines are often provided so that power can be routed from any power plant to any load center, through a variety of routes, based on the economics of the transmission path and the cost of power. Analyses are performed by transmission companies to determine the maximum reliable capacity of each line, which, due to system stability considerations, may be less than the physical or thermal limit of the line.

9.4.3.1 Proposed Transmission System

An addition of generation of the magnitude of BLN requires a reevaluation of the facilities within several hundred miles to appropriately locate and size transmission components. TVA is proposing to use the existing transmission system previously constructed for Bellefonte Units 1 and 2. The existing transmission system siting and design are described in Section 3.7. The siting and design efforts are influenced by several other factors: future growth estimates, additional generation proposed/planned, equipment condition, regulation, and public sentiment. These issues are described in ER Chapters 4, 5 and 8. Environmental impacts from construction are described in Chapter 4, and operation of the proposed transmission system is described in Chapter 5. Impacts from construction are not considered an issue since the proposed transmission system is already constructed.

Environmental impact from the use of components or operation of the transmission system is identified as small. Since the impacts, including maintenance, are small, no mitigation is required.

The measures and controls to limit adverse transmission system impacts that were developed as a result of this environmental review are described in Sections 4.6 and 5.10.

The maintenance practices that are used to keep potential impacts minimal to the aquatic or terrestrial ecology from the transmission system that could be avoided or mitigated are described in Subsections 5.6.1 and 5.6.2.

Minority or low-income population’s impact from the transmission systems are discussed in Subsection 5.8.3.

The power transmission and electrical distribution systems are designed to be capable of distributing the electricity generated by BLN. Changes or upgrades to the current system are performed on a proactive and on an as-needed basis. No additional work is anticipated as being necessary.

9.4.3.2 Alternatives to the Proposed Transmission System

The analysis of each alternative transmission system considers various factors during construction and operation, for comparison with those of the already constructed system. Table 9.4-7 covers separate presentations of alternative corridor route total lengths, total area and comparable right-of-way widths for the two (2) alternatives to the transmission system for the BLN site (Reference 1). A further discussion of these alternatives is included in Section 9.1 of Tennessee Valley Authority, "Final Environmental Statement for Bellefonte Nuclear Plant Units I and 2," June 1974. No alternative designs were identified that are environmentally preferable to the existing designs.

9.4.3.2.1 Alternative Corridor Routes

The existing power transmission system is discussed Section 3.7. The evaluation of alternative transmission corridor routes is complete. TVA evaluated six alternative route selections and reduced the route selection to the existing Bellefonte Units 1 and 2 transmission system and two alternatives. This evaluation was done in preparation for the Bellefonte Units 1 and 2 construction permit application (Section 2.2.6 of the Tennessee Valley Authority, "Final Environmental Statement for Bellefonte Nuclear Plant Units I and 2," June 1974). The primary choice and major alternative routes for transmission rights-of-ways are illustrated in Figure 9.4-4.

Transmission facilities have already been constructed in anticipation of Bellefonte Units 1 and 2 operation, prior to the plant deferment in 1988. Using Table 9.4-7 and Section 9.1 of the Tennessee Valley Authority, "Final Environmental Statement for Bellefonte Nuclear Plant Units I and 2," June 1974, Bellefonte and two alternative sites were found to be suitable for the electric power plant and transmission system. From the standpoint of environmental impacts the alternatives were essentially equivalent. The BLN site has economic advantages relative to Sites C and G from Table 9.4-7 and Section 9.1 of the Tennessee Valley Authority, "Final Environmental Statement for Bellefonte Nuclear Plant Units I and 2," June 1974. To remove the existing system and relocate to an alternative site would be cost prohibitive and would not be environmentally preferable. Furthermore, the construction of a transmission system on an alternative transmission corridor would result in additional land impacts, terrestrial impacts, and possible aquatic impacts. Therefore, alternative transmission corridors are environmentally inferior to the existing transmission lines.

