Chapter 8 Need for Power

Chapter 8 presents the need for power evaluation based on Georgia Power Company's Integrated Resource Plan (IRP). As discussed in Chapter 1 Georgia Power Company (GPC), through the Georgia Public Service Commission's Integrated Resource Planning process, has identified that an economic need for additional base load generation is identified no later than June 2015. The addition of new baseload generation at VEGP will represent the first addition in baseload generation since 1989. GPC is a regulated utility and must satisfy the State of Georgia's detailed review considering future power needs and also must seek state approval to pursue new nuclear generation at the VEGP site. The State of Georgia retains approval authority over the types of electric generation that will be constructed and operated within its border. NUREG-1555 proposes that a state-approved IRP can support the NRC need for power evaluation if it is (1) systematic, (2) comprehensive, (3) subject to confirmation, and (4) responsive to forecasting uncertainty. It is SNC's determination that the GPC IRP satisfies these criteria and therefore no additional independent review by the NRC is required. The following sections discuss how the IRP process satisfies the need for power analysis.

- SNC Approach (Section 8.1)
- Integrated Resource Planning in Georgia (Section 8.2)
- Georgia Power Integrated Resource Plan (Section 8.3)
- Other Planning (Section 8.4)
- Conclusion (Section 8.5)

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8.1 SNC Approach

NRC Regulation 10 CFR 52.17(a)(2) indicates that an early site permit (ESP) application need not include an assessment of need for power, allowing applicants to defer the analysis until submittal of a combined construction and operating license (COL). Southern Nuclear Company (SNC) intends to apply for a COL for the Vogtle Electric Generating Plant (VEGP) in 2008 and therefore has included need for power in its ESP application.

SNC has been authorized to submit the ESP application by Georgia Power, acting as agent for the co-owners of the existing VEGP: Georgia Power Company (GPC), Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (Dalton Utilities).

The co-owners support the development of additional nuclear units at VEGP. In May, 2005, the co-owners entered into a Development Agreement that contemplates the licensing, design and engineering, construction, and operation of up to two additional units at the site. The Development Agreement also grants the requisite rights to use the VEGP site and authorizes GPC to perform development activities on behalf of the co-owners, including preparing and filing ESP and COL applications, and developing and constructing infrastructure improvements as authorized by the NRC in an ESP and related limited work authorizations.

The Development Agreement created a schedule for the co-owners to reach more detailed agreements and a mechanism for the co-owners to elect to participate in the new units. The co-owners have the right to participate up to their current interests in VEGP Units 1 and 2 (i.e., GPC 45.7%, OPC 30%, MEAG 22.7% and Dalton Utilities 1.6%). In December, 2005, the co-owners indicated their current intent to participate in this power project at their pro-rata interests.

Collectively, the co-owners have a service area that encompasses the entire state of Georgia, except for the northwest corner (see Figure 8.1-1), and they supply electricity to approximately 6.2 million people or 76 percent of Georgia's year 2000 population (not including Savannah Electric and Power customers). Savannah Electric and Power merged with GPC on July 1, 2006, adding an additional 320,000 residents in a 2,000-square mile region along the Georgia coast. Demand for electricity in Georgia is expected to grow by an annual average rate of 1.8 percent per year through 2030 **(EIA 2005)**.

In order to ensure that the need for power analysis provides a high level of assurance that capacity from the new units would be needed, SNC has first prepared the need for power analysis as if GPC were to be the sole owner of the potential additional units at the VEGP site, and then analyzed the effect that other ownership needs would have on this analysis.

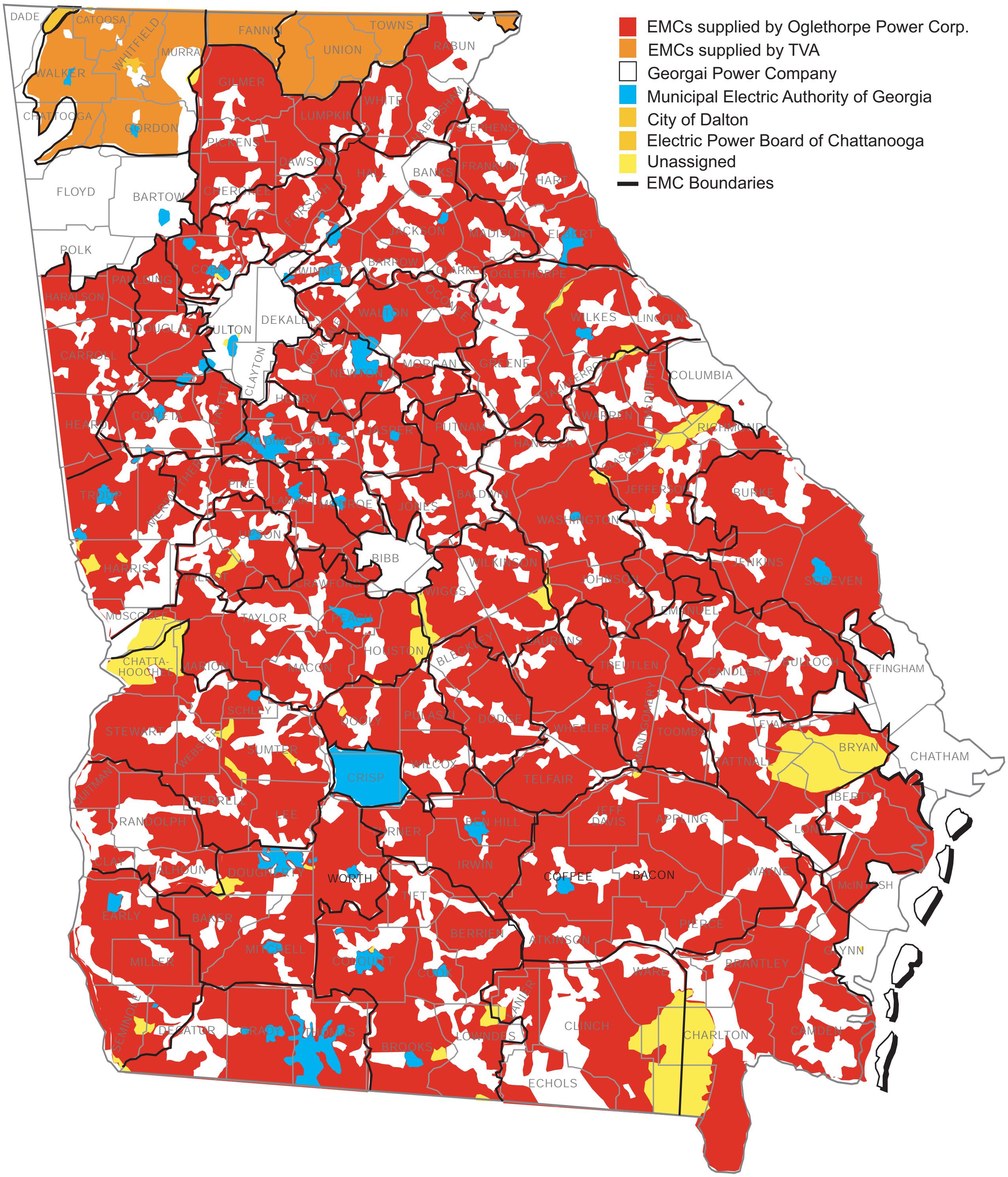

Figure 8.1-1 Georgia Electric Suppliers Assigned Service Areas

Section 8.1 References

(EIA 2005) Energy Information Administration, Annual Energy Outlook, Electric Generation and Renewable Resource, Table 68, Electric Power Projects by Electricity Module Region – Southeastern Electric Reliability Council, Washington, D.C. December.

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8.2 Integrated Resource Planning in Georgia

The mission of the Georgia Public Service Commission (GPSC) is to ensure that consumers receive safe, reliable and reasonably-priced electric services from financially viable and technically competent companies subject to its jurisdiction. The GPSC has the authority to set rates and require long-range plans and projections. The GPSC expects the electric industry in Georgia to remain traditionally regulated in its present form **(GPSC 2005)**.

The GPSC fully regulates GPC **(GPSC 2005)**. By statute, GPC must submit to the GPSC at least every 3 years an Integrated Resource Plan (IRP) that:

- Includes the utility's electric demand and energy forecast for at least a 20-year period,
- Includes the utility's program for meeting the requirements shown in its forecast in an economical and reliable manner,
- Includes the utility's analysis of all capacity resource options, including demand-side and supply-side options, and
- Sets forth the utility's assumptions and conclusions with respect to the effect of each capacity option[1]

Provisions in the statute require the GPSC to hold a public hearing on the IRP and establish criteria for the GPSC to use in determining whether to approve and adopt the plan.[2] A related provision prohibits the utility from constructing an electric plant, or increasing the capacity of an existing plant, without first obtaining from the GPSC a certificate of public convenience and necessity. A certificate application must include the current IRP and a cost-benefit analysis for the proposed additional capacity.[3]

By statute, the Consumer's Utility Counsel Division of the Governor's Office of Consumer Affairs represents state residents and small commercial customers in utility proceedings, including IRP review, before the GPSC **(CUC 2006)**. This provides a viewpoint that might not otherwise be present in the review process for IRPs.

The GPSC has established detailed regulatory requirements for IRPs.[4] The requirements include the following:

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[1] Official Code of Georgia (OCG) Title 46, Chapter 46-3A is available on the Georgia General Assembly website at http://www.legis.state.ga.us/cgi-bin/gl_codes_detail.pl?code=46-3A-1. Accessed May 23, 2006, [OCG 46-3A-1(7)].

[2] Ibid. at OCG 46-3A-2(b) and -2(c). Updated annually to reflect changes in the triennial base plan approved by the commission.

[3] Ibid. at OCG 46-3A-3(a) and -3(b).

[4] Georgia Public Service Commission Regulation Chapter 515-3-4 is available on the Georgia Public Service Commission website at http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1. Accessed May 23, 2006. (GPSC 515-3-4).

- Energy and demand forecasting – The plan must report and use 3 years of historic data and address each of the next 20 years. Forecasting must be weather-normalized and address the jurisdictional area, retail and wholesale loads, customer classes, and annual load factors. The regulation specifies forecasting methodology and determinants, and standards for data inputs. Finally, the plan must include an evaluation of the sensitivity of the results to changes in major assumptions and estimates used. The sensitivities must include a reasonable range of sales and demand and include base growth, high-growth, and low-growth scenarios.[5]
- Capacity resource identification – The plan must identify existing resources, including power purchases, sales and exchanges, demand-side programs, cogeneration, standby generation, interruptible service, pooling or coordination agreements, generation, and transmission. It must address potential new supply- and demand-side resources and the associated decision-making process (the regulation details the process for securing long-term new supply-side options).[6]
- Integrated plan development and filing – In addition to energy and demand forecasting and capacity resource identification, the plan must address alternatives to proposed generation; environmental impact of proposed and alternative generation; economic, environmental, and other benefits to the state and consumers; and financial information. The plan must identify the integrated combination of demand- and supply-side resources selected to satisfy future energy demands. Periodically after plan approval, the utility must report on actions taken to implement the plan and any deviations from the plan.[7] A new plan must be filed every 3 years.[8]

The GPSC staff retains experts to assist in reviewing the utility's IRP, developing data requests and reviewing responses, providing reports to and testimony before the GPSC, and responding to GPSC requests. The GPSC can approve the plan, approve it subject to stated conditions or modifications, approve it in part and reject it in part, reject it in its entirety, or provide an alternate plan. The review process takes approximately 150 days.

In addition to IRP requirements, the GPSC has detailed requirements for obtaining GPSC approval, called certification, of new supply-side resources.[9] An application for GPSC certification for constructing or purchasing additional capacity, called a power purchase agreement, must include a discussion of how the proposed application is consistent with the current IRP, a cost-benefit analysis, and detailed information about the proposal and

[5] Ibid. at GPSC 515-3-4-.03.
[6] Ibid. at GPSC 515-3-4-.04.
[7] Ibid. at GPSC 515-3-4-.05.
[8] Ibid. at GPSC 515-3-4-.06.
[9] Ibid. at GPSC 515-3-4-.07, -.08, -09, and -10.

alternatives.[10] Once the GPSC certifies a power purchase agreement, that capacity is added to the plan, called the "base case", for meeting forecast loads. Adding capacity to the base case lags much of the forecast timeline. For example, the current GPC forecast extends to the year 2025 and GPC just applied for GPSC certification of agreements to add capacity beginning in 2009 **(GPC 2006)**.

[10] Ibid. at GPSC 515-3-4.07(2).

Section 8.2 References

(CUC 2006) Consumer's Utility Counsel Division, Georgia's Office of Consumer's Affairs, available online at http://consumer.georgia.gov/00/channel_modifieddate/0,2096,5426814_38871066,00.html, accessed June 6, 2006.

(GPC 2006) Georgia Power Company, 2006, Georgia Power Company's Application for the Certification of 2009 Capacity Resources and Certification of the Upgrade to the Rocky Mountain Pumped Storage Hydroelectric Generating Facility; Docket No. 22528-U, Letter, Fletcher (GPC) to McAlister (Georgia Public Service Commission), May 10, available online at Georgia Public Service Commission website at http://www.psc.state.ga.us/cgi-bin/docftp.asp?txtdocname=92034, accessed June 6, 2006.

(GPSC 2005) Georgia Public Service Commission, Georgia Public Service Commission 2005 Annual Report, Atlanta, available online at http://www.psc.state.ga.us/pscinfo/2005Annual.pdf, accessed June 6, 2006.

8.3 Georgia Power Integrated Resource Plan

With the merger with Savannah Electric and Power, GPC now serves over 2 million retail customers in all but several counties in northwest Georgia. In July 2004, the GPSC issued its final order approving the fifth GPC IRP **(GPSC 2004)**. The order is an excellent explanation of the proceedings and conclusions, and SNC has included a copy in Appendix C. The following paragraphs summarize the order, which SNC is adopting by reference, and aspects of the related docket on the GPSC website **(GPSC 2004)**.

The 2004 IRP approval was the culmination of GPSC and staff review of the GPC plan and application for approval **(GPC 2004)**; GPC responses to 11 sets of staff requests for additional information; motions, briefs, and other submittals by 10 interveners; GPC and intervener testimony during 5 days of hearings; and staff reports. The approval process took 5 months. A redacted version of the GPC plan and formal documentation associated with its approval are available on the GPSC website **(GPSC 2006)**. GPC and the GPSC also maintain a trade-secret version of the plan. Table 8.3-1 is a summary outline of the 2004 IRP; the actual plan is contained in several book volumes.

The GPSC final order summarizes the proceedings and the GPSC authority to impose the IRP process on GPC. The order discusses the models used to forecast demand, analysis of the accuracy of past forecasts, the weather normalization process, and a PSC-staff requested addition of a higher growth projection. The GPSC approved a 13.5 percent reserve margin for planning within 3 years and a 15 percent margin for longer forecasts and approved planning that identifies the need for new resources beginning in 2009 and continuing through 2023. The GPSC noted testimony expressing concern over relying totally on natural gas for future resource additions, due to its expected continued high prices. The order approves several demand-side measures being implemented and directs consideration of additional measures; approves pricing tariffs and green power initiatives; concurs with transmission system planning; and assesses GPC's planning for costs and other impacts that future environmental protection requirements might pose. The order reaffirms previous GPSC direction that GPC own 70 percent of capacity relied upon, limiting purchased power to no more than 30 percent of total supply-side resources. Finally, the order directs actions to be taken before the next triennial IRP update and format changes for that update.

In 2006, GPC submitted to the GPSC a revised energy and demand forecast **(GPC 2006)**. This submittal updates the forecast in the 2004 IRP and will form the basis for the next triennial plan update, in 2007. The load forecast includes underlying assumptions of load growth by customer class and of fuel prices. Because of the sensitive nature of the contents, the load forecast is available only as a "trade secrets" document.

Table 8.3-1 Contents, Georgia Power 2004 Integrated Resource Plan

Main Report

Section 1	Summary of 2004 Integrated Resource Plan
Section 2	Integrated Resource Planning Process Overview
Section 3	Budget 2004 Load and Energy Forecast
Section 4	Comparison of the Forecast with Existing resources
Section 5	Demand-Side Plan
Section 6	Supply-Side Plan
Section 7	Integration of Demand-Side Programs into the Benchmark Supply-Side Plan
Section 8	Integrated Resource Plan
Section 9	Summary of Transmission Planning
Section 10	Renewable Resources
Section 11	Hydro Electric Operation and Re-Licensing
Section 12	Action Plan
Section 13	Attachments

Technical Appendix Volume 1A

2004 IRP Plan & Mix Study
Generation Technology Book
Financial Review

Technical Appendix Volume 1B

Environmental Compliance Strategy
Unit Retirement Study
Reserve Margin Study

Technical Appendix Volume 2

2004 Budget Load & Energy Forecast

Section 8.3 References

(GPC 2004) Georgia Power Company, 2004 Integrated Resource Plan, Atlanta, January 30, 2004 (date received by Georgia Public Service Commission), Redacted version available on Georgia Public Service Commission website at http://www.psc.state.ga.us/cgi-bin/docftp.asp?txtdocname=70086, accessed May 25, 2006.

(GPSC 2004) Georgia Public Service Commission, Final Order, Docket No. 17687U, Document No. 74366, available on Georgia Public Service Commission website at http://www.psc.state.ga.us/cgi-bin/documentresults.asp?page=2, accessed June 21, 2005.

(GPSC 2006) Georgia Public Service Commission, Georgia Public Service Commission Docket No. 17687, Atlanta, available online at http://www.psc.state.ga.us/cgi-bin/documentresults.asp, accessed June 6, 2006.

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8.4 Other Planning

GPC, OPC, and MEAG are members of the Southeastern Electric Reliability Council, Inc. (SERC). Dalton Utilities is represented at SERC by Southern Company. SERC is the regional reliability organization responsible for promoting, coordinating, and ensuring the reliability and adequacy of the bulk power supply systems in the area served by the member systems and is one of eight such councils that comprise the North American Electric Reliability Council, Inc. (NERC). SERC maintains a website with council information **(SERC 2006)**.

SERC members submit demand, energy, aggregate capacity and transmission line information to SERC for compilation into regional input for submittal to the U. S. Energy Information Administration (EIA).[11] The members also submit unit data directly to EIA.[12] SERC publishes load growth, net energy, and peak demand forecasts for the region **(SERC 2005)** based on member-submitted data but does not perform any independent analysis.

Southern Company, through its subsidiaries, is one of the largest producers of electricity in the United States, with a 120,000-square mile service territory served by its four regulated retail electric utility subsidiaries: Alabama Power, GPC, Gulf Power, and Mississippi Power.

Southern Company performs integrated planning and system operations for its subsidiary utilities. Through a contractual arrangement, the utilities in each state share their capacity resources to benefit from the economies of scale associated with a large system **(FPSC 2005)**. Southern Company has established a subsidiary, SNC, to operate company nuclear power plants **(Southern Company 2006)**; the co-owners have formally agreed that, if constructed, SNC will operate the additional units.

8.4.1 Co-owner Planning

The GPSC is reviewing a 2006 GPC application for certification (i.e., approval) of three power purchase agreements that would provide a total of 1,039 megawatts of additional generating capacity for 15 years beginning in 2009. The application includes an update of the load forecast that the GPSC approved in the 2004 IRP. The updated GPC load forecast shows that by 2015, GPC will need to add or procure [confidential commercial information] megawatts of capacity **(GPC 2006)** because of load growth and expiring power purchase agreements. If the GPSC certifies the pending agreements, GPC will still need to add or procure [confidential commercial information] megawatts of capacity by 2015, the earliest date that VEGP Unit 4 would go commercial. VEGP Units 3 and 4 would each generate approximately 1,000 megawatts electric net, or 2,000 megawatts combined. Thus, the GPC forecast of absolute demand supports the

[11] Form EIA-411, *Coordinated Bulk Power Supply Program Report.* SERC submits to NERC, which submits to EIA a form for each regional council.
[12] Form EIA-860, *Annual Electric Generator Report*.

addition of both units, with [confidential commercial information] megawatts to be met by other capacity additions.

The 2004 IRP did not include nuclear power as an option for meeting future demand and, consistent with the IRP, GPC has begun planning for capacity additions in 2010 and 2011 that do not account for new nuclear power capacity.[13] However, the GPSC has reviewed GPC costs for pursuing VEGP Units 3 and 4 licensing and has authorized GPC to record these as capital costs for future recovery in rates[14]. In addition, the Georgia legislature recently passed resolutions urging the GPSC to encourage utilities to consider building new nuclear plants in Georgia.[15] GPC has committed to the GPSC that GPC's next triennial IRP, due to the GPSC in January 2007, will address the nuclear option. Should the GPSC approve of incorporation of VEGP Units 3 and 4 into the GPC planning for future capacity, GPC would plan other capacity additions around Units 3 and 4 coming on line as scheduled for operation.

If GPC owned both units outright, it could make beneficial use of the generating capacity within the GPC service territory. As an alternative, GPC would also have recourse to the Southern service territory (the Southern system shows a cumulative need for [confidential commercial information] megawatts of additional capacity by 2015 **[GPC 2006]**) and to electricity sales on the open market. However, GPC does not expect that this will be necessary.

OPC, MEAG, Dalton Utilities, and some of the OPC and MEAG members each have their own process for determining their individual needs for power. If these co-owners of VEGP Units 1 and 2 finalize their ownership in Units 3 and 4 as planned, their need for power would displace some of the GPC need and GPC would have to seek other capacity additions to compensate.

Although the ultimate participation percentages of each co-owner in Units 3 and 4 has not been determined, and likely will not be decided until 2008, the co-owners support additional nuclear generating capacity, based on their analyses of future needs for power. MEAG and OPC members are located throughout Georgia. The customers served by the co-owners and their members represent most of the population of Georgia, assuring that the additional units will be dedicated to the State's electric power needs.

MEAG has 49 members (48 cities and one county) who provide electricity to retail customers in small to moderate-sized Georgia municipalities. These members must purchase their power from MEAG. OPC is an electric membership corporation owned by 38 retail electric membership corporations. Through commercial agreements, OPC supplies electricity to these electrical utilities from its existing generating capacity and through purchased power contracts.

[13] Georgia Public Service Commission, Docket Nos. 21447 and 21448. Available on Georgia Public Service Commission website at http://www.psc.state.ga.us. Accessed June 16, 2006.
[14] Georgia Public Service Commission, Order, Docket No. 22449U, decided June 22, 2006. Available on Georgia Public Service Commission website at http://www.psc.state.ga.us. Accessed June, 2006.
[15] Georgia Senate Resolution 865, 2006. The Georgia House passed a similar resolution.

OPC supplies approximately 70% of the total load of its members. Dalton Utilities operates its independent municipal electric authority and is not a member of MEAG.

MEAG owns about 1,600 megawatts of capacity from several facilities that provide energy to its members of approximately 600,000 retail customers; OPC counts approximately 1.5 million customers in the State through its members, with 5,878 megawatts of owned or managed capacity. Taken together with GPC's approximately 2 million customers and Dalton Utilities' 13,200 customers, the four co-owners essentially serve the entire State of Georgia other than a small area in the northwestern portion of the State which is served by the Tennessee Valley Authority. This is the same geographical region that will be served by the additional units at the VEGP.

Each of the VEGP co-owners, as part of their resource planning, have estimated their current peak capacity needs, and their projected capacity needs in 2015, the nominal in-service date of VEGP Unit 3:

Forecasted Approximate Peak Load/Need in MW (2006)
CONFIDENTIAL COMMERCIAL INFORMATION

Dalton	[Confidential commercial information]
MEAG	[Confidential commercial information]
OPC	[Confidential commercial information]
GPC	[Confidential commercial information]

Forecasted Approximate Peak Load/Need in MW (2015)
CONFIDENTIAL COMMERCIAL INFORMATION

Dalton	[Confidential commercial information]
MEAG	[Confidential commercial information]
OPC	[Confidential commercial information]
GPC	[Confidential commercial information]

As shown in Table 8.4-1, SNC has collected data from the co-owners that support their projected estimates that, in total, [confidential commercial information] MW of generating capacity need to be added or procured by the year 2015. Based upon the percentages indicated, the co-owners have more need than the bounding analysis. Participation of the other co-owners would result in an overwhelming case for the need for Unit 3 and 4 capacity but would not change the conclusion of SNC's need for power analysis.

In summary:

- Georgia has an integrated resource planning process that satisfies NRC criteria for eliminating the need for additional, detailed NRC review;

- Co-owner GPC is subject to the state process, has a demonstrated need for additional capacity that VEGP Units 3 and 4 would provide, and would need GPSC approval prior to proceeding with the project with or without participation by the other co-owners;
- The state process gives NRC assurance that the project would not proceed without state concurrence that the need for power is real and that the benefits of satisfying that need would be realized; and
- With the participation of the other co-owners, as envisioned, the additional generating units will provide the relevant service area with only a portion of the co-owners projected need for power.

See Section 10.4 for discussion of additional benefits of co-owner participation in the proposed action.

Table 8.4-1 Information Supporting the Estimated Need for Power in Georgia in 2015

CONFIDENTIAL COMMERCIAL INFORMATION

Year	Total Accredited Generating Capacity (MW)	Accredited Baseload Generating Capacity (MW)	Peak Demand (MW)	Net Capacity Needed for Baseload (MW)	Net Capacity Needed for Peak Power (MW)	Required Reserve Margin (percent)
			GPC[a] (45.7 percent ownership)			
2006	20,070	11,001	[confidential commercial information]	[confidential commercial information][b]	[confidential commercial information]	[confidential commercial information][c] %
2015	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information][b]	[confidential commercial information]	[confidential commercial information][c] %
			OPC (30 percent)			
2006	6,584	3,433	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]%
2015	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]%
			MEAG (22.7 percent)			
2006	2,409	1,519	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]%
2015	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]%
			Dalton Utilities (1.6 percent)			
2006	317	241	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]%
2015	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]	[confidential commercial information]%

a. Georgia Power data includes both GPC and Savannah Electric.

b. Estimated average demand during summer months of June through September.

c. Target reserve margin for 2006 planning. Through Georgia Power's participation in the Southern Power pool, reserves are shared with other Southern Company operating companies resulting in a lower effective reserve margin requirement (as shown above) for an individual entity such as Georgia Power. The Southern pool has a target reserve margin of 13.5% in the 0-3 year timeframe and 15% beyond 3 years.

Section 8.4 References

(FPSC 2005) Florida Public Service Commission, A Review of Florida Electric Utility 2005 Ten-Year Site Plans, December 2005, available online at http://www.psc.state.fl.us/general/publications/reports.cfm#eng, accessed June 6, 2006.

(GPC 2006) Georgia Power Company, 2006, Georgia Power Company's Application for the Certification of 2009 Capacity Resources and Certification of the Upgrade to the Rocky Mountain Pumped Storage Hydroelectric Generating Facility; Docket No. 22528-U, Letter, Fletcher (GPC) to McAlister (Georgia Public Service Commission), May 10, available online at Georgia Public Service Commission website at http://www.psc.state.ga.us/cgi-bin/docftp.asp?txtdocname=92034, accessed June 6, 2006.

(SERC 2005) Southeastern Electric Reliability Council, Inc., Southeastern Electric Reliability Council 2005 Information Summary, July, available online at http://www.serc1.org/Pages/DocumentSearch.aspx?FN=SERC/SERC%20Publications/Information%20Summary, accessed May 25, 2006.

(SERC 2006) Southeastern Electric Reliability Council, Inc., available online at http://www.serc1.org/Pages/Homepage.aspx, access May 25, 2006.

(Southern Company 2006) Southern Company, available online at http://www.southernco.com/ accessed June 6, 2006.

8.5 Conclusion

The Georgia integrated resource planning process satisfies the NRC need for power analysis and meets the NRC criteria for an acceptable state plan.

The following paragraphs demonstrate that the Georgia integrated resource planning process meets the NRC criteria for an acceptable state plan:

- Systematic – Georgia law and GPSC regulations, orders, and requests prescribe the Georgia integrated resource planning process that includes evaluation of the need for additional electric generation capacity. Planning, as currently structured, dates to 1992 and is updated every three years. Each triennial review culminates in a GPSC order approving (with modifications as necessary) and adopting the plan. The GPSC approval process involves prescribed reviews and hearings and typically takes 150 days. SNC has concluded that the statutory, regulatory, and administrative requirements that make up the Georgia process comprise a methodical state process for regularly reviewing, in a thorough fashion, the need for power that GPC is responsible for satisfying.
- Comprehensive – The State of Georgia's planning encompasses energy and demand forecasting, capacity resource identification, integrated plan development, supply-side and demand-side resource evaluation, renewable resource assessment, and includes comparisons of historic forecasted versus actual load results. The plan looks forward 10 years for transmission and 20 years for demand and energy planning. SNC has concluded that the Georgia need-for-power planning process encompasses all of the components that NRC would cover if NRC had to perform a detailed review, covering the subject completely.
- Subject to Confirmation – The utility prepares the plan. The GPSC staff and outside experts review the plan and perform their own analyses, as needed. The GPSC solicits public comment and utility, staff, and public testimony, and maintains supporting documentation on a publicly available website. A division of the Governor's Office represents state residents and small commercial customers in the proceedings. The Georgia integrated resource planning process is subject to confirmation in multiple ways; several entities review the utility-prepared plan, the GPSC review is conducted in a public forum, and the GPSC requires interim reviews on plan implementation. SNC concludes that the resultant need-for-power analysis is fully corroborated, including supporting evidence.
- Responsive to Forecasting Uncertainty – Planning begins with an evaluation of the accuracy of past forecasts and incorporates lessons-learned into current forecasting. The plan also must include an analysis of the sensitivity of all major assumptions and estimates used and include, at a minimum, base case, high-growth, and low-growth scenarios. Uncertainty factors evaluated include population and demand growth, customer mix changes, weather normalization, gas fuel cost volatility, reserve margins, unit retirements, conservation

impacts, and environmental compliance costs. SNC concludes that Georgia's use of established models capable of performing sensitivity analyses, together with GPSC-required uncertainty analysis, ensures that the state process responds appropriately to uncertainty that is inherent in the forecasting process.

SNC concludes that Georgia, having opted to retain traditional regulation of its investor-owned utility, has the kind of integrated resource planning process that meets the NRC need for power evaluation and satisfies their criteria for an acceptable state need for power analysis.

Chapter 9 Alternatives

The proposed action is NRC issuance of an early site permit to SNC for approval of the VEGP site for one or more nuclear power facilities separate from filing of an application for a construction permit or combined license (COL) for such a facility115 The SNC goal in preparing its ESP application environmental report is to obtain NRC approval of the site and to minimize the amount of additional environmental review needed for a COL application, thereby maximizing owner and the State of Georgia assurance that new nuclear capability is a viable generation option.

Chapter 9 describes the alternatives to construction and operation of new nuclear units with closed cycle cooling at the Vogtle Electric Generating Plant (VEGP), and alternative plant and transmission systems. The descriptions provide sufficient detail for the reader to evaluate the impacts of the 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 includes two phrases that warrant introduction, “relevant service area” and “region of interest.” SNC uses relevant service area to refer to the geographic area where VEGP Units 3 and 4 co-owners would sell electricity. SNC uses region of interest to refer to the geographic area SNC evaluated for locating alternative energy sources and sites.

For most of this analysis, SNC defined the region of interest to be contiguous with the Southern Company service territory in Georgia, Alabama, Mississippi, and Florida. The Southern Company service territory does not limit power purchase analysis; the co-owners can purchase power generated almost anywhere in the U.S., Canada, or Mexico provided there is transmission capability to import the power. Traditionally utilities could locate alternative energy sources and sites only within their relevant service area (i.e., relevant service area and region of interest were the same).

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9.1 No-Action Alternative

9.1.1 Vogtle Early Site Permit

The no-action alternative for a proposed early site permit (ESP) is non-issuance of that permit (i.e., NRC denies the application for an early site permit for the proposed site). In this context, no-action would accomplish none of the benefits intended by the ESP process, which would include early resolution of siting issues prior to large investments of financial capital and human resources in new plant design and construction, early resolution of issues on the environmental impacts of construction and operation of proposed reactors, the ability to confirm the suitability of sites on which nuclear plants may be located, and the facilitation of future decisions on whether to build new nuclear plants. Not issuing the ESP would avoid no significant environmental impacts, because no such impacts are caused by a site suitability determination. The only activities that are permissible under an ESP are limited work activities allowed by 10 CFR 50.10(e)(1), and those activities are permissible only if the final environmental impact statement concludes that the activities will not result in any significant environmental impacts that cannot be redressed. For reasons discussed below, however, SNC believes that it is unreasonable to assume that the no-action alternative would result in no additional capacity being constructed.

9.1.2 Combined License

SNC has also evaluated the no-action alternative as it would relate to not constructing and operating new generation capacity, which would be the no-action alternative in the case of a COL application (i.e., non-issuance of a COL). This evaluation is consistent with the SNC goal of maximizing the value of an ESP by minimizing the amount of additional environmental review needed for a COL application. Under this no-action alternative, the proposed project would not be constructed or operated at the VEGP site. The applicant would lose the benefits of having an ESP (if issued) and of being able to develop its preferred nuclear plant site.

9.1.3 Additional Capacity Construction Impact of No-Action Alternative

Electricity demand in the Southeast, which is driven primarily by increased population and higher per capita consumption of electricity, is expected to increase by 1.8 percent annually for the foreseeable future **(EIA 2006)**. Without additional capacity, the co-owners of the proposed project would not be able to maintain an adequate reserve margin. One of the co-owners, Georgia Power Company (GPC), would be at potential variance with its public service obligations to provide sufficient power within its service territory, while other co-owners would jeopardize their missions of providing capacity to other electric suppliers throughout the State of Georgia. Customers would lose the possibility of having less expensive nuclear-generated electricity displace more expensive generation options in the dispatch mix. The co-owners would not be able to support national goals to advance the use of nuclear energy. The regional fuel supply portfolio would remain heavily dependent on coal and continue to increase reliance on natural gas. With no marked change in diversity of fuel supply, the region would remain heavily dependent on fossil-fuel generation and might be negatively affected by increased air emissions and increased fuel costs. If the co-owners took no action at all to meet growing demands, the ability of the co-owners of the proposed project to continue to supply low-cost, reliable power to their customers would be impaired. Consequently, it would be unreasonable for the co-owners or the State to take no action at all to meet growing demands for electricity. Therefore, the no-action alternative could take the following general paths.

- Demand Side Management – Georgia and its utilities have active demand side management (DSM) programs and continue to pursue additional opportunities for DSM. However, state projections, even assuming contributions, show unmet demand.
- No New Generating Capacity – The co-owners and the state may choose not to pursue construction of any new generation capacity, and thus the need for power presumably must be met by other alternative means that involve no new generating capacity. These alternatives would include demand-side management, energy conservation, and power purchased from other electricity providers. This evaluation is discussed in Section 9.2.1. 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.
- Construct Non-nuclear Alternatives – The required generating capacity could be provided by the construction of generating alternatives other than the proposed project. The new capacity could be constructed at the VEGP site other existing generating facility sites or at other, non-designated, "greenfield" sites. Assessments of these alternatives are provided in Section 9.2.2.
- Combination – It is possible that some combination of the above approaches could be taken to provide the equivalent of the generating capacity precluded by the NRC's denial of the early site permit. 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 Section 9.2.2.13.

Because the no-action alternative is the denial of the early site permit, the proposed project would not be constructed or operated at the VEGP site. It follows, therefore, that the environmental impacts described and predicted in this report for the new nuclear units would not occur. However, while the predicted impacts would not occur at VEGP if the facility were not built, some of these impacts (or greater impacts) could occur at other sites if new nuclear generating capacity is constructed and operated at those other sites to meet the presumed need for power. These impacts are evaluated (i.e., compared with those of the proposed project) in Section 9.3.

Section 9.1 References

(EIA 2006) Energy Information Administration, Supplemental Tables to the Annual Energy Outlook 2006, Washington, D.C, February, available online at http://www.eia.doe.gov/oiaf/aeo/supplement/index.html.

9.2 Energy Alternatives

Alternatives that do not require new generating capacity are discussed in Section 9.2.1, while new generation alternatives are discussed in Section 9.2.2. In Section 9.2.2, some of the alternatives that require new generating capacity were eliminated from further consideration and discussion based on their availability in the region, overall feasibility, ability to supply baseload power, or environmental consequences. In Section 9.2.3, the alternatives that were not eliminated are investigated in further detail relative to specific criteria such as environmental impacts, reliability, and economic costs.

While alternative energy technologies are reviewed here for the purposes of this environmental report, their availability relative to nuclear technologies was not a factor in selecting emerging nuclear technologies as the superior alternative. The decision to develop nuclear power on land adjacent to the existing VEGP units was based on market factors such as the proximity to an already-licensed station, the ability to incorporate existing environmental permits in the operation and plant parameters, property ownership, and other location features conducive to the plant's intended generating objective.

9.2.1 Alternatives That Do Not Require New Generating Capacity

This section is intended to provide an assessment of the economic and technical feasibility of meeting the demand for energy without constructing new generating capacity. Specific elements may include:

- Purchasing power from other utilities or power generators,
- Reactivating or extending the service life of existing plants within the power system,
- Implementing DSM actions (including conservation measures),
- A combination of these elements that would be equivalent to the output of the project and therefore eliminate its need.
- In Section 9.2.1, the relevant service area definition is applicable only to SNC's demand side management analysis because reducing demand outside the relevant service area would not relieve demand within the relevant service area.

9.2.1.1 Purchasing Power from Other Utilities or Power Generators

SNC has evaluated conventional and prospective purchase power supply options that could be reasonably implemented. The co-owners of the VEGP site have entered into long-term purchase contracts with several entities to provide firm capacity and energy. Power covered by these contracts is already included in current and future capacity estimates. Therefore, SNC does not consider the power purchased by these contracts to be available to satisfy the purchased power alternative.

If power were to be purchased from sources within the U.S., Canada, or Mexico, the generating technology likely would be one of those described in this ER (probably coal, natural gas, or nuclear). The description of the environmental impacts of other technologies described in Section 9.2.2 is representative of the purchased electrical power alternative to the Units 3 and 4. Under the purchased power alternative, the environmental impacts of power production would still occur, but would be located elsewhere within the region or the Nation or in another country.

The Georgia Public Service Commission placed a cap on the amount of total generation capacity that can be met through purchased power contracts. The cap was set at 30 percent so that the state does not become overly reliant on purchased power **(GPSC 2004)**. Consequently, long-term electrical power purchase contracts could defer the need for additional generation capacity, but would not eliminate the need to construct baseload capacity.

Purchasing power from other utilities or power generators is not considered a reasonable or environmentally preferable alternative to the proposed project of large baseload capacity.

9.2.1.2 Reactivating or Extending Service Life of Existing Plants

The plants that would likely replace the proposed project would be coal or natural gas units. Coal and natural gas plants slated for retirement tend to be ones that are old enough to have difficulty in economically meeting today's air emissions limits. In the face of increasingly stringent environmental restrictions, delaying retirement, or reactivating plants in order to avoid the construction of a large baseload plant would require major construction to upgrade or replace plant components. As a result, the environmental impacts of a refurbishment scenario are bounded by the coal- and natural gas-fired alternatives evaluated in Section 9.2.2.

It is conceivable that another nuclear plant could be a potential alternative source by reactivation or license renewal. Of the three nuclear plants operated by SNC, two have received renewed operating licenses. SNC will submit an application for renewal of the operating licenses for VEGP in 2007 and this analysis assumes the continued operation of VEGP Units 1 and 2. Continued operation of a nuclear power plant would avoid the environmental impacts related to construction, so continued operation of a nuclear power plant would have fewer environmental impacts than construction of a new plant. However, continued operation of an existing nuclear plant does not provide additional generating capacity.

Therefore, given a real need for the proposed project, reactivation or extended service life for existing plants are not considered reasonable or environmentally preferable alternative energy sources.

9.2.1.3 Demand Side Management

Demand side management (DSM) is the practice of reducing customers' demand for energy through programs such as energy conservation, efficiency, and load management so that the need for additional generation capacity is eliminated or reduced. DSM can minimize environmental effects by avoiding the construction and operation of new generating facilities. Those impacts that would result from the construction of the proposed facility, or from the supply of the additional power through other means, would be avoided if DSM were sufficient to reduce the need for additional power.

Georgia and its electric utilities maintain a number of residential, commercial, and industrial programs to reduce both peak demands and daily energy consumption and continue to pursue additional opportunities for DSM.

For example, GPC, one of the co-owners of the proposed project, uses an assessment and screening methodology in its resource planning to identify DSM measures and conduct a qualitative review of each measure for applicability to the Company's customer base, climate, and to determine the measure's cost-effectiveness. In its most recent Integrated Resource Plan (IRP) filing, GPC evaluated a total of 266 residential DSM measures that provided potential energy savings through:

- increased energy efficiency for electric appliances, electric space cooling and heating equipment, and electric lighting;
- electric water heating measures; and
- heating and cooling savings resulting from improvements to the home's exterior shell.

GPC also evaluated 246 commercial and industrial (non-residential) DSM measures.

A qualitative evaluation was conducted to eliminate DSM measures that were not applicable to the GPC's customer base or climate. A total of 106 residential and 92 non-residential measures were passed from the qualitative screening analysis to the economic screening for cost-effectiveness analysis. The following cost-effectiveness tests were calculated for each measure: Participant's Test (PT), Rate Impact Measure (RIM) test, Total Resource Cost (TRC) test, and the Societal Cost Test (SCT). Measures that passed the TRC were eligible for consideration in DSM program development.

There were 9 residential and 2 non-residential demand-side measures that passed the RIM test. In all cases, those measures passing the RIM test either failed the TRC test, provided insufficient funds from benefits to cover the additional program administrative costs, provided insufficient funds (in the form of a rebate) from benefits to cover a meaningful portion of the measure's incremental costs to the participant, or were measures which had a very high Participant Test benefit/cost ratio (therefore, a high level of free-ridership[1]) thus eliminating the measures as cost effective resources when compared to the alternative supply-side resource. As a result of this, no new DSM programs were identified for development. Instead, GPC plans

[1] Electric utility DSM program "Freeriders" are participants who would have made program-supported changes even in the absence of an efficiency program. Freeriders impose administrative costs without providing benefits.

to continue its existing DSM programs and provide information to customers in their ongoing energy information program regarding the potential new measures which passed the RIM test.

State projections indicate that the available energy savings from DSM programs are insufficient to meet future demand. Energy conservation would offset only a small fraction of the energy needed in the region **(ICF 2005)**. Therefore, conservation alone would not be a reasonable alternative to the proposed project.

From an environmental impact standpoint, conservation could be considered in combination with other sources. Combinations of the viable alternatives, coal and natural gas, are addressed in Section 9.2.2.13. That evaluation concluded that such combinations would not result in an environmentally preferable alternative. The ability to offset some portion of required capacity is not expected to significantly reduce environmental impacts.

9.2.2 Alternatives That Require New Generating Capacity

9.2.2.1 Introduction

This section discusses possible alternatives requiring new generating capacity that could reasonably be expected to meet the additional generating capacity expected from the proposed project for the VEGP site. SNC's ESP application is premised on the installation of a facility that would primarily serve as a large baseload generator and that any feasible alternative would also need to be able to generate baseload power. In performing this evaluation, SNC determined that NUREG-1437 *Generic Environmental Impact Statement for License Renewal of Nuclear Plants,* 1999 (NUREG-1437) provides a useful analysis of alternative sources. SNC also analyzed integrated gasification combined cycle as an additional alternative. To generate the reasonable set of alternatives in NUREG-1437, the NRC included commonly known generation technologies and consulted various state energy plans to identify alternative generation sources typically being considered by state authorities across the country. From this review, the NRC established a reasonable set of alternative technologies for power generation. This section, as a starting point, considers (1) alternatives not yet commercially available, (2) fossil fuels, and (3) alternatives available within the Southeast.

During the lifetime of the proposed project, technology is expected to continue to improve operational and environmental performances. Thus, any analyses of future relative competitiveness or impacts are subject to that uncertainty. However, as in the case of alternatives evaluated in Section 9.2.1, SNC believes that sufficient knowledge is available to make a reasonable assessment.

The NRC considered these reasonable alternatives pursuant to its statutory responsibility under NEPA: wind, geothermal, oil, natural gas, hydropower, municipal solid wastes (MSW), coal, photovoltaic cells, solar thermal power, fuel cells, and biomass. Although NUREG-1437 is specific to license renewal, the alternatives analysis in it can be compared to the proposed action to determine if the alternative technology represents a reasonable alternative to the proposed action and satisfies the intent and requirements of 10 CFR 52 regarding an ESP application.

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

- The alternative energy conversion technology is developed, proven, and available in the relevant region within the life of the proposed project.
- The alternative energy source provides baseload generating capacity equivalent to the capacity needed, and to the same level of availability as the proposed VEGP units.
- 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 were considered technically or economically infeasible after a preliminary review and were not considered further. Alternatives that were considered to be technically and economically feasible were assessed in greater detail in Section 9.2.3.

SNC is considering a two unit plant using Westinghouse's Advanced Passive pressurized water reactor (AP1000) configuration for the VEGP site. For analysis purposes, SNC assumed a target value of 2,234 MWe for the net electrical output from a new two-unit facility at VEGP. This is a bounding value and is the basis for the alternatives analysis in the following paragraphs.

9.2.2.2 Wind

Wind power systems produce power intermittently because they are only operational when the wind is blowing at sufficient velocity and duration **(McGowan and Connors 2000)**. While recent advances in technology have improved wind turbine reliability, average annual capacity factors for wind power systems are relatively low (25 to 40 percent) **(McGowan and Connors 2000)** compared to 90 to 95 percent industry average for a baseload plant such as a nuclear plant.

The energy potential in the wind is expressed by wind generation classes ranging from 1 (least energetic) to 7 (most energetic). Wind regimes of Class 4 or higher are suitable for the advanced utility-scale wind turbine technology currently under development. Class 3 wind regimes may be suitable for future utility-scale technology. **(APPA 2004)**

According to the Wind Energy Resource Atlas of the United States **(NREL 1986)**, the Southeast region is a Class 1 area, and the only places in the region with wind regimes of Class 3 or higher are exposed ridge crests and mountain summits in the southern Appalachian Mountains.

Offshore wind energy potential is in the initial stages of investigation in the Southeast. Southern Company (parent company of GPC) and the Georgia Institute of Technology are collaborating on an offshore wind power project off the coast of Savannah, Georgia that could generate 10 MWe of power. The goal of the project is to determine if offshore wind power is a feasible and efficient renewal energy option for power generation. (Southern Company 2005)

Mountain ridges highly confined and represents an extremely small percentage of exposed land in the Southeast region **(NREL 1986)**. The total wind energy potential in the Southeast is approximately 171 MWe. The available land area within the Southeast with wind regimes of Class 3 or higher is approximately 35 square miles **(AWEA 2002)**.

Mountain ridge-top locations are remote, requiring incremental costs for developing access roads and power transmission infrastructure. Moreover, the hilly terrain increases the complexity of installation and the overall costs of wind energy due to the variable directional wind flows observed in mountainous regions compared to flatter landscapes. This variation tends to decrease the amount of usable energy that can be extracted from the wind, resulting in lower capacity factors. Reduced capacity factors increase overall cost per kilowatt-hour of energy generated. **(Bowers 2005)**

Use of mountain ridge tops is of additional concern in the Southeast due to aesthetic concerns. Southeastern mountain locations are enjoyed for recreation by a large percentage of the public. Scenic vistas are important and considerable public resistance to the use of mountainous areas for the location of wind farms in the Southeast is likely **(Bowers 2005)**. In addition, wind energy is at a minimum in the Southeast in the summer months **(Bowers 2005)**, but the co-owners are summer-peaking utilities. Consequently, wind generation requires redundant power generation resources to meet seasonal peak loads.

Estimates based on existing installations indicate that a utility-scale wind farm would require about 50 acres per MWe of installed capacity **(McGowan and Connors 2000)**. Wind farm facilities would occupy 3 to 5 percent of the wind farm's total acreage **(McGowan and Connors 2000)**. Assuming ideal wind conditions and a 35 percent capacity factor, a wind farm with a net output of 2,234 MWe would require about 319,143 acres (499 sq mi) of which about 9,574 acres (15 sq mi) would be occupied by turbines and support facilities. Based on the amount of land needed, the wind alternative would require a large green field site, which would result in a LARGE environmental impact.

Capital costs for wind energy systems range from $1,300 to $1,700 per kilowatt **(FPL Energy 2006)**. In areas with wind regimes of Class 4 or higher, the levelized cost of electricity produced by wind energy systems is 4.0 to 6.0 cents per kilowatt-hour **(FPSC&DEP 2003)**. Wind energy costs are expected to be higher in areas like the Southeast that have lower wind regimes **(FPSC&DEP 2003)**.

Wind energy is not a reasonable alternative because wind energy, due to its intermittent nature, cannot be relied upon for baseload power. Furthermore, there are insufficient wind resources in the relevant service area to offer a comparable generating capacity, and wind energy offers a distinct environmental disadvantage, relative to nuclear energy due to its LARGE land use impacts.

SNC has concluded that, due to the limited availability of area having suitable wind speeds, daily and seasonal variability of wind in the region, the amount of land needed, and aesthetic impacts, wind generation is not a reasonable alternative for baseload power in the Southeast.

9.2.2.3 Solar Technologies

There are two basic types of solar technologies that produce electrical power: photovoltaic and solar thermal power. Photovoltaics convert sunlight directly into electricity using semiconducting materials. Solar thermal power systems use mirrors to concentrate sunlight on a receiver holding a fluid or gas, heating it, and causing it to turn a turbine or push a piston coupled to an electric generator. **(Leitner and Owens 2003)**

Solar technologies produce more electricity on clear, sunny days with more intense sunlight and when the sunlight is at a more direct angle (i.e., when the sun is perpendicular to the collector). Cloudy days can significantly reduce output. To work effectively, solar installations require consistent levels of sunlight (solar insolation). **(Leitner and Owens 2003)**

Solar thermal systems can be equipped with a thermal storage tank to store hot heat transfer fluid, providing thermal energy storage. By using thermal storage, a solar thermal plant can provide dispatchable electric power. **(Black & Veatch 2005)**

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 unsuitable 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 6.0 kilowatt-hours per square meter per day or higher for solar thermal power systems **(Leitner 2002)**. The Southeast receives 3.5 to 5 kilowatt hours of solar radiation per square meter per day **(NREL 2005)**.

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. **(Leitner 2002)**

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 insulation and type of plant, but is about 8 acres per megawatt for photovoltaic systems and 3.8 acres per megawatt for solar thermal power plants **(Leitner 2002)**. Assuming capacity factors of 24 percent for photovoltaics and 32 percent for solar thermal power, facilities having 2,234 MWe net capacity are estimated to require 74,467 acres (116 sq mi), if powered by photovoltaic cells, and 26,529 acres (41 sq mi), if powered by solar thermal power.

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 $3,600 to $8,050 per kilowatt and capital costs for solar thermal installations range from $2,700 to $4,600 per kilowatt. Recent estimates indicate that in areas with good solar insolation, the levelized cost of electricity produced by photovoltaic cells is 19.4 to 47.4 cents per kilowatt-hour, and electricity from solar thermal systems can be produced for a cost of 10.8 to 18.7 cents per kilowatt-hour. Solar energy costs are expected to be much higher in areas like the Southeast that have lower solar insolation. **(FPSC&DEP 2003)**

SNC has concluded that solar energy is not a reasonable alternative because solar energy, due to its intermittent nature, cannot be relied upon for baseload power. Furthermore, SNC finds that there are insufficient solar resources in the relevant service area to offer a comparable generating capacity, solar energy generating costs exceed nuclear power, and solar energy offers a distinct environmental disadvantage, relative to nuclear energy due to its LARGE land use impacts.

Solar-powered technologies do not currently compete with conventional fossil-fueled technologies in grid-connected applications due to higher capital costs per kW of capacity. Southern Company has evaluated numerous solar options over the past 20 years. Data derived from these technology evaluations, coupled with high capital costs, indicate that solar power is not practical as a utility-scale power generation option. **(Bowers 2005)**

SNC has concluded that, due to the high cost, low capacity factors, lack of sufficient incident solar radiation, and the substantial amount of land needed to produce the desired output, solar energy is not practical as a utility-scale power generation option.

9.2.2.4 Hydroelectric power

Hydroelectric power is a fully commercialized technology. About 5 percent of the electric generating capacity in the Southeast is hydroelectric **(EIA 2004a)**. Hydropower's percentage of U.S. generating capacity is expected to decline because hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and destruction of natural river courses **(EIA 2005)**.

According to the U.S. Hydropower Resource Assessment the undeveloped hydropower potential in the Southeast is approximately 1,066 MW. Studies have concluded that there are no remaining sites in the Southeast that would be environmentally suitable for a large hydroelectric facility **(Conner et al. 1998)**.

Land use for a large scale hydropower facility is estimated to be quite large. NUREG-1437 estimates land use of 1,600 square miles per 1,000 MWe generated by hydropower. Based on this estimate, a 2,234 MWe project would require flooding more than 3,574 sq mi resulting in a LARGE impact on land use. Further, operation of a hydroelectric facility would alter aquatic habitats above and below the dam, which would adversely impact aquatic species.

Recent estimates indicate that capital costs for a hydropower facility range from $1,300 to $5,980 per kilowatt. The levelized cost of electricity produced from new hydropower facilities is estimated at 4.0 to 14.0 cents per kilowatt-hour. **(FPSC&DEP 2003)**

SNC has concluded that, due to the lack of suitable sites in the Southeast and the amount of land needed, in addition to the adverse environmental impacts, hydropower is not a reasonable alternative for baseload power.

9.2.2.5 Geothermal

Geothermal energy is a proven resource for power generation. Geothermal power plants use naturally heated fluids as an energy source for electricity production. To produce electric power, underground high-temperature reservoirs of steam or hot water are tapped by wells and the steam rotates turbines that generate electricity. Typically, water is then returned to the ground to recharge the reservoir. **(NREL 1997)**

Geothermal energy can achieve average capacity factors of 95 percent and can be used for baseload power where this type of energy source is available **(NREL 1997)**. Widespread application of geothermal energy is constrained by the geographic availability of the resource **(NREL 1997)**. In the U. S., high-temperature hydrothermal reservoirs are located in the western states, Alaska and Hawaii. There are no known high-temperature geothermal sites in the Southeast. **(SMU 2004)**

Geothermal power plants require relatively little land. An entire geothermal field uses 1 to 8 acres per MWe **(Shibaki 2003)**. Assuming a 95 percent capacity factor, a geothermal power plant with a net output of 2,234 MWe would require at least 2,352 acres (4 sq mi).

The major environmental concerns associated with geothermal development are the release of small quantities of carbon dioxide and hydrogen sulfide, noise, and disposal of sludge and spent geothermal fluids **(Shibaki 2003, NREL 1997)**. Subsidence and reservoir depletion may be a concern if withdrawal of geothermal fluids exceeds natural recharge or injection **(Shibaki 2003)**.

Recent estimates indicate that capital costs for geothermal power plants range from $2,560 to $3,840 per kilowatt. The levelized cost of electricity produced from geothermal power plants is estimated to be in the range of 4.7 to 7.6 cents per kilowatt-hour. **(CEC 2003)**

SNC has concluded that, due to the lack of high-temperature geothermal reservoirs, geothermal power is not a reasonable alternative for baseload power in the relevant service area.

9.2.2.6 Biomass Related Fuels

Electric power generation from combustion of biomass has been demonstrated and offers a reliable source of renewable energy. Because biomass technologies employ combustion processes to produce electricity, they can generate electricity at any time. Biomass fired facilities generate electricity using commercially available equipment and well-established technology.

The Southeast does have abundant biomass resources in the form of wood waste and other agricultural residues. Over 22 million tons of biomass with an average heat content of 13 million BTU per ton is produced each year in Georgia alone **(Curtis et al. 2003)**.

Energy crops such as switchgrass could be grown to ensure a reliable supply of biomass feedstocks for generation of electricity. The environmental impacts from converting large tracts of land to production of energy crops may include detrimental effects on wildlife habitat and biodiversity, reduced soil fertility, increased erosion, and reduced water quality. The net environmental impacts would depend on previous land use, the particular energy crop, and how the crop is managed. Displacing natural land cover, such as forests and wetlands, with energy crops would likely have negative impacts.

Nearly all of the biomass-energy-using electricity generation facilities in the United States use steam turbine conversion technology. The technology is relatively simple to operate and it 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. Therefore, the technology is relegated to applications where there is a readily available supply of low-, zero-, or negative-cost delivered feedstocks.

Recent estimates indicate that capital costs for biomass power plants range from $2,000 to $3,450 per kilowatt. The levelized cost of electricity produced from biomass power plants is 6.3 to 11.8 cents per kilowatt-hour. **(FPSC&DEP 2003)**

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 co-firing with coal. For more than 10 years, Southern Company has been evaluating co-firing biomass fuels in existing coal-fired generating plants. While Southern Company has proven that biomass can be successfully co-fired with coal, it is not without technical challenges. Biomass is much less dense than coal, requiring a large volume of fuel to be handled. Larger areas of biomass storage and additional handling are required to accommodate the lower-density materials. Moreover, the ash residue left from combusting biomass contains alkali and alkaline earth elements, such as sodium, potassium and calcium. These compounds bind irreversibly with the catalysts used in selective catalytic reduction (SCR) reactors that have been installed on coal-fired generating plants. These compounds can lead to increased catalyst plugging and cause deactivation of SCR catalysts, thus reducing or eliminating the ability of this technology to reduce NOx emissions. **(Bowers 2005)**

SNC has concluded that, 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.

9.2.2.7 Municipal Solid Waste

Municipal solid waste (MSW) can be directly combusted in waste-to-energy facilities to generate electricity. At the power plant, MSW would be unloaded from collection trucks and shredded or processed to ease handling. Recyclable materials would be set aside, and the remaining waste would be fed into a combustion chamber to be burned. The heat released from burning the MSW would be utilized to produce steam, which turns a steam turbine to generate electricity.

