PMVogtleCOLPEm Resource

From: Sackschewsky, Michael R [michael.sackschewsky@pnl.gov]
Sent: Thursday, March 11, 2010 3:58 PM
To: Sutton, Mallecia
Subject: Documents to ADAMize
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Attached are the Georgia Power 2010 integrated resource plan and land cover information from USGS. Both are being referenced in the Vogtle COL draft SEIS.

Hearing Identifier: Vogtle_COL_Public
Email Number: 437

Mail Envelope Properties (C7BE995E.F512%michael.sackschewsky)

Subject: Documents to ADAMize
Sent Date: 3/11/2010 3:58:03 PM
Received Date: 3/11/2010 3:58:51 PM
From: Sackschewsky, Michael R

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Tracking Status: None

Post Office: pnl.gov

Files	Size	Date & Time
MESSAGE	161	3/11/2010 3:58:51 PM
2010 IRP Main Document final.pdf	2313939	
National Land Cover Database Zone 55 Land Cover Layer.pdf	113763	

Options
Priority: Standard
Return Notification: No
Reply Requested: No
Sensitivity: Normal
Expiration Date:
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2010 Integrated Resource Plan
Main Document

TABLE OF CONTENTS

Page

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2010 INTEGRATED RESOURCE PLAN

TECHNICAL APPENDICES INDEX

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1 – SUMMARY OF 2010 INTEGRATED RESOURCE PLAN

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SECTION 1 – SUMMARY OF 2010 INTEGRATED RESOURCE PLAN

1.1 FOREWORD

This 2010 Integrated Resource Plan ("IRP") is the seventh IRP filed by Georgia Power Company ("Georgia Power" or the "Company") since the enactment of the Integrated Resource Planning Act, O.C.G.A. § 46-3A-1 et seq., which requires the filing of such a plan every three years. This 2010 IRP is designed to meet customer needs through a mix of demand and supply side options, including an expansion of the Company's current demand-side programs, introduction of new demand-side programs, and identification of the potential for new supply-side resources for 2015 and beyond. The Company has updated all of its planning assumptions for the 2010 IRP. This 2010 IRP will be used to support any necessary self-owned or purchased power certification for additional resources and for the accompanying certification application for the Company's demand-side programs (filed separately under Docket No. 31082).

The Company seeks approval of:

1) Its 2010 Integrated Resource Plan and the associated Action Plan;

2) The capital costs of (but not yet the recovery of) transmission used to connect certified capacity to the grid, including network improvements, as well as costs the Company will incur for certain solar PV and other renewable projects, as set out in the Selected Supporting Information section of Technical Appendix Volume 2; and

3) The capital and O&M costs (but not yet the recovery of) measures taken to comply with existing government imposed environmental mandates, as set out in the Selected Supporting Information section of Technical Appendix Volume 2.

1.2 INTRODUCTION

Georgia Power, a subsidiary of Southern Company, is an investor-owned electric utility serving customers in 57,000 of the state's 59,000 square miles. The Company has just over 2.3 million retail customers in all but four of Georgia's 159 counties.

Southern Company is the parent of Georgia Power, Alabama Power Company ("Alabama Power"), Gulf Power Company ("Gulf Power"), Mississippi Power Company ("Mississippi Power"), and Southern Power Company ("Southern Power"), (collectively the operating companies), as well as certain service and special-purpose subsidiaries. The operating companies, known as the Southern Electric System ("System"), coordinate system operations and jointly dispatch their generating units to capture the economies available from power pooling. The System is a member of the Southeastern Electric Reliability Council ("SERC"), a group of electric utilities (and other electric related utilities) coordinating operations and other measures to maintain a high level of reliability for the electrical system in the southeastern United States. The four traditional retail operating companies ("ROCs"), Georgia Power, Alabama Power, Gulf Power, and Mississippi Power, also participate in coordinated generation and transmission planning as appropriate.

Georgia Power's common stock is held by Southern Company, which had 92,799 stockholders of record at year end 2009.

Georgia Power has 154 generating units (34 fossil steam, 75 hydroelectric, 4 nuclear, 2 combined cycle ("CC"), 37 combustion turbine ("CT") units), and 2 diesel generators that provide approximately 15,955 megawatts (MW) of customer-owned generating capacity; 67 percent of the energy supplied from owned units is from coal, 21 percent from nuclear, 2 percent from hydroelectric, and less than 10 percent from natural gas and oil.