No new transmission lines are proposed as a part of this project, and no additional discussion of corridor alternatives is provided beyond those listed in the Tennessee Valley Authority, "Final Environmental Statement for Bellefonte Nuclear Plant Units I and 2," June 1974.

The transmission system and corridors' impacts to historic properties and potential alternatives regarding alternative locations for the system are described in Subsection 4.1.3 and Section 2.8 of the Tennessee Valley Authority, "Final Environmental Statement for Bellefonte Nuclear Plant Units I and 2," June 1974.

9.4.3.2.2 Alternative System Design

Alternatives to the proposed transmission system with the benefit-cost balance are discussed in Section 10.4.

System design alternatives include changes made to the power transmission system design to increase the safety of the public or utility workers or to enable the system to transport the energy more efficiently.

Transmitting electricity at high voltage reduces the current and thus the resistive losses in the conductor. Long distance transmission is typically done with overhead lines at voltages of 110 to 1200 kV. Transmission lines designed for voltage levels less than 765 kV reduce adverse effects from ozone formation. At extremely high voltages, more than 2000 kV between conductor and ground, corona discharge losses are so large that they can offset the lower resistance loss in the line conductors. Underground power transmission is used only in densely populated areas (such as large cities) because of the high cost of installation and maintenance and because the power losses increase dramatically compared with overhead transmission.

Adverse effects of transmission systems can include electric shock, electromagnetic field effects, and visual effects. Effects of proposed transmission lines on members of the public are discussed in Subsection 5.6.3. BLN transmission system connections are made at 500 kV. A change to alternative voltage levels or current types different from planned are not indicated. This does not indicate any significant effect associated with the proposed voltage levels and frequency requiring mitigation. Standard clearances between conductors and anticipated grounding objects are used throughout the transmission corridor to minimize any electric shock potential. Additional mitigation of electric shock potential is not necessary. No alternative tower designs, tower heights, conductor-to-ground clearances, conductor designs, or right-of-way widths are necessary (ER Sections 3.7 and 5.6). Auxiliary transmission facilities do not require alternative locations.

Federal, state, regional, local, and affected Native American tribal agency laws or regulations that affect transmission facility design or operation are satisfied.

9.4.3.2.3 Alternative System Construction

Standard electric utility construction practices appropriate to the voltage and climate are used in the TVA system. Alternative construction practices are not necessary as discussed in Sections 4.1, 4.3, and 4.4. Alternative transmission line routing, construction practices and maintenance methods are discussed in detail in Sections 4.1.2 and Appendix B of Tennessee Valley Authority, “Final Environmental Statement for Bellefonte Nuclear Plant Units I and 2,” June 1974.

No alternative construction methods are indicated to mitigate effects from vegetation, erosion control, access roads, towers, conductors, equipment, or timing.

9.4.3.2.4 Alternative System Maintenance Practices

Potential effects of routine maintenance to terrestrial and aquatic ecosystems are discussed in Subsections 5.6.1 and 5.6.2. Existing transmission lines are to be maintained in accordance with long-standing TVA procedures that consider environmental and visual values. TVA maintains important viewscapes by minimizing the visual intrusion. Natural vegetation is retained at road crossings to help minimize visual effects where possible. No alternative maintenance practices are indicated to mitigate environmental impact.

9.4.4 REFERENCES

1. Tennessee Valley Authority, “Final Environmental Statement for Bellefonte Nuclear Plant Units I and 2,” June 1974.

2. SPX Cooling Technologies, “Hybrid Cooling Tower,” no date, Website, spxcooling.com/en/products/detail/hybrid-circular-tower/, accessed May 2007.

3. USAEC Final Environmental Statement related to Construction of Bellefonte Nuclear Plant Units 1 and 2, Tennessee Valley Authority, Docket Nos. 50-438 and 50-439 dated June 4, 1974.