The initial capital costs for MSW plants are greater than for comparable steam turbine technology at biomass-fired facilities due to the need for specialized waste separation and handling equipment. Recent estimates indicate that capital costs for MSW plants range from $2,500 to $4,600 per kilowatt. The levelized cost of electricity produced from MSW plants is 3.5 to 15.3 cents per kilowatt-hour. **(FPSC&DEP 2003)**

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 **(EPA 2006)**. It is unlikely, however, that many landfills will begin converting waste to energy due to the numerous obstacles and factors that may limit the growth in MSW power generation. Chief among them are environmental regulations and public opposition to siting MSW facilities near feedstock supplies.

Because ash and other residues from MSW operations may contain toxic materials, the power plant wastes must be disposed of in an environmentally safe manner to prevent toxic substances from migrating (leaching) into groundwater supplies. 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. **(EPA 2006)**

The overall level of construction impacts from a waste-fired plant should be approximately the same as that for a conventional coal-fired plant **(FPSC&DEP 2003)**. The air emission profile and other operational impacts (including impacts on the aquatic environment, air, and waste disposal) for a MSW plant would also be similar to a conventional fossil-fueled unit **(FPSC&DEP 2003)**. Some of these impacts would be small, but still larger than the proposed action.

SNC has concluded that, 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.

9.2.2.8 Petroleum Liquids

The Southeast has several petroleum-fired units (including units fired by distillate fuel oil, residential fuel oil, petroleum coke, jet fuel, kerosene, other petroleum and waste oil); however, they produce less than one percent of the region's electricity. While capital costs for new petroleum-fired plants would be similar to the cost of a new gas-fired plant, petroleum-fired operation is more expensive due to the high cost of petroleum. Recent estimates indicate that the levelized cost of electricity produced by petroleum-fired operation is 6.1 to 6.7 cents per kilowatt-hour **(DeLaquil, et al. 2005)**. Future increases in petroleum prices are expected to make petroleum-fired generation increasingly more expensive relative to other alternatives.

The high cost of petroleum has prompted a steady decline in its use for electricity generation in recent decades (EIA 2005b) and no new oil-fired units have been constructed in the U. S. since 1981 **(Cole 2003)**. From a peak of 365 million MWh in 1978 (17 percent of total U.S. net electricity generation in that year), petroleum accounted for just 118 million MWh – three percent – of net electricity generated in 2004 **(EIA 2005b)**. With the peak of domestic petroleum production in 1970, rising imports since then, increasing global prices over the last few years and the prospect for more of the same, plus competition for this valuable fuel commodity not only from the transportation sector but also from the petrochemical industry, it is likely that the downward trend for using petroleum to generate electricity will continue.

Also, construction and operation of a petroleum-fired plant would have identifiable environmental impacts. For example, NUREG-1437 estimates that construction of a 1,000-MWe petroleum-fired plant would require about 120 acres. Assuming a 95 percent capacity factor, a petroleum-fired power plant with a net output of 2,234 MWe would require about 282 acres. 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. **(NUREG-1437)**

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.

9.2.2.9 Fuel Cells

Fuel cell power plants are in the initial stages of commercialization. While more than 650 large stationary fuel cell systems have been built and operated worldwide, the global stationary fuel cell electricity generating capacity in 2003 was only 125 MWe **(Fuel Cell Today 2003)**. The production capability of the largest stationery fuel cell manufacturer is 50 MWe per year **(CSFCC 2002)**. The largest stationary fuel cell power plant yet built is only 11 MWe **(Fuel Cell Today 2003)**.

Fuel cells are not cost effective when compared with other generation technologies, both renewable and fossil-based. Recent estimates indicate that the levelized cost of electricity produced by fuel cells is 9.7 to 43.5 cents per kilowatt-hour and capital costs for fuel cell installations range from $1,730 to $4,965 per kilowatt **(CEC 2003)**. Recent estimates suggest that manufacturers would need to at least triple their production capacity to achieve a competitive price of $1,500 to $2,000 per kilowatt **(Shipley and Elliott 2004)**.

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

9.2.2.10 Pulverized Coal

Pulverized coal-fired steam electric plants provide the majority of electric generating capacity in the U.S., accounting for about 51 percent of the electricity generated and about 33 percent of electric generating capacity in 2003 **(EIA 2004b)**. In the Southeast, pulverized coal-fired plants provide about 55 percent of the electricity generated and about 37 percent of its electric generating capacity **(EIA 2004a)**. The environmental impacts of constructing a typical pulverized coal-fired steam plant are well known because coal is the most prevalent type of central generating technology in the U.S.

There are two primary technologies identified for generating electrical energy from pulverized coal: conventional pulverized coal boiler and fluidized bed combustion (FBC). As part of the pulverized coal alternatives evaluation, both technologies (conventional and FBC) were evaluated.

In conventional pulverized coal-fired plants, pulverized coal is blown into a combustion chamber of a boiler where it is combusted. The hot gases and heat energy from the combustion process convert water in the boiler into steam. This high-pressure steam is then passed into a steam turbine to produce electricity. Flue gas is transferred from the steam generator, through a selective catalytic reducer (SCR) for nitrogen oxides (NOx) reduction and into an air heater. From the air heater the flue gas flows to a sulfur dioxide (SO_2) scrubber system and a particulate removal system.

Conventional pulverized coal-fired boilers have been built to match steam turbines which have outputs between 50 and 1300 MWe. In order to take advantage of the economies of scale, most new units are rated at over 300 MWe, but there are relatively few really large ones with outputs from a single boiler/turbine combination of over 700 MWe. This is because of the substantial effects such units have on the distribution system if they should 'trip out' for any reason, or be unexpectedly shut down. (Burns & McDonnell 2005)

FBC is an advanced electric power generation process that minimizes the formation of gaseous pollutants by 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 SO2 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. NOx 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 NOx is formed **(DOE 2003).**

Currently, FBC units are limited to a maximum size of approximately 265 MW **(DOE 2003)**. Although a multi-unit facility could be built, this would not be able to benefit from the economies of scale associated with a 2,234 MW project. Also, because of the lower operating temperature of the FBC system, it doesn’t achieve the higher efficiency levels achieved by 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 boiler (PFBC) 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 boilers using the PFBC technology will be able to generate 50 percent more electricity from coal than a regular power plant from the same amount of coal **(DOE 2003)**. The PFBC technology is currently in the demonstration phase and is not a feasible alternative for the proposed project.

SNC defined the pulverized coal-fired alternative as consisting of four conventional boiler units, each with a net capacity of 530-MWe for a combined capacity of 2,120 MWe. SNC chose this configuration to be equivalent to the gas-fired alternative described below. This equivalency makes impact characteristics most comparable, facilitating impact analysis. Table 9.2-1 describes assumed basic operational characteristics of the coal-fired units. SNC based its emission control technology and percent-control assumptions on alternatives that the EPA has identified as being available for minimizing emissions (EPA 1998). For the purposes of analysis, SNC has assumed that coal and limestone (calcium oxide) would be delivered by rail after upgrading the existing rail spur into VEGP.

Recent estimates indicate that capital costs for conventional pulverized coal-fired power plants range from $1,094 to $1,169 per kilowatt. The levelized cost of electricity produced from pulverized coal-fired power plants is 3.3 to 4.1 cents per kilowatt-hour. **(University of Chicago 2004)**

The U.S. has abundant low-cost coal reserves, and the price of coal for electric generation is likely to increase at a relatively slow rate. Pulverized coal-fired plants are likely to continue to be a reliable energy source well into the future, assuming environmental constraints do not cause the gradual substitution of other fuels. Even with recent environmental legislation, new coal capacity is expected to be an affordable technology for reliable, near-term development. **(EIA 2005)**

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 Section 9.2.3.

9.2.2.11 Integrated Gasification Combined Cycle (IGCC)

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

The IGCC alternative generates substantially less solid waste than the pulverized coal-fired alternative. The largest solid waste stream produced by IGCC installations is slag, a black, glassy, sand-like material that is potentially a marketable byproduct. Slag production is a function of 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.

At present however, IGCC technology still has insufficient 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 integration of coal gasification with a combined cycle power block to produce commercial electricity as a primary output is relatively new and 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, coal properties and their impact on IGCC design, efficiency, economics, etc. However, system reliability is still relatively lower than conventional pulverized coal-fired power plants. There are problems with the integration between gasification and power production as well. For example, if there is a problem with gas cleaning, uncleaned gas can cause various damages to the gas turbine. **(Rardin et al. 2005)**

To advance the technology, Southern Company and the Orlando Utilities Commission are building a $557 million advanced IGCC facility in Central Florida as part of the U.S. Department of Energy's (DOE) Clean Coal Power Initiative. The 285 MW plant will be built at OUC's Stanton Energy Center near Orlando and will gasify coal using state-of-the-art emissions controls. The DOE will contribute $235 million and OUC and Southern Company will contribute $322 million. **(OUC 2004)**

Overall, IGCC plants are estimated to be about 15 to 20 percent more expensive than comparably sized pulverized coal plants, due in part to the coal gasifier and other specialized equipment. Recent estimates indicate that overnight capital costs for coal-fired IGCC power plants range from $1,400 to $1,800 per kilowatt **(EIA 2005a)**. The production cost of electricity from a coal-based IGCC power plant is estimated to be about 3.3 to 4.5 cents per kilowatt-hour.

Southern Company provides wholesale power in Florida, and the Orlando IGCC project has commercial, availability and technical risk factors that may be appropriate for wholesale power producers, but are not appropriate for a traditional cost-of-service utilities. In addition, risks for the Orlando project are mitigated because it is only a 285 MW project; Orlando Utility Commission is a participant, and $235 million in DOE co-funding was secured. These mitigating factors are not available to the co-owners of the proposed project.

Because IGCC technology currently is not cost-effective and requires further research to achieve an acceptable level of reliability, an IGCC facility is not a reasonable alternative to the proposed project.

9.2.2.12 Natural Gas

SNC has chosen to evaluate gas-fired generation, using combined-cycle turbines, because it has determined that the technology is mature, economical, and feasible. Recent estimates indicate that capital costs for gas-fired power plants range from $466 to $590 per kilowatt. The levelized cost of electricity produced from gas-fired power plants is 3.9 to 4.4 cents per kilowatt-hour. **(University of Chicago 2004)**

Existing manufacturers' standard-sized units include a gas-fired combined-cycle plant of 530-MWe net capacity, consisting of two 184-MWe gas turbines (e.g., General Electric Frame 7FA) and 182 MWe of heat recovery capacity. SNC assumed four 530-MWe units, having a total capacity of 2,120 MWe, as the gas-fired alternative at the VEGP 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 9.2-2 describes assumed basic operational characteristics of the gas-fired units. As for the coal-fired alternative, SNC based its emission control technology and percent-control assumptions on alternatives that the EPA has identified as being available for minimizing emissions **(EPA 2000)**. For the purposes of analysis, SNC 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 Section 9.2.3.

9.2.2.13 Combination of Alternatives

Even though individual alternatives might not be sufficient on their own to provide 2,234 MWe capacity due to the small size of the resource or lack of cost-effective opportunities, it is conceivable that a mix of alternatives might be cost effective. The possible combinations of fuel types to generate 2,234 MWe is large, and SNC has not exhaustively evaluated each combination. However, SNC reviewed combinations that due to technological maturity, economics, and other factors, could be reasonable alternatives to the proposed project. Two of these combinations of alternatives are addressed below.

As discussed in Section 9.2.2.2, wind energy, as a stand-alone technology, is not a feasible alternative for baseload power. However, it is conceivable that a mix of wind energy and gas-fired combined cycle units could provide baseload power. For example, the 2,234 MWe target capacity could be met by developing a 120 MWe wind farm, along with four 530 MWe natural gas combined-cycle units. When operating, a combined cycle plant can "follow" the wind load by ramping up and down quickly. When the wind is blowing hard, the combined cycle plant can be ramped down; when the wind is not blowing or is blowing too softly to turn the wind turbines, the combined cycle plant can be ramped up. The impacts associated with the wind portion of the alternative – land use impacts, noise impacts, visual impacts, impacts on birds, etc. – would be more than the stand alone natural gas alternative; therefore, the combination would have greater impacts than a single fuel type. The environmental impacts associated with the combined alternative would compare unfavorably with the proposed project.

If the hypothetical mix included coal-fired generation, the environmental impacts associated with construction (land use, ecology) and air quality would be expected to be greater than that of the proposed project. For example, the 2,234 MWe target capacity could be met by building two 530 MWe coal-fired units along with two 530 MWe natural gas combined-cycle units. The shortfall in capacity could be replaced by other methods, such as purchasing power. This combination coal-gas facility would require approximately 428 acres for permanent structures. As discussed in Section 4.1.1, construction of the proposed project would require about 500 acres of which about 310 acres would be required for permanent facilities. Air quality impacts for two 530 MWe coal-fired units would compare unfavorably with the proposed project due to the large amount of combustion products from coal-fired generation. The additional impact resulting from the two natural gas units would only strengthen the overall favorable position of the proposed project.

Other combinations of the various alternatives are not discussed here. In general, poor annual average capacity factors, higher environmental impacts (land use, ecological, air quality), immature technologies, and a lack of cost-competitiveness are not expected to lead to a viable, competitive combination of alternatives which would be either environmentally equivalent or preferable.

9.2.3 Assessment of Reasonable Alternative Energy Sources and Systems

This section evaluates the environmental impacts from what SNC has determined to be reasonable alternatives to the proposed project: pulverized coal-fired generation and gas-fired generation.

SNC 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 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

SMALL - Environmental effects 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 effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.

LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

In accordance with NEPA practices, SNC considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are small receive less mitigative consideration than impacts that are large).

9.2.3.1 Pulverized Coal-Fired Generation

SNC has reviewed the NRC analysis of environmental impacts from coal-fired generation alternatives in NUREG-1437 and found NRC's analysis to be reasonable. Construction impacts could be substantial, due in part to the large land area required (which can result in natural habitat loss) and the large workforce needed. 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 coal-fired alternative defined by SNC in Section 9.2.2.10 would be located at the VEGP site.

9.2.3.1.1 Air Quality

Air quality impacts of coal-fired generation are considerably different from those of nuclear power. A coal-fired plant would emit sulfur dioxide (SO_2, as SOx surrogate), oxides of nitrogen (NOx), particulate matter (PM), and carbon monoxide (CO), all of which are regulated pollutants. As Section 9.2.2.10 indicates, SNC has assumed a plant design that would minimize air emissions through a combination of boiler technology and post combustion pollutant removal. SNC estimates the coal-fired alternative emissions to be as follows:

SO_2 = 5,587 tons per year

NOx = 1,815 tons per year

CO = 1,815 tons per year

PM:

PM_{10} (particulates having a diameter of less than 10 microns) = 91 tons per year

$PM_{2.5}$ (particulates having a diameter of less than 2.5 microns) = 0.39 tons per year

The acid rain requirements of the Clean Air Act Amendments capped the nation's SO_2 emissions from power plants. Each company with fossil-fuel-fired units was allocated SO_2 allowances. To be in compliance with the Act, the companies must hold enough allowances to cover their annual SO_2 emissions. In 2002, emissions of SO_2 and NOx from Georgia's generators ranked 5th and 10th highest nationally, respectively **(EIA 2004a)**. Both SO_2 and NOx emissions would increase if a new coal-fired plant were operated at VEGP. To operate a fossil-fuel burning plant, Southern Company would have to purchase SO_2 allowances from the open market or shut down existing fossil-fired capacity and apply the credits from that plant to the new one.

In October 1998, EPA promulgated the NOx State Implementation Plan Call regulation that requires 22 states, including Georgia, to reduce their NOx emissions by over 30 percent to address national ozone transport. The regulation imposes a NOx "budget" to limit the NOx emissions from each state. In October 2004, the EPA announced that it would stay implementation of the rule as it relates to Georgia, while it initiates rulemakings to address issues raised in a petition for reconsideration filed by a coalition of Georgia industries. If the NOx reduction rules are implemented in Georgia, each electrical generating unit would need to hold enough NOx credits to cover its annual NOx emissions.

In March 2005, EPA issued the final Clean Air Interstate Rule which addresses power plant SO_2 and NOx emissions that contribute to non-attainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including each of the states within the region of interest, are subject to the requirements of the rule. The rule calls for further reductions of NOx and SO_2 emissions from power plants. These reductions can be accomplished by the installation of additional emission controls at existing coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The likelihood of buying allowances for a new facility would be extremely remote, if possible at all. The coal-fired alternative, while possible, would not be economically feasible because there are no mitigating efforts (like emissions trading) to make the alternative worthwhile. In addition, emission credits' trading generally applies to non-attainment areas. The site that SNC has chosen as the preferred site is located in an attainment area, making emission credit trading not effective as a mitigation technique.

Air impacts from fossil fuel generation would be substantial. Adverse human health effects from coal combustion have led to important federal legislation in recent years and public health risks, such as cancer and emphysema, have been associated with coal combustion. Global warming and acid rain are also potential impacts. SNC concludes that federal legislation and concerns such as global warming and acid rain are indications of concerns about destabilizing important attributes of air resources. SO_2 emission allowances, NOx emission allowances, low NOx burners, overfire air, fabric filters or electrostatic precipitators, and scrubbers are regulatorily imposed mitigation measures. As such, SNC concludes for purposes of this alternatives analysis that the coal-fired alternative may have MODERATE impacts on air quality: the impacts may be noticeable, but would not destabilize air quality in the area due to the use of mitigating technologies.

9.2.3.1.2 Waste Management

The coal-fired alternative would generate substantial solid waste. The coal-fired plant, using coal having an ash content of 10.87 percent, would annually consume approximately 7,260,000 tons of coal. Particulate control equipment would collect most (99.9 percent) of this ash, approximately 788,000 tons per year. Southern Company recycles 35 percent of its coal ash **(Southern Company 2003)**. Assuming continuation of this waste mitigation measure, the coal-fired alternative would generate approximately 512,500 tons of ash per year for disposal.

SOx-control equipment, annually using approximately 183,000 tons of limestone, would generate another 218,000 tons per year of waste in the form of scrubber sludge. SNC estimates that ash and scrubber waste disposal over a 40-yr plant life would require approximately 406 acres.

With proper placement of the facility, coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. There would be space within VEGP property for this disposal. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, SNC believes that waste disposal for the coal-fired alternative would have MODERATE impacts; the impacts of increased waste disposal would be clearly noticeable, but would not destabilize any important resource and further mitigation of the impact would be unwarranted.

9.2.3.1.3 Other Impacts

Construction of the power block and coal storage area would impact approximately 697 acres of land and associated terrestrial habitat. Because most of this construction would be in previously disturbed areas, impacts would be minimal. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion, sedimentation, and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. It is assumed that construction debris from clearing and grubbing could be disposed of on site and municipal waste disposal capacity would be available. Socioeconomic impacts would result from the approximately 200 people needed to operate the coal-fired facility. SNC believes that these impacts would be SMALL due to the mitigating influence of the site's proximity to the surrounding population area. Cultural resource impacts would be unlikely due to the previously disturbed nature of the site, and could be, if needed, minimized by survey and recovery techniques.

Impacts to aquatic resources and water quality would be minimized due to the plant's use of cooling towers and SNC believes that these impacts would be SMALL. The new stacks, boilers, and rail deliveries would be an incremental addition to the visual impact from existing VEGP structures and operations. Coal delivery would add noise and transportation impacts associated with unit-train traffic.

SNC believes that other construction and operation impacts would be SMALL. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved. Due to the minor nature of these impacts, mitigation would not be warranted beyond that mentioned.

9.2.3.1.4 Design Alternatives

The VEGP location lends itself to coal delivery by rail. Section 9.4.1 analyzes alternative designs for the VEGP units 3 and 4 heat dissipation systems. Based on this analysis, SNC 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-foot-high mechanical towers or 600-foot-high natural draft towers would introduce a visual impact.

9.2.3.2 Natural Gas Generation

SNC has reviewed the NRC analysis of environmental impacts from gas-fired generation alternatives in NUREG-1437 that focused on combined-cycle plants and found it to be reasonable. Section 9.2.2.12 presents SNC's reasons for defining the gas-fired generation alternative as a combined-cycle plant at VEGP. Land-use impacts from gas-fired units would be less than those of the coal-fired alternative. Reduced land requirements, due to construction on the existing site and a smaller facility footprint would reduce impacts to ecological, aesthetic, and cultural resources as well. As discussed under "Other Impacts," an incremental increase in the workforce could have socioeconomic impacts. Human health effects associated with air emissions would be of concern, but the effect would be less than those of coal-fired generation.

The gas-fired alternative defined by SNC in Section 9.2.2.12 would be located at the VEGP site.

9.2.3.2.1 Air Quality

Natural gas is a relatively clean-burning fossil fuel. Also, because the heat recovery steam generator does not receive supplemental fuel, the combined-cycle operation is highly efficient (56 percent vs. 33 percent for the coal-fired alternative). Therefore, the gas-fired alternative would release similar types of emissions, but in lesser quantities than the coal-fired alternative. Control technology for gas-fired turbines focuses on the reduction of NOx emissions. SNC estimates the gas-fired alternative emissions to be as follows:

SO_2 = 169 tons per year

NOx = 540 tons per year

CO = 112 tons per year

PM = 94 tons per year (all particulates are $PM_{2.5}$)

The Section 9.2.3.1 discussion of regional air quality, Clean Air Act requirements, and the NOx State Implementation Plan Call is also applicable to the gas-fired generation alternative. NOx effects on ozone levels, SO_2 allowances, and NOx allowances could be issues of concern for gas-fired combustion. SNC concludes that emissions from a gas-fired alternative would be detectable, but they would not noticeably alter local air quality. Air quality impacts would therefore be SMALL, but substantially larger than those of nuclear generation.

9.2.3.2.2 Waste Management

Gas-fired generation would result in almost no waste generation, producing minor (if any) impacts. SNC concludes that gas-fired generation waste management impacts would be SMALL.

9.2.3.2.3 Other Impacts

Similar to the coal-fired alternative, the ability to construct the gas-fired alternative at VEGP would reduce construction-related impacts relative to construction on a greenfield site.

There are two natural gas pipelines within 20 miles of VEGP that could be used to supply natural gas to a gas-fired facility at VEGP. One pipeline, located near Waynesboro, Georgia, approximately 19 miles southwest of VEGP, includes a 14-inch diameter line and a 20-inch diameter line. The other pipeline, located near Augusta, Georgia, approximately 20 miles northwest of VEGP, consists of two 16-inch diameter lines.

To the extent practicable, SNC would route the gas supply pipeline along previously disturbed rights-of-way to minimize impacts. However, this would still be a costly (i.e., approximately

$1 million/mile) and potentially controversial action with ecological impacts from installation of a minimum of 20 miles of buried 16-inch gas pipeline to the VEGP site. An easement encompassing approximately 242 acres would need to be graded to permit the installation of the pipeline. Construction impacts would be minimized through the application of best management practices that minimize soil loss and restore vegetation immediately after the excavation is backfilled. Construction would result in the loss of some less mobile animals (e.g., moles and salamanders). Because these animals are common throughout the area, SNC expects negligible reduction in their population as a result of construction. SNC does not expect that installation of a gas pipeline would create a long-term reduction in the local or regional diversity of plants and animals. In theory, impacts from construction of a pipeline could be reduced or eliminated by locating the gas-fired plant at a site adjacent to an existing pipeline.

Construction of the combined cycle plant would impact approximately 159 acres of land. This much previously disturbed acreage is available at VEGP, reducing loss of terrestrial habitat. Aesthetic impacts, erosion and sedimentation buildup, fugitive dust, and construction debris impacts would be similar to the coal-fired alternative, but smaller because of the reduced site size. Socioeconomic impacts would result from the approximately 88 people needed to operate the gas-fired facility. SNC believes that these impacts would be SMALL due to the mitigating influence of the site's proximity to the surrounding population area.

9.2.3.2.4 Design Alternatives

Section 9.4.1 analyzes alternative designs for the VEGP Units 3 and 4 heat dissipation systems. Based on this analysis, SNC assumed that cooling towers would be used for the gas-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-foot-high mechanical towers or 600-foot-high natural draft towers would introduce visual impacts.

9.2.4 Conclusion

As shown in detail in Table 9.2-3, based on environmental impacts, SNC has determined that neither a coal-fired nor a gas-fired plant would provide an appreciable reduction in overall environmental impact relative to a nuclear plant. Furthermore, each of these types of plants would entail a significantly greater relative environmental impact on air quality than would the proposed project. Therefore, SNC concludes that neither a coal-fired or gas-fired plant would be environmentally preferable to the proposed project.

Table 9.2-1 Coal-Fired Alternative

Characteristic	***Basis***
Unit size = 530 MWe ISO rating net[a]	Assumed
Unit size = 562 MWe ISO rating gross[a]	Calculated based on 6 percent onsite power
Number of units = 4	Assumed
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions **(EPA 1998)**
Fuel type = bituminous, pulverized coal	Typical for coal used in Georgia
Fuel heating value = 11,754 Btu/lb	2001 value for coal used in Georgia **(EIA 2004c)**
Fuel ash content by weight = 10.87 percent	2001 value for coal used in Georgia **(EIA 2004c)**
Fuel sulfur content by weight = 0.81 percent	2001 value for coal used in Georgia **(EIA 2004c)**
Uncontrolled NOx emission = 10 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS **(EPA 1998)**
Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS **(EPA 1998)**
Heat rate = 10,200 Btu/kWh	Typical for coal-fired, single-cycle steam turbines **(EIA 2002)**
Capacity factor = 0.85	Typical for large coal-fired units
NOx control = low NOx burners, overfire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NOx emissions **(EPA 1998)**
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions (EPA 1998)
SOx control = Wet scrubber - limestone (95 percent removal efficiency)	Best available for minimizing SOx emissions **(EPA 1998)**

a. The difference between "net" and "gross" is electricity consumed onsite.

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
kWh	=	kilowatt hour
NSPS	=	New Source Performance Standard
lb	=	pound
MWe	=	megawatt
NOx	=	nitrogen oxides
SOx	=	oxides of sulfur
≤	=	less than or equal to

Table 9.2-2 Gas-Fired Alternative

Characteristic	***Basis***
Unit size = 530 MWe ISO rating net:[a]	Assumed **(Chase and Kehoe 2000)**
Unit size = 551 MWe ISO rating gross[a]	Calculated based on 4 percent onsite power
Number of units = 4	Assumed
Fuel type = natural gas	Assumed
Fuel heating value = 1,025 Btu/ft^3	2001 value for gas used in Georgia **(EIA 2004c)**
Fuel SOx content = 0.0034 lb/MMBtu	EPA 2000, Table 3.1-2a
NOx control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NOx emissions **(EPA 2000)**
Fuel NOx content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas fired units with water injection **(EPA 2000)**
Fuel CO content = 0.00226 lb/MMBtu	Typical for large SCR-controlled gas fired units **(EPA 2000)**
Fuel $PM_{2.5}$ content [b]= 0.0019 lb/MMBtu	EPA 2000, Table 3.1-2a
Heat rate = 6,040 Btu/kWh	**(Chase and Kehoe 2000)**
Capacity factor = 0.85	Assumed based on performance of modern plants

[a] The difference between “net” and “gross” is electricity consumed onsite.
[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
MM	=	million
MWe	=	megawatt
NOx	=	nitrogen oxides
PM2.5	=	particulates having diameter of 2.5 microns or less
≤	=	less than or equal to

Table 9.2-3 Comparison of Environmental Impacts of Alternative Energy Sources to a New Nuclear Unit

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

a. Impacts would be SMALL, but substantially larger than nuclear generation.
b. Coal deliveries by rail would add visual and noise impacts associated with unit-train traffic.

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9.3 Alternative Sites

As required by 10 CFR 52.17(a)(2), this section provides an analysis of alternatives to the proposed ESP site for the construction and operation of the proposed project. NEPA mandates that reasonable alternatives to an action be evaluated. Consistent with this requirement, the site selection process focused on those alternative sites that are considered to be reasonable with respect to the purpose of this application for an ESP. The objective of this evaluation is to verify there is no "obviously superior site" for the eventual construction and operation of the proposed project.

The traditional way of reviewing alternative sites has changed because existing nuclear sites capable of supporting additional units can be included in the mix of alternatives. Existing sites offer decades of environmental and operational information about the impacts of a nuclear plant on the environment. These sites are licensed nuclear facilities, thus, the NRC has found them to be acceptable. The NRC recognizes (in NUREG-1555, Section 9.3(III)(8)) that proposed sites may not be selected as a result of a systematic review:

> *"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 plants proposed to be constructed on the site of an existing nuclear power plant previously found acceptable on the basis of a NEPA review and/or demonstrated to be environmentally satisfactory on the basis of operating experience, and sites assigned or allocated to an applicant by a State government from a list of State-approved power-plant sites. For such cases, the reviewer should analyze the applicant's site-selection process only as it applies to candidate sites other than the proposed site, and the site-comparison process may be restricted to a site-by-site comparison of these candidates with the proposed site. As a corollary, all nuclear power plant sites within the identified relevant service area having an operating nuclear power plant or a construction permit issued by the NRC should be compared with the applicant's proposed site."*

The review process outlined in this section was consistent with the special case noted in NUREG-1555, and took into account the advantages already present at existing nuclear facilities within the relevant service area which have been previously reviewed by NRC and found to be suitable for construction and operation of a nuclear power plant. That prior review process included an alternative site analysis.

9.3.1 Site Preferences and the Region of Interest

9.3.1.1 Site Preferences

The review procedure described in this chapter compares and evaluates existing nuclear sites within the region of interest. The candidate site criteria described in NUREG-1555 are incorporated into the site review in Section 9.3.3. This section explains the applicant's preference for an existing nuclear site. The following preference factors influenced the decision to review existing nuclear sites within the region of interest.

- There are benefits offered by existing nuclear sites. For example, co-located sites offer existing infrastructure and support facilities.
- The environmental impacts of an existing plant are known and the impacts of a new facility should be comparable to those of the operating nuclear plant.
- Site physical criteria, primarily geologic/seismic suitability, have been characterized at existing sites; these criteria are important in determining site suitability.
- Transmission is available and the existing sites have nearby markets.
- Existing nuclear plants have local support and the availability of experienced personnel.

Initially, candidate sites within the region of interest were identified and screened. As discussed in Sections 9.3.2 and 9.3.3, the economically and environmentally preferable alternative for the ESP facility is co-location; therefore, consideration of alternative sites within the relevant service area focused primarily on sites with an existing nuclear power facility. The analysis considered additional issues such as environmental impacts, land use, transmission congestion, proximity to population centers, and economical viability. The assessment focused on existing nuclear sites controlled by Southern Company subsidiaries, but an evaluation was also performed for a greenfield site that had previously been proposed for a four-unit nuclear plant.

9.3.1.2 Region of Interest

NUREG-1555 provides that the region of interest includes the state where the candidate site is located, so that alternatives sites may be considered for review. Southern Company subsidiaries have generating facilities that supply electric power to customers located in Georgia, Alabama, and Mississippi (and a small portion of Florida). Therefore, SNC has defined the region of interest as the three-state Southern Company service area. Three existing nuclear sites meet the threshold criteria discussed below. The region of interest also was the geographic area considered in identifying an appropriate greenfield site. The topography, ecology, and socioeconomics throughout the region are roughly the same. Generally, the region is rural/agricultural with pockets of heavy population near important waterways such as the Savannah River, or in traditionally populated areas such as state capitals and university campuses.

9.3.2 Superiority of Existing Sites Within the Region of Interest

During initial review, SNC determined that the advantages of co-locating the new facility with an existing nuclear power facility outweighed the advantages of any other probable siting alternative. In addition to the factors assessed and described previously in this section, there are several advantages to co-locating nuclear facilities as a general rule. Some of the potential environmental and market advantages include:

- The total number of required generating sites is reduced.

- Construction of new transmission corridors may not be required due to potential use of existing corridors.
- No additional land acquisitions will be necessary, and the applicant can readily obtain control of the property.
- The site has already gone through the alternatives review process mandated by NEPA, and was the subject of extensive environmental screening during the original selection process.
- The site development costs and environmental impact of any preconstruction activities are reduced.
- Construction, installation, and operation and maintenance costs are reduced because of existing site infrastructure.

Existing facilities where SNC could obtain access and control were preferred over the other sites within the region of interest. Sites that were originally designed for more generation than actually constructed also received preference.

Within the region of interest, SNC considered the three existing Southern Company nuclear sites with currently licensed, operating plants; and an undeveloped ("greenfield") site in central Alabama that was originally proposed for a 4-unit nuclear plant in the 1970's, but never developed. Candidate sites include:

- Joseph M. Farley Nuclear Plant (FNP)
- Edwin I. Hatch Nuclear Plant (HNP)
- Vogtle Electric Generating Plant (VEGP)
- Barton Site (greenfield)

9.3.3 Alternative Site Review

The proposed ESP site (VEGP) is reviewed at length in this environmental report. This section reviews other candidate sites using the selection criteria suggested in NUREG 1555, in order to consider whether any of the candidate sites is "obviously superior" to VEGP.

Regulatory Guide 4.2, *Preparation of Environmental Reports for Nuclear Power Stations* (Rev. 2, 1976) notes: "The applicant is not expected to conduct detailed environmental studies at alternative sites; only preliminary reconnaissance-type investigations need be conducted". The alternatives described here are compared based on recently updated safety analysis report (USAR) information about the existing plants and the surrounding area and existing environmental studies. The Barton Site, an undeveloped (greenfield) site in central Alabama, was also reviewed in order to determine if greenfield sites are obviously superior to an existing nuclear site.

In accordance with 10 CFR 51, potential impacts from construction and operation of the proposed project at candidate sites other than the proposed ESP site are analyzed, and a single significance level of potential impact (i.e., SMALL, MODERATE, or LARGE) is assigned to each analysis consistent with the criteria that NRC established in 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

SMALL Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.

MODERATE Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.

LARGE Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

For some analyses, SNC determined the criteria used by NRC in NUREG-1437 were appropriate for the analyses presented here and reviewed the criteria to assign a significance level to impacts.

Impact initiators for the alternative sites are the same as those described in Chapter 4 for construction and Chapter 5 for operation of new units at VEGP.

9.3.3.1 Evaluation of the Joseph M. Farley Nuclear Plant Site

Farley Nuclear Plant (FNP) is located in southeast Alabama on the west side of the Chattahoochee River about 6 miles north of the intersection of U. S. Highway No. 84 and State Highway No. 95 (Figure 9.3-1). It is in the northeastern section of Houston County, Alabama, just across the river from Early County, Georgia. The site is about 100 miles southeast of Montgomery, Alabama, and about 180 miles south-southwest of Atlanta, Georgia, in a sparsely populated, largely rural area. The Chattahoochee River flows in a north-to-south direction, forming the eastern border of the site, and serving as the boundary between Houston County, Alabama (to the west) and Early County, Georgia (to the east). Water is diverted to FNP from the Chattahoochee River and is stored in a 108-acre pond for use as service and make-up water for the facility. Three cooling towers per unit are used to dissipate heat from each closed-loop circulating water system. A small portion of the circulating water flow is returned to the Chattahoochee River.

The exclusion area is bounded by two circles with radii of 4,140 feet, centered on each of the reactor containment centerlines. The FNP property is approximately 1,850 acres.

9.3.3.1.1 Land Use Including Site and Transmission Line Rights-of-Way

The FNP site consists of 1,850 acres on the west bank of the Chattahoochee River in Houston County, Alabama. Approximately 500 acres are used for generation and maintenance facilities, laydown areas, parking lots, and roads. The developed areas are located primarily on a plateau approximately one-half mile west of the river, with the area adjacent to the river mostly undeveloped. The remainder of the site consists of forested areas, ponds, wetlands, and open fields. Alabama Power Company (APC) currently maintains approximately 1,300 acres of the FNP site as a wildlife preserve. The proposed project would require that a portion (up to 550 acres) of the wildlife preserve be cleared for development, reducing habitat for onsite wildlife. However, these impacts would be SMALL because approximately 800 acres of wildlife preserve at FNP would remain undisturbed.

Most land in Houston County is rural, either forested or used as farmland. This rural/agricultural character is found throughout the county, with the exception of the City of Dothan. Following forest and agricultural, transportation and residential are the predominant land uses in Houston County **(SEARP&DC 2003)**. The construction and operation of the proposed project at the site would not be expected to affect the land-use patterns of the area.

There are six transmission lines connecting FNP to the transmission system. These include approximately 326 miles of lines that occupy approximately 5,938 acres of corridor **(NRC 2005)**. The corridors pass through land that is primarily rolling hills covered in forests or farmland. The areas are mostly remote with low population densities. For this analysis SNC assumed that the proposed project would necessitate the addition of one 500-kilovolt transmission line requiring a 200-foot wide transmission corridor. SNC assumed that the line would connect to the Webb Substation, which is approximately 10 miles from FNP and two miles east of Dothan, Alabama. Routing the new transmission line to Webb Substation would require an additional 238 acres of transmission corridor. Land use in the vicinity of the Farley-Webb transmission line corridor is largely agricultural and residential in character. Numerous homes are adjacent to the corridor and hayfields, pastures, and row crops are located within or adjacent to the corridor. A few portions of the corridor traverse small isolated wetlands and forested areas. Widening this corridor by 200 feet would not be expected to permanently affect agricultural areas, but has the potential to affect residents along the right-of-way. For this reason, impacts to land use along the right-of-way would be SMALL to MODERATE.

Houston County, Alabama, is not within the Alabama Coastal Zone (Code of Alabama 1975, Section 9-7-15). One transmission line runs through Jackson County, Florida. Although the State of Florida's coastal zone encompasses the state's 67 counties, the state has limited its federal consistency review of federally licensed and permitted activities to activities located in or seaward of one of the state's 35 coastal counties. Jackson County is not one of Florida's coastal counties [Section 308.23(3)(c) F.S.].

9.3.3.1.2 Air Quality

Air quality impacts of construction and operation of the proposed project would likely be similar at the VEGP site and FNP. 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. Mitigation measures similar to those described for the VEGP site would be taken. Air pollution emissions during construction would be regulated by the Alabama Department of Environmental Management (ADEM) under an Air Permit which would specify any notification, operation and maintenance, performance testing, monitoring, reporting, and record keeping requirements **(ADEM 2005)**. The Air Permit would ensure that construction impacts to air quality in the area would be SMALL.

Houston County, Alabama is part of the Southeast Alabama Intrastate Air Quality Control Region (AQCR) (40 CFR 81.267). The AQCR is designated as being unclassified or in attainment for all criteria pollutants. The nearest non-attainment areas, (for ozone and particulate matter [$PM_{2.5}$]), are Bibb and Monroe Counties, Georgia (Macon), multiple counties in the Metropolitan Atlanta Intrastate AQCR, and Jefferson, Shelby, and Walker Counties (Birmingham, Alabama) **(EPA 2005)**. These Counties are all located 125 to 150 miles from FNP. 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 short time periods. The impacts of station operations on air quality are expected to be minimal. As with the existing units, the proposed project would be subject to a Synthetic Minor Operating Permit to ensure that the operation of the proposed project would not interfere with attaining or maintaining National Primary Ambient Air Quality Standards and National Secondary Ambient Air Quality Standards as established by the Clean Air Act **(ADEM 2005)**.

9.3.3.1.3 Hydrology, Water Use, and Water Quality

The Chattahoochee River (a small river) provides FNP service water, make-up to the circulating water system, and dilution water during periods of low flow, when releases to the river would exceed permit limits. Cooling tower blowdown is returned to the Chattahoochee River. Groundwater is used for potable water, and as make-up water for the demineralizer and fire-protection systems. FNP also discharges service water (composed of surface water and groundwater) to the Chattahoochee River directly and via two tributaries to the river (an unnamed tributary and Wilson Creek). It is assumed that the proposed project at FNP would withdraw water from the Chattahoochee River and pump groundwater to support operation of the new nuclear units.

SNC assumed that the proposed project at FNP would withdraw make-up water from the Chattahoochee River. The average withdrawal rate for the existing units is 69,854 gpm (155 cfs). FNP returns water (directly and via tributaries) to the Chattahoochee at a rate of 57,844 gpm (129 cfs) for a net loss to the Chattahoochee River of 11,692 gpm (26 cfs). Assuming the cooling tower evaporation rate for the proposed project would be 28,880 gpm (~64 cfs), the cumulative net loss to the Chattahoochee River would be 90 cfs. For water years 1976-2004, the annual mean and lowest annual mean flows for the Chattahoochee River near Columbia, Alabama (Station 02343801) were 10,660 cfs and 4,950 cfs, respectively **(Psinakis et al. 2005)**. The cumulative evaporative loss for the proposed project and existing units would represent 0.8 percent of the annual mean flow and 1.8 percent of the lowest annual mean flow for the Chattahoochee River.

Although the withdrawal from the Chattahoochee River would represent a small percentage of the Chattahoochee River flow, increased water use could cause controversy in the area because of water use conflicts between Alabama, Georgia, and Florida. Demand for Chattahoochee River water from upstream users has increased dramatically in recent years. The largest user of the Chattahoochee River is metropolitan Atlanta, Georgia. Metropolitan Atlanta's consumptive use more than doubled from 1980 to 2000. Increased water withdrawal reduces flows downstream, affecting the amount of water available for downstream users, water quality, ecological habitats, navigation, and recreation **(Lipford 2004)**. Although the ACF Compact was created in 1997 to study the impacts of increased demand on the Chattahoochee River, develop allocation formulas for the resource, and monitor the use of the resource **(JSU 2002)**, the Compact was dissolved in 2003 without resolution of the problem **(Pointevent 2003)**. The amount of water from the Chattahoochee River that proposed project would require is small compared with major users in the watershed (i.e., metro Atlanta), and impacts to Chattahoochee River as a result would be SMALL. However, any increase in water withdrawal from the Chattahoochee River might be challenged by neighboring states.

FNP withdraws groundwater for potable water, and as make-up water for the demineralizer and fire-protection systems. Approximately 130 gpm is currently used at FNP **(NRC 2005)** for approximately 950 employees. Assuming that groundwater use is proportional to the number of employees at the plant, an additional 660 employees would require an additional 90 gpm, for a cumulative groundwater withdrawal of 220 gpm. Most of the current groundwater is withdrawn from the deep major (Nanafalia) aquifer, which has a yield of approximately 100 to 700 gallons per minute **(Mayer 1997)**.

Groundwater overdraft areas have recently developed within the southeast Alabama region. The increased demand for water exacerbated by the increase in population in the area is placing strains on the groundwater supply **(SEARP&DC 2003)**. Water problems are most critical in Houston County because it supports the largest population base in southeast Alabama. Depressions have already formed in the potentiometric surface of the Nanafalia aquifer in and near Dothan. No well users in the vicinity of Farley use significantly large amounts of groundwater. Well surveys have shown that municipalities and industries near the site do not require or use large amounts of groundwater. As a result, no significant cones of depression exist in the area surrounding the site. Additional groundwater withdrawal would have little effect on the Nanafalia aquifer, and therefore impacts as a result of operation would be SMALL. However, because groundwater availability is an issue in southeast Alabama, siting additional units at FNP may cause public concern with respect to groundwater availability.

FNP currently operates under a National Pollutant Discharge Elimination System (NPDES) permit issued by the ADEM. As authorized by the Clean Water Act, the NPDES permit program controls water pollution by regulating discharges into waters of the United States. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. The permit contains limits on what can be discharged, monitoring and reporting requirements, and other provisions to ensure that the discharge does not hurt water quality or human's health. Any releases of contaminants to Chattahoochee River (or other Alabama waters) as result of construction or operation of the proposed project at FNP would be regulated by the ADEM through the NPDES permit process to ensure that water quality is protected. Therefore, impacts to water quality would be SMALL.

9.3.3.1.4 Terrestrial Resources Including Protected Species

The FNP site consists of 1,850 acres. Approximately 500 acres are currently used for generation and maintenance facilities, laydown areas, parking lots, and roads. The developed areas are primarily located on a plateau approximately one-half mile west of the river, with the area adjacent to the river mostly undeveloped. The remainder of the site consists of forested areas, ponds, wetlands, and open fields, and 1,300 acres of this land is managed by APC as a wildlife preserve. It is assumed that structures for the proposed project would require that a portion of the wildlife preserve be cleared and developed.

Terrestrial wildlife species that occur in the forested portions of the FNP property are those typically found in similar habitats in south Alabama. Common mammals at the site include the opossum (*Didelphis virginiana*), armadillo (*Dasypus novemcinctus*), eastern cottontail (*Sylvilagus floridanus*), gray squirrel (*Sciurus carolinensis*), raccoon (*Procyon lotor*), and white-tailed deer (*Odocoileus virginianus*). Wading birds (egrets and herons) occur in wetlands, along the edges of ponds, and along the Chattahoochee River. Numerous bird species (e.g., common bobwhite [*Colinus virginianus*], blue jay [*Cyanocitta cristata*], and various warblers), as well as several reptile and amphibian species, including the gopher tortoise (*Gopherus polyphemus*), occur at the site. The gopher tortoise is listed as protected by the Alabama Department of Conservation and Natural Resources (ADCNR). **(NRC 2005)**

There are six transmission lines connecting FNP to the transmission system. These include approximately 326 miles of lines that occupy approximately 5,938 acres of corridor **(NRC 2005)**. The corridors pass through land that is primarily rolling hills covered in forests or farmland. No areas designated by the U.S. Fish and Wildlife Service (FWS) as critical habitat for endangered species exist at FNP or adjacent to associated transmission lines. However, these lines do cross Elmodel Wildlife Management Area in western Georgia and the Lake Seminole Wildlife Management Area in southwestern Georgia. The lines do not cross any other state or federal parks, wildlife refuges, or wildlife management areas. Widening the existing corridor to Webb Station, as described in Section 9.3.3.1.1, would not result in the crossing of any additional state or federal lands or managed areas.

Fourteen federally-listed threatened or endangered terrestrial species are known to occur in the vicinity of FNP or its transmission lines: the endangered gray bat (*Myotis grisescens*), the endangered Indiana Bat (*Myotis sodalis*), the threatened bald eagle (*Haliaeetus leucocephalus*), the endangered wood stork (*Mycteria americana*), the endangered red-cockaded woodpecker (*Picoides borealis*), the threatened (due to similarity of appearance) American alligator (*Alligator mississippiensis*), the threatened Eastern indigo snake (*Drymarchon corais couperi*), the endangered flatwoods salamander (*Ambystoma cingulatum*), the threatened crystal lake nailwort (*Paronychia chartacea minima*), the endangered chaffseed (*Schwalbea americana*), the endangered gringed campion (*Silene polypetala*), the endangered gentian pinkroot (*Spigelia genianoides*), the endangered Florida torreya (*Torreya taxifolia*), and the endangered relict trillium (*Trillium reliquum*).

The only land disturbance required to site the proposed project at FNP would take place in Houston County (on the plant site and along the existing transmission corridor to Webb Substation). Three Federally-listed species are known to occur in Houston County: the bald eagle, the Eastern indigo snake, and the flatwoods salamander. A bald eagle was observed at FNP during a 2001 survey. A single adult eagle was observed along the Chattahoochee River opposite the FNP site. It is unlikely that any eagle nests occur at the site, but bald eagles undoubtedly forage, at least occasionally, on the Chattahoochee River in the vicinity of FNP. In addition, habitat suitable for the Eastern indigo snake exists at FNP. Habitat preferred by the flatwoods salamander does not exist at the FNP site or along the Webb transmission corridor. With the exception of the bald eagle and the Eastern indigo snake, it is unlikely that any other federally-listed wildlife species occur at FNP or along the Farley-Webb transmission corridor.

During construction of the proposed project at FNP, wildlife would be temporarily displaced from 550 acres and permanently displaced from 300 acres dedicated to the proposed project, their supporting facilities, and construction facilities. However, approximately 800 acres of wildlife preserve would remain at FNP and would continue to support terrestrial habitat at the site. The potential exists for the presence of the endangered Eastern indigo snake at FNP. Prior to construction activities, SNC would be required to perform a detailed survey to ensure protection of the endangered Eastern indigo snake. Construction impacts on terrestrial resources (including threatened or endangered species) would be SMALL because mitigation would be performed. Impacts of operation of the proposed project would also be SMALL because sufficient habitat would remain at FNP to support existing wildlife.

9.3.3.1.5 Aquatic Resources Including Protected Species

FNP is located on the west (Alabama) bank of the lower Chattahoochee River at approximately River Mile 43.5. The Chattahoochee River rises in the Blue Ridge Mountains of northeast Georgia and flows south along the entire length of the state for approximately 430 miles before it merges with the Flint River (at Lake Seminole) to form the Apalachicola River. From Lake

Seminole, the Apalachicola River flows south for 106 miles across the Florida Panhandle and ultimately empties into Apalachicola Bay, which is part of the Gulf of Mexico.

Flows in the lower Chattahoochee River (the portion of the river between Walter F. George Reservoir and the Chattahoochee-Flint confluence) are influenced by a series of locks and dams built in the 1950s for flow regulation, hydroelectric power generation, and improved navigation. Historically, the lower Chattahoochee River was subject to extreme seasonal fluctuations in flow and was navigable only at certain times of the year. After the three locks and dams were completed, it was possible for large vessels to move from the Gulf of Mexico to Columbus, Georgia, via a 9-foot-deep and 100-foot-wide channel maintained by the U.S. Army Corps of Engineers. Columbus, Georgia is approximately 75 miles north of FNP.

The aquatic communities of the lower Chattahoochee River in the vicinity of FNP have not been the subject of recent scientific study. The most comprehensive source of information on the local aquatic communities is the Cooling Water Intake Study 316(b) Demonstration for Farley Units 1 and 2, which contains detailed information on phytoplankton, zooplankton, and fish populations. A survey of the freshwater mussels in the Chattahoochee River below FNP was recently conducted **(Yokley 2004).**

The fish community of the Chattahoochee River in the vicinity of FNP is diverse, composed of a mix of common southeastern stream species (many of which adapt well to reservoir conditions), species typically found in swamps and backwaters of rivers, and a small number of migratory and semi-migratory species. Approximately 92 known fish species occur in the Chattahoochee River system **(Mettee et al. 1996)** and perhaps two thirds of these species are found in the lower Chattahoochee. **(NRC 2005)**

Stream fishes commonly observed and occasionally collected in the lower Chattahoochee River near FNP include longnose gar (*Lepisosteus osseus*), redfin pickerel (*Esox americanus*), river redhorse (*Moxostoma crinatum*), greater jumprock (*M. lachneri*), green sunfish (*Lepomis cyanellus*), redbreast sunfish (*L. auritus*), channel catfish (*Ictalurus punctatus*), and several common minnow species (e.g. longnose shiner [*N. longirostris*] and weed shiner [*N. taxanus*]) as well as bowfin (*Amia calva*), spotted sucker (*Minytrema melanops*), chain pickerel (*Esox niger*), and flier (*Centrarchus macropterus*). A number of other fish species found in the Chattahoochee River in the vicinity of FNP are adapted to a range of environmental conditions and are abundant in rivers, lakes, reservoirs, and swamps across the Southeast. These include the gizzard shad (*Dorosoma cepedianum*), common carp (*Cyprinus carpio*), blacktail shiner (*Cyprinella venusta*), bluegill (*L. machrochirus*), and largemouth bass (*Micropterus salmoides*). **(NRC 2005)**

Three Morone species (striped bass [*M. saxatilis*], white bass [*M. chrysops*], and hybrid bass [e.g., palmetto bass, *M. chrysops x saxatilis*]) are found in the lower Chattahoochee River and are sought by anglers in the spring of the year near George W. Andrews Lock and Dam. In addition to these, anadromous (e.g., striped bass) and semi-anadromous (e.g., white bass and hybrid bass) populations, small numbers of catadromous American eels (*Anguilla rostrata*) are also found in the lower Chattahoochee. The size and timing of this seasonal movement of eels are not well understood. Small numbers of eels are found year-round in the Chattahoochee River in the vicinity of FNP. **(NRC 2005)**

Benthic macroinvertebrate populations inhabiting the Chattahoochee River in the vicinity of FNP have not been systematically surveyed **(NRC 2005)**. Rapidly shifting bottom sands were noted to prevent the establishment of a diverse benthic community in this area **(AEC 1974)**. Species diversity and abundance of freshwater mussels have declined in the Chattahoochee River since the early part of the 20th century, with dramatic declines over the past decades. These declines have been attributed to erosion and sedimentation (from land clearing and intensive farming in the river basin); dredging, snag removal, and channel modifications (for navigation); the development of impoundments for flood control and hydropower, runoff of agricultural chemicals and animal wastes (chiefly poultry); mining activities in tributary streams; and discharges from wastewater treatment facilities. In addition, the Asiatic clam (*Corbicula fluminea*) invaded the Chattahoochee River system, competing with native mussels for habitat and resources.

Federally-listed species in the vicinity of FNP include the threatened Gulf sturgeon (*Acipenser oxyrinchus desotoi*), the endangered fat threeridge (*Amblema neislerii*), the threatened Chipola slabshell (*Elliptio chipolaensis*), the threatened purple bankclimber (*Elliptoideus sloatianus*), the endangered shinyrayed pocketbook (*Lampsilis [Villosa] subangulata*), the endangered Gulf moccasinshell (*Medionidus penicillatus*), and the endangered oval pigtoe (*Pleurobema pyriforme*). No designated critical habitat exists for any of the listed species on or in the vicinity of the Farley site or within the ROWs of the associated transmission lines. **(FWS 2004, 2005, 2006)**

Water from the Chattahoochee River is used to for condenser cooling at FNP and would be expected to be used to cool the proposed project constructed at the site. Although aquatic biota, including the common southeastern fishes described previously, would be temporarily displaced during construction of new intake and discharge structures, they would be expected to recolonize the area after construction is complete. Any disturbance to aquatic resources from construction would be localized and of relatively short duration. Any impacts of construction on aquatic resources, including Federally-listed threatened and endangered species would be SMALL.

Withdrawing water from the Chattahoochee River for the proposed project is not expected to result in significant adverse impacts to aquatic environments as a result of impingement and entrainment because the proposed project would utilize cooling towers. In addition, the EPA's recent rulings on cooling water intake structures (40 CFR Part 125), requires cooling water intake facilities to meet certain criteria designed to protect organisms from entrainment and impingement. The potential for adverse impacts to aquatic resources from the operation of the proposed project at FNP would be SMALL.

9.3.3.1.6 Socioeconomics

This section evaluates the social and economic impacts to the surrounding region as a result of constructing and operating the proposed project at the FNP site. The evaluation assesses impacts of construction, station operation, and demands placed by the construction and operation workforce on the surrounding region.

9.3.3.1.6.1 Physical Impacts

Construction activities can cause temporary and localized physical impacts such as noise, odor, vehicle exhaust, vibration, shock from blasting, and dust emissions. The use of public roadways and waterways would be necessary to transport construction materials and equipment. It is assumed that all construction activities would occur within the existing FNP site. Offsite areas that would support construction activities (for example, borrow pits, quarries, and disposal sites) are expected to be already permitted and operational. Impacts on those facilities from construction of the proposed project would be small incremental impacts associated with their normal operation.

Potential impacts from station operation include noise, odors, exhausts, thermal emissions, and visual intrusions. The proposed project would produce noise from the operation of pumps, fans, transformers, turbines, generators, and switchyard equipment, and traffic at the site would also be a source of noise. However, noise attenuates quickly so ambient noise levels would be minimal at the site boundary. Also, FNP is located in a rural area surrounded by forests and agricultural land, so residents in the area are sparse. Commuter traffic would be controlled by speed limits. Good road conditions and appropriate speed limits would minimize the noise level generated by the workforce commuting to the site.

The proposed project would have standby diesel generators and auxiliary power systems. Permits obtained for these generators would ensure that air emissions comply with regulations. In addition, the generators would be operated on a limited, short-term basis. During normal plant operation, the proposed project would not use a significant quantity of chemicals that could generate odors that exceed odor threshold values. Good access roads and appropriate speed limits would minimize the dust generated by the commuting workforce.

Construction activities would be temporary and would occur mainly within the boundaries of the FNP site. Offsite impacts would represent small incremental changes to offsite services. During station operations, ambient noise levels would be minimal at the site boundary. Air quality permits would be required for the diesel generators, and chemical use would be limited, which would limit odors. Therefore, the physical impacts of construction and operation would be SMALL.

9.3.3.1.6.2 Demography

FNP is in Houston County, Alabama on the Chattahoochee River and approximately 100 miles southeast of Montgomery, Alabama. Geneva, Henry, and Houston Counties, Alabama make up the Dothan Metropolitan Statistical Area **(USCB 2006a)**. Geneva County had a 2000 population of 25,764, Henry County had a 2000 population of 16,310, and Houston County had a 2000 population of 88,787 **(USCB 2000a)**. The 2000 population within 50 miles of the site was 393,639 people (50 persons per square mile). The City of Dothan, located 17 miles from FNP, had a 2000 population of 57,737 **(USCB 2000a)**. The 2000 population within 20 miles of the site was 93,120 people (74 persons per square mile). Applying the NUREG-1437 sparseness and proximity matrix, FNP is located in a medium population area.

Based on the analysis in Section 4.4.2.1, SNC assumes that construction of the proposed project at FNP would increase the population in the 50-mile region by 7,200 people. The majority of the current HNP workforce lives in Houston County (77 percent) the remaining employee residences are distributed across 22 counties in Alabama, Georgia, and Florida, mostly within 50 miles of the site. SNC assumes that the residential distribution of the construction workforce would resemble the residential distribution of the current FNP workforce. Therefore SNC anticipates that 5,544 people (77 percent of 7,200) or 6.2 percent of the 2000 population would settle in Houston County. Overall, the population increase from in-migration of construction workers constitutes 1.8 percent of the 2000 population of the 50-mile region. SNC is adopting the NRC definition of impacts as SMALL if plant-related population growth is less than 5 percent of the study area's total population and MODERATE if growth is between 5 and 20 percent. Therefore, SNC concludes that the impacts of plant construction on increases in population would be MODERATE in Houston County and SMALL in the remainder of the 50-mile region.

Based on the analysis in Section 5.8.2.1, SNC assumes that operation of the proposed project at FNP would increase the population in the 50-mile region by 1,750 people. Approximately 77 percent would settle in Houston County. The addition of the new employees and their families would equate to a 1.5 percent increase for Houston County. Overall, the potential increases in population would represent a SMALL increase in the total population.