1.3 THE 2007 IRP

In January 2007, Georgia Power filed its sixth IRP. The 2007 IRP was designed to meet the energy needs of the Company's customers using a mix of supply-side and demand-side resources. The Georgia Public Service Commission ("Commission") adopted the IRP developed by Georgia Power with modifications as specified in its Order dated July 12, 2007 (the "2007 IRP Order").

In response to the Commission's 2007 IRP Order, the Company took the following actions:

1) Maintained a 15 percent planning target reserve margin;
2) Issued, on an accelerated basis, a Request for Proposals ("RFP") with respect to the base load resource needs identified in the IRP for the 2016 to 2017 timeframe;
3) Initiated actions approved in Docket No. 24506-U to retire McDonough Units 1 and 2 and construct McDonough Units 4, 5, and 6;
4) Responded to the Commission's Notice of Proposed Rulemaking ("NOPR") proposing revisions to the Commission's rules regarding the requirements for submitting Transmission Planning Studies, and incorporated such information in this IRP to comply with amended rules approved on December 3, 2007 in Docket No. 25981-U;
5) Responded to the NOPR proposing revisions to the Commission's rules regarding the requirements for the Company to report on its compliance with Title IV of the 1990 Clean Air Act Amendments in order to reflect the changing landscape with regard to environmental compliance, and incorporated such information in this IRP to comply with amended rules approved on October 21, 2008 in Docket 25983-U;
6) Worked with Commission Staff and other interested parties to develop a time table and an action plan that is leading to the development of cost-effective renewable resources as set out in the Company's IRP. The Company continues to pursue various options in order to develop up to three cost-effective renewable projects with capacity of 30 MWs or less;
7) Conducted a detailed evaluation of coal resources and studied the potential impacts of carbon dioxide ("CO_2") costs on customer rates and the impact on decisions to build coal units with or without carbon sequestration;

8) Responded to the need to develop a backup plan for acquiring an alternative base-load resource;
9) Provided adequate advanced written notice to the Commission explaining the Company's intent to either renegotiate existing wholesale contracts or to seek new customers for wholesale capacity;
10) Responded to the Commission's Order requiring certain actions in regards to Demand Side Management ("DSM") programs and planning activities; and
11) Received national certification of its Green Energy Program.

1.4 SIGNIFICANT RECENT DEVELOPMENTS

Since the approval of the 2007 IRP, Georgia Power has received certification of four supply-side resource additions or modifications. These include approval of certain Power Purchase Agreements ("PPAs") in Docket No. 25036-U, approval for retirement of units and additional units at Plant McDonough in Docket No. 24506-U, approval for construction of additional units at Plant Vogtle in Docket No. 27800-U, and the conversion of Plant Mitchell Unit 3 from coal to biomass fuel in Docket No. 28158-U. The Commission is currently considering the issuance of a certificate to transfer certain Wholesale Block Capacity resources to the retail jurisdiction in Docket No. 26550-U.

The Company conducted an RFP for capacity and energy commencing in 2010 that resulted in Commission approval, on October 18, 2007 in Docket No. 25036-U, of three PPAs from natural gas fired facilities. The three PPAs begin June 1, 2010 and include a 20-year PPA with Exelon Generation Company, LLC for approximately 942 MW of capacity and associated energy, a 15-year PPA with Southern Power for approximately 292 MW of capacity and associated energy, and a seven-year PPA with Southern Power for approximately 561 MW of capacity and associated energy.

The Commission approved in Docket No. 24506-U the Company's Application for Decertification of Plant McDonough Units 1 and 2 and Certification of Plant McDonough Units 4, 5, and 6. Construction is underway on the natural gas fired CC Units 4, 5, and 6. The retirement of 517 MW of existing coal-fired capacity of Units 1 and 2 is being coordinated with the commercial operation of the new gas-fired units in 2011 and 2012 (for a net addition of approximately 2003 MW of new capacity in the generation-import dependent Northeast Georgia area).