4. Tennessee Valley Authority letter dated July 11, 2001 to NRC regarding extensions of the expiration dates for Construction Permits Nos. CPPR-122 and CPPR-123 for Bellefonte Units 1 and 2.

5. NRC letter dated June 5, 2002 to TVA - Request for additional information regarding environmental assessment for extension of construction permits (TAC Nos. MB2549 and MB2550).

6. TVA letter dated August 26, 2002 to NRC provided requested additional information.

7. NRC letter dated January 16, 2003 to TVA enclosed a copy of the Environmental Assessment and Finding of No Significant Impact related to the extension dates of Construction Permits and extended the construction permits for Bellefonte Nuclear Plant Units 1 and 2 to October 1, 2011 and October 1, 2014 respectively.

8. TVA letter dated April 6, 2006 requested NRc to terminate the construction permits for the unfinished Bellefonte Units 1 and 2.

9. NRC News No. 06-112 dated September 15, 2006, “NRC Terminates Construction Permits for Unfinished Bellefonte Nuclear Plants.”

10. Alabama Department of Environmental Management (ADEM) National Pollutant Discharge Elimination System (NPDES) Permit # AL 0024635 for the Tennessee Valley Authority (TVA) Bellefonte Nuclear Plant dated November 22, 2004. The expiration date of this permit is November 30, 2009.

11. Tennessee Valley Authority, Bellefonte Final Environmental Report – Operating Stage, Volume 3.

TABLE 9.4-1
Bellefonte Nuclear Plant
Alternative for Heat Dissipation System Costs Which Vary From Base Plant

Alternative Heat Dissipation System	Spray Canal (Combined)	Spray Canal (Closed)	Mechanical Draft Towers (Combined)	Mechanical Draft Towers (Closed)	Natural Draft Towers (Combined)	Natural Draft Towers (Closed)
Estimated Incremental Generating Cost (thousands of 2007 dollars)	24,505	31,320	37,993	16,895	30,809	Base
Maximum Monthly Average Reservoir Heat Input (Btu/hr)	15.6×10^9	5.3×10^8	15.6×10^9	4.8×10^8	15.6×10^9	3.5×10^8
Water Consumed (acre-feet/day)	143	143	141	141	147	147
Transportation Affected (h/yr)						
Ground	82	530	90	495	12	80
Water	231	305	221	240	183	0
Additional Land Required (acres)	480	0	0	0	0	0
Estimated Structure Relocations	0	0	0	0	0	0
Erosion (tons/year)	950	850	850	770	850	770

Source Reference : Table 8.2-3 of Reference 11

TABLE 9.4-2
PRESENT WORTH COST COMPARISONS OF ALTERNATIVE HEAT DISSIPATION FACILITIES

(2007 Dollars)

Alternative	1A	1B	2	3	4	5	6
Heat Dissipation Devise	Spray Canal	Spray Canal	Spray Canal	Mechanical Draft Cooling Tower	Mechanical Draft Cooling Tower	Natural Draft Cooling Tower	Natural Draft Cooling Tower
Type	Combined	Combined	Closed	Combined	Closed	Combined	Closed
Average Annual Net Turbine Heat Rate, Btu/kWh	9477.0	9477.0	9553.6	9483.2	9534.9	9501.3	9534.4
Capital Cost, $ Million	46.88	46.14	15.73	49.38	(-) 4.29	48.67	Base
Replacement Power Cost, $ Million	(-) 11.81	(-) 11.81	3.95	(-) 10.45	0.14	(-) 6.70	Base
Operation Cost, $ Million	(-) 13.37	(-) 13.37	8.83	(-) 9.91	10.53	(-) 10.62	Base
Maintenance Cost, $Million	2.81	2.81	2.81	8.97	10.51	(-) 0.59	Base
Total above base cost, $ Million	24.51	23.77	31.32	37.99	16.90	30.81	Base