9.3.3.1.6.3 Economy

The southeast Alabama region has experienced a reduction in labor force due to numerous industrial plant closings in the past 8 years. These closings primarily affected low-skill textile workers who did not possess the skills required to obtain new jobs. The district was also negatively impacted by the General Agreement on Tariffs and Trade (GATT) which increased competition in the peanut industry with importation of foreign peanuts into the U.S. Layoffs, downsizing, and closures have eliminated thousands of jobs. **(SEARP&DC 2003)**

Houston County's economy has seen a major shift from manufacturing to services and retail trade. The service sector comprises a much larger percentage of the County's earnings than does manufacturing. The County remains a regional retail and medical services center. **(SEARP&DC 2003)**

Henry County has shown strong growth in employment and earnings attributable to manufacturing. While the percentage of employees in the manufacturing sector has decreased, the number employed has increased. Income earnings from farming continue to decrease. **(SEARP 2003)**

Geneva County's earnings from farming have been increasing, with the exception of year 2000. Poultry production is generating significant income to help the County's overall economy. Government is the highest income producer in the county, with farm income being second. Employment has continued to grow in the services and government sectors, while declining in manufacturing, farming, and retail trade sectors. **(SEARP&DC 2003)**

The unemployment rate in the State of Alabama for 2002 was 5.9 percent, compared with 4.3 percent for Houston County, 6.7 percent for Henry County, and 5.7 percent for Geneva County **(SEARP&DC 2003)**. The total number of employees in 2000 for Houston County was almost 60,000. Henry and Geneva Counties had 6,822 and 9,606, respectively **(SEARP&DC 2003)**.

The economic impacts would be spread across the 50-mile region, but would be greatest in Houston County. Impacts are defined as SMALL if plant-related employment is less than 5 percent of the study area's total employment and MODERATE if employment is between 5 and 10 percent. SNC concludes that the impacts of construction on the economy of the region would be beneficial and temporary, and would therefore be SMALL.

The wages and salaries of the operating workforce would have a multiplier effect that could result in increases in business activity, particularly in the retail and service sectors. This would have a positive impact on the business community and could provide opportunities for new businesses to get started, and increased job opportunities for local residents. The economic effect on the 50-mile region would be beneficial. SNC assumes that direct jobs would be filled by an in-migrating workforce, but most indirect jobs would be service-related, not highly specialized, and would be filled by the existing workforce within the 50-mile region and particularly in Henry County. SNC anticipates that most of the indirect jobs created by the operations workforce would be filled by unemployed workers in the region. Expenditures made by the direct and indirect workforce would strengthen the regional economy.

SNC concludes that the impacts of station operation on the economy would be beneficial and SMALL everywhere in the region except Henry County, where the impacts would be MODERATE and beneficial, and that mitigation would not be warranted.

9.3.3.1.6.4 Taxes

Taxes collected as a result of constructing and operating the proposed project at FNP would be of benefit to the State and local jurisdictions that collected and spent them. Corporate and personal income taxes and sales and use taxes would be collected during both the construction and operation of a new unit at FNP. SNC anticipates that FNP would pay annual property taxes to Houston County, even during construction of the proposed project. Alabama assesses property at 30% of its value. Assuming a 40-year operational life, property taxes to Houston County are estimated to be between $15,000,000 and $21,500,000 annually for the first decade of operations and between $3,000,000 and $4,000,000 for the last decade of operations. For the years 1995 through 2002, FNP property taxes provided between 31 and 39 percent of Houston County's total property tax revenues **(NRC 2005)**. The benefits of taxes are defined as large when new tax payments represent more than 20 percent of total revenues for local jurisdictions. Therefore, SNC concludes that the potential beneficial impacts of taxes collected during construction and operation of the proposed project would be LARGE in Houston County and SMALL in the remainder of the 50-mile region.

9.3.3.1.6.5 Transportation

Road access to FNP is via State Road 95, a two-lane paved road with a north-south orientation. State Road 95 passes through the Towns of Columbia to the north and Gordon to the south. Employees traveling from Dothan, Alabama use either U.S. 84 or State Road 52. U.S. 84 is a four-lane highway that intersects with State Road 95 near Gordon. State Road 52 crosses State Road 95 southwest of Columbia. The Alabama Department of Transportation does not maintain level-of-service designation for roadways in the State. However, a daily average of 870 cars traveled State Road 95 near FNP in 2004 **(ALDOT 2006)**. Assuming construction shifts as discussed in Section 4.4.2.2.4 an additional 2,200 cars could be on the two-lane highway during shift change, causing potential congestion. Also, the traffic of hauling construction materials (100 trucks per day) to the site could bring additional congestion to State Road 95, and State Road 52 and U.S. Route 84 from Dothan during certain times of the day. Transportation impacts are considered small when increases in traffic do not result in delays or other operational problems, moderate when increases in traffic begins to cause delays or other operational problems. Therefore, SNC concludes that impacts of construction on transportation would be MODERATE and some mitigating actions might need to be undertaken.

With respect to the operations of the facility, adding an additional 600 cars (during afternoon shift change) to the existing 870 cars per day on the road would not materially congest the highway. Shift changes for the current units and the proposed project at FNP could be staggered so that the traffic increase would not cause congestion. Impacts of the operations workforce on transportation would be SMALL to MODERATE and mitigation would not be warranted.

9.3.3.1.6.6 Aesthetics and Recreation

The developed areas at FNP are primarily located on a plateau approximately one-half mile west of the Chattahoochee River, with the area immediately adjacent to the river mostly undeveloped. The remainder of the site consists of forested areas, ponds, wetlands, and open fields. There are two major topographical subdivisions at the site: (1) gently rolling upland west of the Chattahoochee River Valley and (2) the river terraces and floodplain of the Chattahoochee River. Habitats at the FNP consist of river bluff, forest, ravine forest, floodplain forest, pine-mixed hardwood forest, pine forest, non-floodplain wetlands, and mechanically-maintained grassy areas. **(NRC 2005)**

The construction of the proposed project at FNP could be viewed from offsite at certain locations, but the addition of another facility would not substantially change the view of the current units. There could be a need to construct cooling-water intake and discharge structures at the site. Additional mechanical or natural draft cooling towers would be required. The operation of a new nuclear unit would have visual impacts similar to those of the existing FNP units, with the addition of more visible plumes from cooling towers. Impacts on aesthetic resources are considered to be small if there are no complaints about diminution in the enjoyment of the physical environment and no measurable impact on socioeconomic institutions and processes. Therefore, impacts of construction and operation of the proposed project on aesthetics would be SMALL and would not warrant mitigation.

There are three U.S. Army Corps of Engineers reservoirs in the vicinity of FNP: Walter F. George Lake, George W. Andrews Lake, and Lake Seminole. All have recreational uses in including camping, boat ramps, marinas, picnic areas, playgrounds, swimming areas, and trails **(USACE 2006)**. Walter F. George Lake and George W. Andrews Lake are located over 30 miles upstream of FNP in Henry and Barbour Counties, Alabama, and Clay, Quitman, and Stewart Counties, Georgia. Seminole Lake is located almost 25 miles downstream of FNP on the border of Georgia and Florida, in Jackson County, Florida and Seminole and Decatur Counties, Georgia. Impacts on tourism and recreation are considered small if current facilities are adequate to handle local levels of demand. Construction and operation of the proposed project at FNP would not impact these recreation areas because of their distance from FNP. Therefore, the impacts of facility construction and operation would be SMALL.

9.3.3.1.6.7 Housing

In 2000 Houston County, had 39,571 housing units, of which 3,737 were vacant (9.4 percent). Henry County had 8,037 housing units, of which 1,512 were vacant (18.8 percent), and Geneva County had 12,115 housing units with 1,638 vacant (13.5 percent) **(USCB 2000b)**.

Based on the analysis in Section 4.4.2.2.5, approximately 3,400 construction workers would in-migrate to the 50-mile region. Of these, approximately 2,700 would purchase or rent permanent housing. The 680 temporary workers would rent temporary (e.g., hotels, motels, rooms in private home) or permanent housing, or bring their own housing in the form of campers and mobile homes. Currently, available housing in the three-county area is adequate to accommodate the expected influx of workers. Workers could also find housing in other parts of the 50-mile region or construct new housing. Given this increased demand for housing, prices of existing housing could rise. Houston County (and other counties to a lesser extent) would benefit from increased property values and the addition of new houses to the tax rolls. Increasing the demand for homes could increase rental rates, and housing prices. It is unlikely but possible that some low-income populations could be priced out of their rental housing due to upward pressure on rents. However, the construction workforce would increase over time and any actual housing shortage is unlikely to be as severe as a comparison of maximum workforce to available housing would indicate. The gradual influx of new residents would give the housing market time to adjust to the additional demands.

In summary, the three counties where most of the construction workforce would seek housing have adequate housing resources for the entire workforce. Impacts on housing are considered to be small when a small and not easily discernable change in housing availability occurs, and impacts are considered to be moderate when there is a discernable but short-lived reduction in the availability of housing units. SNC concludes that the potential impacts of construction on housing could be MODERATE in Houston County and would be SMALL in the remainder of the 50-mile region. Mitigation would not be warranted where the impacts were small. Mitigation of the moderate impacts would occur as developers and builders anticipated the increased population and built homes to meet their needs. Additional mitigation would not be warranted.

SNC assumes that operation of the proposed project at FNP would increase the population in the 50-mile region by 1,750 people. Approximately 77 percent would settle in Houston County. While there is currently enough housing to accommodate all the new families expected in Houston County, not all housing may be the type sought by the new workforce. The average income of the new workforce would be expected to be higher than the medium or average income in these counties, therefore, the new workforce could exhaust the high-end housing market and some new construction could result.

SNC concludes that the potential impacts of operations on housing in Houston County would be and SMALL to MODERATE, and SMALL elsewhere in the 50-mile region. Market forces could result in more housing being built in the three-county region, eventually mitigating any housing shortages. Additional mitigation would not be warranted.

9.3.3.1.6.8 Public Services

Public services include water supply and waste water treatment facilities; police, fire and medical facilities; and social services. New construction or operations employees relocating from outside the region would most likely live in residentially-developed areas. It is not expected that public services would be materially impacted by these workers. Impacts on public services are considered to be small if there is little or no need for changes in the level of service provided to the community. Therefore, impacts of construction and operation of the proposed project on public services would be SMALL and mitigation would not be warranted.

9.3.3.1.6.9 Education

Based on the analysis in Section 4.4.2.8, SNC assumes that construction of the proposed project at FNP would increase the school-aged population in the 50-mile region by 1,900 people. Approximately 77 percent would settle in Houston County. Moderate Impacts on local school systems are generally associated with 4 to 8 percent increases in enrollment. The Houston County student population would increase by 7.8 percent, constituting a MODERATE impact on its education systems and mitigation would be warranted.

Based on the analysis in Section 5.8.2.2.7, SNC assumes that operation of the proposed project at FNP would increase the school-aged population in the 50-mile region by 464 people. Approximately 77 percent would settle in Houston County. The Houston County student population would increase by 1.9 percent, constituting a SMALL impact on its education systems and mitigation would not be warranted.

9.3.3.1.7 Historic and Cultural Resources

The National Register of Historic Places lists seven locations in Houston County, Alabama, two sites in Henry County, Alabama, and seven sites in Early County, Georgia **(NPS 2006a)**. Two of these fall within 6 miles of FNP. The Purcell-Killingsworth House, a Victorian mansion in Houston County, was completed in 1890 and was the boyhood home of Bishop Clare Purcell **(HCC 2006)**. The house is currently a bed and breakfast with a historical marker **(BB Online 2006)**. Coheelee Creek Bridge in Early County, built in 1891, is the southernmost covered bridge in the United States **(GDOT 2002)**.

NRC conducted an archaeological records search at the Alabama State Site Files during the license renewal application process. The record searches identified 14 archaeological sites recorded on Farley property, as part of three separate surveys of varying levels of intensity. In 1947, archeologists from the University of Alabama documented five sites. Surveys in 1975, also by the University of Alabama, documented six sites, including one documented in 1947 and re-recorded with a new number. This site, a Late Woodland and early Mississippian period village with an earthen burial mound, was originally partially excavated in 1905 by pioneering Southeastern archaeologist, Clarence Bloomfield Moore. Surveys conducted in 1982 by archaeologists from the Cleveland Museum of Natural History documented four sites. In addition, a previously unrecorded archaeological site, a small chert quarry was discovered in 2004 by archaeologists during NRC field checks in support of license renewal. These 15 sites have not been evaluated for potential eligibility to the National Register of Historic Places. However, several of the sites have been heavily impacted by historic agriculture and two possibly by early construction activities connected with FNP. These sites could lack the integrity necessary for inclusion on the National Register of Historic Places. **(NRC 2005)**

While there are no structures or buildings at FNP that are 50 years in age or older, there is a small historic cemetery containing approximately 25 graves with associated grave markers ranging in date for 1917 to 1969. The cemetery is still occasionally visited by family members. FNP conducts yearly maintenance at the location **(NRC 2005)**.

Siting the proposed project at FNP would require that a formal cultural resources survey be conducted so that no archeological or historic resources would be damaged during construction of the proposed project. Mitigative measures would be performed to prevent permanent damage and ensure that any impacts to cultural resources from construction or operation at FNP would be SMALL.

9.3.3.1.8 Environmental Justice

The 2000 Census data and block groups were used for ascertaining minority and low-income populations in the area. Minority populations exist in the vicinity of FNP, including block groups with significant Black races and Hispanic Ethnicity populations. Low income populations also exist in the 50-mile radius. In Houston County, the Black Races and low-income minority populations exist in the City of Dothan, approximately 17 miles west of FNP. Black and low-income minority populations also exist in Early County, Georgia, bordering FNP to the east across the Chattahoochee River. The only block group with a significant Hispanic Ethnicity minority population is located in Gadsden County, Florida, approximately 50 miles from FNP. No significant minority or low-income populations exist within 6 miles of FNP. Construction activities (noise, fugitive dust, air emissions, traffic, impacts to housing or public services) would not disproportionately adversely affect minority populations because of their distance from FNP. In fact, minority and low-income populations would most likely benefit from construction activities through an increase in construction-related jobs. These benefits would be SMALL.

Operation of the proposed project at FNP is also unlikely to have a disproportionate adverse impact on minority or low-income populations. No unusual resource dependencies, such as subsistence agriculture, hunting, or fishing were identified during the license renewal process for FNP **(NRC 2005)**. Offsite impacts from operation of the proposed project at FNP to minority and low-income populations would be SMALL, and no special mitigation actions would be warranted.

9.3.3.2 Evaluation of the Edwin I. Hatch Nuclear Plant

Hatch Nuclear Plant (HNP) is located in Appling and Toombs Counties, Georgia, southeast of where U.S. Highway 1 crosses the Altamaha River (Figure 9.3-2). It is approximately 11 miles north of Baxley, 98 miles southeast of Macon, 73 miles northwest of Brunswick, and 67 miles southwest of Savannah, Georgia, in a sparsely populated, largely rural area. The Altamaha

River flows in a west-to-east direction through the site, serving as the boundary between Toombs County (to the north) and Appling County (to the south). Water is diverted to HNP from the Altamaha River for use as service and make-up water for the facility. Four cooling towers (one counter-flow and three cross-flow) per unit are used to dissipate heat from each closed-loop circulating water system. A portion of the circulating water flow is returned to the Altamaha River.

9.3.3.2.1 Land Use Including Site and Transmission Line Rights-of-Way

The HNP site encompasses approximately 2,240 acres and is characterized by low, rolling sandy hills that are predominantly forested. The site is divided by the Altamaha River, and includes 900 acres north of the river in southern Toombs County and 1,340 acres south of the river in northern Appling County. All industrial facilities associated with the site are located in Appling County. The area comprising the reactors, containment buildings, switchyard, cooling tower area and associated facilities, to which access is restricted, is approximately 300 acres. Approximately 350 acres of the site are composed of wetlands and transmission corridors, and approximately 1,600 acres are managed for timber production and wildlife habitat. Controlled areas available for use with prior permission include 75 acres of wetlands east of the restricted area and a 100-acre tract of land west of U.S. Highway 1 that is a Boy Scout Camp. Uncontrolled access areas available to the public include a wayside park, a recreation area, and a Visitors Center.

The land in the site region is rural. About 71 percent of the land in the five surrounding counties of Appling, Jeff Davis, Montgomery, Tattnall, and Toombs is wooded, with about 15 percent farmed. **(UGA 2006)**

No land would be acquired for additional facilities at HNP. The footprint of a new plant would be approximately 300 acres and an additional 250 acres would be required for temporary facilities and laydown yards. The proposed project could be configured to fit within the existing, previously disturbed area of the HNP site. Land-use impacts associated with site-preparation, construction, and operation of the proposed project at HNP would be SMALL.

There are six transmission lines connecting HNP to the transmission system, which occupy four transmission line corridors. These include approximately 340 miles of lines that occupy approximately 7,200 acres of corridor. The corridors pass through rolling hills that are primarily a mixture of cultivated land, grazing land, and managed timberlands (paper and pulp stock). The areas are mostly remote with low population densities. It is assumed that the proposed project would necessitate the addition of one 500-kilovolt transmission lines, requiring a 200-foot wide transmission corridor. The additional transmission line could be installed via expansion of an existing right-of-way, or it could follow a new right-of-way. The procedures for adding new transmission lines to connect the proposed project at HNP to the transmission grid are similar to those described in Section 4.1.2. Assuming that any transmission system modifications would be a combination of new right-of-way and expanding existing right-of-way, the land-use impacts associated with the addition of one 500-kilovolt transmission lines would be SMALL to MODERATE.

The HNP site is not subject to the Georgia Coastal Zone Management Act because the plant is not located within one of the designated Georgia coastal zone counties. However, two of the transmission corridors interconnecting with HNP run through Georgia's coastal zone. The Thalmann line (distinct from the VEGP line known as the Thalmann [McIntosh] line) extends 65 miles southeast from HNP to a substation near Thalmann, Georgia in Wayne County; and the Duval line extends 87 miles south from HNP through Charlton County, Georgia, to the Florida state line. Because they are located in coastal zone counties, expanding these transmission corridors to accommodate new lines would require review and certification under the Georgia Coastal Zone Management Act.

9.3.3.2.2 Air Quality

The counties in which HNP is located, Appling and Toombs, are designated as being unclassified or in attainment of the National Air Quality Standards (NAAQS). The nearest non-attainment area is Henry County, Georgia, which is approximately 140 miles northwest of HNP. Henry County, a southeastern suburb of Atlanta, is in non-attainment for ozone and particulate matter with an aerodynamic diameter of 2.5 microns or less (PM2.5) (40 CFR 81. 311). The closest areas to HNP that are designated in 40 CFR 81.408 as mandatory Class I Federal areas, in which visibility is an important value, are the Okefenokee and Wolf Island wilderness areas. These areas are more than 50 miles south and southeast, respectively, from the site.

Air quality impacts from construction and operation of the proposed project at HNP would be similar to those at the VEGP site. Construction impacts would be temporary, and would be similar to any large-scale construction project. Construction emissions would include dust from disturbed land, roads, and construction activities and emissions from construction equipment. Mitigation measures similar to those described for the VEGP site would be taken. During station operation, standby diesel generators would be used for auxiliary power. It is expected that these generators would see limited use and, when used, they would operate for short time periods. Therefore, air pollutant emissions from the standby diesel generators are expected to be minimal. As with the existing units, the proposed project would be subject to a Synthetic Minor Operating Permit to ensure that the operation of the proposed project would not interfere with attaining or maintaining National Primary Ambient Air Quality Standards and National Secondary Ambient Air Quality Standards as established by the Clean Air Act.

Because there are no mandatory Class I Federal areas or NAAQS non-attainment areas within 50 miles of HNP, and air pollutant emissions are expected to be minimal, the air quality impacts from construction and operation of the proposed project at HNP would be SMALL.

9.3.3.2.3 Hydrology, Water Use, and Water Quality

The Altamaha River (a relatively small river with average flow of 11,300 cfs) is the major source of water for HNP. Water is withdrawn from the river to provide cooling for certain once-through loads and makeup water to the cooling towers. Cooling tower blowdown is returned to the Altamaha River. HNP withdraws groundwater for potable and process use. HNP also discharges service water (composed of surface water and groundwater) to the Altamaha River. It is assumed that the proposed project at HNP would withdraw water from the Altamaha River and pump groundwater to support operation of the the proposed project.

SNC assumed that the proposed project at HNP would withdraw make-up water from the Altamaha River. The average withdrawal rate for the existing units is 39,708 gpm (88.5 cfs) **(NRC 2001)**. HNP returns water to the Altamaha at a rate of 19,388 gpm (43.2 cfs) **(NRC 2001)** for a net loss to the Altamaha River of 20,320 gpm (45.3 cfs). The cooling tower evaporation rate for the proposed project would be approximately 28,880 gpm (64 cfs). This would cause a cumulative net loss to the Altamaha River of 109 cfs. For water years 1949-2004, the annual mean and lowest annual mean flows for the Altamaha River near Baxley, Georgia (Station 02225000) were 11,320 cfs and 3,762 cfs, respectively **(USGS 2005)**. The cumulative evaporative loss for the proposed project and existing units would represent 1.0 percent of the annual mean flow and 2.9 percent of the lowest annual mean flow for the Altamaha River. Therefore, impacts of surface water use would be SMALL.

HNP withdraws groundwater for potable and process use from the Floridan aquifer, one of the most productive groundwater reservoirs in the United States. Wells in the Floridan aquifer typically yield 1,000 to 5,000 gpm (**GDNR 2003**). HNP is currently permitted to withdraw a monthly average of 764 gpm. HNP currently uses an average of 126 gpm for approximately 950 employees **(NRC 2001)**. Assuming that groundwater use is proportional to the number of employees at the plant, 660 additional employees would require an additional 88 gpm, for a cumulative groundwater withdrawal rate of 214 gpm.

A major water quantity issue facing Georgia relates to the overuse of water from the Floridan aquifer along the coast, resulting in saltwater intrusions in the Savannah, Georgia - Hilton Head Island, South Carolina, area and in Brunswick, Georgia. To protect the Floridan aquifer from saltwater Intrusion, Georgia is developing policies for groundwater use in 24 coastal counties, including Appling and Toombs, that would promote water conservation and reuse, and require withdrawal permit applicants to provide a justification of need for water use **(GDNR 2005)**.

Well surveys have shown that municipalities and industries near the site do not require or use large amounts of groundwater. As a result, no significant cones of depression exist in the area surrounding the site **(GDNR 2005)**. An additional groundwater withdrawal of 88 gpm would have little effect on the Floridan aquifer, therefore impacts as a result of operation would be SMALL. However, because groundwater availability is an issue in coastal Georgia, siting additional units at HNP may cause public concern with respect to groundwater availability.

HNP currently operates under a NPDES permit issued by the Georgia Department of Natural Resources (GDNR). As authorized by the Clean Water Act, the NPDES permit program controls water pollution by regulating discharges into waters of the United States. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. The permit contains limits on what can be discharged, monitoring and reporting requirements, and other provisions to ensure that the discharge does not hurt water quality or human health. Any releases of contaminants to Altamaha River (or other Georgia waters) as result of construction or operation of the proposed project at HNP would be regulated by the GDNR through the NPDES permit process to ensure that water quality is protected. Therefore, impacts to water quality would be SMALL.

9.3.3.2.4 Terrestrial Resources Including Protected Species

The HNP site consists of approximately 900 acres immediately north of the Altamaha River in Toombs County and 1,340 acres immediately south of the Altamaha River in Appling County. Of the 2,240 acres that make up the site, approximately 300 acres are committed to generation facilities, parking lots, laydown areas, roads, and maintenance facilities. It is assumed that structures required for the construction of the proposed project at HNP would be situated in abandoned fields or developed areas of the existing plant site, and would avoid sensitive areas such as wetlands and mature forests.

The HNP site includes four basic ecological community types: wetlands, deciduous floodplain forests, upland areas, and pine plantations. Approximately 350 acres are comprised of wetlands and transmission corridors. Deciduous floodplain forests of the HNP site include approximately 700 acres of blackgum, cypress, oaks, and hickories in the floodplain of the Altamaha River. Upland areas include old fields and pine forests in various stages of succession, most of which are former agricultural lands and areas disturbed by construction activities in the 1960s and 1970s. Planted pines occupy roughly 400 acres of the HNP site, mostly south and southwest of the generating facilities. Approximately 1,600 acres of the HNP site are actively managed for wildlife and timber production. One state-listed species, the gopher tortoise, is known to occur in undeveloped portions of the HNP property.

Six transmission lines, within four transmission corridors and encompassing approximately 7,200 acres, makeup the transmission system connected to the HNP site. These lines traverse a variety of land use areas including urban and suburban, agricultural, forested, sandhills, floodplains, and abandoned fields. The lines cross three designated Wildlife Management Areas: Ocmulgee, Paulk's Pasture, and the Little Satilla. Otherwise, the lines do not cross any state or federal parks, wildlife refuges, or wildlife management areas. The lines do not cross any "critical habitats" as defined in Section 7 of the Endangered Species Act.

During endangered and threatened species surveys conducted in 1998 and 1999, several state- and federally-listed species were observed (or evidence of these species was found) in or adjacent to existing transmission line corridors. The shed skin of an Eastern indigo snake (listed as "threatened" by USFWS and GADNR), was found in the North Tifton corridor. American alligators (listed as "threatened due to similarity of appearance" by USFWS), were observed at survey locations in three transmission corridors. Red-cockaded woodpeckers (listed as "endangered" by USFWS and GADNR) were observed at two locations adjacent to the Florida transmission corridor. Bachman's sparrows (listed as "rare" by GADNR) were observed in the Florida and Thalmann corridors. Two Federally-listed species not observed in the 1998-1999 surveys, the threatened bald eagle and endangered wood stork, have been observed by GPC biologists and natural resources managers in the general area of HNP, but neither species is believed to nest in the vicinity of the plant. Bald eagles have been seen foraging along the Altamaha River upstream and downstream of HNP, and wood storks have been observed in a beaver pond wetland just east of the HNP cooling towers. No federally-listed plants were found during the 1998-1999 surveys of the HNP site and associated transmission line corridors, but one state-listed plant species (yellow pitcher plant, listed as "unusual" by GADNR) was found on the HNP site, and five state-listed species were identified on the transmission corridors. These consisted of the parrot pitcher plant (threatened), purple honeycomb head (rare), cutleaf beardtongue (rare), yellow pitcher plant (unusual), and hooded pitcher plant (unusual).

Land clearing associated with construction of the plant and transmission lines would be conducted according to Federal and state regulations, permit conditions, existing SNC procedures, good construction practices, and established Best Management Practices. With this in mind, and because the proposed project and any new transmission line would not require extensive land clearing, impacts to terrestrial resources, including endangered and threatened species, from construction and operation of the proposed project at the HNP site would be SMALL.

9.3.3.2.5 Aquatic Resources Including Protected Species

The Altamaha River is formed by the confluence of the Ocmulgee and Oconee Rivers 137 miles above the mouth and flows in a southeasterly direction until it empties into the Atlantic Ocean near Darien, Georgia. Several smaller streams contribute to the flow, but the major volume of water entering the Altamaha basin is via the Ocmulgee and Oconee River basins **(GDNR 2003)**.

The Altamaha River watershed ranks among the most biologically diverse river systems along the Atlantic seaboard. The river supports 11 imperiled pearly mussel species, 7 of which are found nowhere else in the world. At least 120 species of rare or endangered plants and animals are found in the Altamaha River watershed, the largest documented cluster of globally imperiled plants and animals of any watershed in Georgia **(TNC 2006)**. A 1998 survey of the freshwater mussel community in a 12-mile reach of the Altamaha River in the vicinity of HNP documented viable populations of 12 mussel species. Collections were dominated by species that are endemic to the Altamaha River system and species that are considered "Species of Concern" by the USFWS and GDNR because the status of their populations is not known. None of the mussel species collected was state or Federally-listed.

The Altamaha River is one of Georgia's few remaining free flowing streams and contains excellent habitat for numerous freshwater fish species. The diverse fish fauna of the Altamaha River basin includes 74 species representing 25 different families **(GDNR 2003)**. The largest group of species in the Altamaha River basin belongs to the sunfish family (*Centrarchidae*). Other families with large numbers of species are the sucker family (*Cyprinidae*) and the catfish family (*Ictaluridae*).

In addition to resident freshwater species, a number of anadromous fish species are also found within the Altamaha River. American shad, hickory shad, blueback herring, Atlantic sturgeon, and shortnose sturgeon all ascend the river in the spring to spawn **(GDNR 2003)**. American shad are commercially important species and the Altamaha River supports the largest commercial shad harvest of Georgia's rivers. Historically, Atlantic and shortnose sturgeon were also harvested commercially from the Altamaha River. However, the decline in abundance of these two species along the Atlantic coast has led to the listing of the shortnose sturgeon as an endangered species and the closure of the commercial fishery for both species.

The shortnose sturgeon is the only Federally-listed aquatic species known to occur in the Altamaha River in the vicinity of HNP. Shortnose sturgeons were first documented in the Altamaha River in the early 1970s and were the subject of several investigations in the 1980s and 1990s **(NMFS 1998)**. Based on mark-and-recapture studies in the late 1980s and early 1990s, the Altamaha River shortnose sturgeon population was estimated at from 468 to 2,862 individuals and was judged the "largest and most viable" south of Cape Hatteras, North Carolina **(NMFS 1998)**.

GPC evaluated the impact of the existing HNP cooling water intake system on shortnose sturgeon as part of its assessment of the impacts of license renewal and concluded that plant operation would not adversely affect the Altamaha River population. GPC biologists based this on the location and configuration of the cooling water intake, the species' habits and life history, and known spawning locations in the Altamaha River. Because most spawning takes place well downstream of HNP, the potential for entrainment of larvae and impingement of juveniles and adults is greatly reduced. There is a known spawning location in the Ocmulgee River approximately 24 river miles upstream of HNP, but the tendency of demersal sturgeon eggs to sink quickly and adhere to rough substrates and the tendency of larvae to seek cover immediately after hatching suggests that sturgeon spawned in the Ocumulgee would not be vulnerable to impingment and entrainment at HNP.

The construction of a cooling water intake and discharge structure would probably be necessary if a new nuclear unit was sited at HNP. The existing cooling water intake location at HNP has been shown to reduce the potential for entrainment and impingement. The intake structure was constructed flush with the shallow, southern shoreline of the Altamaha River. The deep river channel hugs the northern bank opposite of the intake structure. Literature indicates that shortnose sturgeon migrate along the bottom of river channels, often seeking the deepest water available. This behavior and the cooling water intake location on the shoreline opposite the river channel should minimize the probability of shortnose sturgeon encountering the intake structure **(NRC 2000)**. It is assumed that the design of a new intake structure would be similar to the current system, thereby reducing the potential impacts to sensitive species.

Based on review of the available information, potential impacts to aquatic resources, including federally and state-listed species, are expected to be SMALL from the construction of a new nuclear unit at the HNP site. A MODERATE impact may be created by the increased volume of water displaced from the river and used for the operation of the new nuclear unit. Additional analysis of river volume withdrawal effects would be required. Consultations would be held with the USFWS and GADNR to determine how to operate new units to create the fewest impacts to aquatic resources.

9.3.3.2.6 Socioeconomics

This section evaluates the social and economic impacts to the surrounding region as a result of constructing and operating the proposed project at the HNP site. The evaluation assesses impacts of construction, station operation, and demands placed by the construction and operation workforce on the surrounding region.

9.3.3.2.6.1 Physical Impacts

Construction activities can cause temporary and localized physical impacts such as noise, odor, vehicle exhaust, vibration, shock from blasting, and dust emissions. The use of public roadways, railways, and waterways would be necessary to transport construction materials and equipment. However, extensive work is planned on the existing roads to reduce existing bottlenecks in the regional highway system **(GDOT 2006a)**, so physical impacts on the existing road network would be minimal. It is assumed that all construction activities would occur within the existing HNP site. Offsite areas that would support construction activities (for example, borrow pits, quarries, and disposal sites) are expected to be already permitted and operational. Impacts on those facilities from construction of the proposed project would be small incremental impacts associated with their normal operation.

Potential impacts from station operation include noise, odors, exhausts, thermal emissions, and visual intrusions. The proposed project would produce noise from the operation of pumps, fans, transformers, turbines, generators, and switchyard equipment, and traffic at the site would also be a source of noise. However, noise attenuates quickly so ambient noise levels would be minimal at the site boundary. Also, HNP is located in a rural area surrounded by forests and agricultural land, so residents in the area are sparse. Commuter traffic would be controlled by speed limits. Good road conditions and appropriate speed limits would minimize the noise level generated by the workforce commuting to HNP site.

The proposed project would have standby diesel generators and auxiliary power systems. Permits obtained for these generators would ensure that air emissions comply with regulations. In addition, the generators would be operated on a limited, short-term basis. During normal plant operation, the proposed project would not use a significant quantity of chemicals that could generate odors that exceed threshold values. Good access roads and appropriate speed limits would minimize the dust generated by the commuting workforce.

Construction activities would be temporary and would occur mainly within the boundaries of the HNP site. Offsite impacts would represent small incremental changes to offsite services. During station operations, ambient noise levels would be minimal at the HNP site boundary. Air quality permits would be required for the diesel generators, and chemical use would be limited, which would limit odors. Therefore, the physical impacts of construction and operation would be SMALL.

9.3.3.2.6.2 Demography

The HNP site is located in Appling and Toombs Counties, Georgia. The population distribution around the site is quite low with typical rural characteristics. In the year 2000, Appling County had a population of 17,419 and Toombs County had a population of 26,067 **(USCB 2000c)**. In 2000, the population within 50 miles of the site was 387,582 people (49.4 persons per square mile), and the population within 20 miles of the site was 58,752 people (46.8 persons per square mile). The nearest population center, as defined in 10 CFR 100 is Savannah, Georgia (population approximately 131,510) located approximately 67 miles northeast of HNP **(USCB 2006b)**. Based on the sparseness and proximity matrix in NUREG-1437 HNP is located in a low population area.

Based on the analysis in Section 4.4.2.1, SNC assumes that construction of the proposed project at HNP would increase the population in the 50-mile region by 7,200 people. The majority of the current HNP workforce lives in Appling (30 percent) or Toombs (41 percent), Counties. The remaining employee residences are distributed throughout 28 counties, mostly within 50 miles of the site. SNC assumes that the residential distribution of the construction workforce would resemble the residential distribution of the current HNP workforce. Of the total population increase, 2,160 people (30 percent of 7,200) would settle in Appling County, 2,952 people would settle in Toombs County. These numbers constitute 12.4 percent and 11.3 percent of the 2000 populations of Appling and Toombs Counties, respectively. Impacts are considered to be small if plant-related population growth is less than 5 percent of the study area's total population and moderate if growth is between 5 and 20 percent. The construction employees and their families would represent MODERATE increases to Appling and Toombs Counties' total populations and SMALL increases to the other counties in the 50-mile region.

Based on the analysis in Section 5.8.2.1, SNC assumes that operation of the proposed project at HNP would increase the population in the 50-mile region by 1,750 people. Approximately 30 percent would settle in Appling County and 41 percent would settle in Toombs County. The addition of the new employees and their families would equate to a 3.0 percent increase for Appling County and a 2.8 percent increase for Toombs County. Overall, the potential increases in population would represent a SMALL increase in the total population.

9.3.3.2.6.3 Economy

Based on 2000 census data, within the region surrounding HNP, there are 55,445 persons in the labor force. Appling County's business profile is led by manufacturing (18.4 percent of the county's total employment), followed by educational, health, and social services (17.9 percent), and construction (11.7 percent) **(USCB 2000d)**. The unemployment rate for Appling County in 2004 was 6.1 percent, compared with 4.6 percent for the State of Georgia **(UGA 2006)**.

In neighboring Toombs County, the business profile is led by educational, health, and social services (18.4 percent of the county's total employment), followed by manufacturing (14.9 percent), and retail trade (9.9 percent) **(USCB 2000d)**. The unemployment rate in Toombs County was 6.0 percent in 2004 **(UGA 2006)**.

Economic impacts would be spread across the 50-mile region, but would be greatest in Appling and Toombs Counties. Impacts are small if plant-related employment is less than 5 percent of the study area's total employment and moderate if employment is between 5 and 10 percent. SNC concludes that the impacts of construction on the economy of the region would be beneficial and temporary, and would therefore be SMALL.

The wages and salaries of the operating workforce would have a multiplier effect that could result in increases in business activity, particularly in the retail and service sectors. This would have a positive impact on the business community and could provide opportunities for new businesses to get started, and increased job opportunities for local residents. The economic effect on the 50-mile region would be beneficial. SNC assumes that direct jobs would be filled by an in-migrating workforce, but most indirect jobs would be service-related, not highly specialized, and would be filled by the existing workforce within the 50-mile region and particularly in Appling and Toombs Counties. SNC anticipates that most of the indirect jobs created by the operations workforce would be filled by unemployed workers in the region. Expenditures made by the direct and indirect workforce would strengthen the regional economy.

SNC concludes that the impacts of station operation on the economy would be beneficial and SMALL everywhere in the region except Appling and Toombs Counties, where the impacts would be beneficial and MODERATE, and that mitigation would not be warranted.

9.3.3.2.6.4 Taxes

Taxes collected as a result of constructing and operating the proposed project at HNP would be of benefit to the State and local jurisdictions that collected and spent them. Corporate and personal income taxes and sales and use taxes would be collected during both the construction and operation of a new unit at HNP. SNC anticipates that HNP would pay annual property taxes to Appling County, beginning during construction of the proposed project. Georgia assesses property at 40% of its value. Assuming a 40-year operational life, property taxes to Appling County could average between $20,000,000 and $29,000,000 annually during the first decade of operation and between $3,500,000 and $5,000,000 during the last decade of operation. HNP property taxes provided 68 percent of Appling County's total property tax revenues in 1998 **(NRC 2001)**. The benefits of taxes are large when new tax payments represent more than 20 percent of total revenues for local jurisdictions. Therefore, SNC concludes that the potential beneficial impacts of taxes collected during construction and operation of the proposed project would be LARGE in Appling County and SMALL in the remainder of the 50-mile region.

9.3.3.2.6.5 Transportation

Road access to HNP is via U.S. Highway 1, the major north-south highway route bisecting Appling and Toombs counties. U.S. Highway 1 is a four-lane highway from Baxley past HNP where it enters Toombs County and becomes a two-lane road north of HNP to Interstate 16. Interstate 16 is the major east-west freeway serving the area. In 2004, the annual average daily traffic count for the highway was 5,050 vehicles south of the HNP site and 4,700 vehicles north of the site **(GDOT 2006b)**. The State plans to widen the entire highway to four lanes, which would provide four-lane access from Baxley all the way to Interstate 16 **(GDOT 2006a)**. Right-of-way acquisition for the widening project is anticipated to begin in 2007, and construction would begin after 2008 **(GDOT 2005)**.

Assuming construction ships as described in Section 4.4.2.2.4, an additional 2,200 cars could be on the highway during shift change, causing potential congestion. Also, the traffic of hauling construction materials (100 trucks per day) to the site could cause additional congestion on U.S. Highway 1 during certain times of the day. Heavy congestion and delays could be experienced if planned road improvements on U.S. Highway 1 occur during construction of the proposed project at HNP. Transportation impacts are small when increases in traffic do not result in delays or other operational problems, impacts are MODERATE when increases in traffic begins to cause delays or other operational problems. Overall, impacts of construction on transportation would be moderate and some mitigating actions may need to be undertaken.

With respect to operation of the facility, adding an additional 600 cars (during afternoon shift change) to the existing traffic on the road would not materially congest the highway. Shift changes for the current units and the proposed project at HNP could be staggered so that the traffic increase would not cause congestion. Impacts of the operations workforce on transportation would be SMALL to MODERATE and mitigation would not be warranted.

9.3.3.2.6.6 Aesthetics and Recreation

The HNP site encompasses approximately 2,240 acres and is characterized by low, rolling sandy hills that are predominantly forested. The developed area at HNP is located near the center of a 1,340 acre parcel on the south bank of the Altamaha River. The exisiting facilties at HNP are visible from portions of U.S. Highway 1 and from the adjacent reach of the Altamaha River.

The construction of the proposed project at HNP could be viewed from offsite at certain locations, but the addition of another facility would not substantially change the view which results from the current units. There could be a need to construct cooling-water intake and discharge structures at the site. Additional mechanical or natural draft cooling towers would be required. The operation of a new nuclear unit probably would have visual impacts similar to those of the existing HNP units, with the addition of more visible plumes from cooling towers. Impacts on aesthetic resources are considered to be small if there are no complaints about diminution in the enjoyment of the physical environment and no measurable impact on socioeconomic institutions and processes. Therefore, impacts of construction and operation of the proposed project on aesthetics would be SMALL and would not warrant mitigation.

Recreational facilities located within the boundaries of the HNP site include a 100-acre tract of land west of U.S. Highway 1 used as a Boy Scout Camp, a wayside park, an employee recreation area, and the HNP Visitors Center. Other recreational facilities within 10 miles of HNP include the Altamaha River, the Bullard Creek Wildlife Management Area, Grays Landing, and miscellaneous parks and sports facilities operated by the City of Baxley.

During construction of the proposed project at HNP it is anticipated that access to onsite recreational facilities could be interrupted during periods of peak activity but other recreational facilities in the region could accommodate typical users of the onsite facilities. The attractiveness of the Altamaha River for sport fishing and other recreational uses could be impacted during construction of intake and discharge structures. Other recreational facilities be affected by increased traffic on area roads during peak travel periods, but impacts would be minimal. During the operating period, it is expected that some HNP employees and their families would use the recreational facilities in the region. However, the increase attributable to plant operations would be small compared to overall use of these facilities. Impacts on tourism and recreation are considered small if current facilities are adequate to handle local levels of demand. Therefore, impacts of facility construction and operation on tourism and recreation would be SMALL.

9.3.3.2.6.7 Housing

In 2,000, Appling County had 7,854 housing units, of which 1,248 units (15.9 percent) were vacant. Toombs County had 11,371 housing units of which 1,494 (13.1 percent) were vacant. Jeff Davis County had 5,581 housing units of which 753 (13.5 percent) were vacant.

Montgomery County had 3,492 housing units of which 573 (16.4 percent) were vacant, and Tattnall County had 8,578 housing units of which 1,521 were vacant (17.7 percent). **(USCB 2000c)**

Based on the analysis in Section 4.4.2.2.5, approximately 3,400 construction workers would in-migrate to the 50-mile region. Of these, approximately 2,700 would purchase or rent permanent housing. The 680 temporary workers would rent temporary (e.g., hotels, motels, rooms in private home) or permanent housing, or bring their own housing in the form of campers and mobile homes. Currently, available housing in the two-county area (Appling and Toombs Counties) is minimally adequate to accommodate the expected influx of workers. Workers could also find housing in other parts of the 50-mile region or construct new housing. Given this increased demand for housing, prices of existing housing could rise. Appling and Toombs Counties (and other counties to a lesser extent) would benefit from increased property values and the addition of new houses to the tax rolls. Increasing the demand for homes could increase rental rates, and housing prices. It is unlikely but possible that some low-income populations could be priced out of their rental housing due to upward pressure on rents. However, the construction workforce would increase over time; any actual housing shortage is unlikely to be as severe as a comparison of maximum workforce to available housing would indicate. The gradual influx of new residents would give the housing market time to adjust to its needs.

In summary, the two counties where most of the construction workforce would seek housing have minimally adequate housing resources for the entire workforce. Impacts on housing are considered to be small when a small and not easily discernable change in housing availability occurs, and impacts are considered to be moderate when there is a discernable but short-lived reduction in the availability of housing units. SNC concludes that the potential impacts of construction on housing could be MODERATE in Appling and Toombs Counties and would be SMALL in the remainder of the 50-mile region. Mitigation would not be warranted where the impacts were small. Mitigation of the moderate impacts would occur as developers and builders anticipated the arrival of the workforce and constructed additional housing. Additional mitigation would not be warranted.

SNC assumes that operation of the proposed project at HNP would increase the population in the 50-mile region by 1,750 people. Approximately 30 percent would settle in Appling County and 41 percent would settle in Toombs County. While there is currently enough housing to accommodate all the new families expected in Appling and Toombs Counties, not all housing may be the type sought by the new workforce. The average income of the new workforce would be expected to be higher than the medium or average income in these counties, therefore, the new workforce could exhaust the high-end housing market and some new construction could result.

SNC concludes that the potential impacts of operations on housing in Appling and Toombs Counties would be SMALL to MODERATE, and SMALL elsewhere in the 50-mile region. Market forces could result in more housing being built in the two-county region, mitigating any housing shortages. Additional mitigation would not be warranted.

9.3.3.2.6.8 Public Services

Public services include water supply and waste water treatment facilities; police, fire and medical facilities; and social services. Impacts on public services are considered to be small if there is little or no need for changes in the level of service provided to the community. It is not expected that public services would be materially impacted by the HNP construction or operations workforce. Therefore, impacts of construction and operation on public services would be SMALL and mitigation would not be warranted.

9.3.3.2.6.9 Education

Based on the analysis in Section 4.4.2.8, SNC assumes that construction of the proposed project at HNP would increase the school-aged population in the 50-mile region by 1,900. Approximately 30 percent would settle in Appling County and 41 percent would settle in Toombs County. The Appling County student population would increase by 13.2 percent and the Toombs County student population would increase by 11.6 percent. Large impacts on local school systems are generally associated with project-related enrollment increases above 8 percent. Therefore, the projected increases in the student populations of Appling and Toombs Counties would constitute a LARGE impact on the education systems and mitigation would be warranted.

Based on the analysis in Section 5.8.2.2.7, SNC assumes that operation of the proposed project at HNP would increase the school-aged population in the 50-mile region by 464 people. Approximately 30 percent would settle in Appling County and 41 percent would settle in Toombs County. The Appling County student population would increase by 3.2 percent and the Toombs County student population would increase by 2.8 percent. These increases in student population are below 4 percent of the total student populations in Appling and Toombs counties, hence project-related enrollment increases would constitute a SMALL impact on the education systems and mitigation would not be warranted.

9.3.3.2.7 Historic and Cultural Resources

NRC conducted historical and archaeological records searches at the Georgia Historic Preservation Division, University of Georgia State Archeological Site Files, the National Park Service's National Register Information System, and the National Archeological Database during the license renewal application process. The record searches revealed that no historical or archaeological sites were recorded on lands within the boundaries of HNP, although no cultural resource inventories have been completed for any of the plant site acreage. **(NRC 2001)**

Three archeological surveys have been conducted within a mile of HNP. During a 1977 survey of the lower Ocmulgee River Drainage, four archeological sites were noted in the Altamaha River Park about half a mile west of the HNP boundary. A 1984 survey of the same area identified three additional sites in the same vicinity. The third survey in 1996 included a stretch of U.S. Highway 1 along the site boundary starting northward of the plant entrance. No historical or archaeological sites were noted in Appling County, and 11 historical sites were noted in Toombs County. **(NRC 2001)**

The closest historical sites listed in the National Register of Historic Places (NRHP) include five sites in Appling County and nine sites in Toombs County. In Appling County, four historic sites are located in Baxley and one site is located in Surrency. In Toombs County, six historic sites are located in Vidalia and three sites are located in Lyons. There are no properties listed in the NHRP that are located within a 10-mile radius of HNP. **(NPS 2006b)**

One unrecorded historical site is known to exist on the HNP site. The Bell Cemetery is presently located within the HNP family recreation area, and is fenced and maintained by HNP personnel. **(NRC 2001)**

Siting the proposed project at HNP would require that a formal cultural resources survey be conducted so that no archeological or historic resources would be damaged during construction of the proposed project. Mitigative measures would be performed to prevent permanent damage and ensure that any impacts to cultural resources from construction or operation at HNP would be SMALL.

9.3.3.2.8 Environmental Justice

The 2000 Census and block groups were used for ascertaining minority and low-income populations in the area. There are 337 block groups within a 50 mile radius of HNP. Black minority populations exist in 55 block groups; “Aggregate of Minority Races” populations exist in 63 block groups; “Hispanic Ethnicity” minority populations exist in 5 block groups; and “All Other Single Minorities” exist in 3 block groups. No other minority populations exist in the geographic area. The Census Bureau data characterize 12.64 percent of Georgia households as low-income. Based on the “more than 20 percent” criterion, 41 block groups out of a possible 337 contain a low-income population. There are no minority or low income populations within a 6-mile radius of HNP.

Construction activities (noise, fugitive dust, air emissions, traffic) would not disproportionately adversely affect minority populations because of their distance from HNP. In fact, minority and low-income populations would most likely benefit from construction activities through an increase in construction-related jobs. Operation of the proposed project at HNP is also unlikely to have a disproportionate impact on minority or low-income populations. In the HNP License Renewal Environmental Impact Statement **(NRC 2001)**, NRC noted that no unusual resource dependencies or practices, such as subsistence agriculture, hunting, or fishing through which the populations could be disproportionately adversely affected have been identified. In addition, no location-dependent disproportionate adverse impacts affecting these minority and low-income populations have been identified or observed **(NRC 2001)**. SNC concludes that environmental justice consequences of the construction and operation of the proposed project at HNP would be SMALL, and that mitigation would not be warranted.

9.3.3.3 Evaluation of the Barton Site

The Barton Site is undeveloped property that was acquired in the 1970's by APC, a wholly-owned subsidiary of Southern Company, for the purpose of constructing a four-unit nuclear generating facility. Approximately 60 acres near the center of the site is owned by others and would need to be acquired before any facilities could be built on the property. The Barton Site is located in south-central Alabama, adjacent to the west bank of the Jordan Reservoir about 14 miles above the Jordan Dam on the Coosa River (Figure 9.3-3). It is about 27 miles north of Montgomery, 44 miles northeast of Selma, 58 miles south of Birmingham, 19 miles northwest of Wetumpka, and 15 miles southeast of Clanton. The site is about equally divided by the county line between Chilton and Elmore Counties and is bordered by Coosa County on its northeastern edge.

9.3.3.3.1 Land Use Including Site and Transmission Line Rights-of-Way

The Barton Site consists of 2,800 acres on the west bank of Jordan Reservoir between Chestnut Creek to the north and Jake Creek to the south. The undeveloped site is predominantly forested, and is characterized by moderately rolling hills with maximum local relief of about 300 feet occurring between the river and nearby ridge tops.

The land in the site region is rural. About 86 percent of the land in the Coosa River basin is wooded with this wood being used for production of pulpwood and timber. About 12 percent of the land in the basin is used for agricultural purposes, and about one percent is urban.

Construction of the power plant and transmission lines would alter land use at the site from vacant to industrial use. The footprint of a new plant would be approximately 400 acres and an additional 150 acres would be required for temporary facilities and laydown yards. Because the site is undeveloped, additional acreage would be required for roads, parking lots, and a switchyard. The entire 2,800 acres would be excluded from future agricultural and recreational use for the estimated 40-year life of the plant.

State Road 22 passes approximately 3.6 miles north of the Barton Site at its closest point. A 4-mile paved road with a 100-foot right-of-way would be constructed to provide vehicle access from State Road 22 to the Barton Site. Development of the road would require approximately 50 acres. The Louisville & Nashville Railroad passes approximately 5.5 miles southwest of the site at its closest point. A 6-mile connecting rail spur, requiring approximately 120 acres, would also be constructed to transport materials and equipment to the site. Land-use impacts associated with site-preparation, construction, and operation of the proposed project at the Barton Site would be LARGE.

SNC assumed that two 500-kilovolt transmission lines requiring a 300-foot wide transmission corridor would be needed to connect the proposed project to APC's transmission system. It is assumed that the lines would connect to the substation at the Gaston Generating Plant, which is approximately 35 miles north of the Barton Site near Wilsonville, Alabama. Routing the new transmission lines to the Gaston Generating Plant would require about 1273 acres of transmission corridor. Although the most direct route would, in general, be used between terminations, consideration would also be given to avoiding possible conflicts with any natural or man-made areas where important environmental resources are located. Route selection would also avoid populated areas and residences to the extent possible. The use of lands which are currently used for forests or timber production would be altered. Trees would be replaced by grasses and other low-growing types of ground cover. The new transmission corridor would not be expected to permanently affect agricultural areas, but has the potential to affect residents along the right-of-way. For this reason, impacts to land use along the rights-of-way would be MODERATE.

The region surrounding the Barton Site is not within the Alabama Coastal Zone (Code of Alabama 1975, Section 9-7-15). It is assumed that transmission lines to connect the proposed project at the Barton Site to APC's transmission system would be routed to the substation at the Gaston Generating Plant. The route for the new transmission lines would not pass through any portion of the Alabama Coastal Zone.

9.3.3.3.2 Air Quality

The four counties surrounding the Barton Site, Chilton, Elmore, Coosa, and Autauga, are designated as being unclassified or in attainment of the National Air Quality Standards (NAAQS). The nearest non-attainment area is Shelby County, Alabama, which is approximately 25 miles northwest of the site. Shelby County, a southeastern suburb of Birmingham, is in non-attainment for ozone and PM2.5 (40 CFR 81.301).

Air pollutant emissions from construction and operation of the proposed project at the Barton Site would be similar to those at the VEGP site. Construction impacts would be temporary, and would be similar to any large-scale construction project. Particulate emissions in the form of dust from disturbed land, roads, and construction activities would be generated. Mitigation measures similar to those described for the VEGP site would be taken. Air pollutants would be emitted from the exhaust systems of construction vehicles and equipment and from vehicles used by construction workers to commute to the site. The amount of pollutants emitted in this way would be small compared to total vehicular emissions in the region. It is not expected that construction-related emissions would result in any violation of NAAQS.

During station operation, standby diesel generators would be used for auxiliary power. It is expected that these generators would see limited use and, when used, they would operate for short time periods. The proposed project would be subject to a Synthetic Minor Operating Permit to ensure that the facility operations would not interfere with attaining or maintaining Primary and Secondary NAAQS **(ADEM 2005)**. Therefore, air pollutant emissions from the standby diesel generators are expected to be minimal and would not result in any violation of NAAQS.

The closest area to the Barton Site that is designated in 40 CFR 81.408 as a mandatory Class I Federal area, in which visibility is an important value, is the Sipsey Wilderness Area. The Sipsey Wilderness Area is approximately 145 miles northwest of the site. Because there are no mandatory Class I Federal areas within 50 miles of the site, any potential visibility impacts from the proposed units on Class I areas would be negligible.

The air quality impacts from construction and operation of the proposed project at the Barton Site would be SMALL.

9.3.3.3.3 Hydrology, Water Use, and Water Quality

The Barton Site is located within the Piedmont Province. The Piedmont Province is underlain by a two-component aquifer system that is composed of a fractured, crystalline-rock aquifer characterized by little or no primary porosity or permeability; and the overlying regolith, which generally behaves as a porous-media aquifer. Rock type, structural features, and regolith thickness vary locally and affect the storage capacity and hydraulic conductivity of an aquifer. The volume of water in storage is controlled by the porosity of the regolith and to a lesser degree by the amount of fracturing of the rock. Because of the limited storage in fractures, water levels in these aquifers respond rapidly to pumping and seasonal changes in rainfall. Yields from wells completed in fractured crystalline-rock aquifers generally range from 1 to 25 gpm. **(Robinson et al. 1996)**

Groundwater at the Barton Site is typical of the Piedmont region. It is present in open fractures of gneissic bedrock and in the interstices of the saprolite in the overlying regolith. Permeabilities in the bedrock and overlying regolith are low, and water levels respond rapidly to pumping and rainfall. Inspection of the topography, geology, stream patterns, and water table contour maps show that the water underlying the site flows either directly to the Coosa River, or indirectly to the river, first discharging into tributary streams that act as interceptor drains to groundwater flow. Thus, all groundwater underlying the site eventually reaches the Coosa River.

As discussed above, the aquifer underlying the site has low permeability; wells developed on the property would have low yields. Therefore, SNC assumed that all water needed to support the proposed project at the Barton Site would be withdrawn from the Jordan Reservoir. Jordan Reservoir is located on the Coosa River and extends approximately 18 miles upstream from Jordan Dam to Mitchell Dam through Chilton, Coosa, and Elmore Counties. Jordan Reservoir has a surface area of 5,880 acres at a normal water surface elevation of 252 feet msl. The Bouldin development, located on a man-made canal off the Coosa River, also receives flow from Jordan Reservoir and discharges into the Coosa River. Including the Bouldin forebay, the lake has 118 miles of shoreline and a surface area of 6,800 acres. The reservoir is used for hydroelectric generation, limited storage for power generation, navigation flow augmentation, maintenance of downstream water quality, industrial and municipal water supply, irrigation, recreational opportunities and serves as habitat for fish and wildlife. There is no flood control storage in Jordan Reservoir, including the Bouldin forebay; rather the reservoir is operated in an approximate run-of-river mode, with daily inflow basically equaling outflow.

The cooling tower evaporation rate for the proposed project would be 28,880 gpm (64 cfs). It is assumed that an additional 90 gpm (0.2 cfs) would be needed for domestic purposes. For water years 1913-2004, the annual mean and lowest annual mean flows for the Coosa River at Jordan Dam near Wetumpka, Alabama (Station 02411000) were 16,230 cfs and 5,402 cfs, respectively **(Psinakis et al. 2005)**. The total loss attributable to the proposed project would represent 0.4 percent of the annual mean flow and 1.2 percent of the lowest annual mean flow for the Coosa River.

Although the water withdrawal from the Jordan Reservoir would represent a small percentage of the Coosa River flow, increased water use could cause controversy in the area due to recent water use conflicts between Alabama, Georgia, and Florida. Demand for Coosa River water from upstream users has increased dramatically in recent years. The headwaters of the Basin are in northern Georgia where expanding urban areas are placing increased demands on the water resources that, in turn, reduce available water resources downstream in Alabama. Between 1970 and 1990, water used for public supply in the portion of the Alabama-Coosa-Tallapoosa (ACT) Basin increased 44 percent to almost 185 million gallons per day. Total water use in the Alabama portion of the ACT Basin increased about 7 percent **(USGS 2006)**. Increased water withdrawal reduces flows downstream, affecting the amount of water available for downstream users, water quality, ecological habitats, navigation, and recreation **(Lipford 2004)**. The amount of water from the Coosa River that would be required by the proposed project is small compared with major users of the resource, and impacts to Coosa River as a result would be SMALL. However, any increase in water withdrawal from the Coosa River would be scrutinized by neighboring states.

