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1.0 PURPOSE AND NEED FOR PROPOSED ACTION

1.1 Project Overview

In response to the increasing demands for bulk power, the Tennessee Valley Authority (TVA) seeks to use existing facilities to the greatest extent possible. This approach has the three-fold benefits of assuring future power supplies, avoiding the large capital outlays associated with new construction, and avoiding the environmental impacts resulting from siting and construction of a new power generating facility.

Consistent with the above, TVA proposes to extend operation of Units 1, 2, and 3 of its Browns Ferry Nuclear Plant (BFN) located in Limestone County, Alabama. This would require obtaining a renewal of the units' operating licenses from the Nuclear Regulatory Commission (NRC). Renewal of the current operating licenses would permit operation for an additional twenty years past the current (original) 40-year operating license terms which expire in 2013, 2014, and 2016 for Units 1, 2, and 3, respectively.

This Supplemental Environmental Impact Statement (SEIS) is being prepared to provide the public and TVA decision-makers an assessment of the environmental impacts of extending unit operation. License renewal by itself involves existing BFN facilities, and does not involve any new construction or modifications beyond normal maintenance and minor refurbishment. However, there are other proposed projects not directly related to license renewal that are connected to, or could affect, license renewal. One of these projects is the recovery of Unit 1, which has been in a non-operational status for 15 years. Other projects include the addition of a few new office buildings. In the interests of completeness, these actions are being included in this SEIS.

Independent of the matters considered in this SEIS, TVA earlier reviewed the environmental impacts and approved a project which will uprate the maximum operating power level of Units 2 and 3 to 120% of their originally licensed power levels. This increase is known as Extended Power Uprate (EPU). The various alternatives in the SEIS have been modified as appropriate to reflect the higher operating levels. If Unit 1 is returned to service, it is currently contemplated that it would also be operated at EPU.

A connected action also being addressed in this SEIS is the construction at BFN of a dry cask storage facility for storage of spent nuclear fuel. Currently, spent nuclear fuel at BFN is stored under water in pools specially designed for that purpose, but which have a finite capacity. Even without license renewal or Unit 1 restart, BFN requires expansion of its spent fuel storage capacity in 2005 for reasons discussed in Chapter 2. Construction of a dry cask storage facility at BFN is included in this SEIS because license extension and Unit 1 restart would impact the ultimate size of the facility.

1.2 Brief History and Description of BFN

TVA began major construction on BFN in 1967. BFN is an 840-acre tract located on Wheeler Reservoir in Limestone County, Alabama, 10 miles southwest of Athens, Alabama (Figure 1.2-1). BFN has three General Electric boiling water reactors and associated turbine-generators that can produce more than 3 billion watts of power. Each of BFN's three nuclear reactors is connected to its own dedicated generator.

BFN is TVA's first nuclear power plant. Unit 1 began commercial operation in August 1974, Unit 2 in 1975, and Unit 3 in 1977. Unit 1 has been idled since 1983, and extensive work is required to bring the unit up to current standards.

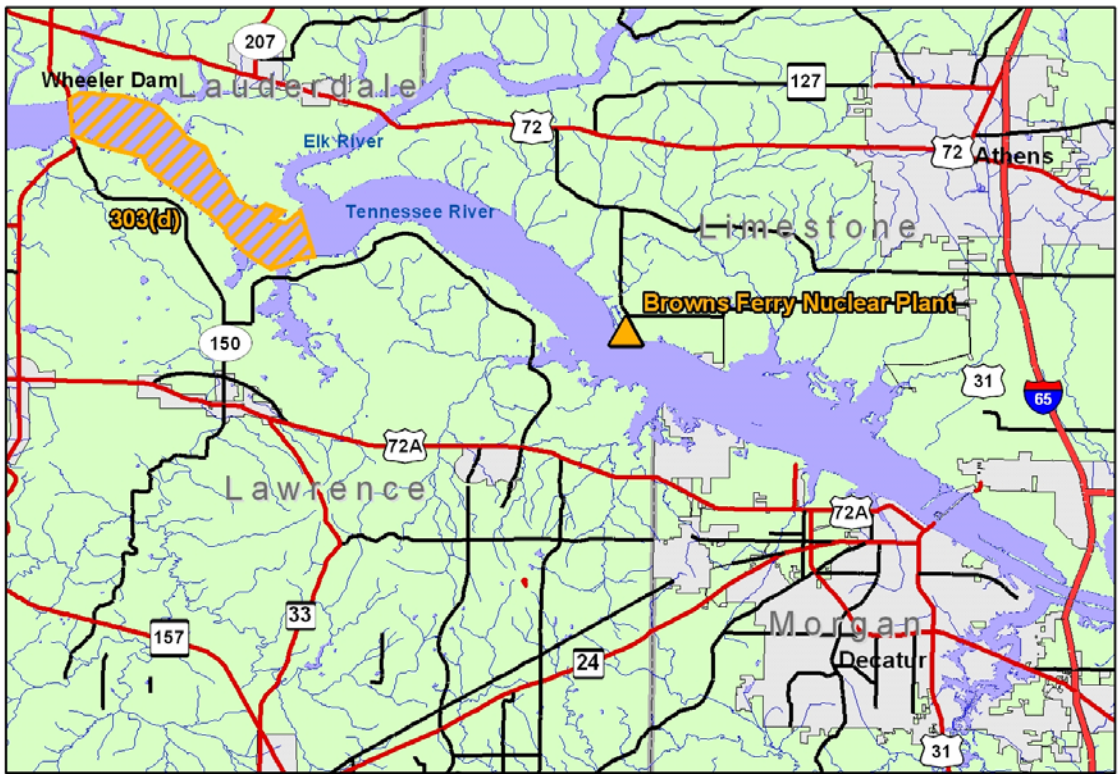
After an extended shutdown in 1985 to review the TVA nuclear power program and to correct significant weaknesses, Unit 2 returned to service in May 1991, and Unit 3 in November 1995. Operating characteristics, since restart from this regulatory outage, are expected to be more representative of future operations because of the changes in personnel, procedures, and equipment, as compared to the pre-1985 period. For example, since return to service from the regulatory outage, Units 2 and 3 have performed well, with consistently higher levels of availability and generating capacity than before the outage.

1.3 The TVA Power System

TVA was established by an Act of Congress in 1933 as a federal corporation to develop and conserve the natural resources of the Tennessee Valley region and to improve the lives of the region's population. From its beginning, TVA's challenge has been to look at economic development and natural resource issues in a comprehensive fashion. TVA has also been expected to demonstrate the unique strengths of "a corporation vested with the power of government with the flexibility and initiative of a private enterprise" (Lilienthal, 1944). TVA is managed by a three-member Board of Directors appointed by the President and approved by the U. S. Senate.

In its first 15 years of existence, TVA built a series of multipurpose dams on the Tennessee River system. One of the by-products of these dams was abundant, inexpensive electricity. The hydroelectric power generated by these dams met most of the rapidly increasing needs of the region through the 1940s. By the early 1950s, however, the growing demand was exceeding the capacity of the dams and the Watts Bar Fossil Plant, which TVA constructed in 1945. During the next 20 years, TVA built 11 large coal-fired generating plants to meet the region's growing needs. Some of these plants were the largest, first-of-their-kind, coal-fired units in the world. The 1960s brought even greater growth to the region. To meet the anticipated need for more power, TVA began an ambitious program of nuclear plant construction.