Notes:
1) All costs shown are present worth cost difference in 2007 dollars using alternative 6 as a base:
2) The alternative 6 NDCT's had already been installed at a cost of approximately $58 million for a two-unit plant(1979 Dollars). This converts to $165 million for a two-unit plant in 2007 dollars. The estimated installation cost of the alternatives is the capital cost plus $165 million.
3) Closed-Cycle and Combined-Cycle systems are described in Subsection 9.4.1.3.
4) Only viable alternates are included in Tables 9.4-1 and 9.4-2

Source Reference: Table 2.6-1 of Reference 11

TABLE 9.4-3
BLOWDOWN TEMPERATURES

	MDCT, °F Closed-Cycle	Spray Canal, °F Closed-Cycle
Fall	77	83
Winter	74	72
Spring	77	83
Summer	84	91

TABLE 9.4-4 (Sheet 1 of 3)
COMPARISON OF ALTERNATIVES TO THE PROPOSED INTAKE SYSTEM (BASE CASE & ALTERNATIVES 2 & 3)

Factors Affecting System Selection	Shoreline Intake System – Base Case Alternative 1 (Proposed Case)	Shoreline Intake System Alternative 2	Shoreline Intake System Alternative 3
Construction Impacts	The proposed intake structure located approximately 1200 ft. from the reservoir shoreline with a 5-ft. floating trash boom located at the shoreline to protect the channel from floating debris and Eurasian water milfoil.	This is the same as the proposed alternative 1 except that a skimmer wall would be used in lieu of the floating trash boom. The depth of withdrawal for the skimmer wall is 22 ft. below the minimum reservoir water surface. The existing intake structure built for Units 1 and 2 would need to be modified for the use of Units 3 and 4; construction impacts are small.	The intake structure design is the same as for alternatives 1 and 2, but the structure would be located at the shoreline of the reservoir. The reservoir shoreline location for the intake structure is not desirable since it would be vulnerable to damage and blockage from runaway barges and to fire resulting from oil spills.
Aquatic Impacts	The potentially large adverse operational impacts to aquatic life can be mitigated by reducing intake velocities and using traveling screens to reduce impingement, entrapment and entrainment of aquatic life.	Due to the weak thermal stratification of Guntersville Reservoir, the skimmer wall is not effective in reducing the impact of suspended aquatic life.	The potentially large adverse operational impacts to aquatic life can be mitigated by reducing intake velocities and using traveling screens to reduce impingement, entrapment and entrainment of aquatic life.
Land Use Impacts	Since the existing shoreline intake is used for the Units 3 and 4, land use impacts is not an important differentiating factor for intake systems.	Since the existing shoreline intake is used for the Units 3 and 4, land use impacts is not an important differentiating factor for intake systems.	The existing intake structure needs to be relocated at the shoreline of the reservoir. Land use impacts is not an important differentiating factor for intake systems.

TABLE 9.4-4 (Sheet 2 of 3)
COMPARISON OF ALTERNATIVES TO THE PROPOSED INTAKE SYSTEM (BASE CASE & ALTERNATIVES 2 & 3)

Factors Affecting System Selection	Shoreline Intake System – Base Case Alternative 1 (Proposed Case)	Shoreline Intake System Alternative 2	Shoreline Intake System Alternative 3
Water Use Impacts	The relative position of the intake (shoreline or deepwater intake) has no differentiating impact on the water use requirements and therefore, it is not an important factor.	The relative position of the intake (shoreline or deepwater intake) has no differentiating impact on the water use requirements and therefore, it is not an important factor.	The relative position of the intake (shoreline or deepwater intake) has no differentiating impact on the water use requirements and therefore, it is not an important factor.
Compliance with Regulations	The intake structure for the new units at the BLN site currently meets Section 316(b) of the CWA and the implementing regulations, as applicable. These regulatory restrictions are not an important differentiating factor.	The intake structure for the new units at the BLN site currently meets Section 316(b) of the CWA and the implementing regulations, as applicable. These regulatory restrictions are not an important differentiating factor.	The intake structure for the new units at the BLN site currently meets Section 316(b) of the CWA and the implementing regulations, as applicable. These regulatory restrictions are not an important differentiating factor.
Estimated Capital Costs (millions of 2007 Dollars)(5)	$18.9	$19.3	$39.4