The Barton Site would operate under a NPDES permit issued by the ADEM. As authorized by the Clean Water Act, the NPDES permit program controls water pollution by regulating discharges into waters of the United States. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. The permit contains limits on what can be discharged, monitoring and reporting requirements, and other provisions to ensure that the discharge does not hurt water quality or human health. Any releases of contaminants to Jordan Reservoir (or other Alabama waters) as result of construction or operation of the proposed project at the Barton Site would be regulated by the ADEM through the NPDES permit process to ensure that water quality is protected. Therefore, impacts to water quality would be SMALL.

9.3.3.3.4 Terrestrial Resources Including Protected Species

The plant site is located approximately 15 miles southeast of Clanton, Alabama, along the west side of the Jordan Reservoir, which is an impoundment of the Coosa River. The site encompasses approximately 2,800 acres, and is situated along the Chilton-Elmore county line, directly across the river from Coosa County. The terrain is moderately rolling, with a maximum relief of 300 feet between the Jordan Reservoir (elevation 252-feet msl) and nearby ridge tops. Most of the site is forested, and consists of hardwoods, pines, and mixed hardwood/pine. Based on TerraServer imagery from 1998 **(TerraServer 2005)**, forested habitats occupy the area for about two miles surrounding the site, and land beyond two miles of the site is predominately a mixture of forest and agriculture. Animal species that occur on the Barton Site are those typically found in similar habitats in central Alabama, such as the opossum, eastern cottontail, gray squirrel, raccoon, white-tailed deer, and various reptiles, amphibians, and birds. Since most the Barton Site is forested, it is assumed that at least 550 acres (see Section 9.3.3.3.1) of forest would have to be cleared for the construction of the Barton Nuclear Plant and associated facilities.

SNC is not aware of any known occurrences of federally listed threatened or endangered species on the Barton Site, but formal surveys of the site have not been conducted. Table 9.3-1 indicates federally-listed plant and animal species recorded in Chilton, Coosa, Elmore, and Talledega Counties, which are the counties through which transmission lines from the Barton Site would presumably pass (See Section 9.3.3.3.1). Terrestrial species in Table 9.3-1 consist of the bald eagle, red-cockaded woodpecker, wood stork, Georgia rockcress, and Alabama canebrake pitcher plant. Red-cockaded woodpeckers would not exist at the site due to the absence of habitat for this species (mature pines with minimal hardwoods). Field surveys would be conducted for federally-listed and state protected species as part of the permitting process prior to any clearing or construction activities at the site or along associated transmission corridors.

As mentioned in Section 9.3.3.3.1, it is assumed that two 500-kilovolt transmission lines requiring a 300-foot wide transmission corridor would be needed to connect the proposed project to APC's transmission system. The new lines would most likely connect to the substation at the Gaston Generating Plant, which is approximately 35 miles north of the Barton Site near Wilsonville, Alabama. Routing the new transmission lines to the Gaston Generating Plant would require about 1273 acres of transmission corridor. Although the most direct route would generally be used between terminations, consideration would also be given to avoiding possible conflicts with natural areas where important environmental resources are located. Land clearing associated with construction of the plant and transmission lines would be conducted according to Federal and state regulations, permit conditions, existing SNC procedures, good construction practices, and established Best Management Practices (e.g., directed drainage ditches, silt fencing). With this in mind, impacts to terrestrial resources, including endangered and threatened species, from construction and operation of the Barton plant would probably be SMALL. However, due to the uncertainty associated with route selection and clearing of the Barton Site and transmission corridors, impacts to terrestrial resources could be MODERATE.

9.3.3.3.5 Aquatic Resources Including Endangered Species

The Jordan Reservoir (also known as Jordan Lake) was formed by Jordan Dam and Walter Bouldin Dam. The Jordan Dam is on the Coosa River, while the Walter Bouldin Dam is located on a man-made canal off the Coosa River and discharges into the Coosa River at the confluence of the Coosa and Tallapoosa Rivers. Jordan Reservoir extends 18 miles upstream from the Jordan Dam to the Mitchell Dam and has a surface area of 5,880 acres at a normal water surface elevation of 252 ft msl. Including the Bouldin forebay, the lake has 118 miles of shoreline and a surface area of 6,800 acres. The maximum depth of the lake is 110 ft. The lake has a 10,165 sq mi drainage area and is used for hydroelectric generation, navigation flow augmentation, maintenance of downstream water quality, industrial and municipal water supply, irrigation, recreation, and as habitat for fish and wildlife. The Jordan Reservoir is about 890 feet wide at the Barton Site with a maximum depth of 45 feet. Common sport fish species include largemouth bass, bluegill, warmouth, green sunfish, redear sunfish, crappie, blue catfish, and channel catfish.

Water from the Jordan Reservoir would be expected to cool the proposed project constructed at the Barton Site. Although recreational sport fish and other aquatic species would be temporarily displaced during construction, they would be expected to recolonize the area after construction is complete. Federally-listed aquatic species known to occur in Chilton, Coosa, Elmore, and Talledega Counties consist of one fish (blue shiner), one plant (Kral's water-plantain) and eight mussels and snails (Table 9.3-1). APC cooperates with the U.S. Fish and Wildlife Service in protecting these and other rare species and in developing Biological Assessments as part of various hydroelectric projects. Field surveys would be conducted for federally-listed and state protected aquatic species as part of the permitting process prior to any clearing or construction activities at the site or along associated transmission corridors. Because of this, and since land clearing associated with construction of the plant and transmission lines would be conducted according to Federal and state regulations, permit conditions, existing APC procedures, good construction practices, and established Best Management Practices, impacts to aquatic resources, including endangered and threatened species, from construction of the Barton plant would probably be SMALL.

The most likely aquatic impact from operations of the Barton plant would be entrainment and impingement of aquatic organisms in the Jordan Reservoir. Because the EPA requires facilities to meet criteria designed to protect organisms from entrainment and impingement, the potential for environmental impacts to aquatic resources, including endangered and threatened species, from operation of the Barton plant would probably be SMALL.

9.3.3.3.6 Socioeconomics

This section evaluates the social and economic impacts to the surrounding region as a result of constructing and operating the proposed project at the Barton Site site. The evaluation assesses impacts of construction, station operation, and demands placed by the construction and operation workforce on the surrounding region.

9.3.3.3.6.1 Physical Impacts

Construction activities can cause temporary and localized physical impacts such as noise, odor, vehicle exhaust, vibration, shock from blasting, and dust emissions. The use of public roadways, and railways would be necessary to transport construction materials and equipment. The majority of construction activities would occur within the boundaries of the Barton Site. However, an access road and a connecting rail spur (requiring about 170 acres) would be constructed on lands adjacent to the site. These new transportation rights-of-way would be routed to avoid residences and populated areas. Offsite areas that would support construction activities (for example, borrow pits, quarries, and disposal sites) are expected to be already permitted and operational. Impacts on those facilities from construction of the proposed project would be small incremental impacts associated with their normal operation.

Potential impacts from station operation include noise, odors, exhausts, thermal emissions, and visual intrusions. The proposed project would produce noise from the operation of pumps, fans, transformers, turbines, generators, and switchyard equipment, and traffic at the site would also be a source of noise. However, noise attenuates quickly so ambient noise levels would be minimal at the site boundary. Also, the Barton Site is located in a rural area surrounded by forests and agricultural land, with few residents in the area. Commuter traffic would be controlled by speed limits. Good road conditions and appropriate speed limits would minimize the noise level generated by the workforce commuting to the site.

The proposed project would have standby diesel generators and auxiliary power systems. Permits obtained for these generators would ensure that air emissions comply with regulations. In addition, the generators would be operated on a limited, short-term basis. During normal plant operation, the proposed project would not use a significant quantity of chemicals that could generate odors that exceed odor threshold values. Good access roads and appropriate speed limits would minimize the dust generated by the commuting workforce.

Construction activities would be temporary and would occur mainly within the boundaries of the Barton Site. Offsite impacts would represent small incremental changes to offsite services supporting the construction activities. During station operations, ambient noise levels would be minimal at the site boundary. Air quality permits would be required for the diesel generators, and chemical use would be limited, which should limit odors. Therefore, the physical impacts of construction and operation would be SMALL.

9.3.3.3.6.2 Demography

The Barton Site is located in Chilton and Elmore Counties, Alabama. The site currently meets the population requirements of 10 CFR 100. The population distribution around the site is quite low with typical rural characteristics. The total population of the four counties in the site region is 161,340 persons as of the 2000 Census. Population within the counties were 43,671 in Autauga County, 39,593 in Chilton County, 12,202 in Coosa County, and 65,874 in Elmore County **(USCB 2000e)**. The population within 50 miles of the site was 735,226 people (93.74 persons per square mile), and the population within 20 miles of the site was 90,677 people (72.26 persons per square mile). The nearest population center, as defined in 10 CFR 100 is Montgomery, Alabama (population approximately 201,568) located approximately 27 miles south of the site **(USCB 2006c)**. Based on the sparseness and proximity matrix in NUREG-1437 the Barton Site is located in a medium population area.

Due to the proximity of the Barton Site to the Birmingham and Montgomery metropolitan areas, the most populous metropolitan areas in Alabama, it is expected the majority of construction workers would come from within the region. Workers coming from outside the region would probably commute to the construction site, stay for the week, and go back to their permanent residence on weekends. Any construction employees relocating to the region would most likely be scattered throughout the counties in the region. Should a larger than expected number of construction workers relocate to the region, there would not be a noticeable increase in population for the most impacted counties. If 20 percent of the peak construction workforce, about 880 workers and their families, decided to relocate the population in the region would increase by 2,332 people, (assuming an average household size of 2.65 people). Based on 2000 census data, the addition of the new employees and their families would equate to a 5.9 percent increase for Chilton County and a 3.5 percent increase for Elmore County (assuming that all 2,332 people located to one county or the other). Impacts are considered to be small if plant-related population growth is less than 5 percent of the study area’s total population. Therefore, the potential increases in population during construction would represent a SMALL to MODERATE increase in the total population for the most impacted counties.

Approximately 800 workers (660 operations personnel plus 140 security personnel) would be required for the operation of new generating units at the Barton Site. Most of these workers would be expected to come from within the region. Any employees relocating to the region would most likely be scattered throughout the counties in the region. If all 800 employees and their families were to come from outside the region, the potential increase in population in the most impacted counties would not be substantial. For example, the 800 employees would translate into an additional 2,120 people. The addition of the new employees and their families would equate to a 5.3 percent increase for Chilton County and a 3.2 percent increase for Elmore

County (assuming that all 2,120 people located to one county or the other). Overall, the potential increases in population would represent a SMALL increase in the total population for the most impacted counties.

9.3.3.3.6.3 Economy

Based on 2000 census data, within the four counties surrounding the Barton Site, there are 74,683 persons in the labor force. Of those persons in the labor force, 98.4 percent are in the civilian labor force and 1.6 percent in the armed forces. Of the civilian labor force, 95.1 percent are employed and 4.9 percent are unemployed. The overall unemployment rate for the region is lower than that of the State, which is 6.2 percent. **(USCB 2000f)**

Elmore County's business profile is led by educational, health, and social services (16.8 percent of the county's total employment), followed by manufacturing (14.5 percent), and retail trade (12.0 percent). The unemployment rate for Elmore County in 2000 was 5.0 percent. **(USCB 2000f)**

In neighboring Chilton County, the business profile is led by manufacturing (16.9 percent of the county's total employment), followed by educational, health, and social services (14.7 percent), and construction (13.1 percent). The unemployment rate in Chilton County was 4.3 percent in 2000. **(USCB 2000f)**

Elmore and Chilton Counties, where the magnitude of the economic impacts would be diffused within the larger economic base, would most likely be the main beneficiaries of construction and operation of the proposed project at the Barton Site. Impacts are defined as small if plant-related employment is less than 5 percent of the study area's total employment and moderate if employment is between 5 and 10 percent. SNC concludes that the impacts of construction on the economy of the region would be beneficial and temporary, and would therefore be SMALL.

The wages and salaries of the operating workforce would have a multiplier effect that could result in increases in business activity, particularly in the retail and service sectors. This would have a positive impact on the business community and could provide opportunities for new businesses to get started, and increased job opportunities for local residents. The economic effect on the 50-mile region would be beneficial. SNC assumes that direct jobs would be filled by an in-migrating workforce, but most indirect jobs would be service-related, not highly specialized, and would be filled by the existing workforce within the 50-mile region and particularly in Elmore and Chilton Counties. SNC anticipates that most of the indirect jobs created by the operations workforce would be filled by unemployed workers in the region. Expenditures made by the direct and indirect workforce would strengthen the regional economy.

SNC concludes that the impacts of station operation on the economy would be beneficial and small everywhere in the region except Elmore and Chilton Counties, where the impacts would be beneficial MODERATE, and that mitigation would not be warranted.

9.3.3.3.6.4 Taxes

Taxes collected as a result of constructing and operating the proposed project at the Barton Site would be of benefit to the State and local jurisdictions that collected and spent them. Corporate and personal income taxes and sales and use taxes would be collected during both the construction and operation of the proposed project at the Barton Site. SNC anticipates that the Barton Site would pay annual property taxes to Chilton and Elmore Counties, beginning during construction of the proposed project. Alabama assesses property at 30% of its value. Assuming a 40-year operational life, property taxes that would be split between Chilton and Elmore Counties could average between $15,000,000 and $21,500,000 annually for the first decade of operations and between $3,000,000 and $4,000,000 for the last decade of operations. Chilton and Elmore counties have experienced rapid growth over the past few years, consequently it is difficult to predict the degree of impact on the tax base for these counties that Barton Site property taxes have. Assuming that the valuation of the proposed project at the Barton Site would be similar to the Farley Nuclear Plant in Houston County, tax payments for the site could represent 20 to 30 percent of the tax revenue for these counties. The benefits of taxes are considered moderate when new tax payments by the nuclear plant constitute 10 to 20 percent of total revenues for local jurisdictions and large when new tax payments represent more than 20 percent of total revenues. Therefore, SNC concludes that the potential beneficial impacts of taxes collected during construction and operation of the proposed project would be MODERATE to LARGE in Chilton and Elmore Counties and SMALL in the remainder of the 50-mile region.

9.3.3.3.6.5 Transportation

Road access to the Barton Site would be via State Road 22, which has an east-west orientation. State Road 22 passes through the town of Rockford to the east and merges with U.S. Highway 31 about one mile north of the town of Verbena. Employees traveling from Birmingham and other towns north of the site would access State Road 22 from U.S. Highway 31. Employees traveling from Montgomery and other towns south of the site would access State Road 22 from U.S. Highway 31 via State Road 111 or State Road 143. All roads on these travel routes are two-lane paved roads. The Alabama Department of Transportation does not maintain level-of-service designation for roadways in the State. However, a daily average of 1580 cars traveled State Road 22 near the Barton Site in 2004 **(ALDOT 2006)**. Assuming construction shifts as described in Section 4.4.2.2.4, an additional 2,200 cars could be on a two-lane highway during shift changes, causing potential congestion. Also, the traffic of hauling construction materials (100 trucks per day) to the site could bring additional congestion to State Road 22, U.S. Highway 31 and State Roads 111 and 143 during certain times of the day. Transportation impacts are small when increases in traffic do not result in delays or other operational problems, impacts are MODERATE when increases in traffic begins to cause delays or other operational problems. Impacts of construction on transportation would be MODERATE and some mitigating actions may be needed.

With respect to the operations of the facility, adding at most an additional 800 cars (assuming a single occupant per car) to the existing 1,580 cars per day on the road would not materially congest the highway. Shift changes for the proposed project at the Barton Site could be staggered so that the traffic increase would not cause congestion. Impacts of the operations workforce on transportation would be SMALL and mitigation would not be warranted.

9.3.3.1.6.6 Aesthetics and Recreation

The Barton Site is currently undeveloped and is a popular area for hunters. The construction and operation of the proposed project on the site would exclude the entire 2,800 acres from hunting and other recreational use for the estimated 40-year life of the plant.

The developed areas at the Barton Site would be located near the center of the property, with the area immediately adjacent to the Jordan Reservoir mostly undeveloped. The remainder of the site would consist of forested areas, ponds, and open fields. The Jordan Reservoir is relatively undeveloped, particularly in the upper half of the reservoir, where the Barton Site is located. The reservoir offers excellent opportunities for wildlife viewing, camping, boating, fishing, and other recreation.

The construction and operation of the proposed project at the Barton Site would have minimal impacts on aesthetic and scenic resources. With the exception of the intake and outfall structures, which would be located on the west bank of the Jordan Reservoir, all facility structures would be built near the center of the site. From Jordan Reservoir, the plant may be visible from certain angles, although from most points the structures would be hidden by elevated terrain, trees, and other foliage. The intake and outfall will be visible from portions of the reservoir that are near the site. The upper portions of facility structures may be visible from elevated areas near the site. There would be occasional visible plumes associated with the cooling towers. The visibility of the plumes would be dependent upon the weather and wind patterns, and the location of the viewer within the general topography of the area. Impacts on aesthetic resources are considered to be moderate if there are some complaints about diminution in the enjoyment of the physical environment and measurable impacts that do not alter the continued functioning of socioeconomic institutions and processes. Construction and operation of an industrial facility on a previously undeveloped site would likely result in some complaints from the affected public regarding diminution in the enjoyment of the physical environment. Therefore, impacts of construction and operation of the proposed project on aesthetics would be MODERATE and could warrant mitigation.

There are two APC reservoirs in the vicinity of the Barton Site in addition to the Jordan Reservoir and Bouldin Lake: Lay Lake, and Mitchell Lake. Both reservoirs have recreational uses in including camping, boat ramps, marinas, picnic areas, playgrounds, swimming areas, and trails. Mitchell Lake is located about 4.5 miles upstream of the Barton Site in Chilton and Coosa Counties, Alabama. The upper portions of facility structures and occasional plumes from the cooling towers may be visible from elevated areas near Mitchell Dam. No other impacts on Mitchell Lake's recreation areas would be expected. Lay Lake is located over 18 miles upstream of the Barton Site in Chilton, Coosa, and Shelby Counties, Alabama. Construction and operation of the proposed project at the Barton Site would not impact recreation areas on Lay Lake because of its distance from the Barton Site. Impacts on tourism and recreation are considered small if current facilities are adequate to handle local levels of demand. Therefore, impacts of facility construction and operation would be SMALL.

9.3.3.3.6.7 Housing

In 2000 in Chilton County, there were 17,651 housing units, of which 2,364 were vacant (13.4 percent). Elmore County had 8,037 housing units, of which 1,512 were vacant (18.8 percent), Autauga County had 17,660 housing units with 1,659 vacant (9.4 percent), and Coosa County had 6,142 housing units with 1,460 vacant (23.8 percent) **(USCB 2000f)**. Assuming that the construction workforce would commute from the area within a 50-mile radius of the Barton Site, which has a population of 735,226, there would be few discernible impacts on housing availability, rental rates or housing values, or housing construction or conversion. Those who chose to relocate to the region would find adequate housing available. Impacts on housing are considered to be small when a small and not easily discernable change in housing availability occurs. Therefore, impacts of construction on housing would be SMALL and mitigation would not be necessary. Impacts on housing during the operating period would be SMALL for the same reasons.

9.3.3.3.6.8 Public Services

Public services include water supply and waste water treatment facilities; police, fire and medical facilities; and social services. Both construction and station operating personnel are expected to come from within the region. Construction workers living outside the region would most likely commute to the job site from their residences. Any construction employees relocating to the region would most likely be dispersed throughout the region where there is available housing. New operations employees relocating from outside the region would most likely live in residentially developed areas. It is not expected that public services would be materially impacted by these workers. Impacts on public services are considered to be small if there is little or no need for changes in the level of service provided to the community. Therefore, impacts of construction and operation of the proposed project on public services would be SMALL and mitigation would not be warranted.

9.3.3.3.6.9 Education

The majority of construction workers would be expected to come from the region, with little in-migration of workers from outside the region. Workers living outside the region would most likely commute to the job site from their residences. Therefore, there would be minimal impact from additional children being placed in the school systems within the region.

The majority of the operations workforce would come from within the region where their educational requirements are already being met. As such, the school systems in these areas would not experience any major influx of students because of the operation of the proposed project at the Barton Site. The majority of workers relocating to the region would likely move to the more populous area in the surrounding communities, having access to the more developed public services. For example, workers with school-aged children would be interested in communities with good school districts.

Impacts of construction and operation of the proposed project on education would be SMALL and mitigation would not be warranted.

9.3.3.3.7 Historic and Cultural Resources

SNC conducted historical and archaeological records searches on the National Park Service's National Register Information System and the Alabama Register of Landmarks and Heritage (ARLH), and reviewed information on historic and archeological sites provided in APC's Environmental Assessment for the Coosa River Project.

Two archaeological or cultural resources surveys have been conducted on lands adjacent to the Jordan Reservoir. These surveys noted 13 archaeological sites within or adjacent to the Jordan development, but their locations are not identified. None of the sites are listed on or currently eligible for listing on the NRHP.

The NRHP includes 5 sites in Autauga County, 3 sites in Chilton County, 1 site in Coosa County, and 10 sites in Elmore County. The Verbena historic district, is located about 7 miles west of the Barton Site and is composed of 57 predominantly frame 1-story structures. Notable structures include the Verbena Baptist Church, the multi-gabled Gibson house, the hip-on-hip Brooks-Wingate house, and the Greek Revival Brooks-De Ramus store. The town was first developed as summer resort in late 1880's. It later evolved as a permanent settlement following a resort hotel fire in 1922 and construction of the Mitchell Dam. There are no other properties listed in the NHRP that are located within a 10-mile radius of the Barton Site. **(NPS 2006c)**

The ARLH includes 10 sites in Autauga County, 9 sites in Chilton County, 5 sites in Coosa County, and 39 sites in Elmore County that are not included in the NHRP. The Confederate Memorial Cemetery is located about 6.5 miles southwest of the Barton Site. The Titus historic district and the Gantt Dogtrot House are located about 4.5 southwest of the site. There are no other properties listed in the ARLH that are located within a 10-mile radius of the Barton Site. **(AHC 2003)**

Siting the proposed project at the Barton Site would require a formal cultural resources survey be conducted so that no archeological or historic resources would be damaged during construction of the proposed project. Mitigative measures would be performed to prevent permanent damage and ensure that any impacts to cultural resources from construction or operation at the Barton Site would be SMALL.

9.3.3.3.8 Environmental Justice

The 2000 Census and block groups were used for ascertaining minority and low-income in the area. There are 577 block groups within a 50 mile radius of the Barton Site. Black minority populations exist in 207 block groups; and "Aggregate of Minority Races" populations exist in 200 block groups. No other minority populations exist in the geographic area. The Census Bureau data characterize 16.67 percent of Alabama households as low-income. Based on the "more than 20 percent" criterion, 59 block groups out of a possible 577 contain a low-income population. There are no minority or low income populations within a 6-mile radius of the Barton Site.

Construction activities (noise, fugitive dust, air emissions, traffic) would not disproportionately impact minority populations because of their distance from the Barton Site. In fact, minority and low-income populations would most likely benefit from construction activities through an increase in construction-related jobs. Operation of the proposed project at the Barton Site is also unlikely to have a disproportionate impact on minority or low-income populations. A review of environmental assessments and planning documents for projects in the Coosa River basin and adjacent lands identified no unusual resource dependencies or practices, such as subsistence agriculture, hunting, or fishing through which the populations could be disproportionately affected. In addition, no location-dependent disproportionate impacts affecting these minority and low-income populations have been identified **(USACE 1998, Delaney 2005)**. SNC concludes that environmental justice consequences of the construction and operation of the proposed project at the Barton Site would be SMALL, and that mitigation would not be warranted.

9.3.4 Summary and Conclusions

The decision to co-locate the new nuclear power facility at VEGP near Waynesboro, Georgia was based on a comparison of the three nuclear sites (e.g., VEGP, FNP near Dothan Alabama, and HNP near Baxley, Georgia) that supply electric power to Southern Company's customers and a greenfield site (Barton Site, near Clanton, Alabama) that had previously been proposed for a four-unit nuclear but never developed. The existing VEGP facility currently operates under an NRC license, and the proposed location has already been found acceptable under the requirements for that license. Further, operational experience at the existing facility has shown that the environmental impacts are SMALL, and operation of a new facility at the site should have essentially the same environmental impacts.

SNC's evaluation of alternative sites focused on whether there are any sites that are obviously superior to the VEGP site. The review process was consistent with the special case noted in NUREG-1555, ESRP, Section 9.3(III)(8), and took into account the advantages already present at existing nuclear facilities within the region of influence. Initially, candidate sites within the region of influence were identified and screened. During initial review, SNC determined that the advantages of co-locating the new facility with an existing nuclear power facility outweighed the advantages of any other probable siting alternative. Therefore, consideration of alternative sites within the relevant service area focused primarily on sites with an existing nuclear power facility. The Barton Site was included in the evaluation to determine if greenfield sites are obviously superior to an existing nuclear site.

Tables 9.3-2 and 9.3-3 compare the environmental impacts of construction and operation of the proposed project at each of the alternative sites with impacts at the VEGP site. This site-by-site comparison did not result in identification of a site obviously superior to the VEGP ESP Site

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Table 9.3-1. Federally-Listed Species Recorded in Chilton, Coosa, Elmore, and Talledega Counties, Alabama[a]

Scientific Name	Common Name	Federal Status[b]	Alabama Counties
Birds			
Haliaeetus leucocephalus	Bald eagle	T	Chilton, Coosa, Elmore
Picoides borealis	Red-cockaded woodpecker	E	Chilton, Coosa, Talledega
Mycteria americana	Wood stork	E	Chilton
Fish			
Cyprinella caerulea	Blue shiner	T	Coosa
Invetebrates			
Elimia crenatella	Lacy elimia snail	T	Talladega
Leptoxis taeniata	Painted rocksnail	T	Chilton, Talledega
Lampsilis altilis	Fine-lined pocketbook mussel	T	Chilton, Coosa, Elmore, Talledega
Medionidus parvulus	Coosa moccasinshell mussel	E	Talladega
Pleurobema decisum	Southern clubshell mussel	E	Talladega
Ptychobranchus greenii	Triangular kidneyshell mussel	E	Talladega
Tulotoma magnifica	Tulotoma snail	E	Coosa
Pleurobema georgianum	Southern pigtoe mussel	E	Coosa, Talledega
Plants			
Sagittaria secundifolia	Kral's water-plantain	T	Coosa
Arabis georgiana	Georgia rockcress	C	Elmore
Sarracenia rubra alabamensis	Alabama canebrake pitcher plant	E	Chilton, Elmore

a Source of county occurrence: **FWS 2005**.
b E = Endangered, T = Threatened, C = Candidate for federal listing.

Table 9.3-2 Characterization of Construction Impacts at the Vogtle and Alternative ESP Sites

Category	Vogtle	Farley	Hatch	Barton
Land Use Impacts				
The Site and Vicinity	SMALL	SMALL	SMALL	MODERATE
Transmission rights-of-way	SMALL to MODERATE	SMALL to MODERATE	SMALL to MODERATE	MODERATE
Air Quality	SMALL	SMALL	SMALL	SMALL
Water Related Impacts				
Water Use	SMALL	SMALL	SMALL	SMALL
Water Quality	SMALL	SMALL	SMALL	SMALL
Ecological Impacts				
Terrestrial Ecosystems	SMALL	SMALL	SMALL	SMALL to MODERATE[e]
Aquatic Ecosystems	SMALL	SMALL	SMALL	SMALL
Threatened and Endangered Species	SMALL	SMALL	SMALL	SMALL
Socioeconomic Impacts				
Physical Impacts	SMALL	SMALL	SMALL	SMALL
Demography	SMALL	SMALL to MODERATE[b]	SMALL to MODERATE[c]	SMALL
Economy	SMALL (Beneficial)	SMALL (Beneficial)	SMALL (Beneficial)	SMALL (Beneficial)
Taxes	SMALL to LARGE[a] (Beneficial)	SMALL to LARGE[b] (Beneficial)	SMALL to LARGE[d] (Beneficial)	SMALL to LARGE[f] (Beneficial)
Transportation	MODERATE	MODERATE	MODERATE	MODERATE
Aesthetics	SMALL	SMALL	SMALL	MODERATE
Recreation	SMALL	SMALL	SMALL	SMALL to MODERATE
Housing	SMALL to MODERATE[a]	SMALL to MODERATE[b]	SMALL to MODERATE[c]	SMALL
Public and Social Services	SMALL	SMALL	SMALL	SMALL

Table 9.3-2 (cont'd) Characterization of construction Impacts at the Vogtle and Alternative ESP Sites

Category	Vogtle	Farley	Hatch	Barton
Education	SMALL to MODERATE[a]	SMALL to MODERATE[a]	SMALL to LARGE[a]	SMALL
Historic and Cultural Resources	SMALL	SMALL	SMALL	SMALL
Environmental Justice	SMALL	SMALL	SMALL	SMALL

a Impacts in 50-mile radius would be SMALL. Impacts to Burke County would be greater.
b Impacts in 50-mile radius would be SMALL. Impacts to Houston County would be greater.
c Impacts in 50-mile radius would be SMALL. Impacts to Appling and Toombs Counties would be greater.
d Impacts in 50-mile radius would be SMALL. Impacts to Appling County would be LARGE.
e Impacts at plant site would be SMALL, but transmission line impacts could be MODERATE depending on the route.
f Impacts in 50-mile radius would be SMALL. Impacts to Chilton and Elmore Counties would be MODERATE to LARGE.

Table 9.3-3 Characterization of Operation Impacts at the Vogtle and Alternative ESP Sites

Category	Vogtle	Farley	Hatch	Barton
Land Use Impacts				
The Site and Vicinity	SMALL	SMALL	SMALL	SMALL
Transmission rights-of-way	SMALL	SMALL	SMALL	SMALL
Air Quality	SMALL	SMALL	SMALL	SMALL
Water Related Impacts				
Water Use	SMALL	SMALL	SMALL	SMALL
Water Quality	SMALL	SMALL	SMALL	SMALL
Ecological Impacts				
Terrestrial Ecosystems	SMALL	SMALL	SMALL	SMALL
Aquatic Ecosystems	SMALL	SMALL	SMALL	SMALL
Threatened and Endangered Species	SMALL	SMALL	SMALL	SMALL
Socioeconomic Impacts				
Physical Impacts	SMALL	SMALL	SMALL	SMALL
Demography	SMALL	SMALL	SMALL to MODERATE[c]	SMALL
Economy	SMALL to MODERATE[a]	SMALL to MODERATE[b]	SMALL to MODERATE[d]	SMALL to MODERATE[e]
Taxes	SMALL to MODERATE[a]	SMALL to MODERATE[b]	SMALL to MODERATE[d]	SMALL to MODERATE[e]
Transportation	SMALL to MODERATE	SMALL to MODERATE	SMALL to MODERATE	SMALL
Aesthetics	SMALL	SMALL	SMALL	MODERATE
Recreation	SMALL	SMALL	SMALL	SMALL
Housing	SMALL	SMALL	SMALL	SMALL
Public and Social Services	SMALL	SMALL	SMALL	SMALL

Table 9.3-3 Characterization of Operation Impacts at the Vogtle and Alternative ESP Sites (Cont.)

Category	Vogtle	Farley	Hatch	Barton
Education	SMALL to MODERATE[a]	SMALL to MODERATE[b]	SMALL to MODERATE[d]	SMALL
Historic and Cultural Resources	SMALL	SMALL	SMALL	SMALL
Environmental Justice	SMALL	SMALL	SMALL	SMALL

a Impacts in 50-mile radius would be SMALL. Impacts to Burke County would be greater.
b Impacts in 50-mile radius would be SMALL. Impacts to Houston County would be greater.
c Impacts in 50-mile radius would be SMALL. Impacts to Appling and Toombs Counties would be MODERATE.
d Impacts in 50-mile radius would be SMALL. Impacts to Appling County would be LARGE.
e Impacts in 50-mile radius would be SMALL. Impacts to Chilton and Elmore Counties would be would be greater.

Figure 9.3-1 Farley 50-Mile Vicinity

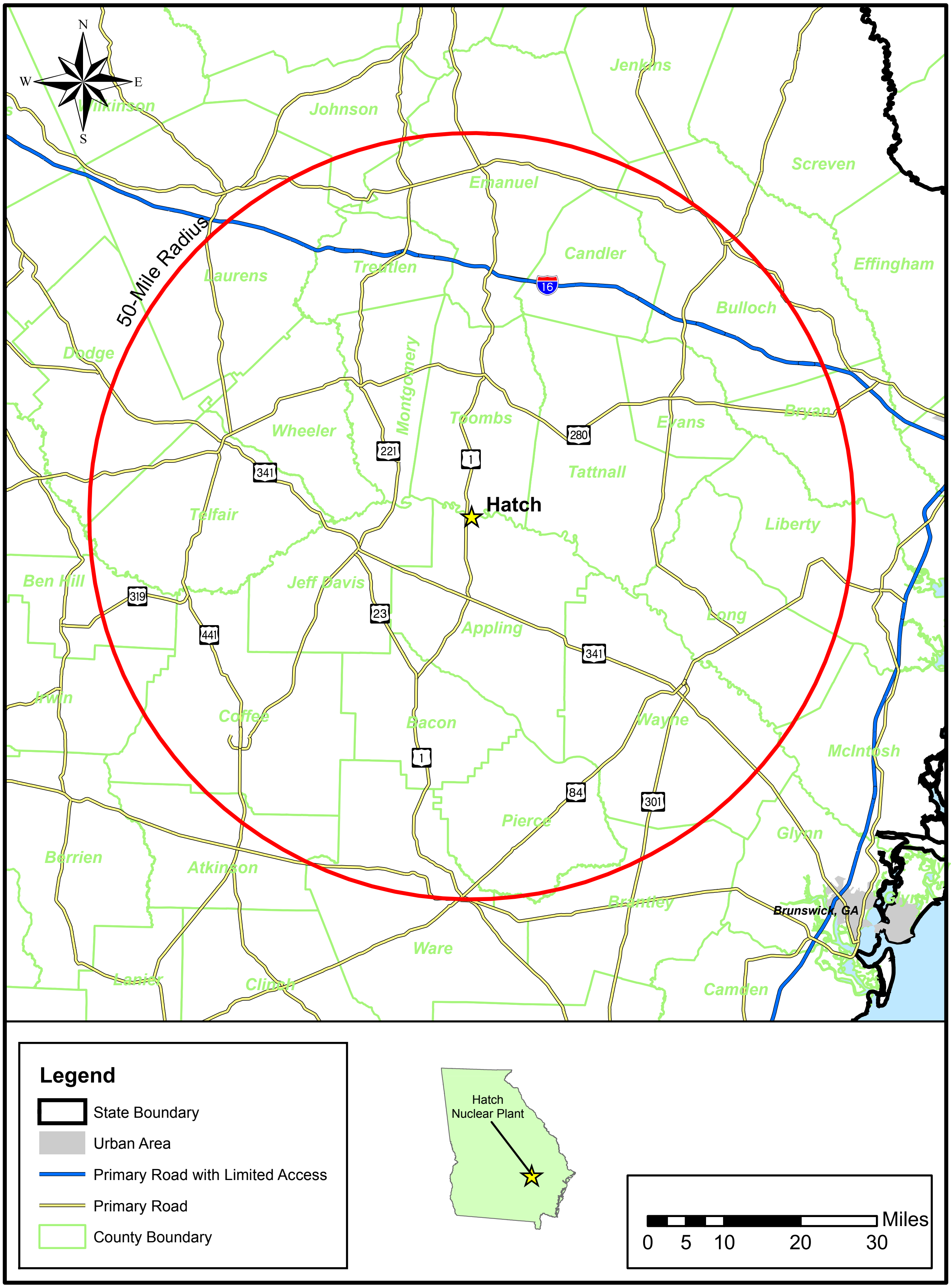

Figure 9.3-2 Hatch 50-Mile Vicinity

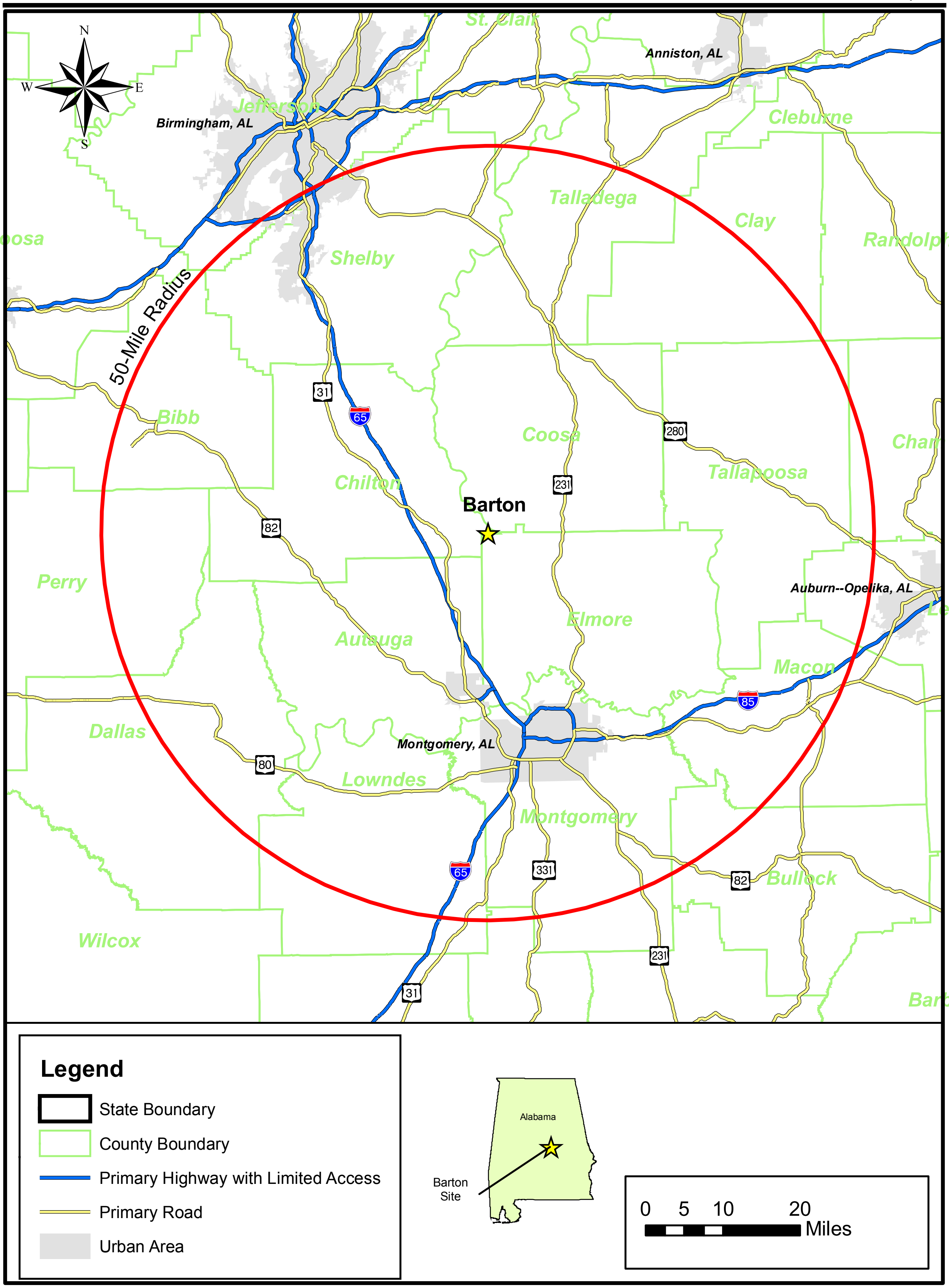

Figure 9.3-3 Barton Site 50-Mile Vicinity

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9.4 Alternative Plant and Transmission Systems

This section discusses alternatives to the heat dissipation, circulating water and transmission systems for the proposed reactors at the VEGP site. Section 9.4.1 evaluates alternative heat dissipation systems, Section 9.4.2 alternative circulating water systems and Section 9.4.3 alternative transmission systems.

9.4.1 Heat Dissipation Systems

9.4.1.1 Screening of Alternative Heat Dissipation Systems

This section discusses alternatives to the proposed heat dissipation system (Section 5.3.3.1) based on the guidance provided in NUREG-1555. Alternatives considered are those generally included in the broad categories of “once through” and “closed cycle” systems. The closed cycle category includes the following types of heat dissipation systems:

- Mechanical draft wet cooling towers
- Natural draft wet cooling towers
- Wet dry cooling towers
- Dry cooling towers
- Cooling ponds
- Spray canals

An initial environmental screening of the above alternative designs was done to eliminate those systems that are obviously unsuitable for use at the VEGP site. The following alternatives were eliminated from further consideration.

<u>Once-through cooling</u> - The water requirements for a once-through cooling system would be 850,000 gpm (1890 cfs) per unit **(Westinghouse 2003)**. This water requirement in combination with the existing water usage for VEGP Units 1 and 2 would withdraw most, if not all, of the flow of the Savannah River. (USGS [2004] estimates the annual mean flow (9,208 cfs) of the Savannah River at the Augusta, Georgia gaging station for the period 1952 - 2003. The average annual mean flow for the same years varies from 4,470 to 16,580 cfs.) Additionally, once through cooling would pose risks of thermal effects and damage to aquatic organisms. EPA regulations (40 CFR Part 125) governing cooling water intake structures under Section 316(b) of the Clean Water Act make it difficult for steam electric generating plants to use one-through cooling systems. For these reasons, once-through cooling was eliminated from further consideration.

<u>Cooling ponds</u> - Studies supporting the construction of VEGP Units 1 and 2 included the potential use of a large (approximately 8,000 acres) cooling reservoir in a closed cycle system. This heat dissipation option was discarded due to serious questions regarding the amount of

seepage loss from the reservoir and uncertainty regarding applicability of water quality standards to the impoundment. The proposed new plant footprint is within the 3,169-acre VEGP site. As described in Section 2.2.1.1, the VEGP plant and auxiliary facilities occupy about 800 acres. A cooling pond system would require more land than is available on the VEGP site. In addition, issues regarding seepage losses and applicability of water quality standards to the reservoir would need to be addressed. These issues, coupled with the land requirements, are sufficient to preclude further consideration of cooling ponds for the new units.

<u>Spray ponds</u> – This alternative is similar to cooling ponds as it involves the creation of new surface water bodies. Spray modules are included to promote evaporative cooling in the ponds, which reduces the land requirements. However, this advantage is offset by higher operating and maintenance costs for the spray modules. This alternative is considered unsuitable for the VEGP site for the same reasons as cooling ponds.

<u>Dry cooling towers</u> – This alternative is not suitable for the reasons discussed in EPA's preamble to the final rule addressing cooling water intake structures for new facilities (66 FR 65256; December 18, 2001). Dry cooling carries high capital and operating and maintenance costs that are sufficient to pose a barrier to entry to the marketplace for some facilities. In addition, dry cooling has a detrimental effect on electricity production by reducing the efficiency of steam turbines. Dry cooling requires the facility to use more energy than would be required with wet cooling towers to produce the same amount of electricity. This energy penalty is most significant in the warmer southern regions during summer months when the demand for electricity is at its peak. The energy penalty would result in an increase in environmental impacts as replacement generating capacity would be needed to offset the loss in efficiency from dry cooling. EPA concluded that dry cooling is appropriate in areas with limited water available for cooling or where the source of cooling water is associated with extremely sensitive biological resources (e.g., endangered species, specially protected areas). The conditions at the VEGP site do not warrant further consideration of dry cooling.

<u>Wet dry cooling towers</u> – These towers are used primarily in areas where plume abatement is necessary for aesthetic reasons or to minimize fogging and icing produced by the tower plume. Wet dry cooling towers use approximately one-third to one-half less water than wet cooling towers **(EPA 2001)**. Due to the rural setting of the site, neither of these advantages is significant. Additionally, somewhat more land is required for the wet dry cooling tower due to the additional equipment (fans and cooling coils) required in the tower assembly. The same disadvantages described above for dry cooling towers would apply to the dry cooling portion of the wet dry cooling tower. The dry cooling process is not as efficient as the wet cooling process because it requires the movement of a large amount of air through the heat exchanger to achieve the necessary cooling. This results in less net electrical power for distribution. Consequently, there would be an increase in environmental impacts as replacement generating capacity would be needed to offset the loss in efficiency from dry cooling. This alternative could

be utilized at the VEGP site; however, it is not considered to be environmentally preferable to the proposed wet cooling towers.

Feasible alternatives - Only mechanical draft and natural draft cooling towers are considered suitable heat dissipation systems for the VEGP site and are evaluated in detail. Since natural draft cooling towers were selected as the primary heat dissipation system for the proposed action (see Section 5.3.3.1), mechanical draft cooling towers are considered as an alternative heat dissipation system and evaluated further in Section 9.4.1.2. In accordance with NUREG-1555, the heat dissipation alternatives were evaluated for land use, water use, and other environmental requirements (Table 9.4-1).

9.4.1.2 Analysis of Mechanical Draft Cooling Tower Alternative

SNC modeled the impacts from mechanical draft cooling towers using the SACTI code described in Section 5.3.3.1. Engineering data for the AP1000 was used to develop input to the SACTI model. Four identical cooling towers (two AP1000 units with two cooling towers per unit) were modeled with a heat rejection rate of 7.54×10^9 Btus per hour and circulating water flow of 600,000 gallons per minute for each pair of towers. The tower height was 68 feet. Four cycles of concentration were assumed. The meteorological data was from the VEGP meteorological tower for the year 1999, which had the most complete data set.

Length and Frequency of Elevated Plumes - The SACTI code calculated the expected plume lengths by season and direction for the combined effect of the four mechanical draft cooling towers for the AP1000 units. The longest average plume lengths would occur in the winter months while the shortest would be in the fall. The plumes would occur in all compass directions.

Projected plume lengths, directions, and frequencies are provided in the table below.

	Winter	***Fall***
Median plume length (miles)	0.12	0.12
Predominant direction (median)	NE, ENE, NNE, WSW	SW, WSW, SSW
Longest plume length (miles)	6.2	0.25
Frequency of longest plume (percent)	3.9	7.1

Ground-Level Fogging and Icing - The mechanical draft cooling towers would produce ground-level fogging. Fogging would occur less than 42 hours per year, and most of that fogging would be limited to a 1,000-foot radius of the cooling tower. The most probable direction of fogging would be south to south-southwest and west-southwest to west of the towers. No adverse operational or environmental impact from fogging is expected. No icing would occur.

Solids Deposition - Water droplets drifting from the cooling towers would have the same concentration of dissolved and suspended solids as the water in the cooling tower basin. The water in the cooling tower basin is assumed to have concentrations four times that of the Savannah River, the source of cooling water makeup. As these droplets evaporate, either in the air or on the vegetation or equipment, they would deposit these solids.

The maximum predicted salt deposition rates beyond 0.5 mile would be as follows:

- *Maximum pounds per acre per month:* *13.2*
- *Distance (miles) to maximum deposition:* *0.5*
- *Direction to maximum deposition:* *east*
- *Season of maximum deposition:* *winter*

At distances less than 3,000 feet from the towers, salt deposition would be very large in all directions. Sensitive equipment could not be located within this radius. Approximately 90 percent of the deposition would occur within 2,300 feet of the cooling towers.

Cloud Shadowing and Additional Precipitation - The SACTI code predicted that the precipitation expected from the mechanical draft cooling towers would be a maximum of approximately 1.5 inches of rain per year at 0.19 mile of the towers. In summer, this maximum precipitation would occur north-northeast of the towers. In fall, it would be located southwest to west-southwest and south of the towers. This value is small compared to the precipitation of 33 inches for the year of the meteorological data used for this analysis, which was a year of low rainfall. The 30-year average rainfall at Augusta is 45 inches and at Waynesboro is 47 inches (1971 - 2000) (see Section 5.3.3.1.4).

Other Impacts - The potential for increases in absolute and relative humidity exist where there are visible plumes.

Summary - The potential for fogging and salt deposition would be slightly greater for mechanical draft cooling towers than for natural draft cooling towers. This alternative heat dissipation system would not be environmentally preferable to the proposed natural draft cooling towers.

An economic study conducted to support construction of VEGP Units 1 and 2 concluded that mechanical draft cooling towers were the economic choice over natural draft towers. At that time, a present worth evaluation considering capital cost, power requirements, impact on turbine performance, and maintenance and insurance costs concluded that mechanical draft towers were less costly by more than $1 million per unit. However, natural draft towers were selected for Units 1 and 2 due to environmental considerations. Natural draft cooling towers are proposed for the VEGP units 3 and 4 due to the same considerations.

These differences in impacts are not significant for the VEGP site. These heat dissipation system alternatives are considered environmentally equivalent.

9.4.2 Circulating Water Systems

In accordance with NUREG-1555, this section considers alternatives to the following components of the plant circulating water system:

- intake systems
- discharge systems
- water supply
- water treatment

NUREG-1555 indicates that the applicant should consider only those alternatives that are applicable at the proposed site and are compatible with the proposed heat dissipation system. As discussed in Section 9.4.1, only mechanical draft and natural draft wet cooling towers are considered viable and feasible heat dissipation systems for the VEGP site.

Heat dissipation with wet cooling towers relies on evaporation for heat transfer. The water from the cooling system lost to the atmosphere through evaporation must be replaced. In addition, this evaporation would result in an increase in the concentration of solids in the circulating water. To control solids, a portion of the recirculated water must be removed, or blown down, and replaced with fresh water. In addition to the blowdown and evaporative losses, a small percentage of water in the form of droplets (drift) is lost from the cooling towers. Water pumped from the Savannah River (Section 9.4.2.1) intake structure would be used to replace water lost by evaporation, drift and blowdown from the cooling towers. Blowdown water is returned to the Savannah River via a discharge structure at the river (Section 9.4.2.2).

9.4.2.1 Intake Systems

The makeup water system for VEGP Units 1 and 2 uses a concrete intake structure and a sheet-pile-lined intake canal to draw water from the Savannah River. Makeup water for the circulating water system for the new units would be withdrawn from the Savannah River via a new recessed shoreline intake structure located upstream of the existing VEGP water intake. A conceptual description of the intake design is provided in Section 3.4. Other than differences in dimensions, the design is the same as the intake structure for VEGP Units 1 and 2.

The design of the intake structure for VEGP Units 1 and 2 was modified during the construction phase. The modifications included changing the design for the intake structure canal from slope riprap to vertical sheet pile, adding lateral escape passageways for fish at the intake channel entrance, and providing one independently operating pump per cell (**NRC 1985**). These design modifications were made to reduce the potential impacts on aquatic resources. The design of the intake structure for the new units incorporates these similar features, to reduce impingement and entrainment of aquatic organism (see Sections 3.4.2.1 and 5.3.1) modifications.

Alternative intake systems for the new units include a shoreline or an offshore intake structure. An intake located at the shoreline would result in greater impingement and entrainment of aquatic organisms from the Savannah River. An offshore intake would extend into the channel and interfere with river navigation. No environmentally preferable alternatives to the proposed intake structure were identified.

The location of the existing intake and discharge structures for VEGP Units 1 and 2 and proposed locations for the new intake and discharge structures are shown on Figure 3.1-3. In order to avoid recirculation, the intake structure for the new units must be located upstream of the existing intake structure for VEGP Units 1 and 2, which is directly upstream of the cooling water blowdown discharge point. As described in Section 2.2.1.1, the Savannah River 100-year floodplain ranges from approximately 100 to 800 feet wide at the VEGP site. The floodplain is demarcated from the rest of the VEGP site by steep bluffs along virtually all of the river shoreline. Placement of the new intake structure upstream of the existing intake structure, where the floodplain is at its widest point on the VEGP property would minimize impacts to the marl bluffs, but alter more floodplain habitat. Alternate locations further upstream would increase the amount of undisturbed land impacted by construction of the intake structure. Land that is currently undisturbed would be impacted both to access that portion of the VEGP site and to construct the makeup water pipeline from the intake to the plant. In addition, pumping costs would increase due to the longer distance from the makeup water intake to the cooling towers. The area between the intake structure for Units 1 and 2 and the proposed location for the new intake is characterized by steep bluffs and significant archaeological resources. Construction of an intake structure in that area would incur high costs and result in significant impacts to the bluffs and the archaeological sites. These alternative locations are not environmentally preferable to the proposed site for the river water intake.

9.4.2.2 Discharge Systems

As noted above, the circulating water system for the new units would be a closed loop system utilizing wet cooling towers for heat dissipation. All cooling system discharges, including cooling tower blowdown, would be discharged to the Savannah River via a new discharge structure to be built downstream of the existing VEGP discharge structure. The design is the same as the discharge structure for VEGP Units 1 and 2 (see Section 3.4.2.2).

The original design for the discharge line from VEGP Units 1 and 2 called for a submerged multiport diffuser. The design was changed to a single-port discharge in Amendment 3 to the Vogtle construction permits CPPR-108 and CPPR-109. The predicted benefits of this change were that the thermal plume would be smaller, the plume would not impinge on the Georgia shoreline, and the total width of the river affected by the thermal plume would be less **(NRC 1985)**.

The environmental impact of releasing the effluent through the new discharge line was determined to have minimal impact to aquatic biota in the river. SNC evaluated a single submerged port as the conceptual discharge design for the proposed new units. If the mixing zone resulting from such a design were unreasonably large, a more complex multi-port diffuser would have been considered.

The choice of port diameter is a compromise between (1) mixing zone size (favored by smaller diameter) and (2) pumping costs (to move the necessary flow through the discharge port at higher velocity) and river bed scour (caused by high jet velocity along the bed). The proposed 2-foot diameter discharge port design represents a compromise between these mixing zone and discharge velocity considerations. No environmentally preferable alternatives to the proposed discharge structure were identified.

Impacts from the combined effects of the discharges from VEGP Units 1 and 2 and the new units are assessed in Section 5.3.2. To avoid recirculation of blowdown into the Units 1 and 2 intake, the new discharge structure must be located downstream of the existing cooling tower blowdown discharge from VEGP Units 1 and 2, which is immediately downstream of the existing intake. The proposed discharge location maximizes the distance between the thermal plume and offsite property owners further downriver. Impacts from the combined effects of the discharges form VEGP Units 1 and 2 and the new units are assessed in Section 5.3.2.

9.4.2.3 Water Supply

As discussed above, there would be a need for continuous makeup water to the closed loop circulating water system. The maximum makeup water flow to the cooling towers in the normal heat sink is estimated at 57,784 gpm (Table 3.0-1, based on two AP1000 units). There are two potential sources of makeup water supply for the VEGP site, the Savannah River and groundwater wells. Other surface water bodies in the Savannah River basin (see Section 2.3.2.1) would not provide sufficient volume to support the makeup requirements of the circulating water system or are located too distant from the site.

The VEGP uses both surface and groundwater sources. The Savannah River is the source of makeup water for the circulating water system natural draft cooling towers for Units 1 and 2, and a backup source of makeup to the nuclear service cooling water towers. VEGP Units 1 and 2 use groundwater for reactor demineralizer makeup, normal makeup to the nuclear service cooling towers, fire protection, and potable water. Two makeup wells producing from the Cretaceous aquifer supply water to storage tanks from which water is withdrawn as needed. These wells designated MU-1 and MU-2A are capable of supplying 2,000 gpm and 1,000 gpm, respectively, of makeup water on a continuous basis. A third well, designated TW-1, is the alternate makeup well and is capable of supplying up to 1,000 gpm on a continuous basis for plant use. SNC has estimated the recoverable water quantity in the Cretaceous aquifer at approximately 21 billion acre-feet, which provides a safe yield of 5 billion gallons per day. However, considering factors such as pumping well interference, water level fluctuations caused by climatic changes, competing groundwater uses, regional concerns about salt-water intrusion, and the need to preclude drawdown from causing subsidence of plant foundations, it is unlikely that a well field could be designed to meet the makeup water requirements for the circulating water system. Therefore, the Savannah River would be used for makeup to the circulating water system cooling towers.

9.4.2.4 Water Treatment

Evaporation of water from cooling towers leads to an increase in chemical and solids concentrations in the circulating water, which in turn increases the scaling tendencies of the water. The circulating water system for the new units would be operated so that the concentration of solids in the circulating water would be approximately four times the concentration in the makeup water (i.e., four cycles of concentration). The concentration ratio would be sustained through blowdown of the circulating water from the cooling towers to the Savannah River and the addition of makeup water.

As described in Section 3.3.2.1, the Savannah River would be the source of makeup water for the new units' circulating water system. This water supply would be treated to prevent biofouling in the intake and makeup pipe to the new units. Additional treatment for biofouling, scaling or suspended matter reduction through the addition of biocides, antiscalants, and dispersants would occur in the cooling tower basin. Sodium hypochlorite and bromine are used to control biological growth in the circulating water system for Units 1 and 2 and would likely be used in the new system for VEGP Units 3 and 4 (see Section 5.2.3). These chemicals replaced a gas chlorination system that originally served the circulating water system for Units 1 and 2. Sodium hypochlorite is as effective a biocide and alleviates some of the safety concerns associated with storing and using gaseous chlorine. Alternative biocides include hydrogen peroxide or ozone. The final choice of chemicals or combination of chemicals would be dictated by makeup water conditions, technical feasibility, economics, and discharge permit requirements. Since the discharges from the system would be subject to NPDES permit limitations that consider aquatic impacts, different water treatment chemicals would be environmentally equivalent.

9.4.3 Transmission Systems

The power transmission system from the proposed VEGP units has not been designed. There are numerous factors that could give rise to changes to the current transmission and distribution system over the life of the ESP. As described in Section 3.7.2, the transmission and distribution system for the two existing units of the VEGP may be different than currently configured at the time of new reactor construction. Therefore, analysis of the transmission and distribution system, including any related environmental impact and alternative design evaluations are not provided in this ESP application.