Figure 1.2-1 Location of Browns Ferry Nuclear Power Plant



Despite this growth program, TVA's electric rates remained among the lowest in the nation throughout the 1960s. However, the 1970s, beginning with the 1973 oil embargo, brought unprecedented change to the entire electric utility industry's ability to control costs and rates charged to customers. Coal costs and the costs of constructing nuclear units rapidly increased, forcing TVA and most other electric utilities to increase their rates. As energy costs across the nation continued to climb in the late 1970s and early 1980s, TVA introduced programs to encourage customers to reduce their demand for electricity. These programs, focusing on energy conservation and reducing peak electric loads, work in concert with TVA's existing generating resources to meet customer energy needs.

TVA's power system in 2000 had generating capacity of about 29,469 MWs (TVA, 2000a). Based on 2000 data, that generating system consisted of 11 coal-fired plants (53% of total generation capacity), five nuclear generating units at three sites (20%), 29 hydroelectric dams (12%), 56 combustion turbines at four sites (10%) and one pumped storage facility (5%). The system is linked by 17,000 miles of transmission lines that distribute power to 750 wholesale delivery points, as well as 57 interconnections to 13 neighboring utilities.

Today, TVA is one of the largest producers of electricity in the United States, generating 4 to 5% of all electricity in the nation. In 2000, TVA generated 152 million MWh of electricity. TVA's power system serves approximately eight million people in a seven state region, encompassing nearly 80,000 square miles (Figure 1.3-1). TVA's electricity is distributed to homes and businesses through a network of 158 power distributors, including 108 municipally-owned

utilities and 50 electric cooperatives. TVA also sells power directly to approximately 60 large industrial customers and federal facilities.

1.4 Projecting TVA's Needs for Generating Capacity

1.4.1 The *Energy Vision 2020* Planning Process

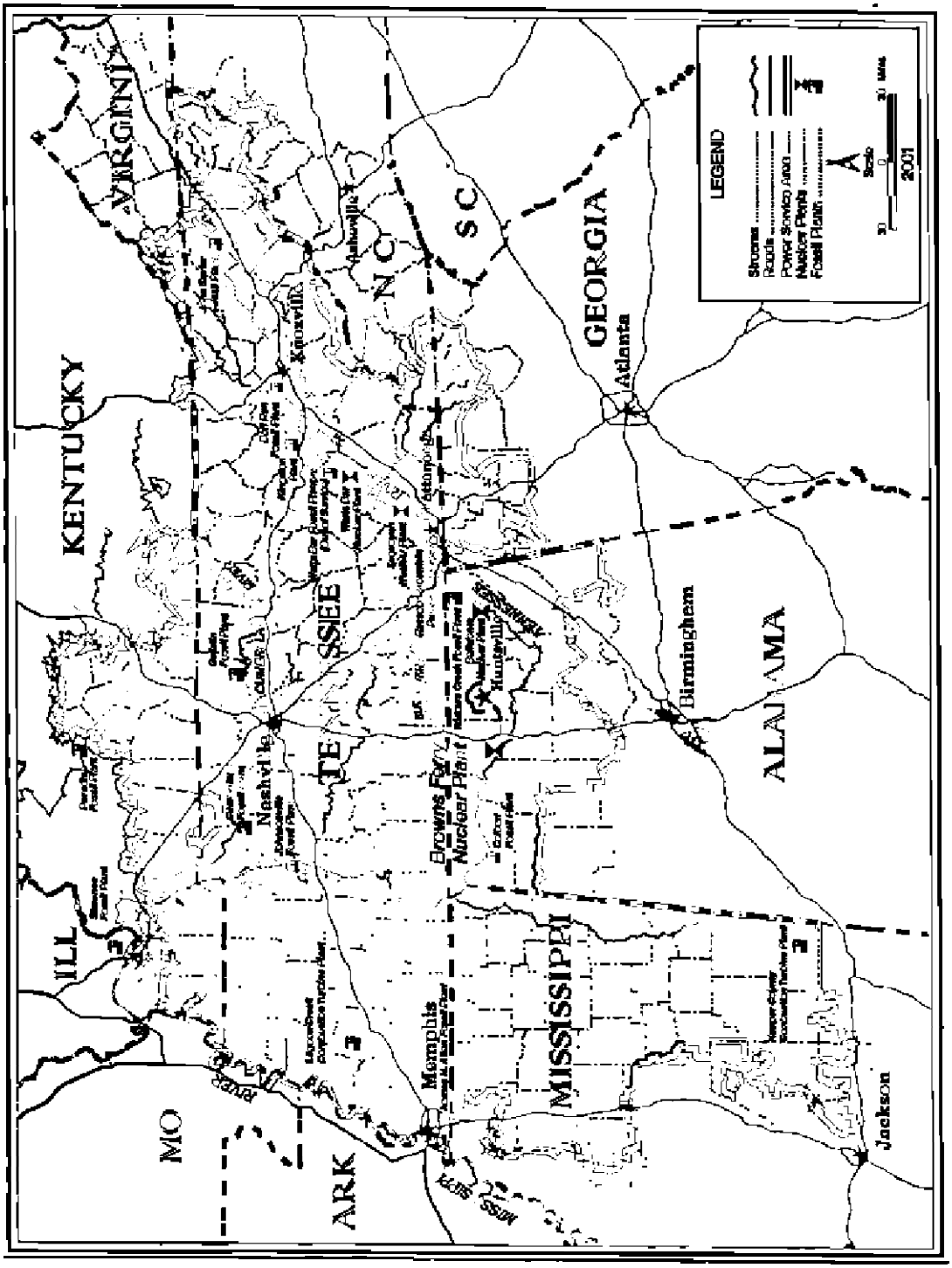
Under the National Energy Policy Act of 1992 (PL 102-486), TVA was directed to employ a least-cost energy-planning process for the addition of new energy resources to its power system. In response to this directive, TVA began work on an Integrated Resource Plan (IRP) in February 1994. An IRP is a plan which broadly identifies the actions that a utility anticipates taking to meet demands for electric service and to achieve its long-term goals and objectives. TVA completed this planning process in December 1995 with the publication of *Energy Vision 2020 - Integrated Resource Plan/Programmatic Environmental Impact Statement* (TVA, 1995).

Because the projected demand for electricity exceeds TVA's current generation capacity, much of *Energy Vision 2020* is an evaluation of ways to meet that demand. This evaluation used the best industry practices in integrated resource planning, included multiple evaluation criteria, considered future uncertainties, and reflected extensive public input. The evaluation criteria used to compare energy resource strategies included:

- Long-run cost and value criteria,
- Short- and mid-term rates,
- Reliability,
- Environmental impacts,
- Economic development,
- Financial requirements,
- Risk management, and
- Equity among rate classes.

These criteria and their associated measures became the basis for ranking a large number of supply-side and customer service alternatives. They were later used in an analysis to evaluate and improve TVA's proposed strategies. The results of this analysis showed that customer service alternatives, such as demand-side management and rate restructuring, were not, by themselves, adequate to meet the projected electrical demand increases.

Figure 1.3-1 Tennessee Valley Authority Power System



Energy Vision 2020 considered over 60 customer service alternatives that end-use customers can use to obtain energy efficiencies. These alternatives include traditional demand-side management (i.e., energy efficiency and load management), self-generation, beneficial electrification, and rate alternatives.