TABLE 9.4-4 (Sheet 3 of 3)
COMPARISON OF ALTERNATIVES TO THE PROPOSED INTAKE SYSTEM (BASE CASE & ALTERNATIVES 2 & 3)

Factors Affecting System Selection	Shoreline Intake System – Base Case Alternative 1 (Proposed Case)	Shoreline Intake System Alternative 2	Shoreline Intake System Alternative 3

Notes: 1. The environmental costs for the shoreline intake alternatives (1,2, and 3) are estimated to be $8.5 million (2007 Dollars) more than for the alternatives with a deepwater intake (4, 5, and 6).

2. All costs shown are present worth cost in 2007 dollars. The 1974 dollars from Section 2.6.6(9)(g) of Reference 11 were converted to 2007 dollars. The dollar values were increased by the Consumer Price Index (CPI) ratio of the March 2007 southern region value of 197.904 to the March 1974 value of 46.7. CPI data were taken from the U.S, Department of Labor Bureau of Labor Statistics.

3. Note that the alternative 1 intake has already been installed for use with Bellefonte Units 1 and 2, and therefore the cost already incurred.

4. Note that information describing how BLN currently meets the performance standards specified in the EPA regulations implementing Section 316(b) is provided in Subsection 5.3.1.1.1.

5. Costs associated with operation and maintenance of these alternative intake designs would be minimal compared to the capital costs associated with their construction, and are not expected to affect the evaluation or conclusion.

TABLE 9.4-5 (Sheet 1 of 3)
COMPARISON OF ALTERNATIVES TO THE PROPOSED INTAKE SYSTEM (BASE CASE & ALTERNATIVES 4 & 5)

Factors Affecting System Selection	Shoreline Intake System - Base Case Alternative 1 (Proposed Case)	Deepwater Intake System Alternative 4	Deepwater Intake System Alternative 5
Construction Impacts	The proposed intake structure located approximately 1200 ft. from the reservoir shoreline with a 5-ft. floating trash boom located at the shoreline to protect the channel from floating debris and Eurasian water milfoil. Since the existing intake structure built for Units 1 and 2 is modified for the use of Units 3 and 4, construction impacts are small.	This alternative consists of a submerged intake located in the bottom of the original river channel nearest the site shoreline. From the submerged intake, four 60-in. steel pipes extend to and through a permanent earth dike across the embayment at the shoreline. A traveling screen system for the submerged intake to remove trash and debris is not feasible for this system. Periodic inspection and removal of debris and siltation by underwater divers would be required. The pumping structure would be located in the embayment.	This alternative is the same as alternative 4 except that the intake pipes extend to the pumping structure and no permanent earth dike is required.
Aquatic Impacts	The potentially large adverse operational impacts to aquatic life can be mitigated by reducing intake velocities and using traveling screens to reduce impingement, entrapment and entrainment of aquatic life.	The potentially large adverse operational impacts to aquatic life can be mitigated by reducing intake velocities and using traveling screens to reduce impingement, entrapment and entrainment of aquatic life.	The potentially large adverse operational impacts to aquatic life can be mitigated by reducing intake velocities and using traveling screens to reduce impingement, entrapment and entrainment of aquatic life.