Table 9.4-1 Screening of Alternative Heat Dissipation Systems

Factors Affecting System Selection	Mechanical Draft Wet Cooling Tower (MDCT)	Natural Draft Wet Cooling Tower (NDCT)
Land Use		
Onsite land requirements	An MDCT system would require more land (25 acres per reactor unit). An MDCT system could be placed within the confines of the VEGP site.	NDCT system would require 2.3 acres (excluding basin) per reactor unit. An NDCT system could be placed within the confines of the VEGP site.
Terrain considerations	Terrain features of the VEGP site are suitable for a MDCT system.	Terrain features of the VEGP site are suitable for a NDCT system.
Water Use	Raw water consumption of 28,900 gpm per reactor unit.	Raw water consumption of 28,900 gpm per reactor unit.
Atmospheric Effects	Impacts would be SMALL (see Section 9.4.1.2). MDCT present greater potential for fogging and salt deposition.	Impacts would be SMALL (see Section 5.3.3) and not warrant mitigation.
Thermal and Physical Effects	Discharges associated with MDCT would meet water quality standards. The volume of water affected by the mixing zone is less than 1% of the volume in the river stretch from the discharge to its furthest downstream extent. Because of the relatively low discharge velocities and rapid plume dilution, only minor scouring of the river bottom is expected. (Section 5.3)	Discharges associated with NDCT would meet water quality standards. The volume of water affected by the mixing zone is less than 1% of the volume in the river stretch from the discharge to its furthest downstream extent. Because of the relatively low discharge velocities and rapid plume dilution, only minor scouring of the river bottom is expected. (section 5.3)
Noise Levels	MDCT would emit broadband noise that is largely indistinguishable from background and unobtrusive (Section 5.3.4.2).	NDCT would emit broadband noise that is largely indistinguishable from background and unobtrusive (Section 5.3.4.2).
Aesthetic and Recreational Benefits	Consumptive water use for a MDCT system would be consistent with minimum stream flow requirements for Savannah River navigation and environmental maintenance, fish and wildlife water demand, and recreation. MDCT plumes resemble clouds and would not disrupt the view scape.	Consumptive water use for a NDCT system would be consistent with minimum stream flow requirements for Savannah River navigation and environmental maintenance, fish and wildlife water demand, and recreation. NDCT plumes resemble clouds and would not disrupt the view scape

Table 9.4-1 Screening of Alternative Heat Dissipation Systems (cont.)

Factors Affecting System Selection	Mechanical Draft Wet Cooling Tower (MDCT)	Natural Draft Wet Cooling Tower (NDCT)
Legislative Restrictions	An intake structure for an MDCT system would meet Section 316(b) of the CWA and the implementing regulations, as applicable. NPDES discharge permit thermal discharge limitation would address the additional thermal load from MDCT blowdown. These regulatory restrictions would have SMALL impacts on this heat dissipation system.	An intake structure for an NDCT system would meet Section 316(b) of the CWA and the implementing regulations, as applicable. NPDES discharge permit thermal discharge limitation would address the additional thermal load from NDCT blowdown. These regulatory restrictions would not negatively impact application of this heat dissipation system.
Is this a suitable alternative for the SNC VEGP site?	Yes	Yes

Source: **Westinghouse 2003**, Table 3.1-1

Section 9.4 References

(EPA 2001) U.S. Environmental Protection Agency, *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities* (EPA-821-R-01-036), November, 2001.

(NRC 1985) U.S. Nuclear Regulatory Commission, *Final Environmental Statement Related to the Operation of Vogtle Electric Generating Plant, Units 1 and 2, NUREG-1087*, Office of Nuclear Reactor Regulation, Washington, D.C., March, 1985.

(USGS 2004) United States Geological Survey, *Water Resources Data – Georgia 2003*, Water Data Report GA-03-1, Atlanta, Georgia, 2004.

(Westinghouse 2003) Westinghouse Electric Company, LLC, *AP1000 Siting Guide: Site Information for an Early Site Permit*, APP-0000-X1-001, Revision 3, April 24, 2003.

Chapter 10 Environmental Consequences of the Proposed Action

This chapter presents the potential environmental consequences of constructing and operating the two new AP1000 units at the Vogtle Electric Generating Plant (VEGP) site. The environmental consequences are evaluated in the following five sections:

- Unavoidable adverse impacts of construction and operations (10.1)
- Irreversible and irretrievable commitments of resources (10.2)
- Relationship between short-term uses and long-term productivity of the human environment (10.3)
- Benefit-Cost Balance (10.4)
- Cumulative Impacts (10.5)

10.1 Unavoidable Adverse Environmental Impacts

Unavoidable adverse impacts are predicted adverse environmental impacts that cannot be avoided and for which there are no practical means of mitigation. This section considers unavoidable adverse impacts from construction and operation of two AP1000 reactors at the VEGP site and of one transmission line to an existing substation.

10.1.1 Unavoidable Adverse Environmental Impacts of Construction

Construction impacts are described in detail in Chapter 4. Table 4.6-1 briefly describes those impacts and identifies the measures and controls that will be implemented to reduce or eliminate impacts. The expected impacts and the mitigation measures that are available to reduce these impacts are summarized in Table 10.1-1. For many of the impacts related to construction activities, mitigation measures that will be applied are referred to as "best management practices." Typically, these mitigation measures are based on the types of activities that are to be performed. The mitigation measures are frequently implemented through permitting requirements, and plans and procedures developed for the construction.

Unavoidable adverse impacts from construction of two new units at the VEGP site would all occur in Burke County and would include the loss of some second-growth forest resources, including some bottomland hardwoods forest, to land clearing; additional traffic on local roads; potential housing shortages and school crowding; a decrease in the ability of the fire protection infrastructure to meet the needs of the increased population; and incidental external dose to construction workers working nearby the existing units. Nearly all of the impacts, other than socioeconomic, from the construction of new units and associated transmission line are small and many can be mitigated. The moderate or large socioeconomic impacts can be reduced through mitigation. The influx of construction workers has the potential to lead to a short-term housing shortage and short-term capacity concerns in local schools in Burke County. Also, increased construction traffic will have the potential to impact existing traffic patterns and levels of service in the vicinity of VEGP. The fire protection infrastructure in Burke County is considered underfunded and understaffed. Increased property tax revenues during new unit construction could fund additional fire protection infrastructure, teachers, and school resources. SNC can put traffic mitigation programs such as carpooling, or staggered shifts, signage and turn lanes in place to alleviate traffic concerns. The short-term housing impact will generate new home starts which will eliminate that short-term impact.

10.1.2 Unavoidable Adverse Environmental Impacts of Operations

Operational impacts of new units at the VEGP site are discussed in detail in Chapter 5. Table 5.10-1 briefly describes those impacts and identifies measures and controls that will be implemented to reduce or eliminate adverse impacts. The expected impacts and the mitigation measures that are available to reduce these impacts are summarized in Table 10.1-2. Unavoidable adverse impacts from operations of two new units at the VEGP site include evaporative water loss from the Savannah River, additional groundwater withdrawal, air emissions, radioactive and non-radioactive waste to be treated and disposed of, radioactive emissions into the Savannah River and the air, increases in local traffic, and the addition of two natural draft cooling towers to the landscape.

The level of unavoidable adverse impacts from operation of the new units will be small when applicable mitigation measures are considered.

10.1.3 Summary of Adverse Environmental Impacts from Construction and Operations

As can be seen from Table 10.1-1 and Table 10.1-2, most of the adverse environmental impacts associated with the construction and operation of new units at the VEGP site will be reduced to SMALL through the application of mitigation measures. The unavoidable impacts are summarized by category below beginning with socioeconomics which is the only category that will have other than small impacts.

During construction, moderate to large socioeconomic impacts may result from the influx of 4,400 construction workers. Early in the construction phase in Burke County there is the potential for a shortage of suitable long-term housing or rental units. In addition, there is the possibility that the area schools' may not be able to accommodate the children of the construction workers. Fire protection infrastructure, already inadequate could not be able to meet the needs of the county. Roads in the vicinity of the VEGP site will experience increased traffic. Mitigation measures that could be implemented by SNC to minimize traffic impacts include staggering shifts, encouraging car pooling, erecting signs alerting drivers of increased construction traffic, and adding turn lanes at VEGP. Increases in tax revenue that will result from the construction of the new units could be used for school funding, road improvements, and upgrades to the fire protection infrastructure. If housing is not available, local market forces will likely stimulate new home construction. All other socioeconomic impacts from construction activities will be small and temporary.

Socioeconomic impacts during operations will be small. The estimated maximum increase in total population in the region due to the operations workforce is 2,600 people, a small fraction of the total projected population of the region. Most impacts that are functions of population increase (i.e., traffic, impacts to housing and school, tax revenue impacts) will be small. The impacts of increased tax revenues will be large, but most people would consider those impacts beneficial.

Two additional natural draft cooling towers will be visible from River Road, the Savannah River, and from a few locations in the surrounding Georgia and South Carolina counties. The incremental increase in visible impacts from two to four towers will not have any short- or long-term impacts to local residents or visitors, and will therefore be small.

Unavoidable, but small, adverse environmental impacts will be related to land use. Approximately 500 acres on the site will be affected; most of the land that will be cleared at VEGP has been disturbed within the last 30 years, although some is mature second growth pine or mixed hardwood forest. The proposed project is in keeping with the current use of the property, which is generation of power. It is estimated that approximately 2.0 square miles will be required for a new transmission corridor.

Clearing activities and construction of the new units will likely cause wildlife to leave or avoid the construction sites and relocate to other nearby areas. Although any changes to the wildlife population density in the site area or along the transmission line would be difficult to measure.

In addition, clearing of the 2 sq mi transmission corridor could affect some natural habitats. The land use maps of the areas where the corridor will be located, indicated that much of the land is rural forested or agricultural. The conversion of 2 sq mi of rural forested or agricultural land in west central Georgia will not adversely affect land use in the region. GPC will work with the Georgia Department of Natural Resources to ensure that this transmission corridor will be useful for productive wildlife habitat. After construction of the transmission corridors is completed, wildlife are expect to return. Operations of two new units at VEGP will not adversely affect land use at the VEGP site or in the corridor.

Construction activities along the river shoreline will adversely affect some shoreline habitat. In addition, they have potential to temporarily increase the sediment load in that section of the river, although, it is unlikely the increase would be measurable. Consumptive water loss from the Savannah River will be less than 2 percent of the 7Q10 low flow conditions, an amount that would drop the level of the river at VEGP less than 1 inch. Impacts to aquatic biota from water withdrawal will be small. Operation of the additional cooling towers will result in small amounts of salt deposition, but the deposits will be less than one half of the level considered a threshold for leaf damage and maximum deposition will occur on VEGP property. Very small, controlled and permitted concentrations of chemicals will be released to the river; however, these releases will have no measurable effect on water quality, the aquatic biota, or on downstream water users. The thermal plume from the new units will be small, less than 800 cubic feet under worst case conditions, and will not affect the water quality or the biota of the river. Less than 20 percent of the width of the river will be affected by the discharge structure and mixing zone.

Both construction and operation of the new units will increase the amount of groundwater used at VEGP. However, in both cases, the currently permitted withdrawal limit will not be exceeded.

The new units will discharge small amounts of radioactive liquids and gases within permit and regulatory limits. Potential doses to workers and the public were calculated and determined to be well within regulatory limits.

No major releases of pollutants to the atmosphere will result from operation of the new units; however, testing of standby generators and occasional use of the auxiliary boiler will emit some air pollutants. The emissions from the cooling towers have the potential for making micro-level changes to the meteorology, but only in the immediate vicinity of the towers.

The AP1000 will generate radioactive waste that will need to be disposed. The 660-person workforce and the new units themselves will generate additional non-radioactive wastes. Existing permitted radioactive and sanitary landfills have the capacity to accept these additional wastes.

It is reasonable to expect that populations closest to the VEGP site would be most affected by activities at VEGP. VEGP is adjacent to several Black Races census block groups. The only adverse impact categorized as greater than small is the volume of traffic on River Road. However, SNC has identified mitigation measures to alleviate congestion. Other impacts would be small or benefical. No impacts that would be disproportionately high and adverse on minority or low-income populations were identified.

Table 10.1-1 Construction-Related Unavoidable Adverse Environmental Impacts

Category	Adverse Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Land Use	Approximately 500 acres of land will be cleared during construction, with the potential for erosion. Land will not be available for other uses.	Comply with requirements of applicable federal, state and local construction permits/approvals and local ordinances. Clear only areas necessary for installation of the power plant/infrastructure. Restrict construction activities to the construction footprint. Use adequate erosion controls and stabilization measures, such as those provided in the Georgia Stormwater Manual. Restrict activities to actual construction site and access ways. Locate soil stockpiles near the construction site. Revegetate all affected temporary-use areas after completion of construction	310 acres of land occupied on a long-term basis by nuclear plant and associated infrastructure.
	Construction of transmission corridor across approximately 60 linear miles of eastern Georgia	Minimize potential impacts through compliance with permitting requirements and best management practices, including sediment basins. Restrict sites of access to corridor for construction equipment. Limit maintenance access roads Revegetate, with attention to wildlife structure or food plots.	Land use on some land will change from woodland or agriculture to open scrub or grassland.

Table 10.1-1 (cont.) Construction-Related Unavoidable Adverse Environmental Impacts

Category	Adverse Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
	Potential to disturb buried historic, archaeological, or paleontological resources	Conduct sub-surface testing prior to start of any onsite work to identify buried historic, cultural, or paeleontological resources. Follow established VEGP procedures to stop work and contact appropriate regulatory agencies if potential unanticipated historic, cultural, or paleontological resources are discovered.	Potential for destruction of unanticipated historic, cultural, or paleontological resources
	Construction debris will be disposed in on-site of off-site landfills	Use waste minimization to reduce volume of debris	Some land will be dedicated to disposal of construction debris and not available for other uses
Hydrologic and Water Use/	Construction has potential to erode sediments into water resources and will dewater the shallow aquifer	Adhere to applicable regulations, permits, and plans. Use best Management practices as found in the Georgia Stormwater Manual Install drainage controls to direct dewatering runoff.	Dewatering of shallow aquifer to surface water.
	Construction will require approximately 460 gpm of groundwater	Practice water conservation as practical No other measures or controls will be necessary because withdrawals will be less than allowed by current permits	Use of groundwater as source for all water used for construction.
	Construction along river banks or stream banks (in the case of the transmission line) could introduce sediments into the river or stream	Adhere to best management practices. Install drainage controls Revegetate as soon as possible after clearing.	No unavoidable adverse impacts

Table 10.1-1 (cont.) Construction-Related Unavoidable Adverse Environmental Impacts

Category	Adverse Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
	Use of heavy equipment introduces the possibility of petroleum spills that could enter surface water	Use good maintenance practices to maintain equipment, and prevent spills and leaks. Invoke VEGP's existing SPCC plan for construction activities.	No unavoidable adverse impacts
Aquatic Ecology	Construction at river's edge will cause the loss of some organisms, and temporary degradation of habitat Transmission line construction across streams will cause the loss of some organisms and temporary degradation of habitat	Install coffer dams or similar engineering protective measures around the construction site Use best management practices to minimize erosion and sedimentation Install storm water drainage system at large construction sites and stabilize disturbed soils	No unavoidable adverse impacts
Terrestrial Ecology	Habitat loss will kill or displace animals Clearing and grading will kill or displace animals Construction noises could startle or scare animals	Plant footprint is sited on previously disturbed area that is poor natural habitat. Site new corridor to avoid critical or sensitive habitats/species as much as possible per Georgia regulations and GPC practices. Limit vegetation removal and construction activities to construction site or corridor and access roads	No unavoidable impacts
	Birds may collide with tall construction equipment	No measures or controls will be necessary because impacts will be small.	No unavoidable impacts

Table 10.1-1 (cont.) Construction-Related Unavoidable Adverse Environmental Impacts

Category	Adverse Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Socio-economics	Construction workers, employees at the existing units, and local residents will be exposed to elevated levels of dust, noise and exhaust emissions from vehicles	Train and appropriately protect VEGP employees and construction workers to reduce the risk of potential exposure to noise, dust and exhaust emissions. Make public announcements or prior notification of atypically loud construction activities. Use dust control measures (such as watering, stabilizing disturbed areas, covering trucks). Ensure construction equipment is maintained Manage concerns from adjacent residents or visitors on a case-by-case basis.	No unavoidable impacts
	Construction workers, employees at the existing units, outage employees, and local residents will be exposed to elevated levels of traffic	Post signs near construction entrances and exits to make the public aware of potentially high construction traffic areas. Add turn lanes at construction entrance Consider buses, vans, carpools, or staggered shifts	Level of service on River Road will be reduced during shift change
	Construction workers could be injured	Provide on-site services for emergency first aid, and arrange with local hospital emergency room to accept trauma victims, and conduct regular health and safety monitoring. Provide appropriate job-training to construction workers.	No unavoidable impacts
	Initially sufficient housing to support the influx of construction workforce may be unavailable in Burke County	Builders and developers will meet the demand for additional housing, and because the project has a long lead time, and the construction workforce will build gradually, it is likely that adequate housing will always be available.	Potential short-term housing shortage in Burke County.

Table 10.1-1 (cont.) Construction-Related Unavoidable Adverse Environmental Impacts

Category	Adverse Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
	Initially there may be insufficient classroom space for the influx of construction workers families	Increased tax revenues as a result of the large construction project will fund additional school resources.	In the short-term there could be school crowding and inadequate fire protection in Burke County
	Inadequate fire protection infrastructure in Burke County will be further reduced	Increased tax revenues will be used to purchase additional equipment and hire/train staff	
Radiological	Construction workers will be exposed to small doses of radiation from the existing units	None required. All doses will be well within regulatory limits.	Small radiation exposure to construction workers.
Atmospheric and Meteorological	Construction will cause increased air emissions from traffic and construction equipment, and fugitive dust	Use dust control measures (such as watering, stabilizing disturbed areas, covering trucks) Ensure that construction equipment is well maintained.	No unavoidable adverse impacts
Environmental Justice	Except for increased traffic on River Road, no disproportionately high or adverse impacts to minority or low-income populations were identified.	Consider buses, vans, carpools, or staggered shifts	No unavoidable adverse impacts

Table 10.1-2 Operations-Related Unavoidable Adverse Environmental Impacts

Category/ Vogtle ESP ER Section	Adverse Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Land Use	Operating the new units will increase radioactive and non-radioactive wastes that are required to be disposed in permitted disposal facilities or permitted landfills	Practice waste minimization to minimize the volume of wastes.	Some land will be dedicated to permitted landfills or licensed disposal facilities and will not be available for other uses.
Hydrological and Water Use	Operations will result in discharge of small amounts of chemicals to the Savannah River	All discharges will comply with Georgia NPDES permit and applicable water quality standards. Revise the existing VEGP Storm Water Pollution Prevention Plan or prepare and implement a new one to avoid/minimize releases of contaminated storm water. Revise the existing VEGP Spill Prevention Countermeasures and Control Plan or prepare and implement a new one to avoid/minimize contamination from spills.	No unavoidable adverse impacts
	Water for some systems will be provided by groundwater	Maximum normal groundwater use will be within existing permit limits	Water withdrawn from groundwater will not be available for other uses. In the unlikely event of off-normal pumping by more than one unit, the groundwater withdrawal limits could be exceeded and the aquifer drawdown could be accelerated
	Maintenance activities at the site and along the transmission line could result in small petroleum spills	Revise the existing VEGP Spill Prevention Countermeasures and Control Plan or prepare and implement a new one to avoid/minimize contamination from spills. Adhere to the GPC SPCC plan when working on transmission lines	No unavoidable adverse impacts

Table 10.1-2 (cont.) Operations-Related Unavoidable Adverse Environmental Impacts

Category/ Vogtle ESP ER Section	Adverse Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
	Maximum surface water consumptive use will be less that 2 percent of 7Q10.	No mitigation required.	Water lost through evaporation will not be available for other uses
	Operations will result in a small thermal plume discharged to the Savannah River	The differences between plume temperature and ambient water temperature will be maintained within limits set in the NPDES permit	No unavoidable adverse impacts
Aquatic Ecology	Operations will result in discharge of small amounts of chemicals to the Savannah River	The NPDES permit limits are set to ensure that discharges do not affect aquatic populations or water quality.	No unavoidable adverse impacts
	Routine maintenance activities could result in petroleum spills near water	Revise the existing VEGP Spill Prevention Control and Countermeasures Plan or prepare and implement a new one to avoid/minimize contamination from spills.	No unavoidable adverse impacts
Terrestrial Ecology	Some birds will collide with the cooling towers or the transmission line	This is not a problem with the existing cooling towers and is not expected to be a problem with the new towers. Bird collisions with transmission lines are so rare that none have been reported to GPC. No mitigation is necessary	No unavoidable adverse impacts
	Salt drift will be distributed in a 3,300 foot radius around each tower.	The rate of deposition will be less than that expected to cause leaf damage. No mitigation is necessary.	No unavoidable adverse impacts
	Episodic loud noises at the site or along transmission line could frighten animals.	None necessary	No unavoidable adverse impacts

Table 10.1-2 (cont.) Operations-Related Unavoidable Adverse Environmental Impacts

Category/ Vogtle ESP ER Section	Adverse Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Socioeconomic	The plants emit low noise	Noise levels would normally not be above background at the site boundary. No mitigation is necessary.	No unavoidable adverse impacts
	Episodic loud noises could annoy nearby residents	Handle incidents on a case-by-case basis.	
	New transmission line has potential to produce electric shock in people standing near the line	Build transmission line to NESC code to minimize noise and electric shock	No unavoidable adverse impacts
	Additional cooling towers and plumes would impact existing viewscape.	Consider landscaping to hide towers from boaters on the river	No unavoidable adverse impacts
	Two additional units will double the traffic on local roads during shift change. More frequent outages at VEGP will increase traffic even further.	Consider staggering outage shifts to reduce plant-associated traffic on local roads during shift changes	No unavoidable adverse impacts
	Emissions from diesel generators and the auxiliary boilers	No mitigation needed. Emission would be within limits established in certificates of operation	No unavoidable adverse impacts
	Population in the region may increase by 2,600 people	No mitigation required. The increased tax revenues from construction will support upgrades to additional infrastructure. Housing availability is adequate in the region.	No unavoidable adverse impacts
Radiological	Potential doses to members of the public from releases to air and surface water.	All releases will be well below regulatory limits. No mitigation required.	No unavoidable adverse impacts

Table 10.1-2 (cont.) Operations-Related Unavoidable Adverse Environmental Impacts

Category/ Vogtle ESP ER Section	Adverse Impact	Mitigation Measure	Unavoidable Adverse Environmental Impacts
Atmospheric and Meteorological	Median plume from cooling towers will be about 0.5 miles long with a maximum plume length of 6.2 miles expected 3.5 percent of the time	No mitigation required	No unavoidable adverse impacts
	Diesels and the auxiliary boiler would contribute to air emissions	Comply with permit limits and regulations for installing and operating air emission sources.	No unavoidable adverse impacts
Environmental Justice	No disproportionately high or adverse impacts on minority or low-income populations resulting from operation of the proposed new units have been identified.	None required.	No unavoidable adverse impacts

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10.2 Irreversible and Irretrievable Commitments of Resources

This section describes the expected irreversible and irretrievable environmental resource commitments used in the construction and operation of the new units. The term "irreversible commitments of resources" describes environmental resources that will be potentially changed by the construction or operation of new units and that could not be restored at some later time to the resource's state prior to construction or operation. Irretrievable resources are generally materials that will be used for the new units in such a way that they could not, by practical means, be recycled or restored for other uses.

10.2.1 Irreversible Environmental Commitments

Irreversible environmental commitments resulting from the new units, in addition to the materials used for the nuclear fuel include:

- Groundwater and surface water,
- Land
- Aquatic and terrestrial biota, and
- Releases to air and surface water

10.2.1.1 Groundwater and Surface Water

Permitted groundwater capacity will be sufficient for the water demands during construction and operation of the new units. Once groundwater is removed from the aquifer it will be consumed or managed as surface water run-off. Some of the cooling water taken from the Savannah River will be lost through evaporation. In both cases, the impact to the resource will be small. Because the resource use is consumptive, it will not be available for other uses, now or in the future.

10.2.1.2 Land Use

Land committed to the disposal of radioactive and non-radioactive wastes is committed to that use, and cannot be used for other purposes.

Once the units cease operations and the plant is decommissioned in accordance with NRC requirements, the land that supports the facilities could be returned to other industrial or non-industrial uses.

10.2.1.3 Aquatic and Terrestrial Biota

Construction will temporarily adversely affect the abundance and distribution of local flora and fauna on the VEGP site. However, no significant effect on habitat or individual species is expected to occur. Similar impacts should occur on the new transmission corridor. Once construction is complete flora and fauna will recover in areas that are not affected by operations.

10.2.1.4 Releases to air and surface water

Radioactivity, air pollutants, and chemicals will be released from the facility during normal operations. Releases can alter air and water quality. All the releases from the new units will be made in accordance with duly-issued-permits, and will not measurably adversely affect the resource.

10.2.2 Irretrievable Commitments of Resources

Irretrievable commitments of resources during construction of the new units generally will be similar to that of any major, multi-year, construction project. Unlike the earlier generation of nuclear plants, asbestos and other materials considered hazardous will not be used, or will be used sparingly and in accordance with safety regulations and practices. DOE's report **(DOE 2004)** on new reactor construction estimates 12,239 yds of concrete, and 3,107 tons of rebar for a reactor building; 2,500,000 linear feet of cable for a reactor building and 6,500,000 linear feet of cable for a single unit; and up to 275,000 feet of piping greater than 2.5 inches for a single 1300 MW(e) reactor. While the amounts of these materials required will be large, the amounts will not be atypical of other types of power plants such as hydroelectric and coal-fired plants, nor of many large industrial facilities (e.g., refineries and manufacturing plants) that are constructed throughout the United States. Use of construction materials in the quantities associated with those expected for a nuclear power plant, while irretrievable unless they are recycled at decommissioning, will have a small impact, with respect to the availability of such resources.

During operations, the main resources that are irreversibly and irretrievably committed are the uranium that is used in fuel and the energy required to create the fuel. The World Nuclear Association studies supply and demand of uranium and states that a 50-year supply of lower-cost uranium is available and that supply could be expected to increase as market prices rise. A doubling in market price from 2003 could be expected to increase measured resources tenfold, over time **(World Nuclear Association 2005)**. Therefore, the uranium that will be used to generate power by the new units, while irretrievable, will have a small impact with respect to the long-term availability of uranium worldwide.

Other irretrievable commitments of resources include those materials used for the normal industrial operations of the plant that can not be recovered or recycled or that are consumed or reduced to unrecoverable forms, including elemental materials that will become radioactive.

Section 10.2 References

(Defense National Stockpile Center 2006) Defense Logistics Agency, "Inside DNSC," available online at https://dnsca.dla.mil/DNSC/contentview.asp?contentpage=inside&folder=dnsc, accessed 4/26/06.

(DOE 2004) U.S. Department of Energy, Study of Construction Technologies and Schedules, O&M Staffing and Cost, Decommissioning Costs and Funding Requirements for Advanced Reactor Designs, Vol. 2 – MPR-2610, prepared by Dominion Energy Inc., Bechtel Power Corporation, TLG, Inc., and MPR Associates under Contract DE-AT01-020NE23476, May 27.

(World Nuclear Association 2005) Supply of Uranium, available online at www.world-nuclear.org/info/printable_information_papers/inf75print.htm, accessed on 4/26/06.

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10.3 Relationship Between Short-Term Uses and Long-Term Productivity of the Human Environment

This environmental report has focused on the analyses and resulting conclusions associated with the environmental and socioeconomic impacts arising from activities during the construction and operation of new units at the VEGP site. These activities are considered to be short-term uses for purposes of this section. In this section, the long-term is considered to start with the conclusion of decommissioning of the new units at the VEGP site. This section includes an evaluation of the extent to which the short-term uses preclude any options for future use of the VEGP site.

10.3.1 Construction of New Units at VEGP and Long-Term Productivity

Section 10.1 summarizes the potential unavoidable adverse environmental impacts of construction of the new units and the measures proposed to reduce those impacts. Some adverse environmental impacts will remain after all practical measures to avoid or mitigate the impacts have been taken. However, none of these impacts represent a long-term effect that will preclude any options for future use of the VEGP site.

The new units will be constructed at the VEGP site, property selected and acquired for power generation. The acreage disturbed during construction of the new units will be larger than that required for the actual structures and other ancillary facilities because of the need for construction laydown and support areas and a parking area for the construction workforce. The clearance of this acreage, plus the noise of the construction, will displace some wildlife and destroy vegetation. Once the new units are completed, the disturbed areas will be restored. Wildlife will be expected to return to the restored area.

Noise emitted during some construction activities will increase the ambient noise levels in the vicinity of the site. However, upon completion of these activities, the ambient levels will return to the levels associated with the operation of the existing units. The workforce will be protected by adherence to the OSHA requirements for noise levels. There will be no effects on the long-term productivity of the VEGP site as a result of these impacts.

Construction traffic has the potential to impact traffic in the vicinity of the VEGP site, but the impact will cease once construction is completed.

The construction of the new units will be beneficial to the local area through the generation of new construction-related jobs, local spending by the construction workforce, and payment of taxes to the area. Some socioeconomic impacts that occur as a result of increased population and due to construction will cease once construction is complete and the workforce leaves the area, but changes incurred because of increased tax revenues will persist into the foreseeable future. In those cases, construction will have some impact on the long-term economic productivity of the area, particularly Burke County.

Construction will not affect long-term productivity of the environment.

10.3.2 Operation of the New Units and Long-Term Productivity

Section 10.1 summarizes the potential unavoidable adverse environmental impacts of operation of the new units and the measures proposed to reduce or eliminate those impacts. Some adverse environmental impacts could remain after all practical measures to avoid or mitigate them have been taken. However, none of these impacts represent long-term effects that will preclude any options for future use of the VEGP site.

The VEGP site has been developed as a location for major energy generation facilities. Therefore, the operation of the new units represents a continuation of the current and planned use of the land. However, once the reactors cease to operate and the plant is decommissioned to NRC standards, the land will be available for other industrial or non-industrial uses.

The new units will require cooling water withdrawn from the Savannah River. Some of the water will be lost to evaporation, but the impacts to the river will not be noticeable. After the reactors cease to operate and the units are decommissioned, water withdrawal from the river will cease. Groundwater will be used for some plant systems. After the plant ceases to operate and is decommissioned, groundwater withdrawals will cease.

The operation of the new units will slightly increase air emissions because of diesel generators and the auxiliary boiler that will be operated intermittently. The Technical Support Center will have a small backup generator. This equipment will be operated in accordance with applicable federal, state, and local regulations and they will not create any measurable impacts on regional air quality. Additionally, no long-term impacts will result from salt deposition arising from salt drift from the cooling towers as the analysis has determined the amount deposited will be less than levels at which ecological impacts might occur. Normal maintenance activities and precipitation will prevent the buildup of salt in the soil at the cooling towers. No future issues for the long-term uses of the site will result from the impacts of increased air emissions or salt deposition. Once the plant ceases to operate and is decommissioned, impacts to air will cease.

Chemicals and thermal pollution will be released to the Savannah River, in compliance with state and federal regulations. The releases will not adversely affect the Savannah River water quality during the operation of the plant. After decommissioning, releases to surface waters will cease.

Impacts due to radiological emissions will be small, because the operation of the new units will be in accordance with state and federal regulations. Radiological emissions will not contaminate VEGP property or the surrounding land. Once the plants cease to operate and are decommissioned, radiological releases will cease. No future issues associated with the radiological emissions from operation of the new units will affect the long-term uses of the VEGP site.

Socioeconomic changes brought about by the operation of the plant will likely continue after the plant is decommissioned. Property taxes paid by GPC to Burke County will provide significant revenues to the county for the foreseeable future, and will support greater county infrastructure and social services improvements than taxes on other land uses would. The Burke County population increases during the life of the plant, will use the services provided as a result of VEGP-related tax revenues. Most of Burke County is forested or agricultural, and provides little tax revenue to support county infrastructure and services. Therefore, taxes paid to Burke County will have a long-term effect on the productivity of the county. The economic benefits to Burke County from VEGP would be considered by most people to be a benefit.

10.3.3 Summary of Relationship Between Short-Term Uses and Long-Term Productivity

The impacts resulting from the construction and operation of the new units at the VEGP site will result in some adverse short-term impacts. The principal short-term benefit is the production of electrical energy. In addition, the economic benefit of the VEGP site and the associated workforce is large compared with the economic benefit from agriculture or other likely uses for the site. Because the site will eventually be restored by decommissioning, there will be no impacts to long-term productivity.

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10.4 Benefit-Cost Balance

NRC Regulation 10 CFR 52.17(a)(2) indicates that an early site permit (ESP) application need not include an assessment of benefits, allowing applicants to defer the analysis until submittal of a combined license (COL). Southern Nuclear Company (SNC) intends to apply for a COL for the Vogtle Electric Generating Plant (VEGP) in 2008 but has as a goal minimization of the amount of additional environmental information needed for a COL application. For this reason, SNC has included the benefit-cost balance in its ESP application.

10.4.1 Benefits

10.4.1.1 Need for Power

VEGP Units 3 and 4 will each generate approximately 1,117 megawatts electric (MWe) net, for a total of 2,234 megawatts. Assuming a reasonably low capacity factor of 85 percent, the 2-unit plant average annual electrical-energy generation will be more than 16,000,000 megawatt-hours. A reasonably high capacity factor of 93 percent would result in slightly more than 18,000,000 megawatt-hours of electricity. As discussed in Chapter 8, the Georgia Power Company (GPC) need for this benefit (i.e., need for power) is subject to a Georgia Public Service Commission (GPSC) approval process. GPC and the GPSC will not formally review the case for including new nuclear capacity in the GPC generation mix until GPC submits its 2007 Integrated Resource Plan (IRP). However, the GPSC has approved the current GPC load forecast that shows a need for generating capacity that VEGP Units 3 and 4 could provide.

10.4.1.2 Fuel Diversity and Natural Gas Alternative

Fuel diversity is key to affordable and reliable electricity. A diverse fuel mix protects electric companies and consumers from contingencies such as fuel unavailability, price fluctuations, and changes in regulatory practices **(EEI 2006**). History has taught us that it is risky to develop an over-reliance on any one energy source. In fact, a balanced energy portfolio has been the key to providing America with a growing supply of affordable electricity for the past 30 years **(CEED 2006)**.

The GPC fuel mix is made up of approximately 72 percent coal, 19 percent nuclear, 3 percent hydroelectric, and less than 6 percent natural gas and oil **(GPC 2004)**. As observed in the press and academia, because fuel diversity has been excellent, Georgia's electrical utility industry was not overly dependent on natural gas for power generation **(ABC 2002)**. However, the GPC IRP for 2004 shows a trend of increasing dependence on gas, and a corresponding decreasing dependence on nuclear, coal, and hydro energy, with gas projected to account for **[confidential commercial information]** percent of GPC capacity by 2023. With no other fuel in the mix, gas would in that time frame fuel approximately **[confidential commercial information]** megawatts of base and intermediate load generation **(GPC 2004)**.

The projected GPC future reliance on gas is considerably higher than U. S. Energy Information Administration projection of natural gas providing 24 percent of the nation's electricity by 2025 **(NRRI 2005)**. The Georgia legislature has pointed out that virtually all new power plants built in Georgia in the last 15 years are fueled by natural gas, exposing electricity consumers to punishing price volatility, and went on to urge Georgia utilities to study the feasibility of building new nuclear power plants (Senate Resolution 865). Testimony during the 2004 IRP approval process expressed concern about GPC planning to rely exclusively on natural gas for future resource additions, a concern that the GPSC echoed in approving the plan **(GPSC 2004**. See Appendix C).

Closely intertwined with the issue of fuel diversity is the issue of using natural gas to generate electricity. Maintaining fuel diversity is a matter of maintaining a balance of fuel mixes. Relying heavily on gas is a matter of choosing a limited resource over more abundant fuels.

High prices for natural gas and the intense, recurring periods of price volatility experienced over the last 4 years are influenced partly by demand for natural gas in the electric generation sector. Electric sector demand for natural gas is being driven by the large amounts of new gas-fired electric generating capacity built in the United States during the last decade. More than 90 percent of all new electric generating capacity added over the past 5 years is fueled with natural gas. Natural gas has many desirable characteristics and should be part of the fuel mix, but "over-reliance on any one fuel source leaves consumers vulnerable to price spikes and supply disruptions." New nuclear plants provide forward price stability that is not available from generating plants fueled with natural gas. The intense volatility in natural gas prices experienced over the last several years is likely to continue, and leaves the U.S. economy vulnerable. Although nuclear plants are capital-intensive to build, the operating costs are stable and dampen the volatility elsewhere in the electricity market. **(NEI 2005)**

Natural gas has uses that are not readily served by other fuel choices, such as many manufacturing processes. This led the U. S. House to prepare a majority staff report that included the following findings **(USHR 2006):**

- To enhance competitiveness and protect American jobs, natural gas must not be used for baseload electricity generation or for new generating capacity. Natural gas should be reserved for industries that use it as a feedstock or for primary energy – and cannot substitute for it by fuel-switching.
- Nuclear energy must become the primary generator of baseload electricity, thereby relieving the pressure on natural gas prices and dramatically improving atmospheric emissions.

GPC has committed to addressing the nuclear option in its next IRP update in 2007. For Georgia, VEGP Units 3 and 4 represent a step towards maintaining what has been a successful mix of fuel types for generating electricity. The new units will help maintain the state's fuel diversity while meeting state and national goals of creating new baseload generation that would not use natural gas as a fuel.

10.4.1.3 Emissions Reduction

As alluded to by the majority staff report, nuclear generation contributes considerable air quality benefits to the nation. Unlike electricity generated from coal and natural gas, nuclear energy does not result in any emissions of air pollutants associated with global warming and climate change (e.g., nitrogen oxides, sulfur dioxide, carbon dioxide) or methyl mercury. Power plants are responsible for 36 percent of carbon dioxide, 64 percent of sulfur dioxide, 26 percent of nitrogen oxides, and 13 percent of mercury emissions from industrial sources in this country. The majority of industry's emissions are from coal-fired plants. **(USHR 2006)**

Sections 9.2.3.1 and 9.2.3.2 analyze coal- and gas-fired alternatives to VEGP Units 3 and 4, respectively. Air emissions from these alternatives and nuclear power are summarized below:

Regardless of which reasonable alternative one compares to nuclear power, VEGP 3 and 4 would represent a substantial benefit in emission reduction, or emission avoidance, assuming that an alternative power source would be constructed if VEGP 3 and 4 were not. Given the concern within Georgia over projections of future use of gas for generating electricity, the coal-fired alternative would appear to be the most likely chosen in lieu of nuclear power.

10.4.1.4 Licensing Certainty

The regulatory scheme used for the existing domestic fleet of nuclear plants, under 10 CFR 50, was a two-step process that resulted in much uncertainty about cost projections and, in retrospect, final costs. This was due, in part, to the fact that the industry had to make large capital investments prior to resolving licensing issues. In large, capital-intensive construction projects, interest costs are a significant portion of the project cost. Interest charges on overnight capital costs account for a quarter of the levelized cost of electricity from nuclear power plants **(UC 2004)**. Under 10 CFR 50, licensing delays quickly and substantially increased project cost. Design changes, whether driven by licensing concerns, backfit requirements, or other factors, had similar effects.

SNC is looking to NRC's new 10 CFR 52 process to provide early resolution of siting issues prior to large investments of financial capital and human resources in new plant design and construction, early resolution of issues on the environmental impacts of construction and operation of proposed reactors, the ability to bank sites on which nuclear plants may be located, and the facilitation of future decisions on whether to build new nuclear plants. SNC believes that the resultant increase in licensing certainty will reduce project costs by decreasing premiums associated with uncertainty and making licensing and construction scheduling more controllable and reliable. SNC also believes that this increased certainty would become a factor that the Georgia Public Service Commission would consider in evaluating whether to authorize GPC to proceed with the project.

10.4.1.5 Advantages of Nuclear Power

Concerns about global warming and climatic change make it reasonable to expect that, eventually, the United States may have to strictly curb emissions from fossil-fuel electric generation plants, conceivably to the point of displacing coal- and gas-fired electricity generation. If environmental policies greatly restrict carbon emissions in the future, the cost of building and operating fossil-fired plants could increase by 50 to 100 percent. Nuclear power is the only technology currently available that is a viable alternative to fossil-fired plants for baseload generation. In view of the time that it takes to gear up the nuclear industry, the prospect of needing nuclear power to displace fossil-fuel power is one of the reasons for national concern with maintaining a nuclear energy capability. **(UC 2004)**

10.4.1.6 Tax Payments

The VEGP owners will pay property taxes on the new units for the duration of the 40-year operating licenses. Burke County received the taxes paid on VEGP property. As described in Section 5.8.2.2.1, over the life of the plant, annual tax payments could range from approximately $29,000,000 during initial operations to approximately $3,500,000 in the last years of the 40 year operational life. Most people consider large tax payments a benefit to the taxing entity because they support the development of infrastructure which supports further economic development.

10.4.1.7 Local Economy

The new units would require a workforce of about 660 people. The multiplier effect would create additional indirect jobs. In total, 1,600 new jobs within about a 50-mile radius of the plant (Section 5.8.2.2.1) would be created by the start-up of the new units and would be maintained throughout the life of the plant. Many of these jobs would be in the service sector and could be filled by unemployed local residents, lessening demands on social service agencies in addition to strengthening the economy. The economic multiplier effect of the increased spending by the direct and indirect labor force created as a result of two new units would increase the economic activity in the region, most noticeably in rural Burke County.

Nuclear plants such as VEGP generate approximately $350 million in total output for the local community and roughly $60 million in total labor income. These figures include direct effects, which reflect expenditures for goods, services, and labor, and secondary effects, which include subsequent spending in the community. The economic multiplier effect is one way of measuring secondary effects and means that every dollar spent by nuclear plants result in the creation of an additional $1.13 in the community. **(SSEB 2006)**

10.4.2 Costs

10.4.2.1 Monetary – Construction

In evaluating the VEGP Units 3 and 4 monetary cost, SNC reviewed published literature, vendor information, internally-generated general information, and internally-generated site-specific information. There are many cost studies available in the literature with a wide range of cost estimates. SNC found four studies to be most authoritative due to the breadth and depth of their analyses and the fact that other studies tend to be based on them. These are the following:

- MIT Study **(MIT 2003)**
- UC Study **(UC 2004)**
- EIA Study **(EIA 2004)**
- OECD Study **(OECD 2005)**

The phrase commonly used to describe the monetary cost of constructing a nuclear plant is "overnight capital cost." The capital costs are those incurred during construction, when the actual outlays for equipment and construction and engineering are expended. Overnight costs are exclusive of interest and include engineering, procurement, and construction costs, owner's costs, and contingencies.

Estimates of overnight capital costs range from $1,100 per kilowatt to $2,300 per kilowatt, with $1,500 to $2,000 per kilowatt being the most representative range. Many factors account for the range; the specific technology and assumptions about the number of like-units built, allocation of first-of-a-kind costs, site location and parity adjustments to allow comparison between countries, and allowances for contingencies are some examples. The estimates are not based on nuclear plant construction experience in this country, which is more than 20 years old. Actual construction costs overseas have been less than most recent domestic construction, suggesting that the industry has learned from the domestic experience. There is an assumption that that the overseas' experience can be applied domestically and the studies have found the overseas experience to be most applicable to estimating the cost of new domestic nuclear plant construction.

The four studies tend to support $2,000 per kilowatt as a reasonable high-end overnight capital cost estimate. The $2,300 value is based on construction in Japan. While no explanation is offered as to why this is so high, it is reasonable to suggest that contributing factors are the high cost of living in Japan (labor accounts for more than 20 percent of costs) and difficulties associated with construction on an island. For the purposes of analysis in this environmental report, to avoid understating the cost, SNC has chosen to use the $2,000 per kilowatt value.

Together with an installed capacity of 2,234 MWe, $2,000 per kilowatt results in a VEGP Units 3 and 4 construction cost of approximately $4.5 billion.

10.4.2.2 Monetary – Operation

As for construction costs, the four studies show a wide range of operation cost estimates Operation costs are frequently expressed as levelized cost of electricity, which is the price at the busbar needed to cover operating costs and annualized capital costs. Overnight capital costs account for a third of the levelized cost, and interest costs on the overnight costs account for another 25 percent **(UC 2004)**. Levelized cost estimates range from $36 to $83 per megawatt hour (3.6 to 8.3 cents per kilowatt hour). Factors affecting the range include choices for discount rate, construction duration, plant lifespan, capacity factor, cost of debt and equity and split between debt and equity financing, depreciation time, tax rates, and premium for uncertainty. Estimates include decommissioning but, due to the effect of discounting a cost that would occur as much as 40 years in the future, decommissioning costs have relatively little affect on the levelized cost. Using the same criteria as for construction costs, SNC has concluded that $65 per megawatt hour (6.5 cents per kilowatt hour) is a reasonably high-end levelized cost of electricity for nuclear generation. This compares well with preliminary cost information that GPC has filed with the GPSC **(GPC 2004)**.

In addition to nuclear plant costs, the four studies provide coal- and gas-fired generation costs for comparison to nuclear generation costs. One study **(OECD 2005)** showed nuclear costs competitive with coal and gas. The other studies showed nuclear costs that exceed those of coal and gas. One study **(MIT 2003)** indicated that new nuclear power is not economically competitive but went on to suggest steps that the government could take to improve nuclear economic viability. Since the study, the government has undertaken those steps as follows:

- U. S. Department of Energy has provided financial support for plants testing the U. S. Nuclear Regulatory Commission licensing processes for early site permits and combined operating licenses
- The U. S. government has endorsed nuclear energy as a viable carbon-free generation option
- The Energy Policy Act of 2005 instituted a production tax credit for the first advanced reactors brought on line in the U. S.

SNC has concluded that the government steps have negated the MIT study's conclusion that new nuclear power is not economically competitive.

10.4.2.3 Environmental and Material

Section 10.1 identifies unavoidable adverse impacts of the proposed action (i.e., impacts after consideration of proposed mitigation actions), and Section 10.2 identifies irretrievable commitments of resources. Table 10.4-2 includes these costs.

10.4.3 Summary

Table 10.4-2 summarizes benefits and costs of the proposed action. Costs that are environmental impacts are those anticipated after implementation of proposed mitigation measures.

Table 10.4-1 Avoided air pollutant emissions

Pollutant	Coal Emissions (tons per year/ 2,120 MW)[a]	Gas Emissions (tons per year/ 2,120 MW)[a]	Nuclear Emissions (tons per year)[b]
Sulfur dioxide	5,587	169	0
Nitrogen oxides	1,815	540	0
Carbon monoxide	1,815	112	0
Particulates having a diameter of less than 10 microns	91	94	0
Particulates having a diameter of less than 2.5 microns	0.39	94	0

a. Based on constructing two units to replace the power produced by Units 3 and 4 (see Section 9.2).

b. Nuclear power plants have emergency and auxiliary equipment that is fossil-fuel-fired and emits pollutants. The equipment is generally operated only for testing purposes for less than 250 hours per year. As such, the emissions are considered de minimus and are excluded here.

Table 10.4-2 Benefit-Cost Summary

Benefit-Cost Category	Description
	BENEFITS
Electricity generated	16,000,000 to 18,000,000 megawatt-hours per year
Generating capacity	2,234 megawatts
Fuel diversity and natural gas alternative	Nuclear option to coal- and gas-fired baseload generation
Emissions reduction	Avoidance of 169 to 5587 tons per year sulfur dioxide Avoidance of 540 to 1,815 tons per year nitrogen oxides Avoidance of 112 to 1,815 tons per year carbon monoxide Avoidance of 94 to 91 tons per year particulates
Licensing certainty	Early resolution of environmental issues, reliance on nuclear as generation option
Advanced Light Water Reactor development	Maintaining domestic nuclear technology capability as hedge against possible need to control global warming
Tax payments	Payments could range from approximately $29,000,000 to $3,500,000 annually over the life of the units
Local economy	Add 1600 jobs to the local economy
Cultural resources	Mitigative work adding to local historic and pre-historic knowledge base
	COSTS
Construction cost	$4.5 billion (overnight capital cost)
Operating cost	6.5 cents per kilowatt-hour (levelized cost of electricity)
Land use	310 acres occupied on long-term basis by nuclear plant and associated infrastructure. On-site landfill may restrict future uses of that land. Portion of new transmission line corridor that is wooded would be converted to open scrub or grassland
Housing	Potential short-term housing shortage in Burke County during the beginning of the 7.5-year construction period
Local Infrastructure	Potential short-term inadequate fire protection in Burke County during the beginning of the 7.5-year construction period
Cultural resources	Potential for destruction of historical, cultural, or paleontological resources

Table 10.4-2 Benefit-Cost Summary (cont.)

Benefit-Cost Category	Description
Groundwater use	During 7.5-year construction period, use of Cretaceous and Tertiary aquifers will increase potentiometric surface drawdown at site boundary by a maximum of approximately 2.3 feet. Dewatering of shallow, water-table aquifer would have only small, local affect. During 40-year operation period, an average 752 gpm will be withdrawn from the Cretaceous and Tertiary aquifers. This consumptive use will increase potentiometric surface drawdown at site boundary by a maximum of approximately 12.6 feet (based on four operating units). The drawdown effect is expected to disappear after operations cease.
Surface water use	During the 40-year operation period, approximately 37,000 gpm will be withdrawn from, and 9,000 gpm discharged to, the Savannah River. The balance, approximately 26,000 gpm, will be lost through evaporation.
Material	25,000 yds concrete 6,000 tons rebar 13,000,000 linear feet cable 550,000 feet of piping having diameter > 2.5 inches 981 metric tons of uranium
Radiological	Construction worker dose: 12.1 millirem per year (total body) Operation worker dose: 80.7person-rem Maximally exposed individual (public) dose: 0.12 millirem per year (total body) during operation Collective dose to the public: 0.013 person-rem per year during operation Population dose risk from severe accident: 4.2×10^{-2} person-rem per reactor year

Section 10.4 References

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(UC 2004) The University of Chicago, The Economic Future of Nuclear Power; A Study Conducted at The University of Chicago, August, available on U. S. Department of Energy website at http://www.ne.doe.gov/nucpwr2010/NP2010rptEconFutofNucPwr.html, accessed June 22, 2006.

(USHR 2006) U. S. House of Representatives, Securing America's Energy Future, Majority Staff Report to Committee on Government Reform and Subcommittee on Energy and resources, May 8, available on Committee website at http://reform.house.gov/GovReform/Files/Default.aspx?CatagoryID=152, accessed on June 20, 2006.

10.5 Cumulative Impacts

This section discusses cumulative adverse impacts to the region's environment that could result from the construction and operation of two new units at VEGP. A cumulative impact is defined in Council of Environmental Quality regulations (40 CFR 1508.7) as an "impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions."

To determine if cumulative impacts will be expected the existing environment in the region of VEGP (Chapter 2) was considered in association with the environmental impacts presented in Chapters 4 and 5 for operating two new units at VEGP. The section also contemplates renewal of VEGP Units 1 and 2 operating licenses, and the cumulative impacts of four units on the affected environment.

10.5.1 Cumulative Impacts from Construction

Construction activities will require some groundwater in addition to that used by the existing facilities. The maximum withdrawal rate of the combined existing units and construction will be less than withdrawal rate permitted by the State. No other large groundwater users are in the vicinity of VEGP. Therefore, cumulative impacts to groundwater during construction will be small.

Approximately 310 acres of the VEGP property will be required for the new units. An additional transmission corridor will be constructed and will require a total of approximately 2.0 sq mi of land over a distance of approximately 60 miles. Eastern Georgia is predominantly rural and most land is agricultural or forested. SNC is unaware of any large projects that will change the predominant land use in Burke County or the counties the corridor will cross. The construction of Units 1 and 2 did not spur a great amount of growth in Burke County, and SNC expects the impacts of Units 3 and 4 to be similar. The project will not contribute to cumulative impacts of changing land use.

During construction noise levels will increase above those now experienced at VEGP, however, the noise levels will return to ones expected for a power generation facility after construction ceases. No other large construction activities are planned in the vicinity, and so noise from construction will not be cumulative with other industrial sources.

Construction will result in increased air emissions from commuter traffic and the construction equipment. However, as noted, this is the only large construction project planned for the area and the air quality in the vicinity is in attainment with air quality standards. No adverse cumulative impacts to air quality are expected.

The maximum construction workforce will be approximately 4,400 people and the percent of the workforce that will live in Burke County could have short-term moderate impacts to the Burke County housing market and social services, particularly schools and fire protection infrastructure. However, no other construction projects of this magnitude have been identified in the area, and so there will be no cumulative impacts due to other large construction workforces. No other cumulative impacts due to construction have been identified.

10.5.2 Cumulative Impacts of Operations

After operations begin, the new units will use groundwater for some operational systems. The groundwater use requirements of the new units and the existing units will be less that the withdrawal rate currently permitted by the State. No other significant current or future users of groundwater in the vicinity of VEGP have been identified. Therefore, cumulative impacts to groundwater during operation will be small and not warrant mitigation.

Noise from the existing units is usually indistinguishable from background, and the new units will generate similar levels of noise. One small power generation facility on the Savannah River Site is within 6 miles of VEGP. No other sources of industrial noise occur in the 6-mile vicinity, and so cumulative noise pollution is expected to be minimal.

Operational activities that could impact surface water such as NPDES-permitted discharges will be small. The maximum mixing zone for the existing units' thermal plume was estimated to be 4,300 cu ft with a downstream distance of about 20 feet and a depth of about 10 feet **(AEC 1974)** but SNC has no data on actual plume size. Based on computer modeling, blowdown from the new units' cooling towers will produce a thermal plume with a surface area of approximately 300 sq ft, a cross-sectional area of approximately 115 sq ft, and a volume of approximately 800 cu ft. Neither plume is large enough to affect the water quality or biota of the river. The new discharge will be downstream of the existing discharge plume and the existing plume will mingle with the new plume, however, this commingling was considered in the previously described model which resulted in a plume of 800 cu ft. The cumulative impacts of the plumes from the existing discharge and the proposed discharge on the Savannah River will be small and will not warrant mitigation.

The new cooling system will withdraw make up water from the Savannah River, as does the existing system. The existing units have a maximum actual consumptive water use of 30,000 gpm (Table 2.9-1) and the new units have a maximum estimated consumptive use of 29,000 gpm. The combined (four units) maximum consumptive use will constitute less than 3 percent of the lowest calculated 7Q10 flow. Between VEGP and the nearest downstream users are several large tributary creeks. The cumulative impacts of VEGP water withdrawal on the Savannah River and downstream users will be small and will not warrant mitigation.

Two natural draft cooling towers will join the two existing towers on the local sky-line. The towers will appear to be clustered together so the visual impact will be only slightly different from what it is now. Two additional towers will increase the size of the plume and its visibility from offsite areas, but will not change the nature of the visual experience. Cumulative impacts on the viewscape will be small and will not warrant mitigation.

The distance between the additional pair of cooling towers and the existing pair of towers will be approximately 3,800 feet. A single cooling tower's plume is estimated to have a maximum salt deposition rate of 2.5 pounds per acre per month, and that maximum deposition will occur 3,300 feet from the tower. Salt deposition was not estimated for Units 1 and 2. However, assuming that all four towers deposited the maximum of 2.5 pounds per acre per month, the deposition rate will be 10 pounds per acre per month. This represents, for a particular location 1 pound per month above concentrations that are considered the threshold for leaf damage. SNC does not believe that salt deposition from all four units warrants mitigation for several reasons. The deposition rate is a calculated maximum rate, and so the actual rate will likely be less. Moreover, because the distance between the two sets of towers will be approximately 3,800 feet – or greater than the maximum deposition distance – maximum deposition areas will not overlap, making deposition from all four towers on the same area of land impossible. Finally, the area most likely to get solids deposition form all four towers, the area between them, is part of the plant complex and is almost all paved or structures.

Impacts to air quality will not be from the reactors, but from support facilities and equipment and cooling towers, as they are now for the existing units. Emissions of criteria pollutants from the new units will be in pounds per year from the emergency diesel generators or the auxiliary boiler. The SRS D-Area Powerhouse, SCE&G's Urquhardt Station, and Plant Wilson are all fossil-fueled and are located within about 25 miles of VEGP. The greater Augusta area has several large industrial facilities with permitted releases to the air. The Augusta-Aiken Interstate Air Quality Control Region is in attainment for all criteria pollutants. The contribution of the four VEGP units' support facilities to regional air quality pollutants is small and would not require mitigation. Cumulative atmospheric and meteorological impacts are not expected.

New reactor units will release small quantities of radionuclides to the environment. Each AP1000 unit is predicted to have liquid emissions of approximately 1,000 curies annually and gaseous emissions of approximately 11,000 curies annually. These Westinghouse AP1000 doses were derived for the DCD using the PWR-GALE model to demonstrate that the design would meet the 10 CFR 50, Appendix I limits **(Westinghouse 2005)**. The predicted liquid and gaseous doses from the AP1000 units are identified in Chapter 3 (Tables 3.0-1, 3.5-1 and 3.5-2). Predicted doses for the existing units, contained in the VEGP Units 1 and 2 UFSAR, were based on a previous version of the PWR-GALE model resulting in dose values higher than actual measured doses. Subsequently, the latest version of the PWR-GALE model used in the AP1000 DCD is even more conservative than the previous version used for Units 1 and 2.

Therefore, this analysis likely does not represent the doses expected from the new units. The existing units annual measured gaseous and liquid emissions, identified in Table 2.9-1, are 115 curies and 1,400 curies respectively. All releases will be within regulatory limits as indicated in Table 5.4-9. In addition to the two existing VEGP units, other existing sources of radionuclide releases to the environment within the 50-mile region include DOE's Savannah River Site; the disposal facility for commercially-generated low-level radioactive waste, Chem-Nuclear in Barnwell, SC; and area hospitals, with the largest contributors the SRS and VEGP.