The evaluation of supply-side alternatives considered numerous methods of generating electricity, including traditional technologies (e.g., coal-fired plants, combustion turbines), as well as potential renewable and advanced combustion facilities. TVA also evaluated alternatives that would give greater flexibility in planning. These alternatives included purchasing competitively-priced power from other suppliers (e.g., independent power producers, cogenerators), buying alternatives on future power delivery (e.g., alternative purchase agreements), and entering business partnering arrangements. Overall, TVA characterized and evaluated over 100 supply-side alternatives based on performance, cost, and environmental impacts.

1.4.2 *Energy Vision 2020* Recommendations and Power Need Forecast

Energy Vision 2020 projected demands for electricity in the TVA power service area through the year 2020, and evaluated ways of meeting these projected increases. It was concluded that TVA would best be able to respond to future uncertainties by maintaining flexibility to deploy a variety of different demand- and supply-side resources as events unfolded. The resulting recommendations of *Energy Vision 2020*, which were adopted by the TVA Board of Directors in February 1996 (TVA, 1996), included the following portfolio components:

- Supply-side alternatives, including combustion turbines, purchasing and exercising call alternatives for both baseload and peaking power, purchasing power from independent power producers, developing renewable energy resources, improving the existing hydroelectric generating system, and converting the unfinished Bellefonte Nuclear Plant to an alternative fuel source, such as natural gas or gasified coal;
- Customer service alternatives, including demand-side management and beneficial electrification; and
- Resource management alternatives to manage risks, including increased use of natural gas to meet future environmental regulations.

The short-term supply-side action plan, designed to meet the demand through the year 2002, includes most of the supply-side alternatives listed in the long-term plan, along with targeted capacities and completion dates (e.g., implement up to 3,000 MWs of purchase call alternatives by 2002), and the development of additional power generation and storage capacity. Under the medium load forecast, the demand for electricity was projected to exceed TVA's 1996 generating capacity of 28,000 MWs by 800 MWs in 1998, and by 6,250 MWs in 2005. The medium load forecast projected a need for an additional 16,500 MWs by 2020.

TVA needs a diverse complement of generating assets to meet customer demands. These assets are called upon as needed to respond to system needs that cycle daily, weekly, and seasonally. As discussed further in Chapter 2, TVA runs certain assets almost continually (referred to as baseload assets) and other assets for short periods, typically hours at a time (referred to as peaking assets) to meet customer needs which fluctuate by as much as 20% on a daily basis and up to 50% seasonally. There is a third type which operates for several days or even weeks at a

time called "intermediate" load assets. Consequently, the types of power plants TVA builds must directly respond to the conditions under which they are operated, with the goals of maximizing energy efficiency and minimizing the cost of electricity ($/kWh) across the system.

Nuclear generation is normally operated as much as possible, since the fuel costs of nuclear units are a relatively small component of the overall costs of operation, unlike fossil-fired units. Another consideration is the physical operating constraints of nuclear plants. Nuclear units are not easily cycled – meaning they cannot be brought on line quickly, and continuously adjusting the output of energy rapidly is neither practical nor economically advantageous compared to other power sources. In contrast, hydropower is a resource that can respond almost immediately to changes in demands for power. Therefore, nuclear units are normally operated as "baseload" capacity (i.e., constant full-power operation, not fluctuating in response to changes in hourly load demand as peaking units do). Baseload is the minimal amount of power that must be available around the clock to meet demand.

Over the past several years, TVA has experienced growth in both peaking and baseload demand. Since the construction of baseload generating assets benefits TVA's ability to meet both peaking and baseload demands, it is useful to understand how both are growing and are expected to grow in the future. In the following, peaking demand is discussed in terms of instantaneous power generation (MW), and baseload demand is considered in terms of power generation over time (megawatt hours, although gigawatt hours is used in the figures). Baseload planning must consider the period over which various units can be available to meet demand.

Figure 1.4-1 shows the power need projections along with actual peaking demand since 1985. Focusing on the period immediately following the release of *Energy Vision 2020*, it is apparent that actual growth in demand is higher than projected in 1995, nearly paralleling the highest projected rate of 3.4% per year for this time interval. TVA projections in its annual report to the Southeastern Electric Reliability Council (SERC) (the vertical bars on Figure 1.4-1) shows continued higher growth over the next ten years, eventually slowing to the medium projection by about 2010 (SERC, 2000).

Figure 1.4-2 shows the total net energy (GWh) need projections along with actual baseload demand since 1985. These data project an average energy growth rate of approximately 2% per year from 2001 through 2009 (SERC). Note that for the year 2000, the actual values were slightly greater than the values that had been projected for that year. Acknowledging the recent rapid growth in baseload demand, TVA currently estimates an additional annual need of 2,000 GWh by 2005, and 5,000 to 15,000 GWh by 2010. Slowing growth in electricity demand caused by the 2001 slowdown in the economy is expected to be a short-term phenomenon; electricity demand should be back or close to the long-term forecast by 2005.