TABLE 9.4-5 (Sheet 2 of 3)
COMPARISON OF ALTERNATIVES TO THE PROPOSED INTAKE SYSTEM (BASE CASE & ALTERNATIVES 4 & 5)

Factors Affecting System Selection	Shoreline Intake System - Base Case Alternative 1 (Proposed Case)	Deepwater Intake System Alternative 4	Deepwater Intake System Alternative 5
Land Use Impacts	Since the existing shoreline intake is used for the Units 3 and 4, land use impacts is not an important differentiating factor for intake systems.	The existing intake structure needs to be relocated at the shoreline of the reservoir. Land use impacts is not an important differentiating factor for intake systems.	The existing intake structure needs to be relocated at the shoreline of the reservoir. Land use impacts is not an important differentiating factor for intake systems.
Water Use Impacts	The relative position of the intake (shoreline or deepwater intake) has no differentiating impact on the water use requirements and therefore, it is not an important factor.	The relative position of the intake (shoreline or deepwater intake) has no differentiating impact on the water use requirements and therefore, it is not an important factor.	The relative position of the intake (shoreline or deepwater intake) has no differentiating impact on the water use requirements and therefore, it is not an important factor.
Compliance with Regulations	The intake structure for the new units at the BLN site currently meets Section 316(b) of the CWA and the implementing regulations, as applicable. These regulatory restrictions are not an important differentiating factor.	The intake structure for the new units at the BLN site currently meets Section 316(b) of the CWA and the implementing regulations, as applicable. These regulatory restrictions are not an important differentiating factor.	The intake structure for the new units at the BLN site currently meets Section 316(b) of the CWA and the implementing regulations, as applicable. These regulatory restrictions are not an important differentiating factor.
Estimated Capital Costs (millions of 2007 Dollars)(5)	$18.9	$35.0	$39.4

TABLE 9.4-5 (Sheet 3 of 3)
COMPARISON OF ALTERNATIVES TO THE PROPOSED INTAKE SYSTEM (BASE CASE & ALTERNATIVES 4 & 5)

Factors Affecting System Selection	Shoreline Intake System - Base Case Alternative 1 (Proposed Case)	Deepwater Intake System Alternative 4	Deepwater Intake System Alternative 5

Notes: 1. The environmental costs for the shoreline intake alternatives (1,2, and 3) are estimated to be $8.5 million (2007 Dollars) more than for the alternatives with a deepwater intake (4, 5, and 6).

2. All costs shown are present worth cost in 2007 dollars. The 1974 dollars from Section 2.6.6(9)(g) of Reference 11 were converted to 2007 dollars. The dollar values were increased by the Consumer Price Index (CPI) ratio of the March 2007 southern region value of 197.904 to the March 1974 value of 46.7. CPI data were taken from the U.S. Department of Labor Bureau of Labor Statistics.

3. Note that the alternative 1 intake has already been installed for use with BLN Units 1 and 2, and therefore the cost already incurred.

4. Note that information describing how BLN currently meets the performance standards specified in the EPA regulations implementing Section 316(b) is provided in Subsection 5.3.1.1.1.

5. Costs associated with operation and maintenance of these alternative intake designs would be minimal compared to the capital costs associated with their construction, and are not expected to affect the evaluation or conclusion.

TABLE 9.4-6 (Sheet 1 of 2)
COMPARISON OF ALTERNATIVES TO THE PROPOSED INTAKE SYSTEM (BASE CASE & ALTERNATIVE 6)