Both VEGP and the Savannah River Site (SRS) release radionuclides into the atmosphere and the Savannah River. Tritium accounts for nearly all the radioactivity released to the river. The SRS maintains an extensive monitoring program in the Savannah River. In 2004, the average tritium concentration at the Highway 301 bridge, downstream of VEGP and SRS, from all sources, was 0.061 picocuries per milliliter (**WSRC 2005**). The U.S. Environmental Protection Agency maximum contaminant level for maintaining safe drinking water is 20 picocuries of tritium per milliliter. SNC anticipates that the new units will release tritium in concentrations similar to the existing units. The cumulative impacts of tritium released to the Savannah River from the SRS and four VEGP will be small and will not warrant mitigation.

The potential maximally exposed individual all-pathways dose from all SRS releases was 0.15 millirem in 2004 (**WSRC 2005**). The maximally exposed individual dose from the existing VEGP units in 2004 was 0.091 millirem. The conservative (maximum) estimated dose to the maximally exposed individual from the new units is 0.12 millirem per year. Therefore, if the same hypothetical individual was the maximally exposed individual to both SRS and VEGP releases, the total annual dose will be 0.21 millirem per year. The regulatory limit for exposure to an offsite member of the public is 25 millirem per year. Cumulative impacts to the maximally exposed individual will be small and will not warrant mitigation.

The fuel cycle specific to new units at VEGP will contribute to the cumulative impacts of fuel production, storage and disposal of all nuclear units in the United States, but the cumulative impacts of the fuel cycle for the existing reactors is small and the addition of the impacts of two new units will not change that conclusion. Fuel and waste transportation impacts from two new units also will be small, and will not increase the cumulative impacts of transportation of all nuclear reactor fuel and wastes.

Non-radioactive solid wastes will be disposed in permitted landfills. The volume of additional wastes will be minimized through waste minimization programs, and therefore, cumulative impacts of waste disposal are expected to be small.

Socioeconomic impacts, including increased tax revenues to Burke County, would be cumulative with socioeconomic changes brought about through the construction and operation of the existing units, and changes due to normal population growth. Taxes from the four units will fund new infrastructure that could attract residents to Burke County. However, the construction and operation of the existing units did not result in large changes to tax-driven land use changes in Burke County, and it is not expected that the new units will either. The infrastructure of Burke, Richmond, and Columbia Counties is adequate to support new operations employees. No other projects that would involve immigration of a large workforce have been identified in the area. Cumulative socioeconomic impacts would be small.

In conclusion, the impacts from the construction and operation of one of more units at the VEGP site will not contribute significantly to existing or future cumulative impacts to the vicinity or the region.

Section 10.5 References

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Appendix A

Agency Correspondence

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Southern Nuclear
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Tel 205.992.5000

SOUTHERN COMPANY
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March 1, 2006 AR-06-0429

Ms. Sandy Tucker
Field Supervisor
U.S. Fish & Wildlife Service
Westpark Center Suite D
105 Westpark Drive
Athens, GA 30606

Re: Vogtle Electric Generating Plant – Early Site Permit
Review of Threatened and Endangered Species and Important Habitats

Dear Ms. Tucker:

Southern Nuclear Operating Company is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) for an Early Site Permit for the Vogtle Electric Generating Plant (VEGP) located in Burke County, Georgia. The application will be based on construction of two Westinghouse AP-1000 reactors and is scheduled for submittal to the NRC by August 15, 2006. The Early Site Permit, when granted, approves the site as suitable for construction of new nuclear units, but does not constitute a commitment on the part of Southern Company to construct new units on the site. The Early Site Permit can be granted for a period of up to twenty years.

As part of the Early Site Permit application process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.45). The NRC will contact your organization during the application review of the Environmental Report. By contacting you early in the application process, SNC hopes to identify any issues that need to be addressed or any information your office may need to expedite the NRC review.

VEGP lies on the west bank of the Savannah River in the eastern sector of Burke County, Georgia, at River Mile 151, approximately 23 river miles upstream from the intersection of the Savannah River and U.S. Highway 301. The VEGP site proper encompasses approximately 3169 acres, roughly one-half of which (1778 acres) are undeveloped (old fields, forests, and wetlands) and managed as a wildlife preserve. The Vogtle site is served by approximately 340 miles of transmission lines divided among six (6) corridors. One of the corridors, Vogtle-Wilson, connects Vogtle to the adjacent combustion turbine plant (Plant Wilson) and is contained entirely on the site property. The other corridors consist of three 230 KV lines: Vogtle-Savannah River Site; Vogtle-Goshen; and Vogtle-Augusta Newsprint (a nine mile loop off of the Vogtle-Goshen line), and two 500 KV lines: Vogtle-Thalmann, and Vogtle-Scherer.

Ms. Sandy Tucker – Page 2

Southern Nuclear has recently completed a Threatened and Endangered Species Study which evaluates potential impacts to threatened and endangered species for the Vogtle site and associated transmission lines. The report is focused on terrestrial and aquatic species that have the potential to occur on the Vogtle site and associated transmission line corridors. The report documents the occurrence of one federally listed species, the wood stork, on two of the existing Vogtle transmission corridors (Vogtle-Scherer and Vogtle-Thalmann). The state threatened gopher tortoise, as well as the spotted turtle, an unusual species in Georgia, were observed on the Vogtle-Thalmann corridor. Two state listed plant species, pond spice and the hooded pitcher plant, were also found on this corridor. The state threatened bay star vine was the only listed species observed on the Vogtle plant site. The presence of the federal and state listed species noted in the report is known and the potential impacts are well understood. There are controls in place to ensure activities such as mowing, clearing, and maintenance conducted on transmission lines do not significantly impact these species. Similar controls are in place on the Vogtle plant site. Based on the listed species inventory documented in the report, no significant impact associated with construction and operation of the proposed two new units at Vogtle should occur. The final report was issued January 16, 2006, and is provided as Attachment 1.

There are two aquatic species known to inhabit the Savannah River; the federally endangered shortnose sturgeon and the robust redhorse, a Georgia Species of Interest. The operation of the existing two units at VEGP does not significantly impact these species. No significant impact to these species is anticipated from construction and operation of the proposed two additional units at the Vogtle site.

This report is provided in advance to allow ample time for your review and to allow time for resolution of questions and comments prior to the August 2006 submittal date. Your response to this correspondence is respectfully requested by June 1, 2006 to support resolution of threatened and endangered species issues prior to submittal of the Environmental Report. We will include a copy of this letter and your response in the Early Site Permit application submittal to the NRC.

Please call me at (205) 992-5807 or Ms. Amy Greene at (205) 992-5805 if you have questions or require additional information.

Sincerely,

Original signed by T. C. Moorer

T. C. Moorer
Project Manager- Environmental Support

Attachment

cc: C. R. Pierce (w/o attachment)
J. M. Godfrey (w/o attachment)
File AR.01.01.06
Document Control R-Type: AR.01.01

Ms. Sandy Tucker – Page 3

bc: (Without attachment)
L. B. Long
B. C. Terry
R. D. Hill
J. T. Davis
A. B. Greene
M. C. Nichols
R. D. Just

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SOUTHERN COMPANY
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August 2, 2006 AR-06-1583

Mr. David Bernhart
Chief, Protected Species Branch
National Marine Fisheries Service
Southeast Regional Office
263 13th Avenue, South
St. Petersburg, Florida 33701

Re: Vogtle Electric Generating Plant – Early Site Permit
Request for Information on Threatened or Endangered Species

Dear Mr. Bernhart:

Southern Nuclear Operating Company (SNC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) for an Early Site Permit for the Vogtle Electric Generating Plant (VEGP) located in Burke County, Georgia. The application will be based on construction of two Westinghouse AP-1000 reactors and is scheduled for submittal to the NRC by August 15, 2006. The Early Site Permit, when granted, approves the site as suitable for construction of new nuclear units, but does not constitute a commitment on the part of Southern Company to construct new units on the site. The Early Site Permit can be granted for a period of up to twenty years.

As part of the Early Site Permit application process, the NRC requires license applicants to assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act. The NRC will contact your organization during the application review of the VEGP Environmental Report. By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC review.

VEGP lies on the west bank of the Savannah River in the eastern sector of Burke County, Georgia, at River Mile 151, approximately 30 river miles upstream from the intersection of the Savannah River and U.S. Highway 301. The VEGP site encompasses approximately 3,169 acres, roughly one-half of which (1,778 acres) are undeveloped (old fields, forests, and wetlands) and managed as a wildlife preserve. The Vogtle site is served by the approximately 340 miles of transmission lines divided among six (6) corridors. One of the corridors, Vogtle-Wilson, connects Vogtle to the adjacent combustion turbine plant, Plant Wilson, and is contained entirely on the site property. The other corridors consist of three 230 kV lines: Vogtle-Savannah River Site; Vogtle-Goshen; and Vogtle-Augusta Newsprint (a nine-mile loop off of the Vogtle-Goshen line), and two 500 kV lines: Vogtle-Thalmann and Vogtle-Scherer.

There are two sensitive aquatic species known to inhabit the Savannah River: the federally endangered shortnose sturgeon and the robust redhorse, a Georgia Species of Interest. The

AR-06-1583
Mr. David Bernhart – Page 2

operation of the existing two units at VEGP does not significantly impact these species. No significant impact to these species is anticipated from construction and operation of the proposed two additional units at the Vogtle site.

This correspondence is provided in advance to support agency resource planning and to allow time for resolution of questions and comments prior to the August 2006 application submittal date. Southern Nuclear will include a copy of this letter in the Early Site Permit application submittal to the NRC.

Please call me at (205) 992-5807 or Ms. Amy Aughtman at (205) 992-5805 if you have any questions or require additional information.

Sincerely,

Original signed by T. C. Moorer

T. C. Moorer
Project Manager – Environmental Support

TCM/AGA

Enclosure: Figures 2.1-1 and 2.1-3

cc: C. R. Pierce (w/o attachment)
J. M. Godfrey (w/o attachment)
File AR.01.01.06
Document Control – R-Type AR.01

bc: (w/ attachment)
R. D. Just
M. C. Nichols
A. G. Aughtman

(w/o attachment)
J. A. Miller
D. M. Lloyd
J. T. Davis

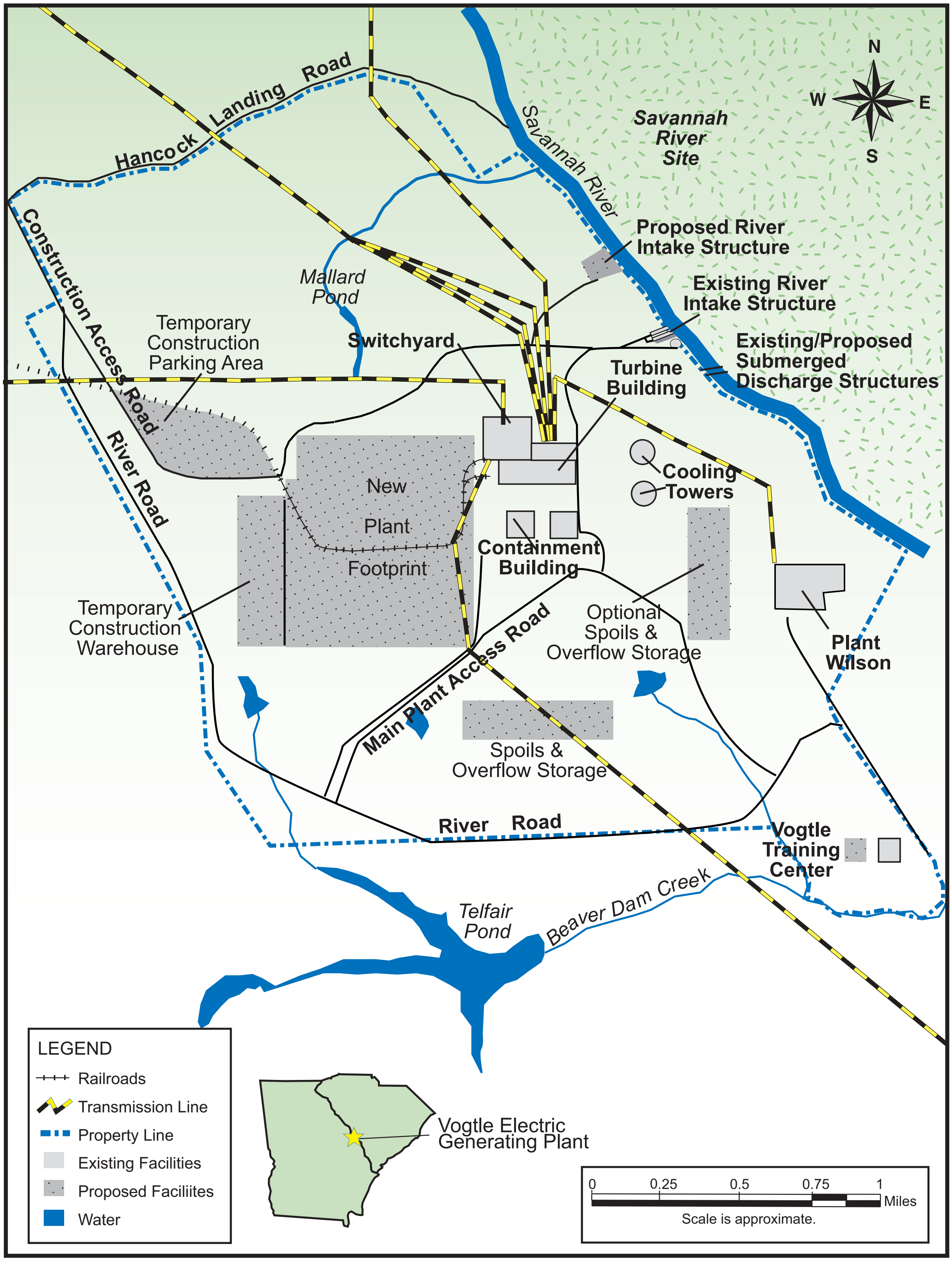

Figure 2.1-1 VEGP Site and Proposed New Plant Footprint

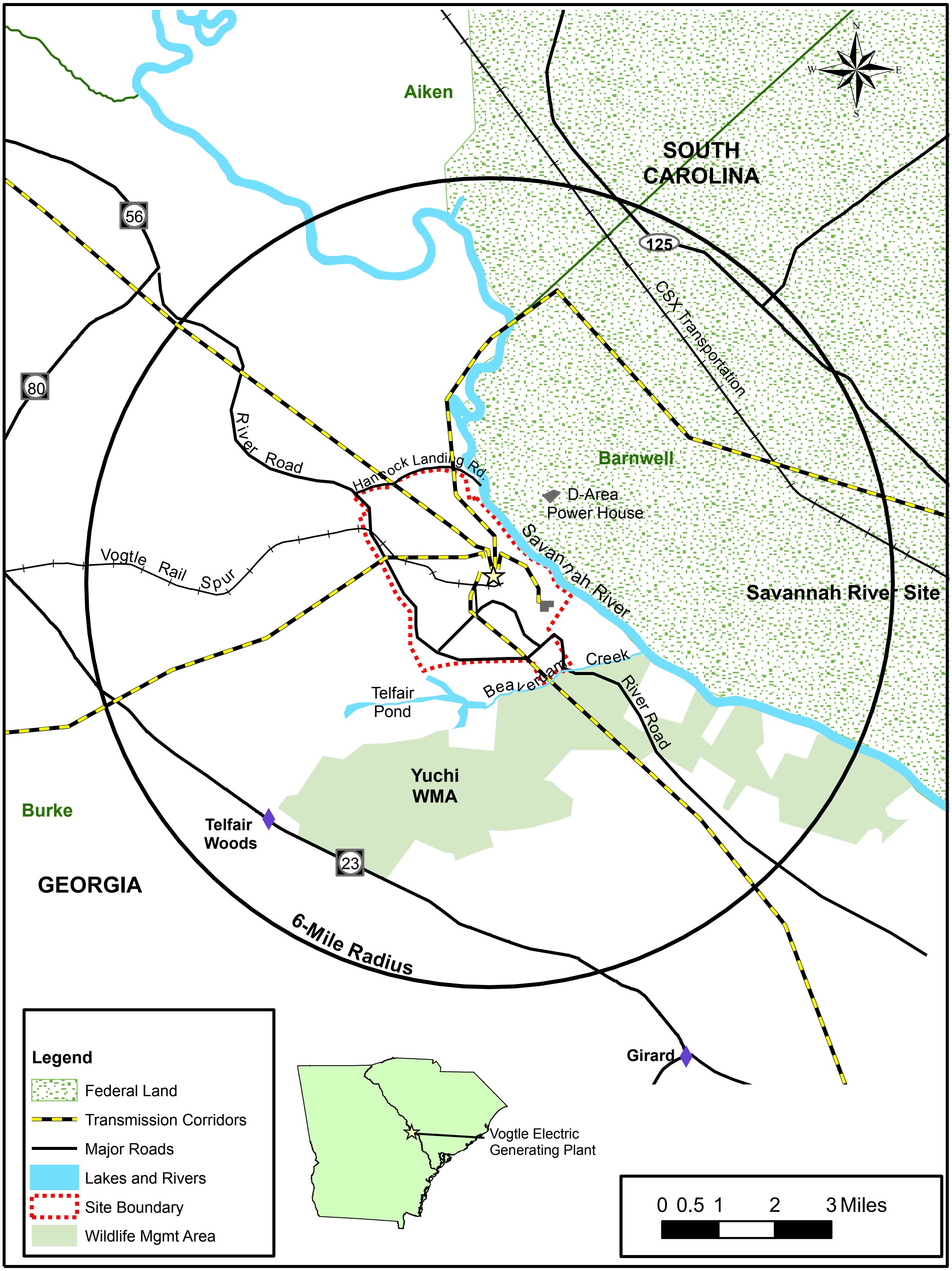

Figure 2.1-3 6-Mile Vicinity

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SOUTHERN COMPANY
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March 1, 2006 AR-06-0431

Mr. Mike Harris
Georgia Department of Natural Resources
Non-game Program
2117 U.S. Highway 278 SE
Social Circle, GA 30279

Re: Vogtle Electric Generating Plant – Early Site Permit
Review of Threatened and Endangered Species and Important Habitats

Dear Mr. Harris:

Southern Nuclear Operating Company is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) for an Early Site Permit for the Vogtle Electric Generating Plant (VEGP) located in Burke County, Georgia. The application will be based on construction of two Westinghouse AP-1000 reactors and is scheduled for submittal to the NRC by August 15, 2006. The Early Site Permit, when granted, approves the site for construction of new nuclear units, but does not constitute a commitment on the part of Southern Company to construct new units on the site. The Early Site Permit authorizes the site for a period of twenty years.

As part of the Early Site Permit application process, the NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.45). The NRC will contact your organization during the application review of the Environmental Report. By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC review.

VEGP lies on the west bank of the Savannah River in the eastern sector of Burke County, Georgia, at River Mile 151, approximately 23 river miles upstream from the intersection of the Savannah River and U.S. Highway 301. The VEGP site proper encompasses approximately 3169 acres, roughly one-half of which (1778 acres) are undeveloped (old fields, forests, and wetlands) and managed as a wildlife preserve. The Vogtle site is served by approximately 340 miles of transmission lines divided among six (6) corridors. One of the corridors, Vogtle-Wilson, connects Vogtle to the adjacent combustion turbine plant (Plant Wilson) and is contained entirely on the site property. The other corridors consist of three 230 KV lines: Vogtle -Savannah River Site; Vogtle-Goshen; and Vogtle-Augusta Newsprint (a nine mile loop off of the Vogtle-Goshen line), and two 500 KV lines: Vogtle-Thalmann, and Vogtle-Scherer.

Southern Nuclear has recently completed a Threatened and Endangered Species Study which evaluates potential impacts to threatened and endangered species for the Vogtle site and associated transmission lines. The report is focused on terrestrial and aquatic species that have the potential to occur on the Vogtle site and associated transmission line corridors. The report documents the occurrence of one federally listed species, the wood stork, on two of the existing Vogtle transmission corridors (Vogtle-Scherer and Vogtle-Thalmann). The state threatened gopher tortoise, as well as the spotted turtle, an unusual species in Georgia, were observed on the Vogtle-Thalmann corridor. Two state listed plant species, pond spice and the hooded pitcher plant, were also found on this corridor. The state threatened bay star vine was the only listed species observed on the Vogtle plant site. The presence of the federal and state listed species noted in the report is known and the potential impacts are well understood. There are controls in place to ensure activities such as mowing, clearing, and maintenance conducted on transmission lines do not significantly impact these species. Similar controls are in place on the Vogtle plant site. Based on the listed species inventory documented in the report, no significant impact associated with construction and operation of the proposed two new units at Vogtle should occur. The final report was issued January 16, 2006, and is provided as Attachment 1.

There are two aquatic species known to inhabit the Savannah River; the federally endangered shortnose sturgeon and the robust redhorse, a Georgia Species of Interest. The operation of the existing two units at VEGP does not significantly impact these species. No significant impact to these species is anticipated from construction and operation of the proposed two additional units at the Vogtle site.

Your response to this correspondence is respectfully requested by June 1, 2006 to support resolution of threatened and endangered species issues prior to submittal of the Environmental Report. We will include a copy of this letter and your response in the Early Site Permit application submittal to the NRC

Please call me at (205) 992-5807 or Ms. Amy Greene at (205) 992-5805 if you have questions or require additional information.

Sincerely,

Original signed by T. C. Moorer

T. C. Moorer
Project Manager- Environmental Support

Attachment

cc: C. R. Pierce (w/o attachment)
J. M. Godfrey (w/o attachment)
File AR.01.01.06
Document Control R-Type: AR.01.01

Mr. Mike Harris – Page 3

bc: (Without attachment)
L. B. Long
B. C. Terry
R. D. Hill
J. T. Davis
A. B. Greene
M. C. Nichols
R. D. Just

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Southern Nuclear
Operating Company, Inc.
P.O. Box 1295
Birmingham, Alabama 35201-1295

Tel 205.992.5000

SOUTHERN COMPANY
Energy to Serve Your World®

August 2, 2006 AR-06-1728

Linda MacGregor
Chief, Watershed Protection Branch
Environmental Protection Division
Georgia Department of Natural Resources
4220 International Parkway, Suite 101
Atlanta, GA 30354

Re: Vogtle Electric Generating Plant – Early Site Permit
Request for Information on Thermophilic Organisms in the Savannah River

Dear Ms. MacGregor:

Southern Nuclear Operating Company (SNC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) for an Early Site Permit for the Vogtle Electric Generating Plant (VEGP) located in Burke County, Georgia. The application will be based on construction of two Westinghouse AP-1000 reactors and is scheduled for submittal to the NRC by August 15, 2006. The Early Site Permit, when granted, approves the site as suitable for construction of new nuclear units, but does not constitute a commitment on the part of Southern Company to construct new units on the site. The Early Site Permit can be granted for a period of up to twenty years.

As part of the Early Site Permit application process, NRC requires applicants to "assess the impact of the proposed action on public health from thermophilic organisms in the affected water" (10 CFR 51.53). NRC guidance and supporting documentation focus on organisms such as *Naegleria fowleri,* which has been known to produce public heath concerns when present in high concentrations.

VEGP lies on the west bank of the Savannah River in the eastern sector of Burke County, Georgia, at River Mile 151, approximately 30 river miles upstream from the intersection of the Savannah River and U.S. Highway 301. The VEGP site encompasses approximately 3,169 acres, roughly one-half of which (1,778 acres) are undeveloped (old fields, forests, and wetlands) and managed as a wildlife preserve. The discharge for VEGP Units 1 and 2 enters the Savannah River via a submerged single port discharge pipe. Discharge limits and monitoring requirements are set forth in the VEGP National Pollutant Discharge Elimination System (NPDES) permit, GA0026786. The discharge structure for the proposed Units 3 and 4 will be of similar design and will enter the river slightly downstream of the existing submerged discharge structure.

AR-06-1728
Ms. Linda MacGregor – Page 2

The VEGP existing discharge temperatures and predicted new discharge temperatures are significantly less than those known to be optimal for growth and survival of thermophilic organisms. SNC is aware of no information that suggests any concern about thermophilic organism concentrations in the river. SNC is consulting with your office for any information that may be available on any potential health effects associated with thermophylic organisms in discharges from steam electric generating facilities in the southeast. A letter confirming receipt of this correspondence and providing any concerns you may have is respectfully requested. The NRC will likely contact your office during the review of the VEGP Early Site Permit application regarding this matter.

This correspondence is provided to allow ample time for your review of this issue prior to being contacted by the NRC. Southern Nuclear will include a copy of this letter in the Early Site Permit application submittal to the NRC.

Please call me at (205) 992-5807 or Ms. Amy Aughtman at (205) 992-5805 if you have any questions or require additional information.

Sincerely,

Original signed by T. C. Moorer

T. C. Moorer
Project Manager – Environmental Support

TCM/AGA

Enclosure: Figures 2.1-1 and 2.1-3

cc: C. R. Pierce (w/o attachment)
J. M. Godfrey (w/o attachment)
File AR.01.01.06
Document Control – R-Type AR.01

AR-06-1728
Ms. Linda MacGregor – Page 3

bc: (w/ attachment)
R. D. Just
M. C. Nichols
A. G. Aughtman

(w/o attachment)
J. A. Miller
D. M. Lloyd
J. T. Davis

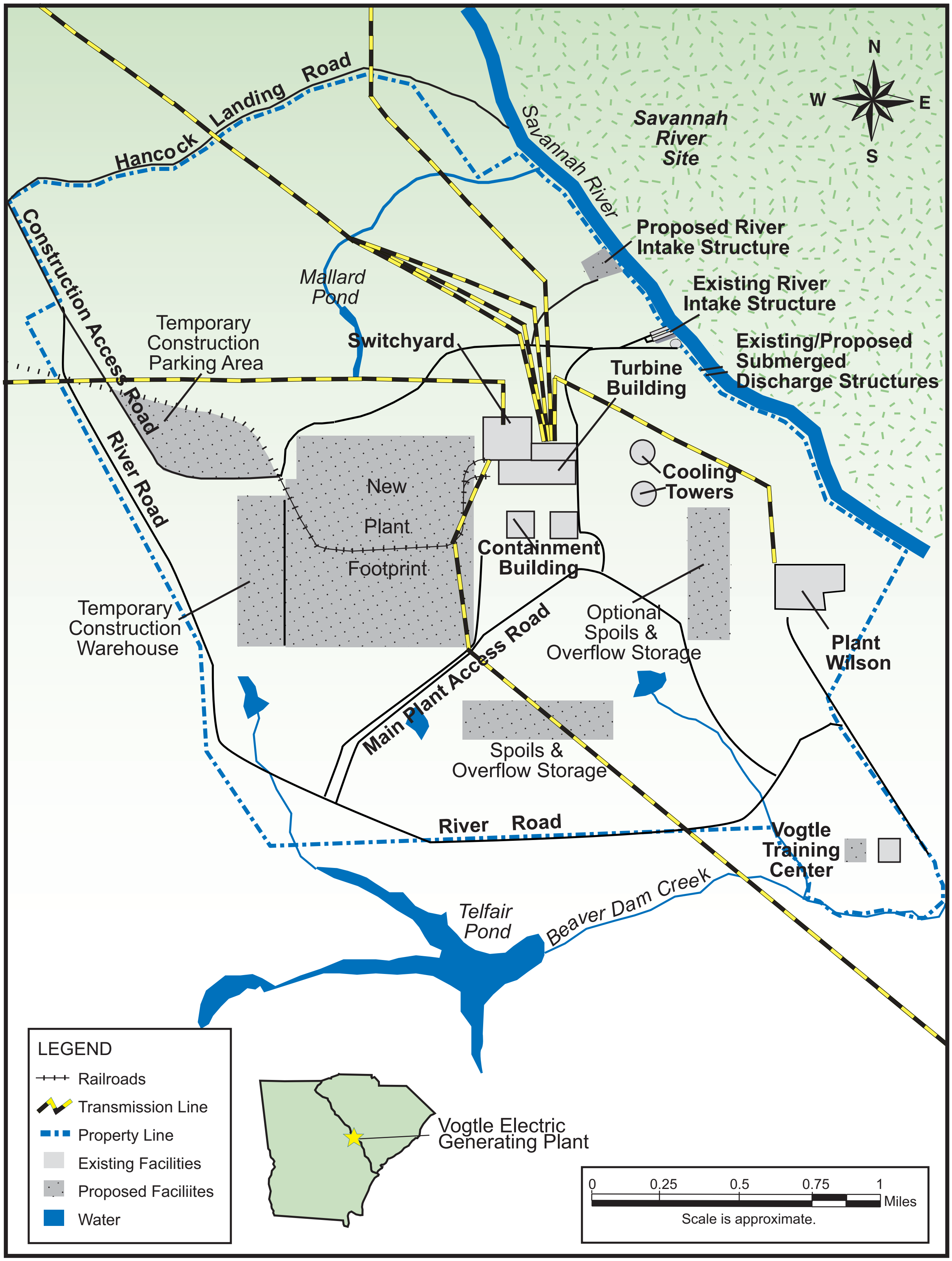

Figure 2.1-1 VEGP Site and Proposed New Plant Footprint

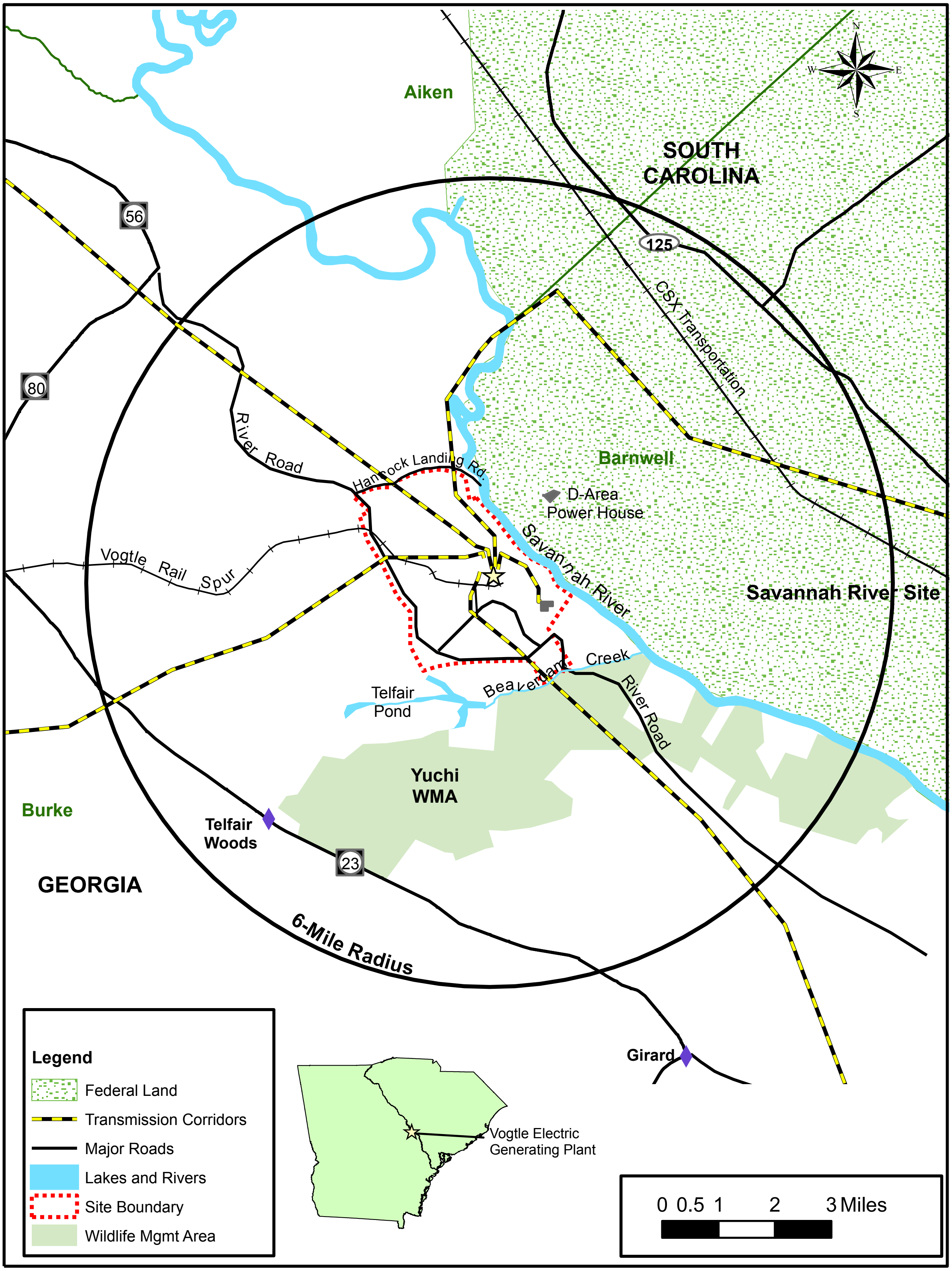

Figure 2.1-3 6-Mile Vicinity

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SOUTHERN COMPANY
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April 24, 2006 AR-06-0851

Dr. Ray Luce
Division Director & Deputy State Historic Preservation Officer
Historic Preservation Division
Department of Natural Resources
34 Peachtree Street, NW Suite 1600
Atlanta, GA 30303-2316

Re: Vogtle Electric Generating Plant – Early Site Permit
Request for Project Initiation on Historic and Archaeological Resources

Dear Dr. Luce:

Southern Nuclear Operating Company (SNC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) for an Early Site Permit for the Vogtle Electric Generating Plant (VEGP) located in Burke County, Georgia. The application will be based on construction of two Westinghouse AP-1000 reactors and is scheduled for submittal to the NRC by August 15, 2006. The Early Site Permit, when granted, approves the site as suitable for construction of new nuclear units, but does not constitute a commitment on the part of Southern Company to construct new units on the site. The Early Site Permit can be granted for a period of up to twenty years.

As part of the Early Site Permit application process, the NRC requires license applicants to assess whether any historic or archaeological properties will be affected by the proposed project. NRC may also request an informal consultation with your office under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to support the NRC consultation.

VEGP lies on the west bank of the Savannah River in the eastern sector of Burke County, Georgia, at River Mile 151, approximately 23 river miles upstream from the intersection of the Savannah River and U.S. Highway 301. The VEGP site encompasses approximately 3,169 acres, roughly one-half of which (1,778 acres) are undeveloped (old fields, forests, and wetlands) and managed as a wildlife preserve. The Vogtle site is served by the approximately 340 miles of transmission lines divided among six (6) corridors. One of the corridors, Vogtle-Wilson, connects Vogtle to the adjacent combustion turbine plant, Plant Wilson, and is contained entirely on the site property. The other corridors consist of three 230 kV lines: Vogtle-Savannah River Site; Vogtle-Goshen; and Vogtle-Augusta Newsprint (a nine-mile loop off of the Vogtle-Goshen line), and two 500 kV lines: Vogtle-Thalmann and Vogtle-Scherer.

AR-06-0851
Dr. Ray Luce – Page 2

Southern Nuclear is currently in Phase I of surveying the Areas of Potential Effect. New South Associates is performing the cultural resources survey and will develop a written report. Southern Nuclear will provide an advance copy of the report to your office to support early review prior to filing the Early Site Permit application with the NRC.

This correspondence is provided in advance of the report transmittal to establish a project reference file and to allow for resource planning. Please assign Southern Nuclear a project number and provide the number in response to this correspondence. Southern Nuclear will include a copy of this letter and your response in the Early Site Permit application submittal to the NRC. Any subsequent correspondence prior to application submittal, such as transmittal of the Phase I report, will also be included.

Please call me at (205) 992-5807 or Ms. Amy Greene at (205) 992-5805 if you have any questions or require additional information.

Sincerely,

Original signed by T. C. Moorer

T. C. Moorer
Project Manager – Environmental Support

TCM/ABG

Enclosure: Figures 2.1-1 and 2.1-3

cc: C. R. Pierce (w/o attachment)
J. M. Godfrey (w/o attachment)
File AR.01.01.06
Document Control – R-Type AR.01

AR-06-0851
Dr. Ray Luce – Page 3

bc: <u>(w/ attachment)</u>
A. S. Hendricks
R. D. Just
M. C. Nichols
A. B. Greene

<u>(w/o attachment)</u>
J. A. Miller
R. D. Hill
J. T. Davis

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Southern Nuclear
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P.O. Box 1295
Birmingham, Alabama 35201-1295

Tel 205.992.5000

SOUTHERN COMPANY
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August 2, 2006 AR-06-1727

Mr. Rodger Stroup
Division Director
State Historic Preservation Office
South Carolina Department of Archives and History
8301 Parklane Road
Columbia, South Carolina 29223

Re: Vogtle Electric Generating Plant – Early Site Permit
Request for Project Initiation on Historic and Archaeological Resources

Dear Mr. Stroup:

Southern Nuclear Operating Company (SNC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) for an Early Site Permit for the Vogtle Electric Generating Plant (VEGP) located in Burke County, Georgia. The application will be based on construction of two Westinghouse AP-1000 reactors and is scheduled for submittal to the NRC by August 15, 2006. The Early Site Permit, when granted, approves the site as suitable for construction of new nuclear units, but does not constitute a commitment on the part of Southern Company to construct new units on the site. The Early Site Permit can be granted for a period of up to twenty years.

As part of the Early Site Permit application process, the NRC requires license applicants to assess whether any historic or archaeological properties will be affected by the proposed project. NRC may also request an informal consultation with your office under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to support the NRC consultation.

VEGP lies on the west bank of the Savannah River in the eastern sector of Burke County, Georgia, directly across from the Department of Energy Savannah River Site, at River Mile 151, approximately 30 river miles upstream from the intersection of the Savannah River and U.S. Highway 301. The VEGP site encompasses approximately 3,169 acres, roughly one-half of which (1,778 acres) are undeveloped (old fields, forests, and wetlands) and managed as a wildlife preserve. The Vogtle site is served by the approximately 340 miles of transmission lines divided among six (6) corridors. One of the corridors, Vogtle-Wilson, connects Vogtle to the adjacent combustion turbine plant, Plant Wilson, and is contained entirely on the site property. The other corridors consist of three 230 kV lines: Vogtle-Savannah River Site; Vogtle-Goshen; and Vogtle-Augusta Newsprint (a nine-mile loop off of the Vogtle-Goshen line), and two 500 kV lines: Vogtle-Thalmann and Vogtle-Scherer.

AR-06-1727
Mr. Rodger Stroup – Page 2

Southern Nuclear is currently in Phase I of surveying the Areas of Potential Effect. New South Associates is performing the cultural resources survey and will develop a written report. Southern Nuclear will provide a copy of the report to your office to upon completion.

This correspondence is provided in advance of the report transmittal to establish a project reference file and to allow for resource planning. Due to a transmission line beginning at the VEGP site and terminating in South Carolina and certain South Carolina sites within a ten-mile radius of the VEGP site being eligible for listing on the *National Register*, Southern Nuclear is initiating communication with your office. If appropriate, please assign Southern Nuclear a project number and provide the number in response to this correspondence.

A copy of this letter will be included in the Early Site Permit submittal to the NRC.

Please call me at (205) 992-5807 or Ms. Amy Aughtman at (205) 992-5805 if you have any questions or require additional information.

Sincerely,

Original signed by T. C. Moorer

T. C. Moorer
Project Manager – Environmental Support

TCM/ABG

Enclosure: Figures 2.1-1 and 2.1-3

cc: C. R. Pierce (w/o attachment)
J. M. Godfrey (w/o attachment)
File AR.01.01.06
Document Control – R-Type AR.01

AR-06-1727
Mr. Rodger Stroup – Page 3

bc: (w/ attachment)
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A. B. Greene

(w/o attachment)
J. A. Miller
D. M. Lloyd
J. T. Davis

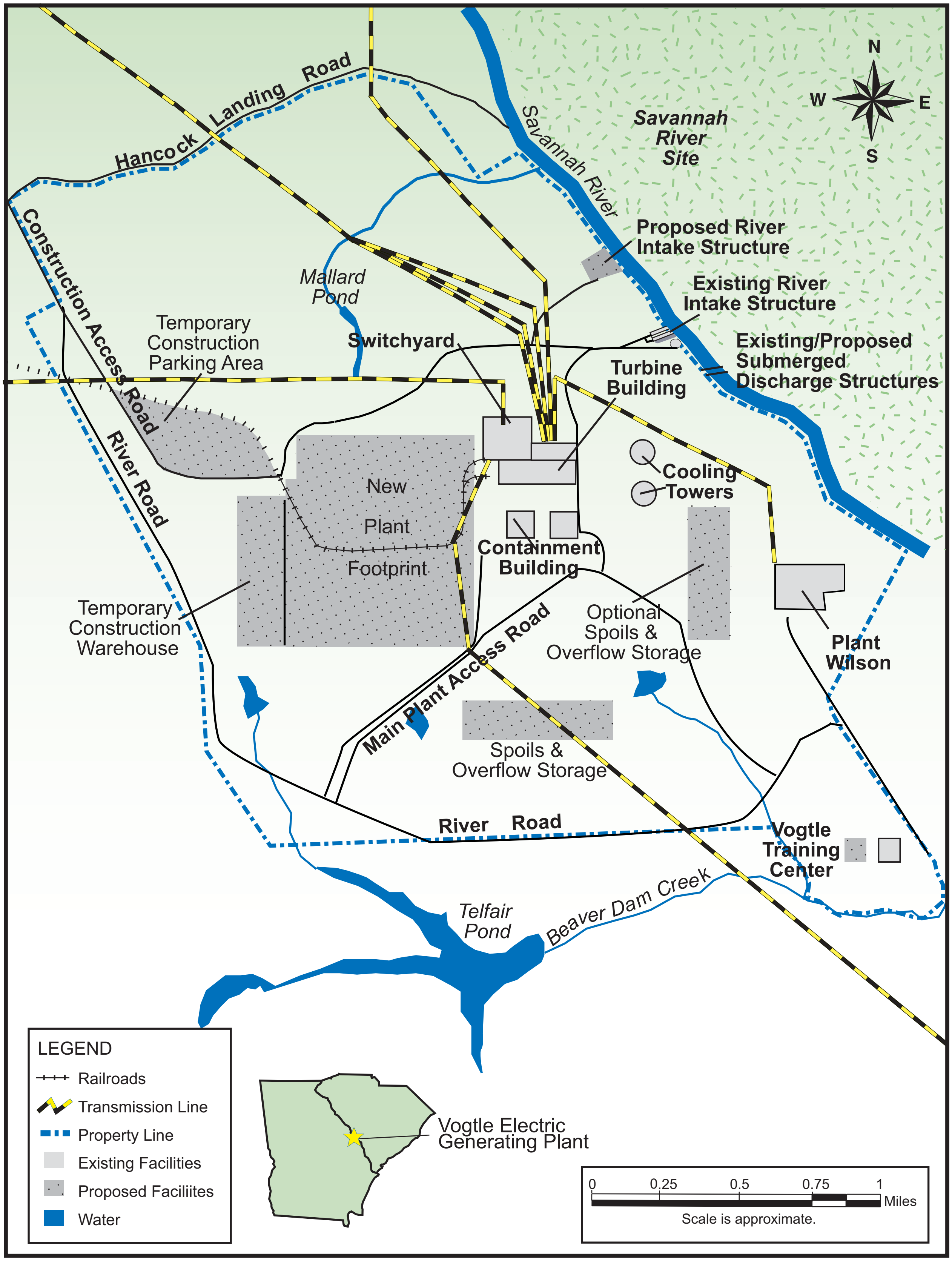

Figure 2.1-1 VEGP Site and Proposed New Plant Footprint

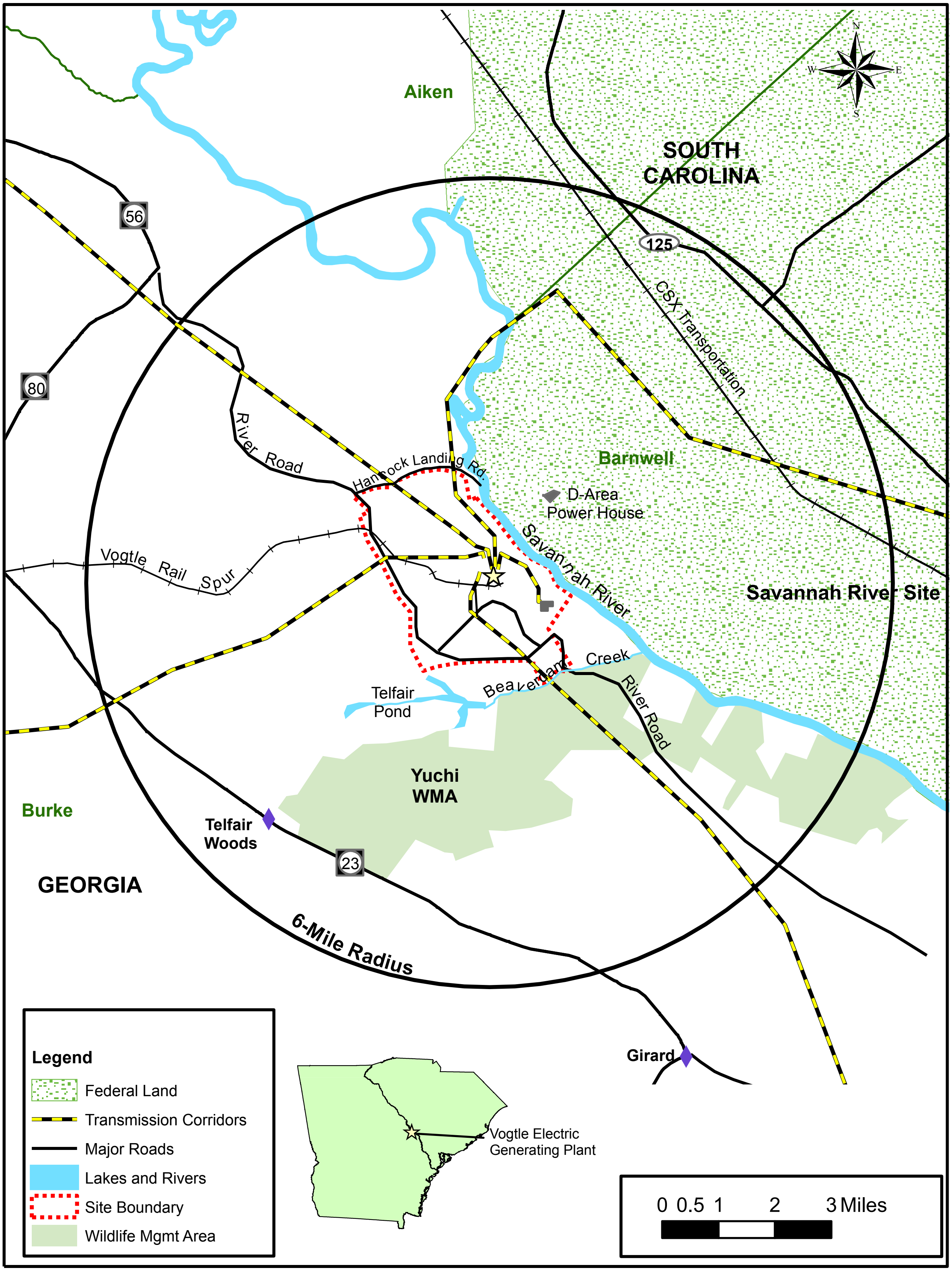

Figure 2.1-3 6-Mile Vicinity

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Appendix B

Bathymetry Map

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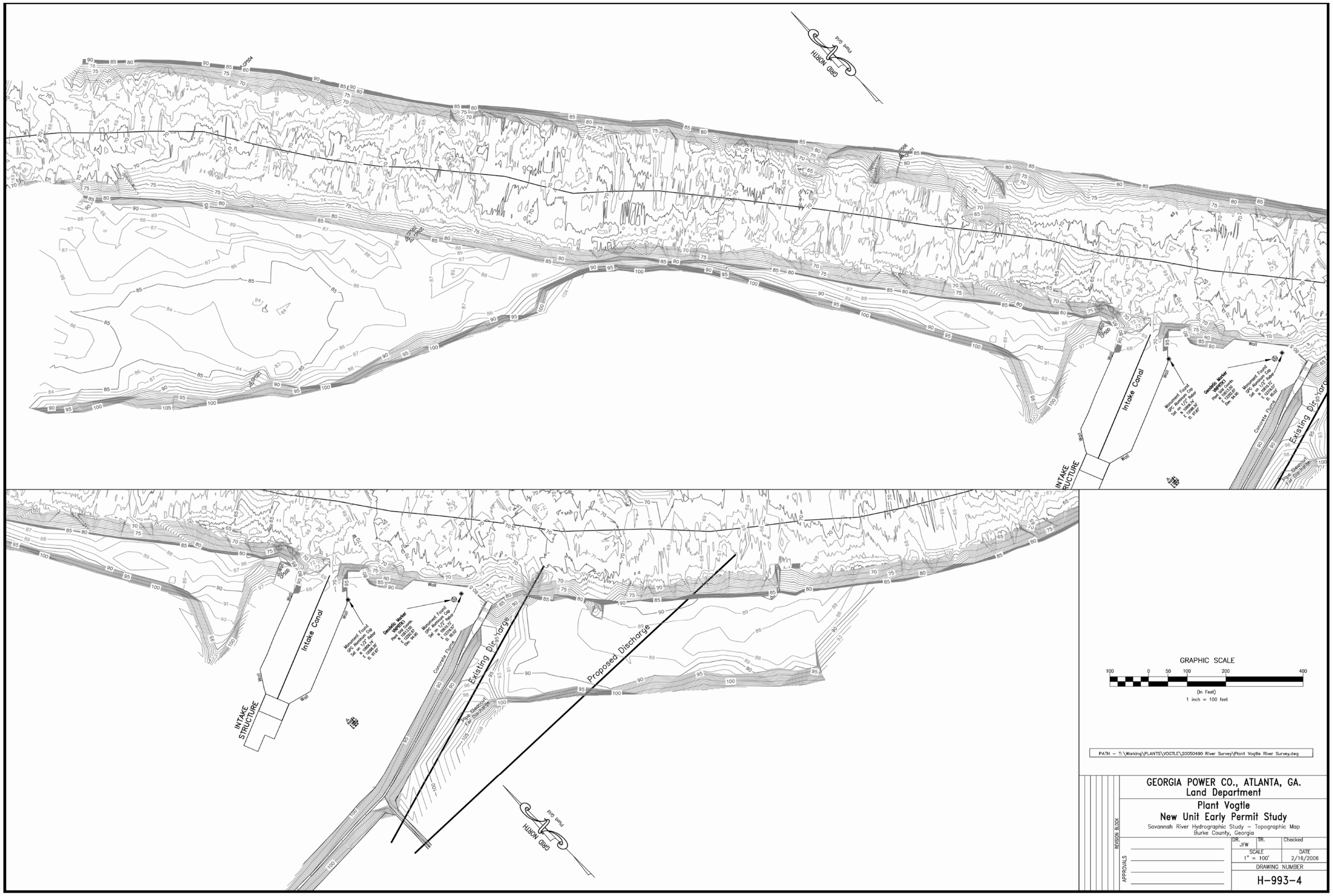
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Plant Grid
Intake Canal
INTAKE STRUCTURE
Existing Discharge
Proposed Discharge
Concrete Flume
Wall
GRAPHIC SCALE
100 0 50 100 200 400
(In Feet)
1 inch = 100 feet
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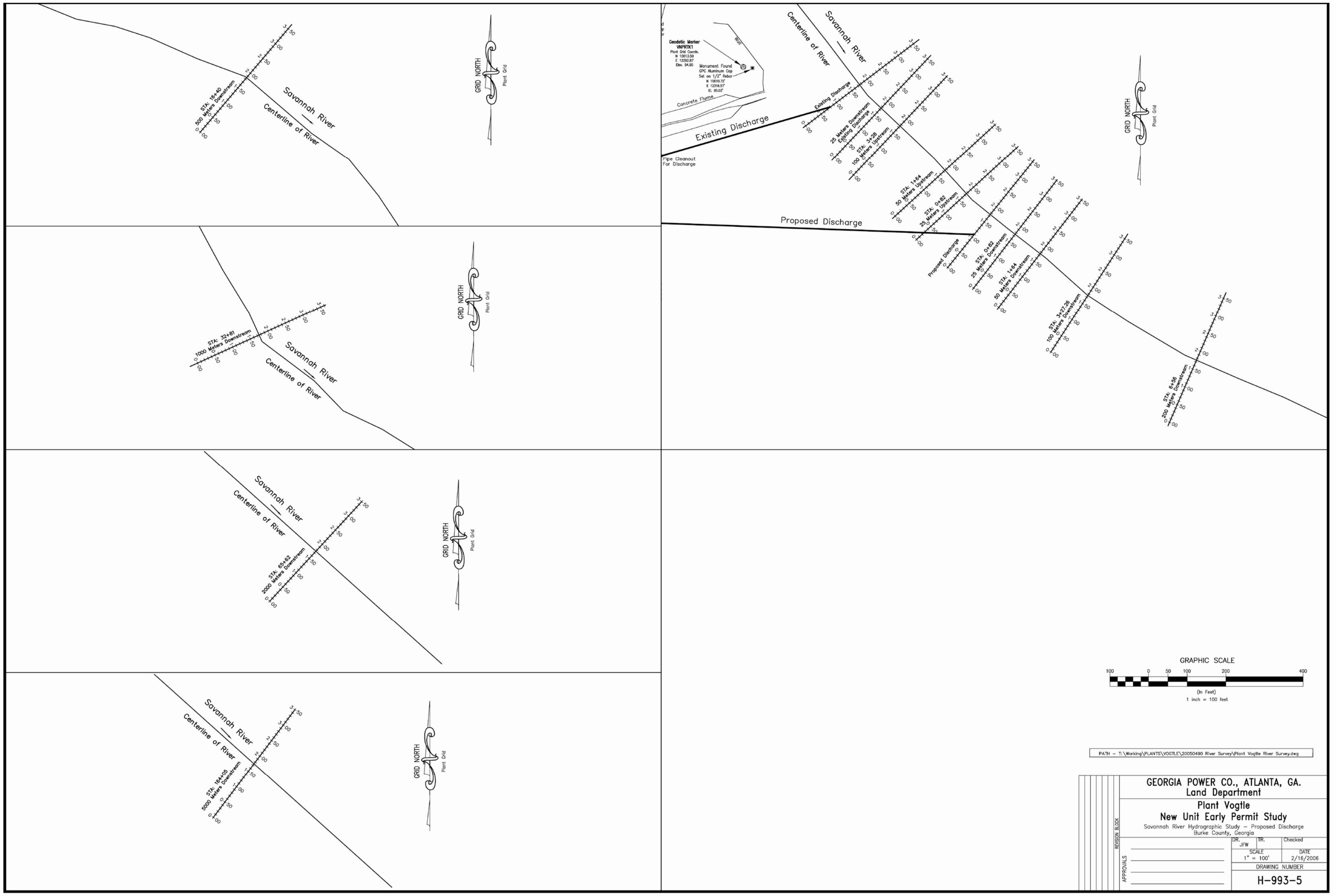
GEORGIA POWER CO., ATLANTA, GA.
Land Department
Plant Vogtle
New Unit Early Permit Study
Savannah River Hydrographic Study – Topographic Map
Burke County, Georgia
REVISION BLOCK
APPROVALS
DR. JFW
TR.
Checked
SCALE 1" = 100'
DATE 2/16/2006
DRAWING NUMBER
H-993-4


Savannah River
Centerline of River
GRID NORTH
Plant Grid
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500 Meters Downstream
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1000 Meters Downstream
STA. 65+62
2000 Meters Downstream
STA. 164+05
5000 Meters Downstream
Existing Discharge
Proposed Discharge
Concrete Flume
Pipe Cleanout For Discharge
Geodetic Marker
Monument Found
25 Meters Downstream Existing Discharge
100 Meters Upstream
STA. 1+64
50 Meters Upstream
STA. 0+82
25 Meters Upstream
STA. 0+82
25 Meters Downstream
STA. 1+64
50 Meters Downstream
STA. 3+27.26
100 Meters Downstream
STA. 6+56
200 Meters Downstream
GRAPHIC SCALE
(In Feet)
1 inch = 100 feet
GEORGIA POWER CO., ATLANTA, GA.
Land Department
Plant Vogtle
New Unit Early Permit Study
Savannah River Hydrographic Study – Proposed Discharge
Burke County, Georgia
REVISION BLOCK
APPROVALS
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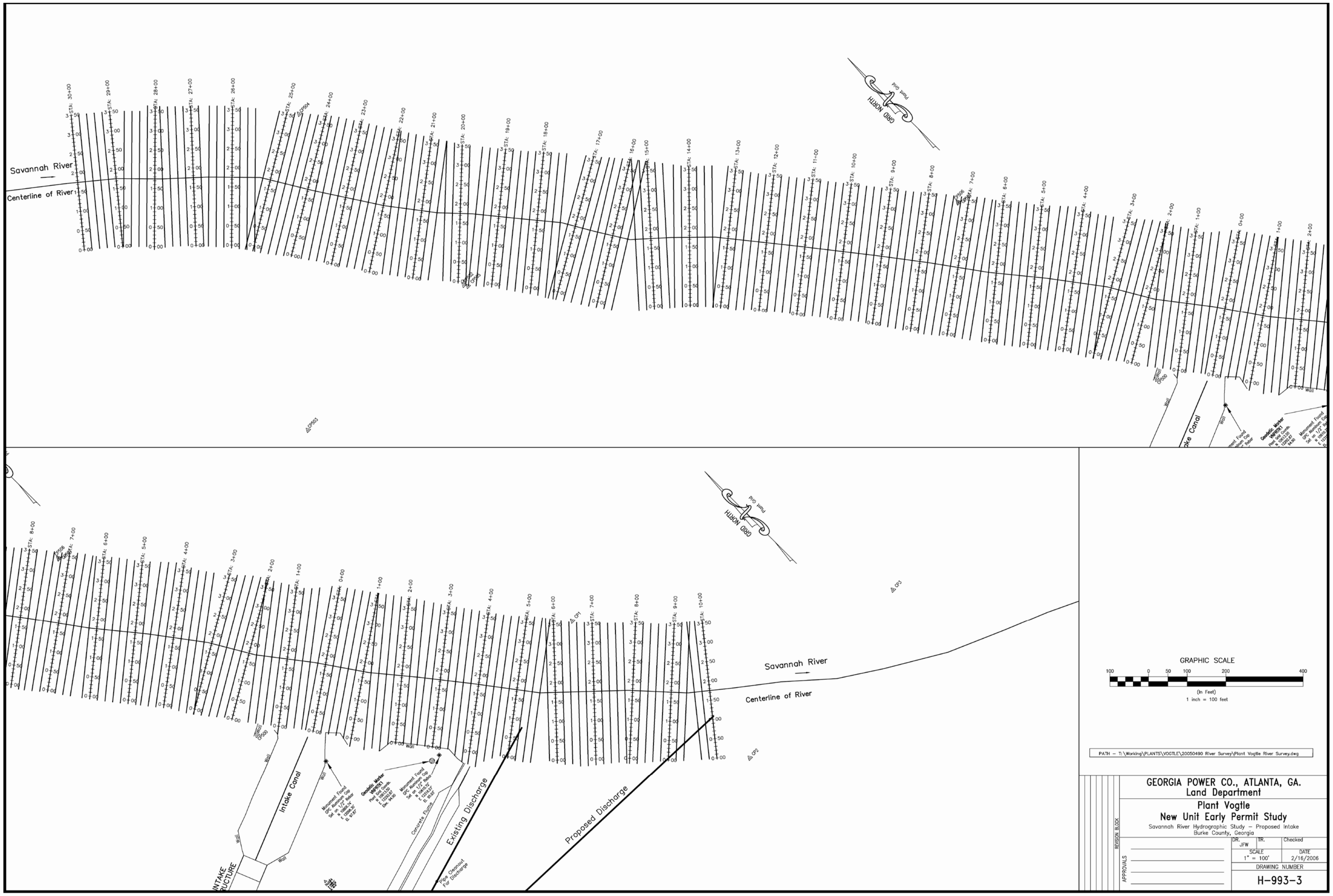
TR.
Checked
SCALE 1" = 100'
DATE 2/16/2006
DRAWING NUMBER
H-993-5


Savannah River
Centerline of River
GRID NORTH
Plant Grid
Intake Canal
INTAKE STRUCTURE
Existing Discharge
Proposed Discharge
GRAPHIC SCALE
(In Feet)
1 inch = 100 feet
GEORGIA POWER CO., ATLANTA, GA.
Land Department
Plant Vogtle
New Unit Early Permit Study
Savannah River Hydrographic Study – Proposed Intake
Burke County, Georgia
SCALE 1" = 100'
DATE 2/16/2006
DRAWING NUMBER
H-993-3

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Appendix C

GPSC Order

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IN RE: DOCKET NO. 17687-U: GEORGIA POWER COMPANY'S 2004 APPLICATION FOR AN INTEGRATED RESOURCE PLAN

DOCKET NO. 17688-U: SAVANNAH ELECTRIC AND POWER COMPANY'S 2004 APPLICATION FOR AN INTEGRATED RESOURCE PLAN

FINAL ORDER

Date Submitted: July 2, 2004 Date Decided: July 9, 2004

APPEARANCES

For Georgia Power Company: Kevin C. Greene, Esq., Melissa L. Pignatelli, Esq., Troutman Sanders; **For Savannah Electric and Power Company**: Leamon R. Holliday, III, Esq., Bouhan, Williams and Levy; **For the Commission Staff**: Jeffrey C. Stair, Esq. Administrative Procedures Attorney, and Helen O'Leary, Administrative Procedures Attorney; **For the Consumers' Utility Counsel Division**: John Z. Wu, Staff Attorney; **For the Georgia Industrial Group**: Randall Quintrell, Esq.; **For the Georgia Textile Manufacturer's Association**: Peyton S. Hawes, Esq.; **For Calpine Corporation:** Michael S. Bradley, Esq., and Charles B. Jones, III, Esq., Sutherland, Asbill & Brennan; **For Southern Alliance for Clean Energy, Inc.:** James J. Presswood, Jr., Esq., Staff Attorney; For **Alliance to Save Energy:** Mr. Harry Misuriello; For **Georgia Environmental Facilities Authority**: Erin Kelley, Esq.; **For Homeowners Opposing Powerline Encroachment**: Richard N. Hubert, Esq., Chamberlain, Hrdlicka, White, Williams & Martin; **For Resource Supply Management**: Mr. Jim Clarkson; **For Georgia Interfaith Power and Light**: J. Renee' Kastanakis, Esq.; Reverend Woody Bartlett; and **For Live Oaks Company, LLC**: Mr. John S. Ellis.