Figure 1.4-1 TVA Historic System Peak Loads and Demand Projections

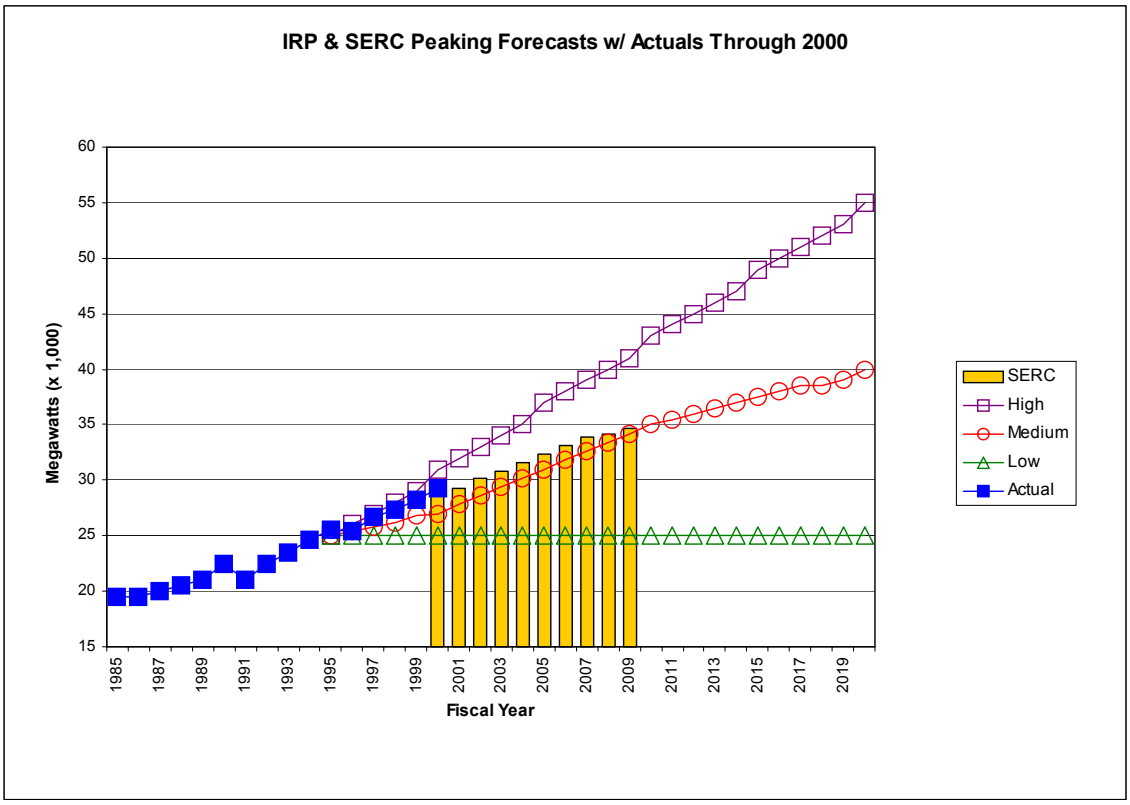
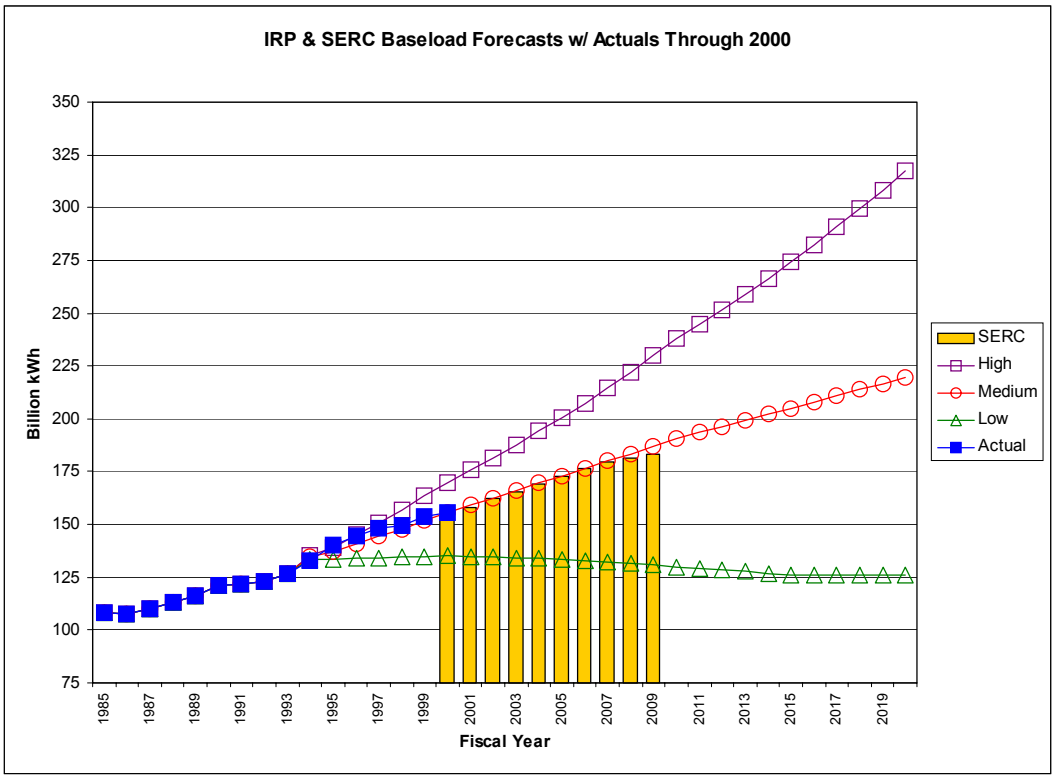


Figure 1.4-2 TVA Historic System BaseLoads and Demand Projections



1.4.3 Experience Since the Release of *Energy Vision 2020*

Since 1995, TVA has added about 3,380 MWs of generating capacity and 1,400 MW in option-purchase agreements to meet the increasing power demand in the Tennessee Valley (TVA, 1999b). Incrementally, the 3,380 MW growth in capacity consists of operational efficiencies resulting from better maintenance and capital improvements at existing fossil, nuclear, and hydro power production facilities, along with additions in capacity at several locations. A list of activities resulting in capacity additions, including option purchase agreements, are described in the following:

- Continuing modernization of existing TVA hydroelectric plants (both conventional and pumped storage) will add approximately 388 MWs of peaking capacity through 2002.
- The Red Hills Power Project in Ackerman, Mississippi, a 440 MW lignite coal-fired plant, is scheduled to begin commercial baseload operation in May 2002. This plant is owned by Tractebel Power Inc., but TVA has contracted to buy the plant's output (TVA Record of Decision, 63 FR 44944).
- 680 MWs of simple-cycle combustion turbines were constructed at TVA's Gallatin and Johnsonville Fossil Plants and began operating during June and July 2000 (Final EIS Notice of Availability, 64 FR 27782, TVA Record of Decision, 64 FR 38932).
- 680 MWs of simple-cycle combustion turbines, constructed at TVA's Lagoon Creek Combustion Turbine Plant site west of Brownsville, Tennessee, began operation in June 2001; an additional 340 MWs of simple-cycle combustion turbines will be constructed at this site for operation by June 2002 (Final EIS Notice of Availability, 65 FR 17265, TVA Record of Decision, 65 FR 30469).
- 340 MWs of simple-cycle combustion turbines are being constructed at TVA's Kemper County Combustion Turbine Plant east of DeKalb, Mississippi, for operation by June 2002 (Final EIS Notice of Availability, 66 FG 15241; TVA Record of Decision, 66 FR 21189).
- Between Units 2 and 3, the 1998 BFN Integrated Plant Improvement project resulted in a net gain of about 100 MWs.
- The current EPU project at BFN will add approximately 232 MWs, and similar planned upgrades at Sequoyah Nuclear Power Plant will add about 25 MWs. A portion of this 275 MWs could reach TVA customers by 2003, and all of the improvements are expected to be completed by mid-2005.
- Various power purchase agreements have been in effect over the period.

Consistent with *Energy Vision 2020*, TVA initiated a program in July 1998 to install selective catalytic reduction systems on 25 existing coal-fired generating units to reduce NO_x emissions. This project is expected to cost approximately $1 billion and take several years to fully implement, but will substantially reduce NO_x emissions (70 to 75% reduction during the ozone season) which contribute to ozone problems (TVA, 1999c). In 2001, TVA announced that it

planned to install five additional scrubbers to further reduce SO_2 emissions at 12 of its coal-fired units. The capital cost of these scrubbers is currently estimated at $1.5 billion.

Other activities that have addressed customer demand for electricity include the following:

- Demand-side customer service initiatives (such as *energy right* home electrical efficiency, direct load control, industrial customer products and services, firm buy-back agreements, etc.) continue to be implemented through TVA power distributors with an estimated 154 MWs of capacity added from 1995 through 1999, and an additional 264 MWs from 2000 through 2002.
- Distributed generation initiatives are being pursued by TVA. These initiatives include operation of the 14 MW emergency diesel generators at the unfinished Bellefonte Nuclear Plant site and the addition of diesel generators at the Meridian (Mississippi) Air Station and Albertville (Alabama) Municipal Water Treatment Plant.

TVA began its "Green Power Switch" program on April 22, 2000, as a market test of electricity form certain renewable sources, including landfill gas, photovoltaic, and wind. This program currently provides about five MWs of generating capacity (Table 1.4-1). Though non-hydro renewables currently represent only a small fraction of TVA's generating capacity, the success of this program has exceeded expectations. During the first 11 months of the program, 3,260 residential and 150 commercial customers signed up to participate. Twelve distributors of TVA power currently offer the Green Power Switch program to their customers. TVA plans to increase generation from such sources, including one project to increase wind power capacity by up to 50 MWs by 2003, and a solar project that would increase capacity to about one MW by 2010. TVA has no current plans for repowering any of its conventional units with renewable fuels (TVA, 2001a).