Factors Affecting System Selection	Shoreline Intake System - Base Case Alternative 1 (Proposed Case)	Deepwater Intake and Cooling Pond System Alternative 6
Construction Impacts	The proposed intake structure located approximately 1200 ft. from the reservoir shoreline with a 5-ft. floating trash boom located at the shoreline to protect the channel from floating debris and Eurasian water milfoil. Since the existing intake structure built for Units 1 and 2 is modified for the use of Units 3 and 4, construction impacts are small.	This alternative is the same as alternative 4 except redundant inlet piping are not provided and a 60-ac. cooling pond is included as a backup in the event the deepwater intake becomes blocked. This system consists of dikes to form the pond and a water conduit with a control valve to pass water from the pond to the intake forebay.
Aquatic Impacts	The potentially large adverse operational impacts to aquatic life can be mitigated by reducing intake velocities and using traveling screens to reduce impingement, entrapment and entrainment of aquatic life.	The potentially large adverse operational impacts to aquatic life can be mitigated by reducing intake velocities and using traveling screens to reduce impingement, entrapment and entrainment of aquatic life.
Land Use Impacts	Since the existing shoreline intake is used for the Units 3 and 4, land use impacts is not an important differentiating factor for intake systems.	Additional 60-ac. land is required for the cooling pond.
Water Use Impacts	The relative position of the intake (shoreline or deepwater intake) has no differentiating impact on the water use requirements and therefore, it is not an important factor.	The relative position of the intake (shoreline or deepwater intake) would have no differentiating impact on the water use requirements and therefore, it would not be an important factor.

TABLE 9.4-6 (Sheet 2 of 2)
COMPARISON OF ALTERNATIVES TO THE PROPOSED INTAKE SYSTEM (BASE CASE & ALTERNATIVE 6)

Factors Affecting System Selection	Shoreline Intake System - Base Case Alternative 1 (Proposed Case)	Deepwater Intake and Cooling Pond System Alternative 6
Compliance with Regulations	The intake structure for the new units at the BLN site currently meets Section 316(b) of the CWA and the implementing regulations, as applicable. These regulatory restrictions are not an important differentiating factor.	The intake structure for the new units at the BLN site currently meets Section 316(b) of the CWA and the implementing regulations, as applicable. These regulatory restrictions are not an important differentiating factor.
Estimated Capital Costs (millions of 2007 Dollars)(5)	$18.9	$34.5

Notes: 1. The environmental costs for the shoreline intake alternatives (1,2, and 3) are estimated to be $8.5 million (2007 Dollars) more than for the alternatives with a deepwater intake (4, 5, and 6).

2. All costs shown are present worth cost in 2007 dollars. The 1974 dollars from Section 2.6.6(9)(g) of Reference 11 were converted to 2007 dollars. The dollar values were increased by the Consumer Price Index (CPI) ratio of the March 2007 southern region value of 197.904 to the March 1974 value of 46.7. CPI data were taken from the U.S. Department of Labor Bureau of Labor Statistics.

3. Note that the alternative 1 intake has already been installed for use with Bellefonte Units 1 and 2, and therefore the cost already incurred.

4. Note that information describing how BLN currently meets the performance standards specified in the EPA regulations implementing Section 316(b) is provided in Subsection 5.3.1.1.1.

5. Costs associated with operation and maintenance of these alternative intake designs would be minimal compared to the capital costs associated with their construction, and are not expected to affect the evaluation or conclusion.

TABLE 9.4-7
COMPARISON OF SITE AND CORRIDOR ALTERNATIVES

Site	**C**	**Bellefonte**	**G**
Population within			
5 mi.	3378	2755	3691
10 mi.	13,112	18,405	16,768
20 mi.	88,359	50,530	100,220
30 mi.	223,524	106,860	287,274
40 mi.	459,347	398,665	467,050
50 mi.	653,925	837,658	683,226
Access facilities			
Highway	Construct 1000 ft. road, reconstruct 3.8 mi. of road, improve 12 mi. of road.	Construct 4000 ft. road, reconstruct 1.5 mi. of road.	Maintain 8 mi. of road.
Railroad			
Miles of construction	16.6	3.5	19
Bridges	2	0	6
Transmission lines			
Construction required, mi.			
500-kV	72	70.5	165
161-kV	0	2.4	12
Number of river crossings	4	3	6
Right-of-way area, (acres)	1750	1550	4300
Site development			
Grading, (million cubic yards)			
Excavation	1.2	0.8	0.3
Fill	1	0.4	0.5

Note: 1. Right-of-way width assumed the same for comparison.