BY THE COMMISSION:

I. STATEMENT OF PROCEEDINGS

On January 30, 2004, Georgia Power Company ("Georgia Power" or "GPC") and Savannah Electric and Power Company (“Savannah Electric”) (collectively referred to herein as “Companies”) separately submitted to the Commission applications for Integrated Resource Plans ("IRPs" or “Plans”) for approval pursuant to O.C.G.A. § 46-3A-1 *et seq.* (“IRP Act” or “Act”). The Georgia Public Service Commission (“Commission”) issued a Procedural and Scheduling Order on March 5, 2004, finding it appropriate and administratively convenient to hold concurrent and consolidated hearings in these dockets. No party entered an objection to the consolidation of the cases. These proceedings were declared to be contested cases as the term is defined in O.C.G.A. § 50-13-13 and were also held to encompass complex litigation pursuant to O.C.G.A. § 9-11-33(a).

The Procedural and Scheduling Order directed the Companies, at a minimum, to address those issues that are required by the IRP Act and Commission Rule 515-3-4 (“IRP Rules”), as well as any directives issued for the Companies to follow in the 2001 IRP cases.[1] In addition to the issues that traditionally are included in an IRP case, the Commission sought input from interested parties whether existing Utility Rule 515-3-4-.04(3), Request for Proposals Procedure for Long-Term New Supply–Side Options, should be modified to provide in greater detail the manner in which new supply side resources are to be requested, evaluated and presented to the Commission for certification.

In accordance with O.C.G.A. § 46-3A-5(c), the Commission established fees for review of the IRPs within sixty days of the filing of the applications. The Commission concluded that $143,060.00 was the appropriate fee for Georgia Power Company,[2] and $61,311.00 for Savannah Electric.[3] On March 16, 2004, Georgia Power and Savannah Electric remitted the established fee amount, thereby making the statutory deadline for this proceeding to be July 14, 2004.

Pursuant to statute, the Commission Staff (“Staff”) and the Consumer Utility Counsel Division (“CUCD”) of the Governor’s Office of Consumer Affairs were parties to these dockets. Applications for Intervention were filed as follows:

---

1 See *Final Order*, Docket Nos. 12499-U, 13305-U and 13306-U, filed on July 17, 2001.
2 Docket No. 17687-U, *Order Establishing Fee for Georgia Power Company’s Application for Approval of the 2004 Integrated Resource Plan*, filed on March 22, 2004.
3 Docket No. 17688-U, *Order Establishing Fee for Savannah Electric and Power Company’s Application for Approval of the 2004 Integrated Resource Plan*, filed on March 22, 2004.

Docket No. 17687–U: Resource Supply Management ("RSM") intervened on February 18, 2004; Georgia Industrial Group ("GIG") intervened on February 19, 2004; Georgia Textile Manufacturers Association ("GTMA") intervened on February 20, 2004; Calpine Corporation ("Calpine") intervened on February 25, 2004; Georgia Environmental Facilities Authority ("GEFA") intervened on February 25, 2004; Southern Alliance for Clean Energy ("SACE") intervened on March 5, 2004;[4] Live Oaks Company, LLC intervened on March 26, 2004; Alliance to Save Energy ("ASE") intervened on April 16, 2004; Georgia Interfaith Power and Light ("GIPL") intervened on April 16, 2004; and Homeowners Opposing Powerline Encroachment, Inc. ("HOPE") intervened on April 19, 2004.

Docket No. 17688-U: Calpine intervened on February 25, 2004; SACE intervened on March 5, 2004;[5] Live Oaks Company, LLC intervened on March 26, 2004; and ASE intervened on April 16, 2004.

No party was denied intervention during the proceedings. [6]

On March 5, 2004, and again on May 25, 2004, the Commission filed amendments to its Procedural and Scheduling Order. Both sets of amendments were not substantive in nature, but, rather, were the result of the Commission's need to modify the dates on which the hearings were to be held and filings were to be made.

The Commission conducted the hearings in three phases in this matter. During the first phase of the hearings, the Companies presented their direct cases on April 19, 2004, and April 20, 2004, through one panel of witnesses comprised of Mr. Richard A. White. Mr. Larry R. White, Mr. Jeffrey A. Burleson, and Mr. Garey C. Rozier.[7]

On May 25, 2004, the Commission Staff presented a panel of witnesses setting forth its positions in these dockets. This panel consisted of Mr. Mark W. Crisp, Mr. Jerry W. Smith, Mr. Evan D. Evans, Ms. Kathleen F. Best, Mr. Daniel R. Cearfoss, Jr. and Mr. Phil M. Hayet. GIG and GTMA co-sponsored two witnesses, Mr. Jeffry Pollock and Mr. John A. Mallinckrodt, who testified on this same date, with Mr. Timothy Eves testifying on behalf of Calpine in between the presentations of the two GIG/GNG witnesses.

---

[4] In the Georgia Power IRP docket, an Amended Application for Leave to Intervene was filed by SACE on May 20, 2004.

[5] Also on May 20, 2004, an Amended Application for Leave to Intervene was filed by SACE in the Savannah Electric IRP docket.

[6] Although Mr. John S. Ellis intervened on behalf of Live Oaks Company, LLC, no appearance at the hearings was made by Mr. Ellis on behalf of this party.

[7] Both Mr. Burleson and Mr. Larry R. White are employed directly by Georgia Power. Mr. Richard A. White is employed by Savannah Electric. Mr. Rozier is employed by Southern Company Services. See Pre-filed direct testimony of the Companies' panel of witnesses, page 1.

A witness panel comprised of Mr. Richard F. Spellman and Mr. Harry Misuriello also testified on behalf of ASE on May 25, 2004, and on May 26, 2004, as well, followed by a panel of three witnesses for SACE that consisted of Mr. James Presswood[8], Ms. Rita Kilpatrick, Mr. William Prindle.[9] This second phase of the hearings concluded after the testimony on behalf of a witness sponsored by GIPL, Ms. Melissa Heath, was provided.

Thereafter, during the third and final phase of the hearing that was held on June 28, 2004, the Companies presented rebuttal testimony through the same panel of witnesses that previously testified to support their direct cases.

At the conclusion of the hearings in these dockets, closing arguments and/or proposed final orders were filed by the Companies, ASE, Calpine, RSM, Staff, and the CUCD on July 1, 2004, or on July 2, 2004, as permitted by the Commission.

On July 9, 2004, at a Special Administrative Session, the Commission considered the positions of the various parties and rendered decisions on the Companies' respective IRPs.

In conjunction with doing so, the Commission hereby adopts in this Final Order, with modifications and further directives, the IRPs filed by Georgia Power and Savannah Electric. In doing so, the Commission sets forth in this Order further direction to Georgia Power and Savannah Electric for further reporting and analysis to be performed and provided to the Commission prior to or in conjunction with their next IRP filings, amendments or applications for de-certification. Finally, this Order issues directives by the Commission that are to be followed by its Staff in order to facilitate a Demand Side Management Working Group and initiate the process required for amending the agency's existing Utility Rule 515-3-4-.04(3), Request for Proposals Procedure for Long-Term New Supply–Side Options.

II. JURISDICTION AND AUTHORITY

Georgia Power and Savannah Electric are public electric utilities serving retail customers within the State of Georgia. Georgia Power and Savannah Electric are two of the five retail operating companies of which the Southern Company system is comprised. This Commission has jurisdiction over Georgia Power's and Savannah Electric's IRPs pursuant to O.C.G.A. § 46-2-1 et seq., generally, and the IRP Act in particular.

[8] Mr. Presswood testified as a subject matter expert during the hearings and also served as SACE's counsel in this proceeding.

[9] Although Ms. Sara Barczak was identified on the pre-filed direct testimony as a witness who would be testifying on behalf of SACE, she was unavailable to appear at the hearing to answer questions about the panel testimony. As such, the panel was permitted to proceed with its testimony in her absence.

The IRP Act requires the Companies to file Integrated Resource Plans at least every three years.[10] The Companies' obligations with respect to the information that is filed is set forth pursuant to criteria identified in the Commission's IRP Rules. A "plan" is defined in the Act as an Integrated Resource Plan that contains the utility's: electric demand and energy forecast for at least a 20-year period; program for meeting the requirements shown in its forecast in an economical and reliable manner; the analysis of all capacity resource options, including both demand-side and supply-side options; and the assumptions used and the conclusions reached with respect to the effect of each capacity resource option on the future cost and reliability of electric service. The Plan also must:

(A) Contain the size and type of facilities which are expected to be owned or operated in whole or in part by such utility and the construction of which is expected to commence during the ensuing ten years or such longer period as the Commission deems necessary and shall identify all existing facilities intended to be removed from service during such period or upon completion of such construction;

(B) Contain practical alternatives to the fuel type and method of generation of the proposed electric generating facilities and set forth in detail the reasons for selecting the fuel type and method of generation;

(C) Contain a statement of the estimated impact of proposed and alternative generating plants on the environment and the means by which potential adverse impacts will be avoided or minimized;

(D) Indicate, in detail, the projected demand for electric energy for a 20-year period and the basis for determining the projected demand;

(E) Describe the utility's relationship to other utilities in regional associations, power pools, and networks;

(F) Identify and describe all major research projects and programs which will continue or commence in the succeeding three years and set forth the reasons for selecting specific areas of research;

(G) Identify and describe existing and planned programs and policies to discourage inefficient and excessive power use; and

(H) Provide any other information as may be required by the Commission.[11]

[10] O.C.G.A. § 46-3A-2.
[11] O.C.G.A. § 46-3A-1(7).

The Commission is required under O.C.G.A. § 46-3A-2 to make determinations as to the adequacy of the IRPs and to ensure that the utilities' Plans have appropriately addressed numerous matters. There must be a determination that the forecast requirements contained in the Plan are based on substantially accurate data and an adequate method of forecasting.[12] The Commission must also find that the Plans identify and take into account any present and projected reductions in the demand for energy that may result from measures to improve energy efficiency in the industrial, commercial, residential, and energy-producing sectors of the state.[13]

Further, the Commission must determine whether the Plans adequately demonstrate the economic, environmental, and other benefits to the state and to customers of the utilities, associated with the following possible measures and sources of supply:

(A) Improvements in energy efficiency;
(B) Pooling of power;
(C) Purchases of power from neighboring states;
(D) Facilities that operate on alternative sources of energy;
(E) Facilities that operate on the principle of cogeneration or hydro-generation; and
(F) Other generation facilities and demand-side options.[14]

After hearings have been conducted on a Plan, the Commission may approve the IRP; approve it subject to stated conditions; approve it with modifications; approve it in part and reject it in part; reject the plan as filed; or provide an alternate plan, upon determining that this is in the public interest.[15]

With regard to its rule-making authority to enact or modify regulations regarding the manner in which new supply-side resources are to be attained for the Companies' retail customers, the Georgia Legislature conferred upon the Commission a general blanket of authority under which it may enact those rules necessary to execute the functions that it has been delegated.[16] Along this avenue of authority, the Commission included in the Procedural and Scheduling Order a request for information from parties in order to determine whether its existing Utility Rule 515-3-4-.04(3), Request for Proposals Procedure for Long-Term New Supply–Side Options, should be enhanced and, if so, in what manner. In furtherance of this purpose, the agency's stated areas of interest included:

(a) The procedures for the issuance of any Request for Proposals (RFP)
(b) The contents of the RFP

[12] O.C.G.A. § 46-3A-2(b)(1).
[13] O.C.G.A. § 46-3A-2(b)(2).
[14] O.C.G.A. § 46-3A-2 (b)(3).
[15] GPSC Utility Rule 515-3-4-.01(2).
[16] O.C.G.A. § 46-2-30.

(c) The need for and role of an Independent Evaluator to oversee the RFP process
(d) Evaluation Criteria and Procedures including selection process for a competitive tier and/or short list of bidders
(e) Codes of conduct for participation in an RFP
(f) The manner in which Information will be made available to bidders
(g) Exceptions, if any, to the RFP procedures
(h) The inclusion of a “Self-build” option by a Georgia-regulated utility, in the RFP process; and
(i) A description of, and the use that is to be made of, a “Target Price” in the RFP evaluation process.[17]

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

To ensure that the competing interests of all parties were properly considered, the Commission has carefully analyzed all evidence of record including the testimony given and the various exhibits entered by all the parties. As set forth hereinafter, the Commission makes findings of fact and conclusions of law[18] based on the evidentiary record created, taking into consideration any joint proposals for a resolution to an issue raised by this agency.

A) REVIEW AND EVALUATION OF THE INTEGRATED RESOURCE PLANS FILED BY GEORGIA POWER COMPANY AND SAVANNAH ELECTRIC AND POWER COMPANY[19]

1) LOAD FORECAST

In Volume 1A, Table 4.2, on page 9 of the Technical Appendix[20] to Georgia Power Company’s 2004 IRP filing, the load forecast for the years 2004 through 2023 is set forth as it pertains to the Companies’ service areas as well as the Southern System as a whole. With regard to the demand and energy forecasts that are used to project load

[17] *Procedural and Scheduling Order*, March 5, 2004, p. 6.
[18] The areas of discussion included in the body of the Order in terms of Findings of Fact and Conclusions of Law speaks only to the areas of the Plans filed that were contested. Matters that were not disputed or previously were decided by the Commission in these dockets are referenced in the ordering paragraphs only.
[19] Due to the way the transcripts of the three phases of the hearing were prepared in these dockets, there is no way to identify specific pages in the transcripts when pre-filed testimony of any witness(es) is(are) referenced. As a consequence, all statements referenced as an authority in this Final Order will be cited from a party’s pre-filed testimony, which, at the hearing, was accepted into the record as evidence.
[20] This information is contained in the Trade Secret version of the Georgia Power’s filing.

for the Companies, the Staff panel of witnesses was the only one to comment on each of them. A review of the testimony provided by Staff regarding the adequacy of the forecasts filed by Georgia Power and Savannah Electric is relevant to this Commission making at determination whether they should be approved as filed.

a) Sufficiency of Load Forecasts

Georgia Power Company

In conducting its analysis, Staff noted that Georgia Power used econometric models developed in-house for the short-term forecasts (2004–2006), and a set of EPRI end-use models (REEPS, COMMEND and INFORM) for the longer-term forecasts (2007-2023). Georgia Power also used the EPRI model, HELM, to produce the demand forecast. The long-term models used are well accepted industry-wide, and Georgia Power performed an appropriate analysis of data input and calibration for each of these load forecast models. Staff acknowledged that some judgment was necessary in the selection of variables for all models, and that Georgia Power appeared to have made reasonable decisions for the Budget 2004 forecast, which was prepared during the spring of 2003.[21] The energy forecast is dependent on the input variables provided by Economy.com.

In its analysis of load, Georgia Power provided data that indicated a recent tendency for this company to over-forecast total company demand, with the errors ranging from approximately 1% to 7% on a weather adjusted basis[22]. However, the more recent interim forecasts appeared to have improved and were in the range of 1% to 4% error. Staff determined that these percentages of errors are in the range of what is acceptable.

A similar review of the weather adjusted comparisons for total company energy[23] revealed that on a total company basis, Georgia Power systematically also has over-forecasted energy usage. However, the forecast errors are within acceptable ranges of 3% to 5%, with more recent forecasts indicating improved accuracy with variances of approximately 1% to 3%.

Staff evaluated the weather adjusted energy forecasts by customer class[24] and concluded that forecast accuracy is within acceptable limits, with the potential exception of the industrial class. (Pre-filed Panel Testimony of Staff, p. 49). The industrial class energy forecast errors from the Budget 1999 through the Budget 2001 forecasts are in the range of 15% over-forecasted. The Budget 2002 forecast improved accuracy

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[21] Georgia Power performed weather-normalization for both energy and demand data in order to provide historically appropriate comparisons of forecasts to actual energy and demand.
[22] *Georgia Power's 2004 IRP Filing* Technical Appendix Volume 2, Section 9, pages 189- 190.
[23] *Georgia Power's 2004 IRP Filing* Technical Appendix Volume 2, Section 9, page 185.
[24] *Georgia Power's 2004 IRP Filing* Technical Appendix Volume 2, Section 9, pages 185-188.

considerably to the 3% to 7% range. Georgia Power lost industrial customers from 1990 through 2003. Over the period, the number of industrial customers declined at the average annual rate of 2.9%. Georgia Power forecasted an average annual rate of decline for industrial customers of 1.6% for the period of 2004 through 2023. The industrial class represented approximately 24% of the total Georgia Power demand in 2003. A ratio has been projected by the Company to decline to about 20% in 2023. On an energy basis, the industrial class represented about 35% in 2003, a ratio is projected to decline to 30% in 2023.[25]

Staff observed that Georgia Power estimated and adjusted the industrial class to account for a trade secret concern that has the potential to be realized in the upcoming years. Id. at 50. Minor adjustments start in 2007 and major adjustments occur in 2008 and beyond. It is likely these estimates will change when trade secret concerns had by the Company are decided one way or another. Secondary economic effects of these trade secret concerns were included in the residential and commercial classes also.

In looking at Georgia Power's forecast, which was prepared in the spring of 2003, Staff concluded that there have been potential signs of some economic recovery in the southeastern United States, which make it prudent to examine a case where some growth in the industrial class resumes before 2008. In order to examine this scenario, Staff recommended a sensitivity case to be performed, that in addition to other data changes, increased the total system load and demand by 1% over the Georgia Power Budget 2004 forecasts. Id. at 51. This case represents the possibility that some economic recovery is now in progress but had not yet been picked up in the Georgia Power forecasting models.

Necessity for Update to Georgia Power's Existing Load Forecast

When doing cross-examination of the Companies' direct testimony, Staff inquired as to whether there would be an updated load forecast filed with the Commission by Georgia Power for use in the upcoming 2004 rate cases. (Transcript (Tr.) 47.) Witness Jeffrey Burleson indicated that one had not been prepared and there was no intention to file one. (Tr.48.) During the rebuttal phase of the hearing, Staff made additional inquiries during cross-examination through which the genuine need for the Commission to obtain a new or updated load forecast from Georgia Power was explored. (Tr.984-997.) Among the points made by Staff that would support a more current load forecast being filed by Georgia Power included the fact that some of the data underlying the one in the IRP was from at least January 2003, maybe earlier (Tr.991-992); the growth predicted in the forecast for the various retail customer sectors may have far exceeded actual growth as per recent Company pronouncements (Tr.986-991); and the significant role that a load forecast plays in a rate case, which Georgia Power filed on July 1, 2004, seeking increased rates. (Tr.990-994.)

[25] Georgia Power Company's Technical Appendix, Vol. 2, Section 2, page 22.

Through its responses, Georgia Power witness Burleson disputed any need for an updated load forecast to be filed. He indicated that, as per the Final Order in the last IRP case (Docket No. 13305-U), Georgia Power only had to notify the Commission if a new load forecast was developed by the Company. (Tr.980.) Mr. Burleson indicated that information tracking any variances in the load forecast is routinely made available to management of the Company in the form of reports. (Tr.982.)

In furthering his opposition to preparing an updated forecast based on actual data becoming available since it was prepared in early 2003, this witness contended that the actual data, once weather normalized, would result in the forecast being lower than what it is presently. (Tr.994-995.) While there may be actual data that shows higher sales for a customer class, Mr. Burleson seemed to infer that such increases were somehow offset by lower than predicted sales in the forecast for another class. (Tr.986-988)

When asked about the importance of its load forecast in terms of its upcoming rate case, Mr. Burleson did concede that there would be overearnings by a utility if its revenue requirements were to be spread across a customer base that was lower than what was forecasted. (Tr.992-994.) In light of this and other inquiries made by Staff, Mr. Burleson stood firm in his position that a load update was not necessary.

While the Commission understands the position of Georgia Power in this regard, it shares Staff's concern about Georgia Power's decision that a more current load forecast will not be made available for the rate case that is to be decided later this year. While Mr. Burleson possesses a great deal of credibility as a witness, the Commission would be derelict in its duty if it were merely to rely on his representations as to the impact that the availability that actual data has had on the forecast, and not to direct that this updated information be filled with this agency. Since the information necessary to update the existing forecast appears to be readily available to representatives of the Company, it should not be any hardship for the Company to do an update to its load forecast.

It also must be noted that the need for an updated load forecast is compounded by the fact that a cost of service study has been done by rate schedule for the first time in the 2004 rate case. If actual sales data deviates from that which is embedded in the existing load forecast, it could result that certain customer classes will have rates set for them that subsidize rates that will be set for consumers that take service under another class's rates. To eliminate any far-reaching ramifications from this occurring, it is imperative that by no later than August 15, 2004, Georgia Power must file an updated load forecast and budget comparison information with the most up-to-date information as of March 31, 2004.

Savannah Electric and Power Company

Staff noted that Savannah Electric prepared short-term (2004–2006) econometric models for most classes. (Pre-filed Panel Testimony of Staff, p. 53). For its industrial class, the company tabulated individual customer forecasts to obtain the forecast of the entire class. Savannah Electric used a set of EPRI end-use models (REEPS, COMMEND and INFORM) for the longer-term forecasts (2007-2023). The company also used the EPRI model, HELM, to produce the demand forecast. The long-term models are well accepted industry-wide and Savannah Electric has performed the appropriate analysis of data input and calibration for each of these models.
Like its sister company, Georgia Power, Savannah Electric performed weather-normalization for both energy and demand data in order to provide historically accurate comparison of forecasts to actual energy and demand. It provided data indicating forecast errors that are in the range of approximately 1% to 5% on a weather adjusted basis, with the exception of the industrial energy.[26] However, a more recent interim Budget 2003 forecast resulted in errors of 1% to 3%. As with Georgia Power, this range of errors is acceptable, and the company's demand forecast is also within standard tolerances. Id.

For the industrial energy forecast comparisons on a weather adjusted basis, Savannah Electric over-projected energy sales by as much as 15% in the most recent forecast. [27] Staff noted that it was advisable to attempt additional econometric or other modeling for the short-term industrial energy sector to see whether any improvement could be achieved since this class represented approximately 20% of the total sales in 2003. Id.

Staff ultimately concluded that Savannah Electric's short-term models fit the historical data and appear to be reasonable and consistent with trends, with the possible exception of the industrial sales forecast, and that the company's demand projections were reasonable. Id. at 54.

Necessity for Update to Savannah Electric's Existing Load Forecast

While Savannah Electric witness Richard White was not asked the same questions about the load forecast as Georgia Power witness Jeffrey Burleson, similar concerns are present about the age of the existing load forecast exist since Savannah Electric also will be filing a rate case later this year. Irrespective of the concern that this utility does not share its sister company's situation in terms of doing a cost of service by individual rate, Savannah Electric likewise is directed to update its load forecast and budget for filing with the Commission based on the relevancy of such information to the rates that will be set next year as a result of its 2004 rate case filing.

b) Recommendations Regarding the Companies' Load Forecast

Based upon the evidence in the record, the Commission finds and concludes that it is appropriate to approve the demand and energy forecasts as filed by Georgia Power and

[26] *Savannah Electric's 2004 IRP Filing,* Technical Appendix, Section 1, pages 46-47.
[27] Id. at 46.

Savannah Electric without modification to any projections to any customer class. In doing so, however, the Commission does find the concerns about the vintage of the forecast information, which is old and can easily be updated by actual data. Providing this more current information is essential because this information will play a critical role in the Company's upcoming rate case. As such, the Commission further finds and concludes that Georgia Power and Savannah Electric shall each update its forecasts utilizing actual data through March 31, 2004. Once updated, these forecasts shall be filed by the Companies on or before August 16, 2004.

2) RELIABILITY—AUTHORIZED TARGET RESERVE MARGIN

In an effort to plan for a reliable system, allowances for capacity resources in excess of a utility's projected peak demand requirement are made for the purpose of recognizing that generating units can fail randomly, and load projections typically have some measure of forecast error. This commitment to have excess capacity provides a reasonable assurance that the utility will always have resources available to serve its load. A system with too large of a reserve margin will tend to have high revenue requirements because it will overbuild capacity on its system. A system with too small of a reserve margin will have to depend on purchases from the wholesale market that can be quite high at times of peak demand, once again resulting in high revenue requirements. The goal of a reserve margin study is to determine the level at which revenue requirements are the lowest for a given level of reserve margin. This results in a well-planned, reliable, and cost-effective utility system.

In the 2004 IRP, the Companies have proposed that the ultimate system reserve margin should be set at 13.5% for the first 3 years, and then 15% for the years after that. As support underlying this recommendation, Southern Company Services conducted a reserve margin study[28] that updated the one that was previously done in 1999. The conclusion reached in both studies was that 15% is the appropriate level of reserve margin for the Southern Company System. In the 2001 IRP, Georgia Power cited to the 1999 study as its basis for relying on 15% as its target reserve margin level for the Southern Company System.[29] Also, in the 2001 IRP, Georgia Power proposed a lower System reserve margin level for the short-term, arguing that it was an acceptable level for the first three years of the IRP study period. Ultimately, the Commission accepted these target reserve margin levels for the 2001 IRP.

For purposes of its 2004 IRP reserve margin study, Southern Company Services relied on its Monte Carlo Frequency and Duration Model "MCFRED," to develop the relationship between system revenue requirement and reliability based on Expected Unserved Energy (EUE). The cost of EUE is the payment which one customer is willing to make to avoid an hour of sudden, unexpected, firm load curtailment on a hot, summer afternoon. The goal of the reserve margin study is to determine the appropriate level of reserve margin such that total system revenue requirement is minimized, considering the cost of generating to serve load, the cost to build new capacity and the

[28] See Technical Appendix Volume 1B of Georgia Power's filing.
[29] *Staff Panel Testimony* filed May 11, 2001, Docket Nos. 13305 and 13306, page 18 at line 5.

cost of expected unserved energy that might result from not having built quite enough capacity to serve load. In the 2004 filing, the reserve margin study explains that several changes were made in the modeling methodology to more closely represent the operational characteristics of the system.

Base on the results of the reserve margin study and the resulting analysis done by Staff, the Commission believes that the Companies' proposed system reserve margin recommendation, which includes a risk adjustment,[30] should be approved in this IRP. Their recommendation appears to be quite reasonable based on a number of facts. These include an acknowledgement that a 15% reserve margin is consistent with what other utilities typically use, that presently there is considerable excess merchant capacity in the southeast region and that Southern Company as a whole is itself in an over-capacity situation.

As such, the Commission finds and concludes that the Companies' proposed 13.5% target reserve margin for the 2004 – 2006 time frame shall be set at 13.5%, with 15% to be used for the remainder of the study period. It is further directed that, in future reserve margin studies, as with all evaluations that are conducted as part of an IRP, consistent modeling data should be used to the greatest extent possible.

3) SUPPLY-SIDE MANAGEMENT

a) Generation Expansion Plan

Georgia Power Company's Resource Planning Process

Georgia Power's base case supply-side Resource Plan, which covers the 20-year period from 2004 through 2023, identifies the need for new resources to begin in 2009 and continue every year thereafter through 2023. In each of those years, Georgia Power proposes to add various combinations of gas-fired combustion turbine ("CT") and combined cycle ("CC") units. Between 2004 and 2008, the Companies' have already made commitments to satisfy their resource needs based on prior IRPs, through reduction in the peak demand forecast, and in accordance with Commission certification proceedings that took place in December 2000 and December 2002.

[30]On page 48 of the Risk Margin study, Southern Company Services reported that the optimal reserve margin for the system is actually lower than the 15% reserve margin that the Companies have recommended. However, through a series of additional analyses, risk factors were derived and added to the lower reserve margin result. The net result of these risk factors is that additional capacity has to be planned for the system to satisfy the higher reserve margin targets. It should be noted that the use of risk adjustments is not unusual when they are applied in such a way that the utility may meet other goals in addition to those required by the basic methodology. Staff determined that planning for a reliable system in an uncertain environment was an adequate reason in these filings to use a risk adjustment.

The December 2000 certification allowed Georgia Power to proceed with the following resources:[31]

- 1,800 MW of purchased power coming online in the 2003 and 2004 time period based on purchases from Southern Power Company. (The Franklin and Harris Power Purchase Agreements (PPAs).

- 12 MW upgrades to the Goat Rock Hydro units

The December 2002 certification included:

- 1,660 MW of purchased power coming online in 2005 based on purchases from Duke Energy Southeast Marketing, LLC and Southern Power Company.[32]

<u>Savannah Electric's Resource Planning Process</u>

Savannah Electric's base case supply-side resource plan also covers the same 20-year time frame and has identified the need for new resources to begin in 2009. Just as in the case of Georgia Power, after 2009, and through the remainder of the planning period, Savannah Electric's resource plan calls for the addition of CT and CC units. Based on decisions made in prior IRPs and approved in Commission certification proceedings (one in March 2000, and another in December 2002), Savannah Electric has already made commitments to satisfy its resource needs covering the period of 2004–2008.

In March 2000, the Commission certification allowed Savannah Electric to proceed with the following resources:[33]

- 200 MW of purchased power coming online in June 2002 based on purchases from Southern Power Company, from its Wansley Combined Cycle Plant. This is a 7.5 year PPA covering the period of June 2002 through December 2009.

The December 2002 certification provided approval for:

- 200 MW of purchased power coming online in June 2005 based on purchases from Southern Power Company, from its McIntosh Combined

[31] *Georgia Power Company's 2004 IRP* Main Document, pages 1-7.
[32] Since both Companies filed their IRPs on January 30, 2004, a joint application was made to the Commission on May 7, 2004, requesting direction to buy the two units, McIntosh 10 and 11, which were the subject of the purchase power agreements that they previously entered with Southern Power Company, and which the Commission certified in December 2002. The Commission issued this directive in an order filed on May 19, 2004, in Dockets 15392-U and 15393-U and will be considering the valuation of them as part of a rate case later this year.
[33] *Savannah Electric and Power Company's 2004 IRP* Main Document, pages 1-8.

Cycle Plant.[34]

- The retirement of approximately 100 MW at Plant Riverside on May 31, 2005, based on the purchase of McIntosh unit.

Based upon the information filed by the Companies in their IRPs, the Commission finds and concludes that the Companies' respective Generation Expansion Plans appear to be adequate.

b) <u>Unit Retirement Study</u>

In conjunction with its 2004 IRP filings, the Companies have considered whether it is prudent to consider for retirement any of their electric plants or the individual units located within them. In doing so, Georgia Power has requested that the Commission de-certify the Plant Atkinson CTs 5A and 5B, which total 80 MW of capacity, and which were retired from service on December 31, 2003. (Pre-filed Panel Direct of the Companies, page 7.) Upon examining whether Georgia's plans for the retirement of these two units are reasonable, Staff testified that they were. (Tr.485.) No other party addressed this issue with Georgia Power at the hearing.

A decision to extend the life of a unit at Plant Kraft has been made by Savannah Electric in its IRP filing. This utility previously had been planning for the retirement of the Kraft CT unit, which is a 17 MW combustion turbine that is capable of providing black start service. However, Savannah Electric since has performed further retirement evaluations (Pre-filed Panel Direct of the Companies, page 14) and is now recommending that the life of Kraft CT 17 MW be extended. Neither Staff (Pre-filed Staff Panel Direct Testimony, pages 43-44) nor any other party has opposed Savannah Electric's doing so.

Based on these considerations, the Commission finds and concludes that it is reasonable for Plant Atkinson CT's 5 A and 5B to be de-certified by Georgia Power Company. The Commission further finds and concludes that it is prudent for Savannah Electric to extend the planned life of the 17 MW Kraft CT unit that is capable of providing black starts and to remove it from further consideration for retirement.

c) <u>Fuel Forecast</u>

Staff expressed concern in its direct testimony that natural gas prices have risen sharply in the past year or two and seem to be forecasted to gradually trend lower from the currently high levels for a few years before returning to an upwardly trending pattern over the long term. (Pre-filed Staff Panel Direct Testimony, p. 16.) Unlike past history, as the natural gas prices decline in the next few years, none of the industry experts appear to expect prices to drop back to around $3.00/mmbtu again over the next 20

[34] See Footnote Number 17.

years. Id. For purposes of making a proper analysis of the IRP filings, Staff compared the Companies' base and high gas forecast to other forecasts including NYMEX and the Energy Information Administration's ("EIA") forecast. Based on its comparison, Staff concluded that the Companies' reference case forecast may be a little low. Id.

The Staff pointed out that price forecasts currently exhibited large fluctuations associated with many uncertainties in the markets. Id. at 15. The EIA 2003 Energy Outlook forecast of the fuel prices may be low given the more recent developments in the natural gas markets. The EIA revised these price forecasts upward in the EIA 2004 Energy Outlook published in December 2003. The gas price for electric generators for the Middle Atlantic region, as reported in the 2004 EIA Energy Outlook, was revised upward by an average of 10.6% for the period 2004 to 2025. Id. at 54-55. For the short-term period 2004 to 2008, the average increase in the gas price forecast for the electric generators is 18.4%. Id. For the period of 2009 to 2025, the average annual price upward revision is about 8.4%. At the retail level, the EIA forecast for residential gas prices in the Middle Atlantic Region was revised upward by an average of 8.8% for the period of 2004 to 2008, and an average of 3.7% for the period of 2009 to 2023. Id. For commercial customers and industrial customers, the price forecast revisions are higher: commercial users: 2004-2008, 19.3%; 2009-2023, 10.3%; and industrial users: 2004-2008, 13.9%; 2009-2023, 9.8%. Id. Even though there is not full agreement with all of the Companies' data assumptions, none were determined by Staff to be completely unreasonable. (Pre-filed Staff Panel Direct Testimony, p. 15.)

Within the testimony of John Mallinckrodt, the Georgia Industrial Group and Georgia Textile Manufacturers Association expressed concern that GPC is planning to rely totally on natural gas for future resource additions. (Pre-filed Testimony of John Mallinckrodt, p. 2.) A primary basis for GPC's reliance on natural gas is an assumption that natural gas prices will drop due to increased imports of liquid natural gas ("LNG"). Id. Mr. Mallinckrodt pointed out that domestic supply is declining, as are imports from Canada, and that even assuming that all LNG that is projected to be imported through both existing, expanded and new terminals, LNG will still not significantly increase domestic gas supply. Id. at 5. GIG/GTMA argued that contrary to GPC's projection of declining natural gas prices in 2004 to 2009 timeframe, natural gas prices are not likely to change significantly relative to current high levels. Id. at 7.

The fuel forecasts of Georgia Power and Savannah Electric utilized in various parts of the IRP originated over a range of dates. For example, fuel prices used in some of the forecast models were based on the EIA 2003 Energy Outlook published in December 2002 (*Georgia Power's 2004 IRP Filing* Main Document, page 3-3; *Savannah Electric's 2004 IRP Filing* Technical Appendix, Section 1, page 76), and it appears that other fuel forecasts were derived for other analyses such as the Optimal Resource Mix Study.

Staff recommended that the Companies update and file prospectively their fuel forecasts on June 30th of each year. (Pre-filed Staff Panel Direct Testimony, p. 87.) As per Staff, the updates should include an assessment of how the conclusions and recommendations reached by the Commission in the most recent IRP order may need to be modified as a result of the updated forecasts. These updates should also include a comparison of the forecasts used in the previous IRP with the actual data for the current year. The Staff also recommended that the Commission consider continuing its previous order requiring Georgia Power and Savannah Electric to file load and fuel forecasts, together with detailed supporting information and analyses each year, rather than at the three year IRP intervals, in order to capture significant changes in the region. Id.

With regard to three of Staff's recommendations, the Companies argued that, pursuant to Commission Rule 515-3-4-.06(5), they already are already required to notify the Commission of any major changes in any condition that would impact resource planning. (Pre-filed Panel Rebuttal of the Companies, page 41.) Georgia Power and Savannah Electric also are currently under the obligation to file with the Commission a copy of each load forecast update prepared by the Companies as soon as such update becomes available. Id. Similarly, since the Companies already currently file a copy of the Environmental Compliance Strategy each year, as well as filing a status report of their certified DSM programs, the obligation to make a further in this area would be burdensome and unnecessary, In sum, the Companies argued that Commission already has in place several mechanisms through which it can stay abreast of their resource planning process in between filed IRPs and additional filings to report on same would be redundant. Id.

The Commission is concerned about the volatility in the price of natural gas, the increasing cost of fuel, and the IRPs' long term reliance on natural gas. In order for this agency to adequately monitor the issues surrounding fuel that have developed in recent years and are expected to continue, the Commission finds and concludes that both Companies shall promptly notify the Commission of any changes in fuel price conditions, including external forecasts that may warrant development of a new utility price forecast. In imparting this information, Georgia Power and Savannah electric also shall advise the Commission of the impacts these changes may have on the long range IRP.

The Commission further finds and concludes that the Companies shall make available any fuel forecast update as soon as it is available. This information shall be provided as appropriate within each 6 month Progress Report to the Commission as required by Utility Rule 515-3-4-.05.

4) DEMAND SIDE MANAGEMENT

a) Demand Side Management Issues Raised by The Companies Proposals

Neither the IRP filing for Georgia Power nor the filing made by Savannah Electric contained any new Demand Side Management ("DSM") programs because, the Companies contended, none were found to be cost-effective by applying the screening tests specified in the Commission's rules and prior orders. (Pre-filed Panel Direct of the Companies, page 41.) Georgia Power and Savannah Electric have indicated that it remains appropriate for this Commission to use the Rate Impact Measure ("RIM") test as the final screening tool to determine whether a DSM measure should be implemented. Id. at 10 and 16. Both Companies also stated their intent to continue the Power Credit program, which was reauthorized by the Commission in its 2001 IRP order. Id. at 9 and 16.

Georgia Power also proposed to maintain its Low Income Weatherization Assistance Program and to continue existing energy information programs that provide customers with cost-effective energy saving options. Id. at 10. Similarly, Savannah Electric has made the same proposal. Id. at 16.

1) Implementation of Additional Measures to Foster Energy Efficiency

a) Partnership with Energy Star®

Georgia Power and Savannah Electric indicated that in April 2004, they entered into a partnership with Energy Star®, through which appliances acknowledged as having a certain level of energy efficiency would be promoted by the Companies in ways such as providing consumers with manufacturers' coupons for energy efficient appliances with their bills. (Tr.1029.)

The Commission finds and concludes that both GPC and Savannah Electric shall continue to develop the partnership that it has entered into with Energy Star® through which appliances acknowledged as having a certain level of energy efficiencies would be promoted by the Companies in ways such as providing consumers with manufacturers' coupons for energy efficient appliances with their bills.

b) Desire for Greater Levels of Customer Education

It was apparent to the Commission through comments made by public witnesses that most of them supported additional education regarding efficient use of electricity. Public witness Ms. Peggy Bartlett stated in relevant part that "[w]here I expected some folks to be quite resistant to suggestions that they change their personal habits with regard to lights, computers, small appliance, copy machines, . . . we have found extremely positive response. People want to know what to do. They are grateful for educational specifics of what they should do." (Tr.428.) Another citizen who made public comments, Ms. Elizabeth Mojica, stated that she was "disappointed in Georgia's lack of renewable energy sources and the poor education of consumers on energy conservation issues." (Tr.446.) Mr. John Heavener, also a public witness who gave up his personal time to come to the hearing, commented that "[a] part of that strategy could be encouraging commercial and residential consumers to utilize Energy Star® appliances and building products as well as instituting education campaigns on how to reduce the demand for energy." (Tr.458.)

The interest among consumers in making efficient use of electric energy also was addressed by Staff witness Evan Evans, who testified that helping people understand how to set programmable thermostats already located in their homes could itself be a program design, and that education along those lines incorporated into the informational program that Georgia Power already has in place would produce benefits. (Tr.521.) In terms of understanding how to exact energy efficiencies from current electric usage, ASE's witness, Dick Spellman, noted that the existence of market barriers resulted in most people lacking awareness of energy efficient technologies, which is why educational programs like the one provided by Georgia Power through brochure information are greatly needed to educate the public. (Tr.849-850.)

Georgia Power and Savannah Electric stated on rebuttal that "[a]lthough [they] work with customers daily on how to use energy efficiently, the Companies are also willing to engage in additional customer education regarding DSM." (Company Panel Rebuttal testimony, page 7.) As support for this representation, the Companies noted a number of ways that they proposed to do so. The Companies further stated their willingness to more aggressively promote their willingness to conduct energy audits for customers upon request in an effort to raise customer awareness of the availability of this service. (Tr. 1027-1037.)

Based upon the foregoing, the Commission finds and concludes that the Companies shall initiate customer education programs through which they each will disseminate information to consumers about the efficient use of electricity. Georgia Power and Savannah Electric also shall more aggressively promote the availability of energy audits for interested customers.

c) <u>Funding for Educational Initiatives</u>

In order for Georgia Power and Savannah Electric to properly implement the customer education programs that they have been charged with initiating, the Commission finds and concludes that Georgia Power shall fund with no more than $2,000,000 annually an energy efficiency campaign that it shall implement to promote consumer awareness of those energy efficiency measures and practices that produce the greatest economic efficiency and benefit to a participant. Savannah Electric shall support a similar initiative with no more than $200,000 annually in funding to do so.

All of the funding authorized for these programs shall be directed to promoting education regarding those energy efficiency measures and practices that produce the greatest economic efficiency and benefit for the participant. In terms of outreach to achieve this goal, the Companies may use any recognized medium through which their customers could reasonably be expected to be reached with energy efficiency information, including, but not limited to, television advertisements, radio spots and advertisements in local newspapers and periodicals.

All such advertisements made through these mediums shall be for the exclusive purpose of promoting education in the area of energy efficiency and shall not serve as a forum to promote the Southern brand (or that of its subsidiaries) in any way, or to further other initiatives of the Companies outside of those contemplated herein. Television, radio and/or print ads shall provide as much information about managing electric usage as possible in the time/space allotted. A general understanding of electric energy efficiency and conservation should be able to be derived by the average viewer after viewing/listening to any advertisements. The theme of all advertisements should be strictly education-based. Any advertisements that the Commission, in its sole discretion, finds not to be adequate for its intended purpose shall not be financed with monies allocated in this order for consumer education.

Copies of television ads, radio scripts and print advertisements containing information that is to be disseminated to the public shall first be provided to the Commission’s Consumer Affairs Office, the Commission’s Public Information Office and the Commission’s Electric Staff in advance of being published. Upon their receipt of same, Staff will immediately give other interested parties five (5) business days to review the content of what the Companies seek to publish in order to raise any objection as to the content of the ads. The Commission shall be the ultimate decision maker as to whether an advertisement shall be approved.

In order for Staff to monitor the spending that the Companies will be doing in providing energy efficiency education, the Companies shall filed quarterly reports with the Commission detailing with specificity the expenditures made through this education program. None of the funds allocated shall be used for any expenditure not expressly contemplated by this order.

d) <u>DSM Working Group</u>

The Integrated Resource Planning statute requires this Commission to consider both demand side and supply-side options. In doing so, this Commission must evaluate “the economic, environmental, and other benefits to the state and to consumers of the utility” associated with these various options. O.C.G.A. §§ 46-3A-1(7) and 46-3A-2(b)(3).

In the early 1990’s, the Commission embraced numerous DSM programs that ultimately proved costly to non-participants and provided little system-wide benefit. The primary reason for this failure was that there was no real focus or targeted objectives in approving those DSM options. As a result of this failure, in its 1995 IRP Order the Commission adopted the RIM test, which virtually eliminated implementation of any DSM initiative. As it has turned out, the Commission went from one extreme to another.

Since 1995, much has changed in the electric industry that now may impact this Commission’s opinion about the need for more DSM. Among other things, many states have found ways to improve and refine these DSM programs. The move towards retail electric deregulation has all but ended, and many regulators are once again considering the public service obligations of utilities that have been granted monopoly rights. These factors, coupled with a dramatic increase in fuel costs to generate energy over the past few years, make the issue of energy efficiency one that must be more closely examined to see whether the position that this agency supported in 1995 regarding the RIM test should be revisited.

In light of these factors, the Commission seeks to find a solution that will strike a balance between economic efficiency and fairness and equity when considering implementation of DSM programs. Regrettably, the record that was created in these dockets has not been not adequately developed in this area for the Commission to be able to find that balance. The positions of the parties on DSM were very far apart and, for most of the hearing, the parties seemed to be talking past each other and not attempting to reach any middle ground.

As such, rather than returning to the hearing process at this time to further develop the record, the Commission believes that a more productive way to proceed would be to form a DSM Working Group that shall meet to develop a proposed DSM initiative for this Commission to consider. Instead of the all-or-nothing approaches that were presented at the hearing, it is the sincere desire of this agency that the Working Group will develop a reasonable and credible DSM initiative.

Based on the foregoing, the Commission finds and concludes that a Working Group of interested stakeholders to develop a proposed DSM Plan for residential and commercial customers for the Commission's consideration. The Commission Staff shall organize and act as the facilitator of the Working Group, which shall consist of the parties in the IRP cases. The Companies shall not be required to pay the cost of retaining a consultant as requested by ASE during the hearing

The Working Group shall convene for the first time no later than August 15, 2004, and meet as often as needed thereafter. Within 10 days after each of its meetings, the Working Group shall file reports with the Commission in these IRP dockets. These reports shall detail the minutes of the meeting and provide status information regarding the project, including milestones reached and a timetable for completion of remaining milestones. The Commission does not find it appropriate to require the Companies to provide $300,000 as requested by ASE to pay costs that may be incurred by the group in executing and fulfilling its mission.

The Companies will provide to the Working Group such data as may be reasonably necessary for the Working Group to perform its tasks and develop its proposed DSM Plan. To the extent that the Companies contend that any such information is proprietary, it shall be filed with the Commission and be made available to members of the group pursuant to the Commission's Trade Secret rules.

The proposed DSM Plan shall be a comprehensive proposal consisting of 1) a mix of DSM initiatives to be recommended to the Commission for approval, including detailed information regarding how each of the initiatives would be implemented; 2) a recommended process for the selection of DSM initiatives in the future; and 3) recommendations regarding the need for changes to the Commission's IRP rules regarding DSM or for proposed legislation.

The recommended mix of DSM initiatives in the DSM Plan shall be selected by the Working Group using the following criteria:

a. The proposed DSM Plan should minimize upward pressure on rates and maximize economic efficiency. This directive is extremely critical given Georgia Power Company's $328 million pending rate increase request and Savannah Electric and Power Company's scheduled rate filing.

b. The cost/benefit analysis results of each initiative using all 3 tests (RIM, Total Resource Cost test and Participants test) shall be considered by the Working Group and shall balance between economic efficiency and fairness and equity.

c. An examination of where growth is occurring on the system shall be performed by the Working Group, which shall attempt to concentrate its recommended initiatives there. Consideration shall also be given to initiatives that encourage participation by low-income customers.

d. In addition to traditional DSM programs, the Working Group shall consider rate design initiatives. In considering such initiatives, the Working Group should consider the cost/benefit analysis of such initiatives and the time periods that such initiatives would be available to a customer.

e. Every effort should be made by the parties to develop innovative programs and market approaches that will prevent upward pressure on rates and subsidies between participants and non-participants.

f. Where appropriate, the Working Group should consider the development of pilot initiatives (limited enrollment, limited terms) as a tool to gauge initiatives.

g. The Working Group shall also provide input to the utilities in the development of the energy efficiency educational efforts approved by the Commission.

By no later than February 15, 2005, the Working Group shall conclude its mission by submitting a proposed DSM Plan to the Commission.

After the Working Group has tendered its recommendation to the Commission, this agency will consider any further action to be taken regarding the appropriate mix of

DSM initiatives to be adopted and the process for the selection of DSM initiatives in the future.

e) Increased Weatherization Program Funding

In their rebuttal testimony, the Companies acknowledged the Commission's concerns regarding low-income customers and expressed a continued commitment to the low-income weatherization assistance programs that have been established for these customers. (Tr.1025-1026.) Under cross examination by the Staff during the rebuttal phase of the hearing, the Companies indicated that they were amenable to increasing the existing level of funding for their respective low-income weatherization programs. Id. Georgia Power proposed raising its funding level by $300,000 annually (Tr.1025), while Savannah Electric indicated that it believed a $30,000 per year funding increase of its program was appropriate. (Tr.1026.)

During the Special Administrative Session held on July 9, 2004, to issue a decision in this matter, the Commission Chairman read a letter (that also was made part of the record) from Georgia Power in which it was stated this utility, and not its ratepayers, would provide this extra funding. Savannah Electric, he noted, was working toward doing the same thing.[35]

As such, the Commission finds and concludes that the low-income weatherization program of Georgia Power Company shall be continued. Its level of funding, now set at $1,000,000, shall be increased by $300,000, thereby making $1,300,000 the total sum of money that shall be dedicated to the program annually for the next three years. Georgia Power Company has agreed that this additional $300,000 in annual funding shall not be recoverable from ratepayers.

Savannah Electric's low-income weatherization program also shall be continued. Its level of funding, now set at $100,000, shall be increased by $30,000, thereby making $130,000 the total sum of money that shall be dedicated to the program annually for the next three years. Savannah Electric shall work toward supplying the additional funding so that the $30,000 will not be paid by ratepayers. After doing so, Savannah Electric shall report back to the Commission with information as to whether this is possible.

In terms of executing their weatherization programs, both Companies shall offer programmable thermostats to customers with central heat and air who wish to have them installed. Education regarding the use of these thermostats also shall be provided to the participants in these programs.

f) Staff's Programmable Thermostat Recommendation

During its direct case, Staff recommended that Georgia Power and Savannah Electric should be required to develop and implement pilot programs that provide customers an

[35] Transcript of Special Administrative Session, July 9, 2004, pages 4-5.

incentive to install programmable thermostats (Energy Star®) in existing residences, and that pilot programs be initiated by both Companies. (Pre-filed Direct Testimony of Staff Panel, page 58.) Initially, it was proposed by Staff that Georgia Power's program should be limited to 25,000 participants, while Savannah Electric's program should have up to 2,000 participants Id.

In the rebuttal testimony of Georgia Power and Savannah Electric, the Companies expressed support for all of Staff's DSM recommendations except for this one. (Pre-filed Panel Rebuttal Testimony of Companies, page 19.) This lack of support stemmed from Georgia Power's further examination of this measure[36] in which programmable thermostats were represented as having passed the RIM test by only $1.00 before any rebate was considered. Id. After the $25 rebate recommended by Staff was added to the cost of the program, Georgia Power noted that the programmable thermostat program failed the RIM test by at least $24 per thermostat. (Tr. 545.) It also was represented that additional program costs would only serve to worsen this disparity, and that the specifics for Savannah Electric regarding this measure's implementation would be similar. Id.

In light of the Commission's decision to create a Working Group to further consider DSM initiatives, the Commission declines to adopt the Staff recommendation on the development of pilot programmable thermostat program at this time.

2) Continuation of Power Credit Program

As proposed by the Companies, the Commission finds and concludes that Power Credit program should be continued. However, as recommended by Staff (Pre-filed Panel Direct of the Staff, page 60), the program shall be further evaluated by the Georgia Power and Savannah Electric based upon the marginal costs that result from this filing and be included with the updated evaluation of other DSM measures within 3 months of the issuance of the Commission's final order in these dockets. Furthermore, until such time that the Companies project that they will begin activating the programs to reduce peak loads, these programs only should be evaluated as providing reliability benefits.

3) Request for Updated DSM Data Made By Staff

With regard to the "consistency of data" issue discussed elsewhere in this order, Georgia Power and Savannah Electric agreed during cross examination by Staff to file the demand side management evaluation, just as it has always done, with what would be the most current data available at the time of the filing. (Tr.1039.) The Companies did, however, indicate the need to come back with a supplemental filing, probably in the late March/early April time frame, which would show the results of the DSM evaluation using all of those new cost assumptions that were developed in the IRP process. Id. Georgia Power Company and Savannah Electric noted that it would be their intent to try and have that data available prior to the presentation of the Companies' direct cases for

[36] This examination centers on use of such a thermostat in a home heated by natural gas.

the next IRPs filed. As a consequence, Georgia Power and Savannah Electric would be providing updated evaluations for all of those measures with the exact same cost data used in the IRP process itself. (Tr.1037.)

To move towards consistency of data in all analysis performed, the Commission finds and concludes that it is appropriate for the utilities to update the DSM evaluation as described herein during the next IRP filing.

5) Use Made of Real Time Pricing Tariffs

In reviewing the Companies' various pricing options, Staff pointed out a number of short-comings with Georgia Power's Real Time Pricing ("RTP") tariffs in terms of it being viewed as a load management tool. Staff argued that due to the way this tariff has been administered, RTP has not resulted in a sizable reduction of load during peak periods. (Pre-filed Direct Testimony of Staff Panel, page 60.) Rather, Staff contended that since it appears that RTP is being used to compete for new loads, the Company's claims of peak load reduction benefits to its system really do not exist. Id. Staff did not dispute that RTP can be a tool for economically adjusting the load shapes of participants in a manner that can benefit not only them but non-participants as well. It did take the position, however, that in order to be effective and beneficial, the hourly price signals must be adequate to encourage participants to change their hourly load shapes. Id. at 60-61. Prices charged of participants on these tariffs must be set to ensure that these customers are supporting the marginal costs incurred to serve them, plus provide a reasonable contribution toward fixed costs. Id. If they are not set to recover these costs, then non-participating customers would be subsidizing the customers on these rates.

The Staff also expressed a concern that the tariff does not contain sufficient requirements for establishing a firm Customer Baseline Load (CBL) below the actual projected load for new load. Id. at 61. The RTP tariff automatically permits an industrial customer to establish its CBL at 60% of the forecasted load for new load, without proof that it can actually operate at 60% of the forecasted load. In addition, the CBL for new loads can be further reduced by reducing load on a one-time basis for only two (2) consecutive hours, with a day-ahead notice. RTP customers have significant economic incentive to reduce their loads for these two hours, considering the fact that they can achieve significant potential savings on all additional load reductions.[37] Staff was concerned that, while RTP tariffs provide significant incentive for customers to temporarily reduce loads to obtain lower RTP prices, reductions may not materialize when the need for significant, sustained load to be shed in the future. Id. at 62. This concern is supported by the fact that estimated RTP reductions for 2003 were such a small fraction of the total RTP load above CBL on Georgia Power's system. If a customer's CBL is set artificially low, then that customer would not be making an appropriate contribution towards fixed costs and those costs would have to be shifted to

[37] This information was derived from the Staff Report filed with the Commission in Docket No. 16896-U, Proceeding to Examine Alleged Discrimination in the Application of Georgia Power Company's Real Time Pricing Tariff, filed on November 14, 2003, p. 8-9.

the remaining non-participating customers.