Table 1.4-1 TVA Generation Capacity by Energy Source

	Capacity (MW)	Portion of TVA Total (%)
Conventional Energy[a]		
Coal Fired[b]	17,407.20	53.46
Nuclear	6,053.10	18.59
Hydro	5,157.50	15.84
Natural Gas	3,910.00	12.01
Diesel Generator	27.00	0.08
Subtotal	32,554.80	99.98
Non-hydro Renewable Energy		
Bioenergy[c]	5.60	0.017
Solar	0.25	0.001
Wind	1.98	0.006
Subtotal	7.83	0.024
TVA Total	32,562.63	100.00

a – Based on unit nameplate capacity, which is somewhat higher than the system available capacity discussed in Section 1.2.
b - Includes cogeneration steam to a nearby industrial facility at Johnsonville Fossil Plant.
c - Includes wood waste cofiring at Colbert Fossil Plant and wastewater biogas cofiring at Allen Fossil Plant.

1.4.4 Integrating Supply-Side and Demand-Side Alternatives to Meet Customer Needs

ONGOING EFFORTS TO ACQUIRE SUPPLY

Some activities implemented by TVA have not performed as intended in delivering reliable power to TVA customers. One of these, involving Option Purchase Agreements (OPAs), has made available some new resources to TVA's system. However, some of the OPAs have either not met stated conditions and requirements, or the entities submitting the proposals could not deliver power by the needed dates. Consequently, the projected power hoped for from this alternative has not fully materialized.

During August 2000, TVA released a two-part request for proposals (RFP) with the goal of acquiring additional peaking capacity (TVA, 2000b). The first part involved purchases of summer peaking capacity and the second part involved constructing new generating capacity. The deadline for submittal of proposals under this RFP was November 8, 2000, but this deadline was extended to April 1, 2001.

Part one solicited offers from TVA power distributors which would allow TVA to purchase up to 600 MWs of summer peaking capacity under a fee arrangement without owning any of the physical plant assets. The new capacity would need to have a June 1, 2003, delivery date and provide TVA exclusive rights during the term of the OPA.

Part two solicited offers from TVA power distributors regarding their purchase (from TVA) of two four-unit combustion turbine facilities at sites within the TVA service region, including the four-unit plant in Kemper County, Mississippi, currently under construction. This capacity must begin operation by June 1, 2002. TVA's goal in this instance is to pay the successful proposer for exclusive rights to the energy produced at the plant, but not to own the physical assets.

A second RFP, released in August 2000, focused on short-term proposals (two to five years duration) with the ability to extend agreements for longer periods. It solicited proposals for "firm" summer (June-August) peaking capacity for delivery beginning in 2001 (TVA, 2000c). "Firm" in this context means first-call priority for shared generating resources. The RFP stated a need of up to 500 MWs and a minimum amount of 50 MWs, but the energy may be from one or more resources. The RFP was open to independent power producers, exempt wholesale generators, qualifying facilities, power marketers, and utilities within the TVA or Southern Company transmission systems. As a result of the RFP, several contracts were entered into under which TVA committed to purchase in excess of a total of 500 MWs of capacity for the summers of 2002 and 2003.

A third RFP, released in January 2001, pertains to long-term (up to 15 years duration) proposals, preferably with options for early termination and/or options to extend for additional periods. The RFP solicits proposals for "firm" baseload and/or summer peaking power supply requirements for delivery beginning 2004 (TVA, 2001b). In this context, "firm" means that TVA must have first-call priority for shared resources. The RFP states a need for up to 600 MW of baseload type capacity and up to 600 MW of summer peaking capacity beginning June 1, 2004. The offers of capacity and energy may be from one or more resources. The RFP is open to all parties, including, but not limited to: TVA power distributors, independent power producers, exempt wholesale generators, qualifying facilities, power marketers, and utilities. The offers must deliver capacity and energy to the TVA transmission system. As a result of the RFP, TVA received

approximately 80 proposals for summer peaking and baseload energy from more than 20 proposers. After conducting detailed analyses that considered reliability, flexibility, fuel costs, environmental impacts, electricity market prices, and other important factors, TVA has determined there are options that could provide a better value to the Valley for summer peaking energy than the proposals submitted, such as short-term market purchases, unsolicited proposals that TVA could receive in the future, etc. Therefore, TVA has elected not to pursue a power purchase agreement for summer peaking capacity from this RFP. Efforts are continuing to analyze the proposals submitted to supply baseload capacity.

Spot market purchases of power, also recommended by *Energy Vision 2020*, could help meet future peak demands for electricity. However, while TVA would continue to selectively use this option in the future, market purchases during seasonal periods which cause high demand on the generating capacity of the region could be subject to sharp increases in price. Under some circumstances, the needed power might not be available at any price, thereby requiring TVA to interrupt power to industrial customers (whose contracts allow this action) or to reduce voltages in power delivered to both residential and industrial customers. Each of these consequences involves a definite, but frequently difficult to quantify, societal and human cost. Spot market purchases, if substantial and attempted during periods of high regional demand, could not be depended upon to provide reliable and economic peaking power for the long-term.

OUTLOOK FOR THE FUTURE

The bottom line is that none of the activities discussed above, either individually or collectively, replace the need for TVA-owned and -operated new electricity generation as demand, continually spurred by economic growth in the region, increases. The combined impact of all demand-side management and renewable energy generation projects, in terms of electricity demand delayed or replaced, is much less than the generation alternatives proposed in this SEIS. This combined impact is also greatly exceeded by demands projected in *Energy Vision 2020*, and by actual growth experienced in the past several years. This is one of the reasons that the proposals for extending operation of the BFN units are being considered.

Exacerbating this complex and fluid planning process is the prospect that, based on peaking and baseload demands recorded in recent years, the medium load capacities targeted in *Energy Vision 2020* may actually be too conservative. Actual peak demands increased by over 4,600 MWs from the winter of 1995 (24,723 MWs) to the summer of 2000 (29,344 MWs), an average annual increase of about 920 MWs (over 3% per year). In fact, peaking demands during the summer of 2000 exceeded by 2,000 MWs the medium load forecast contained in *Energy Vision 2020*. Continued demand increases of this magnitude could, in a few years, exceed TVA's generation capacity and negatively affect TVA's ability to serve its customers.

Over the next few years, TVA plans to further increase capacity through improvements to existing units and the addition of capacity using combustion turbines as peaking units, in combined-cycle baseload plants and in cogeneration configurations with private companies across the service region. However, these increases may not be enough to maintain adequate reserve capacity.

It is reasonable to expect that the delivery of reliable and economic power to customers will require TVA to continue to pursue all of the portfolio options recommended in *Energy Vision 2020*, both demand-side and supply-side. Consistent with *Energy Vision 2020*, from which this SEIS tiers, each of the portfolio options being implemented has received an appropriate

environmental review before a decision was made to proceed with its implementation. Future projects will receive a similar review.

1.5 SEIS Overview/NEPA Approach

This SEIS is being prepared by TVA under the National Environmental Policy Act (NEPA), regulations published by the Council on Environmental Quality (40 CFR Parts 1500-1508), and TVA's procedures implementing NEPA. This SEIS updates and adds to information and analyses in the plant's original environmental impact statement (EIS), and will provide the public and TVA decision-makers a basis for considering the proposed actions.

1.5.1 Tiering from *Energy Vision 2020*

Tiering from the *Energy Vision 2020* Programmatic EIS incorporates it by reference in this SEIS and allows concise and efficient consideration of the strategies and programmatic issues related to both maintenance of existing generation capacity in TVA's power system and the addition of new generation capacity. As discussed in the preceding sections, *Energy Vision 2020* evaluated an array of energy resources, both supply-side and demand-side. These alternatives were ranked using several criteria, including environmental performance. Favorable alternatives were formulated into strategies that would effectively meet baseload energy and peak capacity needs of TVA's customers under a range of conditions ("futures"). A number of these strategies were then combined to create TVA's short- and long-term energy resource plans or, collectively, TVA's Integrated Response Plan (IRP).