2. Requirements under “Bellefonte” column have already been committed. No new construction required.

Source: Reference 1, Table 9.6

TABLE 9.4-8 (Sheet 1 of 3)
SCREENING OF ALTERNATIVES TO THE PROPOSED WATER TREATMENT SYSTEM

Factors Affecting System Selection	Base Case Chemical Treatment	Mechanical Condenser Cleaning	Non-Chemical Treatment: Ultraviolet (UV) Treatment
Chemicals Used	- Biocide/sodium hypochlorite (NaClO) - Algaecide/quarternary amine (ammonium chloride, NH_4Cl) - pH adjustment/sulfuric acid (H_2SO_4) - Corrosion Inhibitor/ortho-polyphosphate - Salt Dispersant/polyacrylate - Antiscalant/phosphonate (Refer to ER Table 3.6-1)	Mechanical cleaning would involve periodic removal of organic and inorganic residue and debris on circulating system condenser piping and related equipment. No chemicals are used.	None
Construction Impacts	Installation of the chemical treatment systems would result in additional commitments of land. Associated soil erosion and sediment impacts, however, would be small.	Periodic mechanical cleaning of the condenser system would not require any substantial construction activities and there would be no related environmental impacts.	Installation of the UV treatment systems would result in additional commitments of land. Associated soil erosion and sediment impacts, however, would be small.

TABLE 9.4-8 (Sheet 2 of 3)
SCREENING OF ALTERNATIVES TO THE PROPOSED WATER TREATMENT SYSTEM

Factors Affecting System Selection	Base Case Chemical Treatment	Mechanical Condenser Cleaning	Non-Chemical Treatment: Ultraviolet (UV) Treatment
Aquatic Impacts	Residual chemicals from this treatment process could impact aquatic resources Biocides, corrosion inhibitors, and pH adjustment chemicals are potentially toxic to aquatic life.	While mechanical cleaning measures would remove biological materials from condenser system surfaces, these measures would not pose systemic impacts on aquatic resources in the Guntersville Reservoir.	The UV treatment would have no residual impacts on aquatic resources in the receiving body of water. UV systems, however, have not been proven effective on large-scale cooling systems; therefore, they may prove infeasible or unreliable.
Land Use Impacts	Since the chemical treatment systems do require additional land, these systems would be wholly-confined to the existing BLN site. There would be no appreciable land use impacts.	Mechanical cleaning would not require any additional commitment of land.	While these UV treatment systems do require additional land, these systems would be wholly-confined to the existing site. There would be no appreciable land use impacts.
Water Use Impacts	Chemical treatment systems would not impact water withdrawal requirements.	Mechanical cleaning would not impact water withdrawal requirements.	UV treatment systems would not impact water withdrawal requirements.

TABLE 9.4-8 (Sheet 3 of 3)
SCREENING OF ALTERNATIVES TO THE PROPOSED WATER TREATMENT SYSTEM

Factors Affecting System Selection	Base Case Chemical Treatment	Mechanical Condenser Cleaning	Non-Chemical Treatment: Ultraviolet (UV) Treatment
Compliance With Regulations	The addition of chemical treatment systems would impact the current NPDES permit for the Tennessee River and Town Creek at BLN. The permit requires modification to support the new units prior to construction. (Refer to Subsection 3.4.1). The effects of cooling tower discharges are considered minimal when water quality criteria are complied with because the low volume discharges are readily dissipated in the receiving water bodies. Note that the cooling tower blowdown effluent is monitored to meet the NPDES permit and dilution of the low volume blowdown reduces water quality effects of contaminants.	Mechanical cleaning is fully compliant with the applicable regulations and existing and pending permit conditions.	The addition of UV treatment systems may impact the NPDES permit for the Tennessee River and Town Creek at BLN. The permit requires modification to support the new units prior to construction.
Environmentally Preferred or Equivalent?	Yes	Yes	No