Staff testified at the hearings that Georgia Power's RTP tariff, as presently administered, has not achieved an appreciable level of load reduction relative to total load above the CBL. Id. at 63. As such, it should be subject to revisions in the upcoming rate case to achieve this goal, if the Commission regards the purpose of RTP to be a load management tool. Id. In addition, the Staff recommended that in its next IRP filing, Georgia Power provide an updated study of the peak load reduction benefits and costs of RTP. Id.

In rebuttal testimony Georgia Power argued that the Staff recommendations do not recognize the primary purposes of the RTP tariffs, which are to provide marginal cost based rates to customers in Georgia that represent market conditions while fully covering cost and making a contribution to fixed costs of customers. (Pre-filed Panel Rebuttal of the Companies, page 21-22.) Georgia Power further argued that its RTP tariffs helped it to compete in the customer-choice market, which results in downward pressure on rates to all of its customers. It was further noted that load management also was a benefit derived from RTP tariffs, through which customers could compare the value of electricity to their cost and make a decision whether or not to purchase energy. Id. Georgia Power testified that it has seen RTP load reduction of over 800 MW in previous years when constrained capacity resources forced the RTP price to extremely high levels. Id.

The Commission finds and concludes that the RTP tariffs shall be further evaluated during the Georgia Power 2004 rate case. If it is found to be appropriate in that case for modifications to the RTP tariffs to be made, the Commission will consider doing so in conjunction with issuing its final order in that docket. For purposes of this case, however, from a system reliability standpoint, it is extremely important to have the best information available to evaluate the load impact of RTP tariffs on the system. Therefore, the Commission finds and concludes that, in its next IRP filing, Georgia Power shall provide an updated study of the peak load reduction benefits from its RTP tariffs.

6) Green Power Programs

Georgia Power Company's 2004 IRP filing includes a stated intention to pursue Green Energy contracts that will provide renewable resources to meet customer requirements.[38] Savannah Electric stated in its IRP filing[39] that it will participate in the Green Power Program approved in Docket No. 16574-U. These programs will not provide capacity resources but will allow willing customers to purchase green energy at zero-cost to non-participants. Both are designed so that they are voluntary for the

[38] See pages 1-7.
[39] See page 9.

participants and will have no adverse impact on non-participants. The green portfolio as contemplated will likely include solar, wind, and landfill gas resources.

In the summer of 2003, the Commission approved for each company a Green Energy tariff that authorizes it to sell renewable energy under certain terms and conditions. Despite obtaining this approval, however, the Companies have represented that they are having difficulty in finding local viable sources for their Green Power Programs (Tr.89), which presently are not active. In its testimony, the Staff Panel recommended that the Companies increase their efforts to locate and contract for green energy resources. (Pre-filed testimony of Staff Witness Panel, p. 71.)

In conjunction with their doing so, Staff also recommended that a target date of one year be established for them to identify a source or sources of green energy, to secure these resources, to establish the availability of the option and to initiate subscriptions with their customers. Id. If, however, within the one year period from August 1, 2004, the Companies remain unable to establish a contractual relationship renewable energy despite employing their best efforts, they should be required to return to the Commission with an explanation and request that their Green Power Programs be re-evaluated. Id. The Companies indicated that they agreed with this recommendation in their rebuttal testimony. (Pre-filed testimony of Companies' Rebuttal Panel, pages 2-3.)

As a consequence of the foregoing, the Commission finds and concludes that the Companies shall increase their efforts to locate and contract for green energy resources. A target date of one year from the date of this final order shall be established at which time the Companies shall identify a green energy source or sources; contract to secure the resources; confirm the availability of the tariff with interested consumers, as well as commence their pre-planned advertising campaigns; and to initiate subscriptions with their customers. If, by August 1, 2005, the Companies remain unable to successfully execute these functions despite employing their best efforts, Georgia Power and Savannah Electric shall file notification of the underlying circumstances with the Commission by September 1, 2005, so that the agency can re-evaluate their Green Power Programs.

7) TRANSMISSION

The Staff Panel was the only set of witnesses that provided any type of examination of the Companies" transmission system planning, the results of which will be set forth generally hereinafter. In doing so, Staff found that the Companies made an assessment of the adequacy and reliability of their transmission system by using the Guidelines for Planning the Southern Company Transmission System (the "Southern Guidelines"), the Guidelines for Planning the Georgia Integrated Transmission System ("ITS Guidelines"), the North American Electric Reliability Council ("NERC") Planning Standards, and the Southeastern Electric Reliability Council ("SERC") Supplements to the NERC Planning Standards. The Companies used two basic criteria for determining its reliability of the transmission grid: (1) overloads on line conductors (based on their thermal limits), and (2) under-voltage on transmission busses.[40] (Pre-filed Panel Testimony of Staff, pages 66-67.)

Staff observed that these criteria were applied first to the "base case" where all generation and loading conditions are at levels that are expected to be "normal." Subsequently, the criteria were applied to contingency cases (in particular to first-contingency failure situations), where a generation unit or a transmission line (or transformer) is removed from service. Id. at 67. Under these contingency conditions, the Companies would be able to determine where trouble spots are given likely operating conditions which would allow them to determine whether operating solutions exist to solve the problem, or whether new transmission facilities must be built to solve it. Insofar as their planning procedures are concerned, the Companies took a typical approach to identifying and proposing various solutions to problem areas on the transmission system, eliminating solutions that do not work, and selecting the most cost-effective solution for the long-term.

Staff's analysis resulted in a finding that three basic types of transmission projects existed: 1) projects related to general improvements to the transmission grid; 2) projects related to the addition of new generation to the transmission grid; and 3) projects related to the increase in interface transfer capacity (imports or exports) between the Southern Company (Georgia Power and Savannah Electric in particular) and adjacent utility systems. Although Staff's review was limited to only 12 projects, each of them appeared to be justifiable.[41] Id. at 68-69. The Companies were believed to have identified projects in the ten-year transmission plan that presently are or will be necessary to provide adequate and reliable electric service to their respective customers. Id. Of course, the Commission does not certify transmission projects in the IRP, and decisions on the inclusion of transmission costs in base rates is a decision that is made in rate cases.

In terms of recommendations, Staff had just one. In future IRP filings, Staff would like the Companies to provide the most inclusive and detailed data available for the first half of its 10-year plan. For the remaining half of its plan, the data provided could contain less in-depth information. Id. at 91. In considering Staff's request in this regard, the Companies have indicated in their rebuttal that they are not opposed to doing so. (Pre-filed Panel Rebuttal Testimony of the Companies, page 3.)

As such, the Commission finds and concludes that future IRP filings should provide specific, comprehensive, detailed data for the first 5 years of the 10-year transmission plan, and less detailed data for the remaining 5 years of the plan.

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[40] There are other planning criteria such as transient stability but the criteria mentioned above are the main ones.

[41] Despite making this statement, Staff noted that it could not be stated with certainty that every other project is absolutely necessary, nor could it be said definitively that there might not be other alternatives to some of the projects that the Companies are proposing.

8) ENVIRONMENTAL COMPLIANCE STRATEGY

In analyzing the Companies' IRP filings, Staff reviewed the 2002/2003 Environmental Compliance Strategy Report contained in the Technical Appendix, Volume 1B of Georgia Power's IRP filing. In doing so, the Environmental Compliance Strategy Report was examined to determine if the many environmental issues impacting electric utility operations were adequately analyzed and properly incorporated into the IRPs. Staff also evaluated the environmental issues and assumptions utilized in the Unit Retirement Study, which is also found in Technical Appendix, Volume 1B.

As a result of conducting its review, Staff made three recommendations to the Commission in which it sought additional information to what had been filed in the IRPs. Its first recommendation was that, within 60 days of a final order in these dockets, a comprehensive assessment be filed by the Companies detailing all of the possible impacts of all pending environmental regulations that may take effect in the next twelve months. This assessment should provide the Commission with an annual update of the impact of newly promulgated environmental regulations or proposed legislation that may modify the Companies' most recently completed IRP process. It also should include a high and low range of potential capital cost requirements if a particular regulation is promulgated or legislation is enacted, and state whether compliance with the enactment will materially change the recommendations made in the 2004 IRPs. Staff further proposed that the Companies be directed to provide the Commission with an annual update of their Environmental Compliance Strategy along with an analysis of how the updated strategy will impact the Companies' planning processes for the addition of generation and transmission. (Pre-filed Panel Testimony of Staff, pages 91-92.)

A second recommendation made by Staff was for the Companies to use in future IRP filings the same environmental scenarios from their Unit Retirement Study as they do in the Resource Planning Model (IRP Base Case). Id. at 92. This request was made based on a belief that in the 2004 filings, the Unit Retirement Study used included two additional cases recognizing the potential for increased levels of compliance, including Regional Particulate, Regional Haze, State NOx 8-hour Ozone SIPs, Mercury MACT, Clear Skies Act, Clean Power Act and Clean Air Planning Act. Id. The scenarios used in the Resource Planning Model Base Case, however, appeared to Staff to only include previous Acid Rain provisions, the 1-hour ozone requirements and the Regional NOx SIP Call for Georgia beginning in 2007. Using the same scenarios in both the IRP base case and the Unit Retirement Study was promoted by Staff as providing for greater homogeneity.

Staff's third recommendation was for Georgia Power to prepare and file an assessment of the potential impact of increased environmental costs due to hydropower re-licensing. Id. at 92-93. The assessment sought should include the potential impact of increased environmental costs due to hydropower relicensing, reflecting not only the costs of re-licensing but also the potential for lost capacity due to operational modifications to mitigate environmental concerns and the potential increased capacity as a result of unit rehabilitation. In addition thereto, Staff recommended that Georgia Power be directed to provide an assessment of the impact of lost hydropower generation on the existing IRP resource mix if, during relicensing, capacity loss occurs due to environmental mitigation.

With respect to its first recommendation, it should be noted that the Company filed on May 21, 2004, Southern Company's 2003/2004 Environmental Compliance Strategy Review, which is an annual filing that is made on behalf of Georgia Power and Savannah Electric. This 2004 environmental filing, which was made one week after Staff's panel testimony was filed, contains much of the information that Staff recommended be filed, although perhaps not to the level of detail that was identified in the panel testimony. (Pre-filed Panel Rebuttal of the Companies, page 43.)

As it pertains to Staff's second recommendation, the Companies indicated that there was no objection with compliance but noted that it appeared to be the product of Staff's confusion that the environmental scenarios from the IRP base case were different from those used in the Unit Study when this was not the case. (Pre-filed Panel Rebuttal of the Companies, pages 49-50).

Regarding the third recommendation, however, Georgia Power has expressed concerns in its panel rebuttal testimony regarding Staff's request as it relates to the preparation and filing of an assessment of potential impacts of increased environmental costs due to Hydropower Re-licensing. In doing so, Georgia Power noted that such an analysis was done in compliance with the 2001 IRP order in which it was noted that cost and other issues related to facility upgrades were largely unknown some 5 years before the first facility was to be relicensed.[42] (Pre-filed Panel Rebuttal of the Companies, page 53.)

Based upon the foregoing, the Commission finds and concludes that the Companies shall continue to file their Environmental Compliance Strategy Review on an annual basis; provided, however, that the scope of this filing shall be supplemented to include: 1) a high and low range of potential capital cost requirements if a particular regulation is promulgated or legislation is enacted, and information whether compliance with the enactment will materially change the recommendations made in the 2004 IRPs; and 2) an analysis of how the updated strategy will impact the Companies' planning processes for the addition of generation and transmission.

The Commission further finds and concludes that it is appropriate for Georgia Power to keep this agency and its Staff abreast of any developments that will result in more concrete information becoming available regarding cost estimates and facility upgrades for the hydropower facilities that are to be relicensed. Information that should be provided to the Commission on this issue, when available, shall include the potential impact of increased environmental costs due to hydropower relicensing, reflecting not only the costs of re-licensing but also the potential for lost capacity due to operational

[42] The hydropower facilities to be relicensed within the next 20 years include Morgan Falls (2009), Bartletts Ferry (2014) and Wallace Dam (2020).

modifications to mitigate environmental concerns and the potential increased capacity as a result of unit rehabilitation. In addition thereto, Georgia Power shall provide in its Environmental Compliance Strategy Review an assessment of the impact of lost Hydropower generation on the existing IRP resource mix if, during relicensing, capacity loss occurs due to environmental mitigation.

9) GENERAL RECOMMENDATIONS

a) Anticipated Impacts of Resource Plans on Rates

In its rebuttal testimony, the Companies opposed providing more detailed information regarding individual company rate impacts resulting from the underlying resource selections. (Companies' Pre-filed Rebuttal Panel Testimony, p. 48.) The panel indicated that more detailed information regarding rate impacts of resource selections was not the purpose of the IRP hearing, which was held to examine the development of resource plans and not project rates. (Tr. 1013-1014.) However, when pressed as to what type of hearing would take place at which the Commission would have the opportunity to examine the potential rate impacts, given that gas prices are high, environmental costs are growing and the company plans to do nothing but build gas-fired units, no forum could be identified. Id. It was also noted during rebuttal that what information had been provided about rate analyses in Exhibit A-1 to Georgia Power's Technical Appendix 1-A pertained to the Southern Company foot print as a whole, and not to each of the individual operating companies. (Tr. 1004-1005.)

Based upon the absence of company-specific details regarding rate-analyses for the resources identified in the plan, the Commission finds and concludes that the Companies must more fully communicate in future IRP filings information regarding the anticipated impacts their resource plans have on their forecasted rates. The nature of the Companies' resource mix clearly is changing. Operating companies' rates are vulnerable to such things as fuel spikes, environmental actions and technology advancements. As the resource mix changes from one that primarily uses coal and nuclear energy to one that more heavily relies on natural gas, the vulnerabilities and rate impacts that accompany such change must be clearly and accurately articulated within the IRP filings. Furthermore, at such time as the ultimate decision is to be made as to selecting one technology type over another, the knowledge of forecasted rate impacts should provide additional guidance in selecting the appropriate resource type. The IRP review, with its focus on a long-term evaluation of resource plans would be the ideal proceeding to also evaluate the resulting impacts on individual operating company customer rates.

b) Filing of Information in Integrated Resource Plans

In future IRP filings, the Companies are encouraged to use consistent data in evaluating all aspects of the IRP. Again, this includes transmission analyses, DSM modeling, retirement studies, as well as the load forecast, etc.

B) DIRECTIVES PERTAINING TO THE IRP RULES REGARDING THE PROCESS FOR ISSUING AND EVALUATING REQUESTS FOR PROPOSALS

As previously stated in this Order, the Commission invited interested parties to provide testimony during the hearings on various topics related to the manner in which bids for purchase power contracts are solicited and evaluated on behalf of the Companies. The purpose of seeking this information was to consider amending Utility Rule 515-3-4-.04(3), Request for Proposals Procedure for Long-Term New Supply–Side Options, to state with greater specificity the steps that were to be followed when a competitive solicitation was to be issued for purchase power to fill a designated supply-side need. Recommendations were made that pertain to the timing issues related to the bidding process to be considered in future solicitations.

a) Modifications Proposed to Existing Utility Rule 515-3-4-.04(3)

The Staff, Calpine, and GTMA/GIG pre-filed testimony[43] that responded to the issues identified by the Commission on this subject, all of which was supportive of having some form of an independent evaluator involved in the RFP process. Each of the witnesses testifying on this topic, however, had different ideas regarding the details that would need to be laid out regarding the manner in which the RFP was to be issued, how they were to be evaluated, and how the winning solicitations were to be selected and presented to the Commission for certification. The Companies, while not as adamant as the other responding parties as to the need to have an independent entity perform these functions, offered testimony as to what they believed would be a fair process through which an independent monitor could assist in the RFP.[44]

As the hearing progressed, representatives of Staff, Calpine, GTMA/GIG, the CUC and the Companies met to discuss this issue to see if a joint solution could be reached. During the rebuttal phase of the hearings, the Companies, on behalf of all of the aforementioned parties, entered into evidence as “Joint Parties Exhibit 1” a Stipulation endorsing the acceptance of measures to be applied in future supply-side solicitations over which a Commission-selected Independent Evaluator would preside. The structure proposed therein represents principles and procedures the sponsoring entities believe should be captured and embodied in a rulemaking by the Commission to modify existing Rule 515-3-4-.04(3) in order to adopt an Independent Evaluator (“IE”) for use in all

[43] Staff’s initial view on the RFP related issues can be found on pages 76 through 87 of its pre-filed panel testimony. Calpine’s preliminary position on these issues was provided by Mr. Timothy Eves on pages 8 through 20 of his pre-filed testimony. GTMA/GIG’s stance on this subject matter was provided by Mr. Jeffry Pollock on pages 5 through 10 of his pre-filed testimony.

[44] The positions taken by the Companies on the contemplated RFP process changed throughout the hearings and can be found on pages 17 through 27 of their pre-filed direct testimony, as well as later in their proposal modifying this initial position found on pages 22 to 40 of their rebuttal.

future RFPs. To make the changes called for by the Stipulation, it was further recommended that a rulemaking be commenced by the Commission.[45]

Based on the agency's review of the Joint Stipulation, which is attached and incorporated by reference herein, the Commission finds and concludes that it is appropriate to approve and accept its terms and provisions as part of the Final Order in these dockets. In order to properly further the enhancements that have been authorized, the Commission finds and concludes that a rulemaking proceeding shall be initiated before the end of August 2004, in which the Commission shall accept and incorporate the proposed amendments to the RFP Rule in accordance with the RFP/IE structure endorsed by the stipulation.

b) Detailed Code of Conduct To Be Prepared by the Companies

The Commission also finds and concludes that the Companies shall prepare and file for the agency's approval no later than August 31, 2004, a detailed code of ethics regarding affiliate communications, particularly as they relate to the preparation and evaluation of competitive solicitations. The depth and breadth of the code of conduct that is to be proposed by Georgia Power and Savannah Electric shall be extended to cover those individuals that are directly or indirectly in the employ of any of its affiliates or parent company and shall be executed in the manner contemplated by the Joint Stipulation.

c) Status Of The 70/30 Directive Regarding The Ownership Percentage Of And The Purchased Power Percentage Of Capacity Called For In the 2001 IRP Order

In his pre-filed testimony, Calpine witness Tim Eves argued that the directive calling for at least 70% ownership of capacity by the Companies and not more than 30% purchased power[46] should be regarded as a flexible Commission "guideline" and not a "hard cap."[47] (Pre-filed testimony of Calpine, p. 21-22.) However, the manner in which the limitations on the percentage of purchased power works is now governed by the terms of the Joint Stipulation. The only remaining question is whether the Commission, at this time, should modify those percentages. Having considered doing so, the Commission expressly declines to make any such modification at this time. In opting not to change the percentages, the Commission notes that the Companies are not and will not be in the next 3 years in a situation in which the issue the 30% cap will be reached. Consistent with the terms of the Joint Stipulation, the Commission will revisit the issue in the 2007 IRP.

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[45] On transcript pages 962-966, Companies' witness Garey C. Rozier provided a good summary of the contents of the Stipulation, which will not be recited again in this Order, but rather, will be made an attachment to and be incorporated by reference.

[46] This 70/30 directive is contained in the *Final Order* issued in IRP Docket Nos. 13305-U and 13306-U.

d) Directives Pertaining to the Contemplated Solicitation for 2009 Capacity Needs

1) Inclusion of Life of Unit Solicitations in Future IRPs

During the hearing, Staff made a recommendation that future capacity solicitations should include requests for consideration of proposals for "life-of-unit" proposals. (Pre-filed Direct Staff Panel Testimony, page 90.) As understood by the Commission, these bids effectively permit a merchant unit owner to sell the capacity and energy to the Companies for the same time period that the Companies themselves would operate a self-build option. On rebuttal, the Companies indicated that it was opposed to seeking life-of-unit proposals on the grounds that it would cause a loss in operating flexibility, was unnecessary since the existing 7 to 15 year solicitations have yielded good results, and would cause confusion as to what is actually meant in by the phrase "life-of-unit" in submitting and evaluating such a bid. (Tr. 1014-1016.)

The Commission disagrees with the Company in part, and would like to see such bids solicited in order to foster competitive bidding in Georgia. In seeking life-of-unit bids, however, the Commission does agree that there exists a potential for confusion as to what exactly is being sought in terms of a supply side resource.

Based on these concerns, the Commission finds and concludes that in the 2009 RFP, the Companies shall seek 30-year contracts for purchased power in addition to the 7- and 15-year contracts that it has been soliciting in recent time. In the event that this directive would conflict with the Commission's 30% limit on total supply-side purchased power resources, the life-of-unit purchases could then be structured as an actual sale of the unit(s) to the Companies.

2) Schedule of Actions for the Next RFP to be Issued

In furtherance of the objectives set forth in the Joint Stipulation regarding the competitive bidding process referenced above, the Commission finds and concludes that the a schedule of events for the release of an RPF shall be adhered to in conjunction with seeking the most economical supply-side capacity assets in the immediate future. On or before July 15, 2005, the Companies will file for approval with the Commission a proposed schedule of events for the release of RFPs for the time period 2009 through 2012. This filing shall also include target dates for submitting proposed IE's, RFP Service Dates, dates for notification of bid and evaluation team members, dates for filing of draft RFP's and standard purchase power agreements and capacity to be sought in each RFP.

Once approved by the Commission, any deviations, planned or unintended, from the established schedule must be authorized by this agency before they are made by the Companies.

IV. ORDERING PARAGRAPHS

WHEREFORE IT IS ORDERED that the Commission adopts the Integrated Resource Plans developed by Georgia Power and Savannah Electric with the augmentations and/or modifications set out below.

ORDERED FURTHER, that the demand and energy forecasts filed by Georgia Power and Savannah Electric be approved without modification to any projections to any customer class.

ORDERED FURTHER, that Georgia Power and Savannah Electric shall update their demand and energy forecasts and budget comparison information through March 31, 2004, in order to reflect actual usage that has occurred since these forecasts were finalized in the spring of 2003. Once updated through this time frame, these forecasts shall be filed with the Commission by no later than August 16, 2004.

ORDERED FURTHER, that in conducting future reserve margin studies, as with all evaluations that are conducted as part of an IRP, consistent modeling data should be used to the greatest extent possible.

ORDERED FURTHER, that the Companies' target reserve margin for the 2004–2006 timeframe shall be set at 13.5%, with 15% to be used for the remainder of the study period.

ORDERED FURTHER, that the Companies' Generation Expansion Plans shall be regarded as adequate based upon the information that has been made available to the Commission .

ORDERED FURTHER, that Plant Atkinson CT's 5 A and 5B shall be de-certified by Georgia Power Company.

ORDERED FURTHER, that Savannah Electric shall extend the planned life of the 17 MW Kraft CT unit capable of providing black starts and remove it from further consideration for retirement until such time when such action is shown to be warranted.

ORDERED FURTHER, that Georgia Power and Savannah Electric shall inform the Commission in a filing of any changes in fuel price conditions, including external forecasts that may warrant development of a new utility price forecast and advise the Commission on the impacts these changes may have on the long range IRP. The Companies also shall make available any fuel forecast update as soon as it is available within each 6 month Progress Report to the Commission called for by Utility Rule 515-3-4-.05.

ORDERED FURTHER, that both GPC and Savannah Electric shall further develop the partnership that it has entered into with Energy Star® through which appliances acknowledged as having a certain level of energy efficiencies would be promoted by the Companies in ways such as providing consumers with manufacturers' coupons for energy efficient appliances with their bills.

ORDERED FURTHER, that Georgia Power and Savannah Electric also shall more aggressively promote the availability of energy audits for interested customers.

ORDERED FURTHER, that the Companies shall offer as part of their low-income weatherization programs the option of having programmable thermostats installed to those customers with central heat and air that wish to have the thermostat installed. Education as to how to use the thermostat shall also be provided.

ORDERED FURTHER, that a Working Group be created of interested stakeholders to develop a proposed DSM Plan for residential and commercial customers for the Commission's consideration. The Commission Staff shall organize and act as the facilitator of the Working Group, which shall consist of the parties in the IRP cases.

ORDERED FURTHER, that the recommendation by ASE and supported by SACE and GIPL for the Companies to be required to fund a consultant for a working group is rejected in its entirety.

ORDERED FURTHER, that the Working Group shall convene for the first time no later than August 15, 2004, and meet as often as needed thereafter.

ORDERED FURTHER, that within 10 days after each of its meetings, the Working Group shall file reports with the Commission in these IRP dockets. These reports shall detail the minutes of the meeting and provide status information regarding the project, including milestones achieved and a timetable for completing those that remain.

ORDERED FURTHER, that the Companies will provide to the Working Group such data as may be reasonably necessary for the Working Group to perform its tasks and develop its proposed DSM Plan. To the extent that the Companies contend that any such information is proprietary, it shall be filed with the Commission and be made available to members of the group pursuant to the Commission's Trade Secret rule.

ORDERED FURTHER, that the proposed DSM Plan shall be a comprehensive proposal consisting of 1) a mix of DSM initiatives to be recommended to the Commission for approval, including detailed information regarding how each of the initiatives would be implemented; 2) a recommended process for the selection of DSM initiatives in the future; and 3) recommendations regarding the need for changes to the Commission's IRP rules regarding DSM or for proposed legislation.

ORDERED FURTHER, that the recommended mix of DSM initiatives in the DSM Plan shall be selected by the Working Group using the following criteria:

a. The proposed DSM Plan should minimize upward pressure on rates and maximize economic efficiency. This directive is extremely critical given Georgia Power Company's $328 million pending rate increase request and Savannah Electric and Power Company's scheduled rate filing.

b. The cost/benefit analysis results of each initiative using all 3 tests (RIM, Total resource Sot test and Participants test) shall be considered by the Working Group and shall balance between economic efficiency and fairness and equity.

c. An examination of where growth is occurring on the system shall be performed by the Working Group, which shall attempt to concentrate its recommended initiatives there. Consideration shall also be given to initiatives that encourage participation by low-income customers.

d. In addition to traditional DSM programs, the Working Group shall consider rate design initiatives. In considering such initiatives, the Working Group should consider the cost/benefit analysis of such initiatives and the time periods that such initiatives would be available to a customer.

e. Every effort should be made by the parties to develop innovative programs and market approaches that will prevent upward pressure on rates and subsidies between participants and non-participants.

f. Where appropriate, the Working Group should consider the development of Pilot Initiatives (limited enrollment, limited terms) as a tool to gauge initiatives.

g. The working group shall also provide input to the utilities in the development of the energy efficiency educational efforts approved by the Commission.

ORDERED FURTHER, that by no later than February 15, 2005, it shall conclude by submitting a proposed DSM Plan to the Commission.

ORDERED FURTHER, that the Commission does not find it appropriate to require the Companies to provide $300,000 as requested by ASE to pay costs that may be incurred by the group in executing and fulfilling its mission.

ORDERED FURTHER, that after the Working Group has tendered its recommendation to the Commission, this agency will consider any further action to be taken regarding the appropriate mix of DSM initiatives to be adopted and the process for the selection of DSM initiatives in the future

ORDERED FURTHER, that given the Commission decision to create a Working Group to consider DSM programs, the Staff recommendation that the Companies develop a pilot programmable thermostat DSM program is not adopted by the Commission at this time.

ORDERED FURTHER, that the low income weatherization program of Georgia Power Company shall be continued. Its level of funding, now set at $1,000,000, shall be increased by $300,000, thereby making $1,300,000 the total sum of money that shall be dedicated to the program annually for the next three years. Georgia Power Company has agreed that this additional $300,000 in annual funding shall not be recoverable from ratepayers.

ORDERED FURTHER, that Savannah Electric's low-income weatherization program also shall be continued. Its level of funding, now set at $100,000, shall be increased by $30,000, thereby making $130,000 the total sum of money that shall be dedicated to the program annually for the next three years. Savannah Electric shall work toward supplying the additional funding so that the $30,000 will not be paid by ratepayers. After doing so, Savannah Electric shall report back to the Commission with information as to whether it can do so.

ORDERED FURTHER, that additional education on the efficient use of electricity shall be made available by the Companies.

ORDERED FURTHER, that Georgia Power shall fund with no more than $2,000,000 an energy efficiency campaign that it shall implement to promote consumer awareness of those energy efficiency measures and practices that produce the greatest economic efficiency and benefit to a participant.

ORDERED FURTHER, that Savannah Electric shall fund with no more than $200,000 an energy efficiency campaign that it shall implement to promote consumer awareness of those energy efficiency measures and practices that produce the greatest economic efficiency and benefit to a participant.

ORDERED FURTHER, that in order to further their respective energy efficiency educational campaigns, the Companies may use any recognized medium through which their customers could reasonably be expected to be exposed, including, but not limited to, television advertisements, radio spots and advertisements in local newspapers and periodicals.

ORDERED FURTHER, that all information disseminated through the media shall be for the exclusive purpose of promoting education in the area of energy efficiency and shall not serve as a forum to promote the Southern brand (or that of its subsidiaries) in any way, or to further other initiatives of the Companies outside of those contemplated herein. Television, radio and/or print ads shall provide as much information about managing electric usage as possible in the time/space allotted. A general understanding of electric energy efficiency and conservation should be able to be derived by the average viewer after seeing/listening to any advertisements. The theme of all advertisements should be strictly education-based. Any advertisements that the Commission, in its sole discretion, finds not to be adequate for its intended purpose shall not be financed with monies allocated in this order for consumer education.

ORDERED FURTHER, that copies of television ads, radio scripts and print advertisements containing information that is to be disseminated to the public as part of the energy efficiency programs shall first be provided to the Commission's Consumer Affairs Office, the Commission's Public Information Office and the Commission's Electric Staff in advance of being published. Upon their receipt of same, Staff will immediately give other interested parties five (5) business days to review the content of what the Companies seek to publish in order to raise any objection thereto. The Commission shall be the ultimate decision maker as to whether an advertisement shall be approved.

ORDERED FURTHER that the Companies shall file quarterly reports at the Commission detailing with specificity the expenditures made through this education program. None of the funds allocated shall be used for any expenditure not expressly contemplated by this order.

ORDERED FURTHER, that to move towards consistency of data in all analyses performed, the Commission finds that it is appropriate for the utilities to update the DSM evaluation as described herein during the next IRP filing.

ORDERED FURTHER, that the Companies shall continue their implementation of the Power Credit Program;

ORDERED FURTHER, that the Power Credit program shall be further evaluated by the Companies based upon the marginal costs that result from this filing and be included with the updated evaluation of other DSM measures within 3 months of the issuance of the Commission's Final Order in these dockets.

ORDERED FURTHER, that with regard to the "consistency of data" issue discussed elsewhere in this order, as it relates to the DSM screening analysis, Georgia Power and Savannah Electric shall file the demand side management evaluation with what would be the most current data available at the time of the filing, but then come back with a supplemental filing, in the late March, early April time frame, that would show the results of the DSM evaluation using all of those new cost assumptions that were developed in the IRP process.

ORDERED FURTHER, the Companies shall update their DSM evaluation in the manner described in this order for use in their 2007 IRP filings.

ORDERED FURTHER, that the Commission shall evaluate the RTP tariffs during the Georgia Power 2004 rate case and make any appropriate tariff revisions at that time as it sees fit.

ORDERED FURTHER, that, in its next IRP filing, Georgia Power shall include an updated study of the peak load reduction benefits from RTP tariffs.

ORDERED FURTHER, that the Companies shall increase their efforts to locate and contract for green energy resources for their Green Energy Programs.

ORDERED FURTHER, that a target date of one year from the date of this Final Order shall be established during which the Companies shall identify a green energy source or sources; contract to secure the resources; confirm the availability of the tariff with interested consumers, as well commence their pre-planned advertising campaigns; and to initiate subscriptions with their customers.

ORDERED FURTHER, that if, by August 1, 2005, the Companies remain unable to successfully execute these functions relating to renewable resources despite employing their best efforts, Georgia Power and Savannah Electric shall file a notification of the underlying circumstances with the Commission by September 1, 2005, so that the agency can re-evaluate their Green Power Programs.

ORDERED FURTHER, that in future IRP filings, the Companies provide the most comprehensive, detailed data available for the first half of their 10-year transmission plan. For the remaining half of its plan, less detailed data may be filed

ORDERED FURTHER, that the Companies shall continue to file their Environmental Compliance Strategy Review on an annual basis; provided, however, that the scope of this filing shall be supplemented to include: 1) a high and low range of potential capital cost requirements if a particular regulation is promulgated or legislation is enacted, and information whether compliance with the enactment will materially change the recommendations made in the 2004 IRPs; and 2) an analysis of how the updated strategy will impact the Companies' planning processes for the addition of generation and transmission.

ORDERED FURTHER, that Georgia Power shall keep this agency and its Staff abreast of any developments that will result in more concrete information becoming available regarding cost estimates and facility upgrades for the hydropower facilities that are to be relicensed. Information that should be provided to the Commission on this issue, when available, shall include the potential impact of increased environmental costs due to hydropower relicensing, reflecting not only the costs of re-licensing but also the potential for lost capacity due to operational modifications to mitigate environmental concerns and the potential increased capacity as a result of unit rehabilitation.

ORDERED FURTHER, that Georgia Power shall provide in its Environmental Compliance Strategy Review an assessment of the impact of lost Hydropower generation on the existing IRP resource mix if, during relicensing, capacity loss occurs due to environmental mitigation.

ORDERED FURTHER, that the Companies must more fully communicate to the Commission in future IRP filings information regarding the anticipated impacts their resource plans have on their forecasted rates. The vulnerabilities and rate impacts that accompany the resource mix change being planned for must be clearly and accurately articulated within the IRP filings.

ORDERED FURTHER, that in conducting IRP studies the Companies should to the greatest extent possible, set as an objective to use consistent data throughout all analyses conducted as part of the IRP.

ORDERED FURTHER, that the Joint Stipulation regarding the RFP/IE rule enhancements agreed to by interested parties in these dockets is approved as part of the Final Order in the dockets, a copy of which is attached and incorporated by reference herein.

ORDERED FURTHER, that a rulemaking proceeding shall be initiated by Staff before the end of August 2004, in which the Commission shall promulgate as rule amendments the RFP/IE structure endorsed by the Joint Stipulation.

ORDERED FURTHER, that the Companies shall prepare and file for the agency's approval no later than August 31, 2004, a detailed code of conduct regarding affiliate communications, particularly as they relate to the preparation and evaluation of competitive solicitations.

ORDERED FURTHER, that the depth and breadth of the code of conduct that is to be proposed by Georgia Power and Savannah Electric shall be extended to cover those individuals that are directly or indirectly in the employ of any of its affiliates or parent company and shall be executed in the manner contemplated by the Joint Stipulation.

ORDERED FURTHER, that consistent with the IRP Final Order issued July 5, 2001, the Commission shall limit the amount of supply-side capacity provided through purchased power contracts to 30 percent of total supply-side resources. A determination of whether this cap should be increased, decreased or eliminated in its entirety is an issue that this Commission will not have the need to contemplate until the 2007 IRP.

ORDERED FURTHER, that in the 2009 RFP, the Companies shall seek 30-year contracts for purchase power in addition to the 7- and 15-year contracts that it has been soliciting in recent time. In the event that this directive would conflict with the Commission's 30% limit on total supply-side purchase power resources, the life-of-unit purchases could then be structured as an actual sale of the unit(s) to the Companies.

ORDERED FURTHER, that on or before July 15, 2004, the Companies will file for approval with the Commission a proposed schedule of events for the release of RFPs for the time period 2009 through 2012. This filing also shall include target dates for submitting proposed IE's, RFP Service Dates, dates for notification of bid and evaluation team members, dates for filing of draft RFP's and standard purchase power agreements and capacity to be sought in each RFP.

ORDERED FURTHER, that once approved by the Commission, any deviations, planned or unintended, from the established schedule of events must be authorized by the agency before they are made by the Companies.

ORDERED FURTHER, that no determinations are made as to the need, effectiveness or reasonability of any rates, tariffs and pricing strategies filed in conjunction with the IRPs in this Order. The feasibility and determination of the appropriate level of these rates, tariffs and pricing strategies shall be made in the general rate cases that have been or will be filed by the Companies in 2004.

ORDERED FURTHER, that all findings of fact and conclusions of law contained within the preceding sections of this Order are hereby adopted as findings and conclusions of this Commission.

ORDERED FURTHER, that a motion for reconsideration, rehearing or oral argument or any other motion shall not stay the effective date of this Order, unless otherwise ordered by the Commission.

ORDERED FURTHER, that jurisdiction over this matter is expressly retained for the purpose of entering such further Order or Orders as this Commission may deem just and proper.

The above by action of the Commission during a Special Administrative Session held on July 9, 2004.

REECE MCALISTER **EXECUTIVE SECRETARY**	**H. DOUG EVERETT** **CHAIRMAN**
DATE	**DATE**

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Attachment A

**PROCEDURES AND PRINCIPLES
FOR AN RFP STRUCTURE UTILIZING
AN INDEPENDENT EVALUATOR
("PROPOSED RFP/IE STRUCTURE")**

Definitions:

"Commission" means the Georgia Public Service Commission.

"Independent Evaluator" or "IE" means the entity or entities selected pursuant to the RFP Rule to conduct a RFP Process.

"IRP" means the filing made by the utility in which it proposes a specific integrated resource plan for adoption/approval by the GPSC.

"IRP Plan" means the specific integrated resource plan adopted by the GPSC for a utility, as may be modified from time to time, and which identifies specific supply-side resource blocks to be added by the utility at specific periods in time.

"PPA Execution Date" means the date on which a power purchase agreement between the soliciting utility and the winning bidder is executed pursuant to a RFP Process.

"RFP" means the notice of a request for proposals distributed to the marketplace by the IE under the RFP Rule identifying the needed resources and the time for providing those resources as set out in the IRP Plan, or any amendment thereto.

"RFP Document" shall mean the collection of materials identified in part IV.4 and distributed to interested bidders and pursuant to which the bids shall be submitted and evaluated during the RFP Process.

"RFP Process" means the preparation and issuance of a RFP and all the activities subsequently associated therewith that are expected to terminate in the execution of a PPA between the soliciting utility and the winning bidder, and in which an Independent Evaluator is selected pursuant to and performs the functions described in this Proposed RFP/IE Structure.

"RFP Rule" means GPSC Rule 515-3-4-.04(3) as amended from time to time, including specifically as amended to adopt the procedures and principles contained in this Proposed RFP/IE Structure.

"RFP Service Date" means that date six months in advance of the date the RFP is expected to be issued, as further described in paragraph II.3.

"Staff" means the Commission Staff assigned to participate in the RFP Process.

I. Requirement to use an RFP Process

1. For each block of required new supply-side resources identified in the IRP, the utility shall propose a schedule for conducting a RFP Process, including specifically the expected date upon which the RFP shall be issued that solicits each such new supply-side resource along with the amount of capacity required. This information shall be considered public information and made available to all potential bidders.

2. The RFP Process shall be utilized for every block of required new supply-side resource identified in the IRP Plan, except as provided in Rule 515-3-4-.04(3)(i). Rule 515-3-4-.04(3)(i) shall be amended to add after the last stand-alone paragraph two additional paragraphs, numbered six (6) and seven (7), which shall read, as follows:

> 6. The Commission shall expressly consider in each IRP, and make a determination in each IRP Plan, whether to exclude from the RFP Process any new supply-side resources identified in the soliciting entity's approved IRP Plan.
>
> 7. It is Commission policy that investor-owned electric utilities under its regulation shall maintain a minimum percentage of their capacity as "self-owned" rate-based assets. Such percentage shall be set by Commission order and may be changed from time to time. In those situations in which the soliciting utility is nearing or finds that it would fall below this minimum percentage level, the soliciting utility shall inform the Commission of this eventuality in advance of the RFP Process at which time the Commission, in its discretion, may suspend these rules and provide guidance to the soliciting utility as to how it should proceed.

II. Role and Selection of an Independent Evaluator

1. The IE will be retained by the soliciting entity under a contract that is acceptable to the Commission and which is consistent with the RFP Rule. In order to help assure independence, the IE shall be selected by and report to the Commission. The soliciting entity (i.e., Georgia Power Company or Savannah Electric and Power Company), the Staff and potential bidders may recommend persons or entities to serve as the IE. The Commission shall establish the minimum qualifications and requirements for an IE and shall select the IE pursuant to the selection process described herein. The role and function of the IE in the RFP Process shall be as set forth herein.

2. Any IE considered by the Commission shall be required to disclose any financial or personal interest involving any soliciting entity or any potential bidder, including but not limited to all substantive assignments for any Southern Company affiliate or any other potential bidder during the preceding five (5) years. The Commission may consider this interest in selecting the IE. The Commission will post on its web site the list of all IE candidates being considered and their statements of interest. The Commission will invite and consider any comments from the soliciting entity and potential bidders concerning the IE candidates prior to the selection of the IE. No IE selected by the Commission may perform services for the soliciting entity or any bidder for a period of two (2) years after the completion of an RFP Process in which the IE served.

3. The IE shall be retained in time to begin service at least six months prior to the expected issuance of the RFP ("RFP Service Date"). Consequently, the IE selection process identified in paragraphs II.2 and II.3 shall be concluded in time for the IE to begin service as of the RFP Service Date. From the date the IE is selected, no bidder or potential bidder shall have any communication with the IE, Staff, or the soliciting entity pertaining to the RFP, the RFP documents, the RFP process, the evaluation or the evaluation process or any related subjects except as those communications are specifically allowed by this proposed RFP/IE structure or as are made publicly through the IE's website

4. The IE will report to the Commission and the Staff. In carrying out its duties, the IE will work in coordination with the Staff and the soliciting entity with regard to the RFP Process as further described herein.

5. If the IE becomes aware of a violation of any requirements of the RFP Process as contained in the RFP Rule, the IE shall immediately report that violation, together with any recommended remedy, to the Commission.

6. The IE's fees shall be funded through reasonable bid fees collected by the soliciting entity. The soliciting entity shall be authorized to collect bid fees up to $10,000 per bid to defray its costs of evaluating the bids and, in addition, the soliciting entity may charge each bid an amount which shall be equal the estimated total cost of the IE divided by the anticipated number of bids. To the extent that insufficient funds are collected through this method to pay all of the IE's fees, the soliciting entity shall pay the outstanding cost. Invoices for services rendered by the IE should be sent directly to the Commission for its

review. After they are reviewed and approved, the invoices will be forwarded to the soliciting entity for payment, which will be made directly to the IE.

III. Affiliate Communications

1. Any affiliate of the soliciting entity that intends to submit a bid in response to the RFP, as well as any other persons acting for that affiliate or on its behalf in support of the development and submission of such bid, shall be known collectively as the "Bid Team”.

2. The representatives of the soliciting entity that will be evaluating the bids submitted in response to the RFP, as well as any other persons acting for or on behalf of the soliciting entity regarding any aspect of the RFP Process, shall be known collectively as the "Evaluation Team."

3. No later than the RFP Service Date, the Bid Team shall be separately identified and physically segregated from the Evaluation Team for purposes of all activities that are part of the RFP Process. The names and complete titles of each member of the Bid Team and the Evaluation Team shall be reduced to writing and filed with the Commission for use by the IE.

4. There shall be no communications, either directly or indirectly, between the Bid Team and Evaluation Team from the RFP Service Date through the PPA Execution Date regarding any aspect of the RFP Process, except (i) necessary communications as may be made through the IE and (ii) negotiations between the Bid Team and the Evaluation Team for a final PPA in the event and then only after the Bid Team has been selected by the soliciting entity as the winning bid. The Evaluation Team will have no direct or indirect contact or communications with any bidder other than through the IE as described further herein, until such time as a winning bid is selected by the soliciting entity and negotiations for a final PPA have begun.

5. At no time shall any information regarding the RFP Process be shared with any bidder, including the Bid Team, unless the precise same information is shared with all bidders in the same manner and at the same time.

6. On or before the RFP Service Date, each member of the Bid Team shall execute an acknowledgement that he or she agrees to abide by the restrictions and conditions contained in paragraphs III.3 through III.5 above. At the PPA Execution Date, each member of the Bid Team shall execute an acknowledgement that he or she has met the restrictions and conditions contained in paragraph III.3 through III.5 above. These acknowledgements shall be filed with the Commission by the Bid Team within 10 days of their execution.

7. Should any bidder, including the Bid Team, attempt to contact a member of the Evaluation Team directly, such bidder shall be directed to the IE for all information and

such communication shall be reported to the IE by the Evaluation Team member. At the RFP Service Date, each Evaluation Team member shall execute an acknowledgement that he or she agrees to abide by the and conditions contained in paragraphs III.3 through III.5 above and, as of the PPA Execution Date, shall execute an acknowledgement that he or she has met the restrictions and conditions contained in paragraphs III.3 through III.5 above. These acknowledgements shall be filed with the Commission by the Evaluation Team within 10 days of their execution.

IV. RFP Structure and Process

Stage One: Identification of Bidders and Design of RFP

1. The soliciting entity will provide the Staff and the IE with a list of the companies that have submitted proposals in the three most recent solicitations conducted on behalf of the soliciting entity, as well as a list of all potential bidders to whom notice of those prior solicitations was sent. The soliciting entity shall be responsible for preparation of the final list of potential bidders to whom notice of the upcoming solicitation will be sent.

2. The soliciting entity will be responsible for preparing an initial draft of the RFP Document, including RFP procedures, evaluation factors, credit and security obligations, a pro forma power purchase agreement, the inclusion of any “proxy price” agreed to by the Staff and the IE against which the soliciting entity wishes to have the RFP bids tested, and a solicitation schedule. No later than one hundred twenty (120) days prior to the planned issue date of the RFP, the soliciting entity will supply the draft of the RFP Document to the Staff and the IE. These drafts shall be posted on the Commission’s website and be accessible through a link established for the use of the IE (the "IE website").

3. If the soliciting entity wishes to consider an option for full or partial ownership of a self-build option, the utility must submit its construction proposal (“Self-build Proposal”) to provide all or part of the capacity requested in the RFP to the IE at the time all other bids are due. Once submitted, the Self-build Proposal may not be modified by the soliciting entity. Provided, however, that in the event that the soliciting entity demonstrates to the satisfaction of the Staff and the IE that the Self-build Proposal contains an error and that correction of the error is in the best interest of customers and will not be harmful to the RFP Process, the soliciting entity may correct the error. Persons who have participated or assisted in the preparation of the Self-build Proposal in any way may not be a member of the Bid Team, nor communicate with the Bid Team during the RFP Process about any aspect of the RFP Process. The soliciting entity's Self-build Proposal must consist of the entire cost to complete the project including the "overnight cost," project capital additions, the Allowance for Funds Used During Construction (AFUDC) and the non-fuel operating and maintenance cost of the proposed self-build facility. The "overnight cost" is the cost to build the plant all at once, or "overnight," without consideration of financing

costs. The utility thus may choose to make no commitment to the structure of the construction organization, to the timing of the project, or to its financing costs.

4. The RFP and RFP Document together shall identify all factors to be considered in the evaluation of bids. In addition to the matters specified in Commission Rule 515-3-4-.04(3)(b), the following materials or matters shall be included in either the RFP or RFP Document, as appropriate:

   i. a pro forma power purchase agreement containing all expected material terms and conditions;

   ii. information on the Southern Company OASIS that will permit each prospective bidder to identify any native load growth transmission service reservation made by or on behalf of the soliciting entity; and

   iii. the solicitation schedule.

   With respect to item 4i above, the Commission shall conduct a process beginning at the conclusion of this IRP case, to be concluded within the shortest time practicable, in which all interested parties may participate to develop a pro forma power purchase agreement that will become part of the RFP Document. It is anticipated that the pro-forma power purchase agreement that is part of the RFP Document may be modified from time to time with the consent of both contracting parties in a manner that does not depart from the terms upon which the winning bid was selected.

5. The Staff and the IE will critique the initial draft RFP and RFP Document and provide their input to the soliciting entity. The soliciting entity may incorporate changes based on this critique if it so chooses. The initial draft RFP and RFP Document, plus the Staff/IE critique thereof, will be posted on the IE website.

6. The IE and Staff, plus the soliciting entity, may conduct at least one public bidders conference to discuss the draft RFP and RFP Document with interested parties, including but not limited to potential bidders. Potential bidders may submit written questions or recommendations to the IE regarding the draft RFP and RFP Document in advance of the bidders' conference. All such questions and recommendations shall be posted on the IE website. The IE shall have no private communication with any potential bidders regarding any aspect of the draft RFP and RFP Document.

7. Based on the input received from potential bidders and other interested parties, and based on their own review of the draft RFP and RFP Document, the Staff and the IE will submit a report to the soliciting entity detailing suggested recommendations for changes to the RFP and RFP Document prior to its issuance. This report shall be provided to the Commission and posted on the IE website for review by potential bidders.

8. The soliciting entity shall submit its final version of the RFP and RFP Document to the Commission for approval or modification. Once approved by the Commission, the final RFP and RFP Document shall be posted on the IE website.

At any time after the RFP is issued, through the time the winning bid is selected by the soliciting entity, the schedule for the solicitation may be modified upon mutual agreement among the soliciting entity, the IE and the Staff, or upon approval by the Commission.

9. At the time the content of the RFP is considered for approval, the Commission may determine whether there will a single round of bidding, or whether a "competitive tier and refreshed bid" process will be used. The Commission will consider comments and views of the soliciting entity and any interested party, including potential bidders, on this issue. In the event that the Commission does not expressly determine that a "competitive tier and refreshed bid" process shall be used, there will be only one round of bidding.

10. Notwithstanding the foregoing, there shall be a single round of bidding to obtain the next supply-side resource identified in the current IRP case and that block of supply-side resource shall be procured through the RFP Process.

Stage Two: Issuance of RFP and Bidder Communications

11. The IE will transmit the final RFP and RFP Document to the bidder list via the IE's website, pursuant to the solicitation schedule contained in the RFP and RFP Document.

12. The only bidder communications permitted prior to submission of bids shall be conducted through the IE. Bidder questions and IE responses shall be posted on the IE website. To the extent such questions and responses contain competitively sensitive information for a particular bidder, this information may be redacted.

13. The soliciting entity may not communicate with any bidder regarding the RFP Process, the content of the RFP and RFP Document, or the substance of any potential response by a bidder to the RFP; provided, however, the soliciting entity shall provide timely, accurate responses to an IE request for information regarding any aspect of the RFP and RFP Document or the RFP Process.

14. Bidders shall submit bids pursuant to the solicitation schedule contained in the RFP and RFP Document. The soliciting entity, Staff, and the IE shall have access to all bids and all supporting documentation submitted by bidders in the course of the RFP Process.

15. The soliciting entity shall cause native load growth reservations to be made on the Southern Company OASIS for all bids that are not otherwise capable of using an existing native load growth reservation for evaluation purposes.

Stage Three: Evaluation of Responses to RFP

16. The evaluation stage of the RFP Process will proceed on two tracks. On one track, the soliciting entity will evaluate all bids based on a total cost impact analysis such as was applied in the 2005/2006 Georgia RFP (the "TCI Analysis"). The soliciting entity will conduct this track in an appropriate manner, consistent with the principles and procedures contained in this Proposed RFP/IE Structure.

17. A second track will be conducted by the Staff and the IE. The Staff and IE shall have discretion to utilize whatever they consider the optimum combination of auditing the soliciting entity track and conducting its own independent evaluation in order to evaluate the resource options submitted to the soliciting entity in the RFP Process. The Staff and IE may apply the TCI Analysis as part of conducting their independent evaluation.

18. The soliciting entity, the Staff or the IE may request further information from any bidder regarding its bid. Any communications between the soliciting entity and a bidder in this regard shall be conducted through the IE. The soliciting entity shall be informed of the content of any communications between the Staff/IE and a bidder. Communications will be conducted on a confidential basis between the IE and the bidder, and may include one face-to-face meeting between the IE, the soliciting entity, and each bidder to discuss the proposal, unless a bidder declines such a meeting.

19. In order to conduct both its independent evaluation function and its auditing function, the IE and the Staff shall have access to all information and resources utilized by the soliciting entity in conducting its TCI Analysis. The soliciting entity shall provide complete and open access to all documents and information utilized by the soliciting entity in its TCI Analysis; and the IE and Staff shall be allowed to actively and contemporaneously monitor all aspects of the soliciting entity evaluation process in the manner they deem appropriate. The soliciting entity shall facilitate this access so that the soliciting entity evaluation process is transparent to the Staff and the IE. The soliciting entity shall have an affirmative responsibility to respond to any request for access or information made by the Staff and/or the IE. To the extent the IE determines that the evaluation processes of the two tracks are yielding different results, the IE shall notify the soliciting entity and attempt to identify the reasons for the differences as early as practicable. Where practicable, the soliciting entity and the IE shall attempt to reconcile such differences.

20. The Staff and the IE, as well as the soliciting entity, may rely on the Southern Services Transmission Planning ("SSTP") group to conduct all necessary transmission analyses concerning bids received. SSTP analyses provided to the Staff and the IE shall be equivalent in quality and content as that provided to the soliciting entity. No bidder, including any bidder that is an affiliate of the soliciting entity, shall

communicate with the SSTP group during the course of the RFP Process regarding any aspect of the RFP.

Stage Four: Bidding Stages

21. If the Commission has directed that a “competitive tier and refreshed bid” process be used, the IE and the soliciting entity will follow steps 22 through 26 in the evaluation process.

22. The soliciting entity shall perform its evaluation of the bids and shall develop a competitive tier that narrows the bids to a manageable number that the soliciting entity believes are the best competitive options ("soliciting entity Competitive Tier"). The Staff and the IE also shall perform their independent evaluation of the bids and develop their own competitive tier that narrows the bids to a manageable number that the Staff and the IE believe are the best competitive options ("Staff/IE Competitive Tier").

23. The soliciting entity shall provide the soliciting entity Competitive Tier to the Staff and the IE. Simultaneously, the Staff and the IE shall provide the Staff/IE Competitive Tier to the soliciting entity.

24. If the soliciting entity Competitive Tier and the Staff/IE Competitive Tier are identical, the IE shall notify all companies on the Competitive Tier lists that they have the opportunity to better their bids as final best offers. The IE shall post the Competitive Tier list on the IE website showing each bidder’s relative rank and the total evaluated cost of each bid. Each bidder on this list will be identified blindly so each bidder knows the identity of the bidder for only its bid but sees its rank compared to those of all other anonymous bidders who made the Competitive Tier.

25. If there are differences between the soliciting entity Competitive Tier and the Staff/IE Competitive Tier, the soliciting entity, the Staff, and the IE shall meet to try to resolve such differences in order to agree on a single Competitive Tier list. To the extent that such agreement cannot be reached, the IE shall notify all parties on each list that they have the opportunity to better their bids as final best offers. The IE shall post the combined Competitive Tier list on the IE website showing each bidder’s relative rank and the total evaluated cost of each bid. Each bidder on this list will be identified blindly so each bidder knows the identity of the bidder for only its bid but sees its rank compared to those of all other anonymous bidders who made the Competitive Tier.

26. The refreshed “better” bids/final best offers shall be evaluated independently by: (1) the soliciting entity; and (2) the Staff and the IE, in each case consistent with the process outlined above for initial bids.

Stage Five: Certification of Resource(s)

27. After it has completed its evaluation, and pursuant to the RFP schedule, the soliciting entity shall notify the Staff and the IE of which resource(s) the soliciting entity has selected to win the bid.

28. The Staff and the IE shall notify the soliciting entity whether they agree with the determination by the soliciting entity. The Staff/IE shall also notify the soliciting entity of the results of their independent evaluation.

29. If the Staff and IE do not agree with the selection made by the soliciting entity, they shall meet to discuss the differences in their selections.

30. The soliciting entity is responsible for determining which resource(s) it will submit to the Commission for certification. The soliciting entity may consider the Staff/IE evaluation in making its decision, but the soliciting entity remains ultimately responsible for the selection.

31. Based on the pro-forma PPA included in the RFP Document, the soliciting entity may negotiate a final PPA with the bidder for each resource it has selected so that the Commission may consider the exact terms under which the resource will be certified. Any such PPA shall be expressly conditioned on the final decision of the Commission in the certification proceeding. If the soliciting entity conducts such negotiations, the IE and the Staff shall have the right, but not the obligation, to attend any and all negotiating sessions for the purpose of monitoring them. In the alternative, the soliciting entity may wait until the certification proceedings are complete to begin negotiations with the bidder for each selected resource based on the pro-forma PPA included in the RFP Document.

32. The soliciting entity shall file with the Commission a request for certification of the resource(s) chosen by the soliciting entity.

33. The Staff and the IE shall participate in the certification proceeding and testify regarding: (1) their independent evaluation of whether the resource selected by the soliciting entity should be selected and if not, which resource(s) in their view should be selected as a result of the RFP process; and (2) whether the soliciting entity conducted the RFP process in a fair and impartial manner.

34. The Commission will conduct the certification proceeding and may take any actions it deems appropriate as allowed by law.

35. If the soliciting entity has not yet negotiated a specific PPA prior to the certification, upon approval of PPA award recommendations by the Commission, the soliciting entity will proceed to negotiate or finalize appropriate contractual arrangements consistent with the approved award(s). The IE and the Staff shall have the right, but not the obligation, to attend any and all negotiating sessions for the purpose of monitoring them. The soliciting entity will make a compliance filing once the PPA is executed and the IE and the Staff will report to the Commission their opinion as to whether the PPA as executed complies with the Commission's certification order.

36. The soliciting entity will maintain a complete record of all materials developed for, generated during, or used in the RFP Process for (3) three years beyond the date of certification of the selected proposal(s), including any such materials prepared and/or used by the IE, as well as hard copies or electronically stored copies of all materials and exchanges posted on the IE's website.

37. The IE will enter into an appropriate agreement pertaining to the disclosure and use of any models, analytical tools, data, or other materials of a confidential or proprietary nature that are provided or made available by the soliciting entity in conjunction with the RFP Process.

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