Nuclear generation is expected to play a vital role in helping TVA meet energy supply demands through the *Energy Vision 2020* study period (1996 through 2020). The *Energy Vision 2020* Resource Integration Strategy Matrices identified five nuclear units, located at three sites, as existing generating assets on the TVA system – BFN Units 2 and 3, Sequoyah Nuclear Plant Units 1 and 2, and Watts Bar Nuclear Plant Unit 1. These five units were determined to contribute 5,517 megawatts, 20%, of the TVA system total project capacity of 27,995 MW in 2005.

The operating nuclear units at BFN will reach the end of their current operating licenses during the *Energy Vision 2020* study period. *Energy Vision 2020* anticipated that Units 2 and 3 would be excellent candidates for license extension for two reasons. First, boiling water reactors, such as those at BFN, are not very susceptible to reactor vessel age degradation; second, these units have been brought up to current standards. TVA continues to closely follow NRC rule-making and rule interpretation for license renewal, as well as the experiences of other nuclear utilities that have applied for license renewal since the Energy Vision EIS was issued. Accordingly, this SEIS addresses extending BFN unit licenses to provides sources of baseload electric energy in TVA's power system for an additional period of 20 years past expiration of the current operating licenses.

Energy Vision 2020 also discussed both the short-term and the long-term options for BFN Unit 1. That EIS identified strategies that were determined to best optimize the relationship among the inter-related factors of costs, rates, environmental impacts, debt and economic development, while meeting customer needs. For the short-term, the IRP concluded that it was not viable to

restart BFN Unit 1 because there were more optimal power supply strategies identified to meet load growth, particularly in consideration of cost, impact on short-term rates, impact on debt and competitiveness.

Since the release of *Energy Vision 2020*, TVA has continued to maintain and improve the efficiency and reliability of its fossil plants, purchased capacity calls in the bulk power markets, and procured additional peaking capacity to meet growth needs that have exceeded the assumptions used in the IRP. The additional peaking capacity consists of gas/oil-fired combustion turbines: 608 MWs by summer 2000, 616 MWs by summer 2001, and 616 MWs by summer 2002. In order to preserve long-term flexibility, BFN Unit 1 has continued to be maintained as an inoperative deferred nuclear asset. This enabled TVA to maintain lower rates and debt for the short-term and consider other alternatives to recovering BFN Unit 1 as conditions changed.

Energy Vision 2020 noted that deferring the decision to recover BFN Unit 1 for several years would allow additional time to acquire information regarding nuclear unit performance and economics and TVA's need for power. Moreover, *Energy Vision 2020* concluded that under certain conditions, recovery of BFN Unit 1 could emerge as a low-cost supply option. This set of conditions, referred to as a "high performance" future, consisted of the high load forecast, low cost to complete the nuclear units, low operations and maintenance costs, and a high nuclear capacity factor. Since issuing *Energy Vision 2020*, a number of developments makes it timely to consider further the recovery of BFN Unit 1 to meet TVA's long-term resource requirements.

***Energy vision 2020* – Capital Cost Recovery Estimates for Browns Ferry Unit 1 Restart**

At the time *Energy Vision 2020* was issued, the cost of recovery for Unit 1 was expected to be in the range of $1.187 to $3.150 billion with a medium value of $2.374 billion. Adjusting the medium figure to 2002 dollars, the cost today would be nearly $3.1 billion. The cost and schedule estimates made in the IRP assumed a significant degree of uncertainty due to a rapidly changing regulatory climate and difficulty in managing large nuclear construction projects. The detailed engineering costs were taken as the low forecast, and historical forecast error data were used to determine the medium and high forecasts. The IRP EIS conservatively applied adjustments to the detailed engineering cost estimates based on the errors in past cost forecasts, despite the fact that previous forecast errors were considered in the detailed engineering cost estimates. Other nuclear units completed by TVA were constructed in an environment where changes to nuclear unit construction were mandated by the NRC, irrespective of quantifiable impact on the safety of the unit. In this environment, the detailed engineering estimate was doubled when compared with other capacity supply alternatives. Thus, the low cost estimate was not considered as a basis for capacity planning. The report recognized that future forecast error could be reduced if regulations were more stable and construction project management improved.

The current regulatory state is considerably more stable than the "post - Three Mile Island" environment preceding *Energy Vision 2020*. An important regulatory development has been the use of probabilistic risk assessment in the implementation of NRC regulations. Before changes are mandated by the NRC, the cost of the modification and the impact on the probability of associated design basis accidents are considered. This is a significant evolution in regulatory philosophy from the environment that existed at the time recovery of BFN Unit 1 was first considered.

Updated Capital Cost Recovery and Capital Cost Experience

In late 2001 through early 2002, TVA has conducted an assessment and engineering "due diligence" review of the cost estimate to further reduce uncertainty associated with recovery and restart of BFN Unit 1. Detailed engineering estimates (including transmission system impacts) now support a cost of recovery of BFN Unit 1 in the range of $1.56 billion to $1.72 billion with a most likely cost of $1.64 billion in 2002 dollars

TVA now has demonstrated experience in reducing the cost of additions and improvements needed to modify existing nuclear operating units to improve reliability. The IRP projected that TVA's additions and improvement costs would be typical of the industry. Annual costs were assumed to be $20 million per site plus $5 million per unit in 1994 dollars. Escalation was expected to be 4.5%. Accordingly, a two-unit site would have been forecast to have $42.6million in additions and improvements costs in 2002. Actual costs for BFN have averaged $29.7 million over the last five years and were$23.8 million for fiscal year 2001.

The existing management and technical infrastructure at BFN, which currently supports the operation of Units 2 and 3, can also be leveraged to create economies of scale for the operation of Unit 1. In calendar year 2000, the cost of operating Units 2 and 3, as published in *Nucleonics Week*, was $12.22/MWh. Based on continued improvements in operating and fuel costs and increases in the available capacity from the uprates described in this SEIS, the current projected cost for continued operation of Units 2 and 3 is $10.46/MWh. The recovery of Unit 1 would further lower this projection to about $9.37/MWh.

TVA has also materially improved the performance of its nuclear plants above the projections used to review alternatives in *Energy Vision 2020*. The mid-range capacity factor assumption in *Energy Vision 2020* for nuclear units is 67%, with a low of 55% and a high of 86%. Nuclear plant performance has significantly improved beyond even the high case assumptions of the IRP. Capacity factors used in the IRP were based on the 67% average annual capacity factor for Sequoyah Units 1 and 2 and BFN Unit 2 following restoration to service of those units through the date the IRP evaluation was performed. This value was used for the medium estimate for future capacity factors for all nuclear units considered. The high estimate for nuclear capacity factor was 86%. BFN has consistently improved capacity factors since Unit 3 was returned to service in 1995, and has demonstrated the ability to sustain a high level of operation by averaging 92% capacity factor over the past five years. Two key factors in this improvement have been the reduction in refueling outage duration, and improvements in overall plant operating performance. Refueling outages at BFN have been reduced from an average of 89 days in the years immediately prior to the IRP to an average of 24 days since then, with a low of 18 days.

Operating costs for a nuclear unit include operations and maintenance, additions and improvements, fuel, and decommissioning. Decommissioning costs are not adversely impacted by the recovery of BFN Unit 1, since TVA has always funded decommissioning accruals in the same manner in which it funds all of its currently operating units. Operations and maintenance costs were projected in the medium case to be $69 per kilowatt per year, with a low value of $55 per kilowatt per year and a high value of $83 per kilowatt per year. The estimates were escalated at 4.5% annually. At this rate, the low forecast for 2001 would be approximately $74.8 per kilowatt per year. However, operations and maintenance expense for 2001 is $62.3 per kilowatt per year, 17% below the low forecast. Incremental, or replacement, cost of nuclear fuel (in 1994 dollars) was assumed to be 41.7 cents per million British Thermal Unit (Btu). The medium escalation forecast was assumed to be 2.5 %, the low was projected at 2.0%, with a high

escalation forecast of 3.5%. The low forecast estimate for nuclear fuel costs in 2001 would be 47.9 cents per million Btu. The actual cost for BFN in 2001 is 47.1 cents per million Btu.

BFN's performance and costs have improved to the point that it is now considered by the Institute of Nuclear Power Operations (INPO) to be among the top performing nuclear plants in the country. It is a Top Quartile performer on Total Production Costs and the INPO Performance Index, and a Top Decile performer on Non-fuel Production Costs, Net Capacity Factor, and Outage Duration.

TVA's load growth since 1994 has exceeded the medium forecast assumed in the IRP. More importantly, a gap between system energy requirements and available generating capacity has occurred as supply side actions implemented by TVA have not performed as expected. For example, the OPA program has added only 1,400 MWs of new capacity to TVA's system versus the 3,000 MWs recommended in *Energy Vision 2020*. Also, there has been no conversion of capacity at Bellefonte that would have supplied additional capacity. Moreover, natural gas prices and the experience of other markets have shown how capacity shortages can impact the cost of power. A more complete discussion of TVA's need for generating capacity can be found in an earlier section.

Comparison With Other Supply Options

In comparison to other power supply options, such as a natural gas-fired combined cycle (NGCC) facility, the cost of BFN is relatively low. A NGCC combined cycle facility operated as a baseload power plant has a capital cost of $550/Kilowatt (kW). With the addition of peaking capacity capabilities, a NGCC facility has a capital cost of $730/kW. The levelized costs of a NGCC plant with peaking capabilities including fuel, fixed and variable O&M, and interest expenses is $51.00/MWh (Reference: Williams Capital Group Equity Research, July 2001). With the economies of a multi-unit site, low capital cost, and low operating cost, the total annual cost of Browns Ferry Unit 1 is expected to be significantly lower with operating and fuel costs at 20% of the level of above referenced NGCC.

While the nuclear option provides lower operating costs relative to the NGCC option, the initial investment in Browns Ferry Unit 1 Restart would cost approximately $1.64 billion in 2002 dollars. In the near term, debt would increase by $1.86 billion in 2007 above a resource plan considering NGCC and market purchases as the principal alternative sources of supply. However, adding more than 1,254 MW net of baseload capacity that operates at or above a 90% capacity would reduce the average cost of power by 0.05 cents/kWh and would ultimately reduce long-term debt. In conclusion, there is now strong support for the lowered expectations of capital cost, improved operating performance, and high demand case that would bolster recovery of BFN Unit 1 as a low cost power supply option.

1.5.2 Tiering from the BFN Environmental Statement

An earlier environmental document was prepared by TVA to evaluate the effects on the environment of construction and operation of BFN. The Atomic Energy Commission (AEC), a former regulatory agency of the Federal government, since superseded by the NRC, participated in the preparation of this three-volume document as a cooperating agency. When the final document was issued in 1972 it was titled as follows: Final Environmental Statement, Browns Ferry Nuclear Plant, Units 1, 2, and 3. The AEC concluded on August 28, 1972, that this Environmental Statement was adequate to support the proposed license to operate the plant. Since this 1972 document is actually what is now commonly designated as an environmental impact statement (EIS) it will be referred to as such throughout this SEIS.

This SEIS will reference (and not repeat) analyses contained in the original EIS wherever possible. However, since methodologies may have changed or additional information may have been obtained over the years, each subject area will be reevaluated in the light of current knowledge and practices. Additional topics will be addressed as appropriate.

1.5.3 Other Relevant NEPA Reviews

1.5.3.1 Completed NEPA Actions

1.5.3.1.1 Generic Environmental Impact Statement for License Renewal of Nuclear Plants, NUREG-1437

Anticipating that it would receive applications for renewal of the operating licenses of a significant portion of existing nuclear power plants, the NRC prepared a *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), NUREG-1437, (NRC 1996) to examine the possible environmental impacts that could occur as a result of renewing licenses of individual nuclear power plants under 10 CFR 54. The GEIS, to the extent possible, establishes the bounds and significance of these potential impacts. The analyses in the GEIS encompass all operating light-water reactors. For each type of environmental impact, the GEIS establishes generic findings covering as many plants as possible. The GEIS makes maximum use of environmental and safety documentation from original licensing proceedings and information from state and federal regulatory agencies, the nuclear utility industry, the open literature, and professional contacts. The GEIS identifies 92 environmental issues and reaches generic conclusions on environmental impacts for 69 of those issues that apply to all plants or to plants with specific design or site characteristics.

Under the NRC's environmental protection regulations in 10 CFR Part 51, renewal of a nuclear power plant operating license is identified as a major federal action significantly affecting the quality of the human environment, and thus an EIS is required for a plant license renewal review. The EIS requirements for a plant-specific license renewal review are specified in 10 CFR Part 51. Operating licenses may be renewed for up to 20 years beyond the 40-year term of the initial

license. License renewal applicants (such as TVA) perform evaluations and assessments of their facility to provide sufficient information for the NRC to determine whether continued operation of the facility during the renewal term will endanger public health and safety or the environment.

The assessment in NRC's GEIS is relevant, and applies to the assessment of impacts of the proposed actions at the BFN. TVA has determined that this GEIS is still reasonably available. Copies can be obtained electronically at NRC's Internet website.

TVA may reference, in whole or in part, applicable material covered in the GEIS, wherever appropriate.

1.5.3.1.2 Highly Enriched Uranium FEIS

In accordance with TVA procedures implementing NEPA and consistent with 40 CFR 1506.3, TVA adopted a Final EIS (FEIS) issued by the U. S. Department of Energy (DOE), Office of Fissile Materials Disposition, in June 1996. This FEIS is titled "Disposition of Surplus Highly Enriched Uranium Final Environmental Impact Statement." Notice of the availability of the FEIS was published by the EPA in the *Federal Register* on June 28, 1996. A separate DOE Notice of Availability, summarizing the Highly Enriched Uranium Final EIS appeared in the *Federal Register* that same day. TVA determined that the FEIS meets the standards for an adequate FEIS. TVA's Notice of adoption was published in the *Federal Register* on February 14, 2001. A Record of Decision (TVA, 2001c) was issued for the project in November 2001.

The FEIS assessed the environmental impacts that may result from the disposition of U. S. origin weapons-usable highly enriched uranium (HEU) that was or may be declared surplus to national defense or defense-related program needs. In addition to the No Action Alternative, this EIS assessed four alternatives that would aid U. S. non-proliferation policies. These alternatives would eliminate the weapons usability of HEU by blending it down with natural uranium, low enriched uranium (LEU) or depleted uranium to create LEU to be used either as commercial reactor fuel feedstock or disposed of as low-level radioactive waste. The EIS assessed the disposition of approximately 200 metric tons of surplus HEU.

The potential blending sites considered in the EIS were: DOE's Y-12 Plant at Oak Ridge, Tennessee; DOE's Savannah River Site (SRS) in Aiken, South Carolina; Babcock and Wilcox Naval Nuclear Fuel Division Facility in Lynchburg, Virginia; and the Nuclear Fuel Services Fuel Fabrication Plant in Erwin, Tennessee. Several domestic commercial nuclear fuel fabrication plants, including Siemens Nuclear Power's plant in Richland, Washington, were identified as potential destinations for the LEU produced. Evaluations of impacts at the potential blending sites on site infrastructure, water resources, air quality, noise, socioeconomic resources, waste management, public and occupational health and environmental justice were included in the EIS. The impact of intersite transportation of nuclear and hazardous materials was also assessed. The preferred alternative was blending down as much of the HEU to LEU as possible while gradually selling the commercially usable LEU for use as reactor fuel. DOE plans to continue the activity over an approximately 15- to 20-year period.

TVA has now entered into contracts with Framatome-Cogema and Siemens for fuel blending and fabrication services, and has executed an Interagency Agreement with the DOE to obtain approximately 33 metric tons of HEU. These 33 metric tons of HEU are a portion of the 200 metric tons identified in the DOE EIS. The HEU for eventual use as blended down LEU fuel in

BFN would originate from DOE's Y-12 Plant at Oak Ridge, Tennessee and the Savannah River Site in Aiken, South Carolina. Blending down and processing of the HEU to LEU would occur at the Nuclear Fuel Services (NFS) facility in Erwin, Tennessee, and at DOE's SRS in Aiken, South Carolina. Commercial fuel fabrication would occur at Siemens Power Corporation (SPC) in Richland, Washington.

The first use of HEU in BFN reload fuel is scheduled for the spring of 2005, which is the first of 14 reload fuel batches. For Units 2 and 3, each refueling every other year, the last fuel reload from the 33 metric tons of HEU would occur in 2018, unless additional HEU stocks are dispositioned at BFN. Recovery and restart of Unit 1 could result in earlier consumption of this material.

Facility construction and uranium processing services at NFS would extend over a period of 2002 through 2007. The work would be licensed and regulated by the NRC and the State of Tennessee. Since the work is very similar to the uranium processing work done at NFS since 1958, minimal additional impacts are expected with respect to waste water and air discharges. DOE may potentially surplus additional HEU later that may be processed into commercial reactor fuel for use either by TVA or other utilities.

1.5.3.2 Unit Uprates

EPU will result in approximately 232 MWe of additional electrical output from BFN. An Environmental Assessment has been completed for this proposal (TVA, 2001d). The assessment described the impacts of taking no action (i.e., continuing to operate at the currently licensed level) and undertaking the power uprate. The various alternatives in this SEIS have been modified as appropriate to reflect the higher operating power levels. If Unit 1 is returned to service, it is currently contemplated that it would also be operated at the EPU level. However, the project to uprate Units 2 and 3 is feasible, independent of any future decision TVA may make regarding license renewal for Units 1, 2, and 3, and the recovery and restart of Unit 1.

1.5.3.3 Reservoir Operations Study (ROS)

As mandated by the Congress, TVA manages its integrated system of 49 dams and reservoirs primarily to promote navigation, flood control, and consistent with these purposes, the generation of electric energy. In addition to these main objectives, TVA operates the reservoir system to provide a host of other benefits, including flows for power plant cooling water. Most of TVA's eleven coal-fired plants and three nuclear plants, depend upon these flows in order to operate efficiently.

The purpose of the ROS is to determine if changes in TVA's reservoir operating policies would produce greater overall public value. On February 25, 2002, TVA issued a Notice of Intent to prepare a programmatic environmental impact statement (EIS). Alternatives will address TVA's major reservoir operating objectives of navigation, flood risk reduction, and power production, as well as water quality, water supply, recreation and economic development. TVA is presently in the scoping phase for that study.

1.6 Purpose of the Proposed Action

The purpose of the proposed action (extending unit operation and possibly recovering Unit 1) is to continue to make maximum use of existing power production facilities at the BFN site into the foreseeable future and meeting growing demands on the TVA system in a cost effective and environmentally-sound manner. Obtaining license extensions for BFN Units 2 and 3 would allow the plant to continue to generate electric power for an additional 20 years beyond the expiration dates of the current operating licenses (i.e., 2014 to 2034 for Unit 2, and 2016 to 2036 for Unit 3). Similarly, recovering and restarting Unit 1, which has been in a non-operational status since 1985, with an extended operating license could also significantly increase the electric power production of the BFN during the 20-year renewed license period (2013 - 2033).

1.7 Need for the Proposed Action

Continued operation of the BFN units was part of a system-wide evaluation of future energy needs undertaken by TVA. A range of options to meet those needs was evaluated in TVA's *Energy Vision 2020*, released on December 21, 1995.

Energy Vision 2020 anticipated that existing TVA plants will continue to be the backbone of TVA's power supply in the future (*Energy Vision 2020,* p. 7.1). Continued energy generation from BFN is a major component of TVA's generating assets, representing 8% of generating capacity and about 13% of annual energy generation in FY2000. Because of its low operating costs, BFN will continue to be a key generating asset even if some TVA customers elect other suppliers for some of their requirements under electricity deregulation.

In *Energy Vision 2020*, TVA's load forecasting indicates that its customers' future electricity needs will exceed TVA's current generating capacity. Additionally, each year TVA provides updated projections of supply and demand for the DOE's Annual Report EIA-411 (USDOE, 2000). This year's report shows expected energy demand growing at over 2% annually from 2001 through 2008. The net capacity resources needed to meet the growth in demand increases by over 8,000 MWs between 2000 and 2008 (See line item 13 on Table Item 2.1, "Projected Capacity and Demand – Summer," of the EIA-411 report). This trend continues today in the TVA control area. Based on the energy growth seen in the past several years, an annual growth rate of 2 to 3% is anticipated over the next 20 years (TVA, 2001a). Continued growth in electricity demand is principally driven by the forecast economic growth of the Tennessee Valley region.

The short-term action plan of *Energy Vision 2020* identified a need for 3,500 MWs of baseload and peaking additions through the year 2002. Since *Energy Vision 2020* was completed in 1995, TVA has continued to evaluate and select the best energy resource alternatives from its IRP portfolio based on the latest proposals and TVA's forecast of power needs. The total system generation capacity has been increased with the successful completion of Watts Bar Nuclear Plant Unit 1 and the return to service of BFN Units 2 and 3. All three units have operated above expectations and have proven to be very reliable.

TVA projects have been scheduled to maintain, restore, and/or increase net dependable capacities for TVA's combustion turbines, fossil plants, hydroelectric plants, and pumped storage units. OPAs have been entered into to provide part of the peaking capacity needs. For some of the

baseload capacity needs, TVA has a contract for delivery of electricity from the Red Hills Power Project, a lignite-fired plant near Ackerman, Mississippi, which is scheduled to begin commercial baseload operation in May 2002. TVA's natural gas-fired combustion turbine plant at the Lagoon Creek Site near Brownsville, Tennessee, began operation in June 2001.

The national energy plan released by the Administration (National Energy Policy, May 2001) calls for a balanced response to meeting increasing public demands for electricity. This includes expeditious development of additional energy sources such as nuclear energy. The energy plan specifically identifies unit uprates and unit license renewal as parts of the strategy for meeting current and future electric power demands.

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