In Docket No. 27800-U, the Commission approved on March 17, 2009 the Company's application for the certification of Plant Vogtle Units 3 and 4. The Company's ownership share in the project will result in an addition of 503.6 MW in 2016 (Unit 3) and another 503.6 MW in 2017 (Unit 4). The Commission also approved in Docket No. 27800-U the Company's plan for the installation of emission controls at its Plant Branch Units 1 – 4 and Plant Yates Units 6 and 7. However, the Company has suspended further engineering and construction activity on the emission control projects at Plant Branch Units 1 and 2 and Plant Yates Units 6 and 7 until more information is available from the rulemaking and legislative process, thereby, mitigating the risk related to significant capital expenditures associated with those projects. It is our intent to continue to operate these units and reevaluate the construction schedule as more information becomes available. (Please see additional information in Section 6, Supply Side Plan.)

The Company requested in Docket No. 28158-U to convert the existing Plant Mitchell Unit 3 from an approximately 155 MW coal-fired generating unit to a 96 MW biomass-fired electric generating facility, of which approximately 79 percent is allocated to retail service. The Commission approved the application on March 26, 2009. Since the certification of the conversion of Plant Mitchell Unit 3, the United States Environmental Protection Agency ("EPA") has delayed the release of Industrial Boiler Maximum Achievable Control Technology ("Boiler MACT") rules and is also expected to release draft coal combustion by-products regulations for power plants ("CCB Regulations"), which will address how coal ash is handled and disposed. As a result, on January 8, 2010, the Company requested a delay in converting Plant Mitchell Unit 3 to biomass fuel until the EPA issues these rules and regulations. (Please see additional information in Section 10, Renewable Resources.)

In Docket No. 26550-U, the Company offered certain wholesale generation capacity to enter retail service. The Commission issued an order accepting the blocks 5 and 6 offer of 178 MW which will enter retail at different times as the capacity becomes available over 2011 - 2016. The Commission also issued an order approving acceptance of approximately 78 MW of Scherer Unit 3, approximately 54 MW will enter retail on January 1, 2016, with the additional 24 MW entering retail on June 1, 2016.

Since the approval of the 2007 IRP, fuel costs have experienced significant volatility. Fuel commodity prices increased to record prices in the summer of 2008 and subsequently declined significantly in 2009. This price volatility highlights the need for fuel diversity to protect customers from fuel price fluctuation.

Another significant event since the 2007 IRP is the increasing likelihood for climate change legislation and possible renewable electricity standards. During 2009, federal climate legislation passed the U.S. House of Representatives and is currently under review in the U.S. Senate. The legislation as proposed would significantly impact Georgia Power and its customers through the imposition of a price applied to carbon dioxide emissions and through requirements to generate certain amounts of electricity from renewable energy sources.

Furthermore, as mentioned above, expected new environmental legislation and regulations that target or affect coal-fired electricity generation are creating significant uncertainty regarding the need for, and cost-effectiveness of, installing emissions controls on some of Georgia Power's coal-fired generating units. The details of these potential new requirements are discussed in the Environmental Compliance Strategy and the potential impacts are shown in the Unit Retirement Study (in the Technical Appendix Volume 2).

1.5 THE SUPPLY-SIDE PLAN

Georgia Power's current supply-side plan, as approved in the 2007 IRP, the Application for Certification of Plant Vogtle Units 3 and 4 and Updated IRP, and recent capacity needs updates provided to the Commission, is sufficient to provide cost-effective and reliable sources of capacity and energy through 2015.

With regard to certain coal-fired generating units, additional environmental upgrades may be required for certain units to operate after 2014. However, it is cost-effective to operate those units at least until environmental rules are finalized and more information is available. By doing so, the Company continues to provide retail customers the benefit of the low fuel costs associated with the units. Georgia Power will bring decertification requests regarding such coal units at the appropriate time, if the economics show a benefit of retirement.

While the Commission has previously approved and certified the new capacity which will come on line between this and the filing of the next IRP in 2013, certain transmission costs will be imposed on the system as a result of this new capacity. Those transmission costs are described and set out in the Selected Supporting Information section of Technical Appendix Volume 2. In addition, Technical Appendix Volume 2 includes certain costs the Company will incur to implement a portfolio of solar PV demonstration projects. Section 10.5.2 of the Main Document of the IRP contains a description of these projects. Technical Appendix Volume 2 also includes costs associated with other renewable projects approved in the 2007 IRP. These projects are discussed in Section 10.1. The Company believes that it is appropriate to review and approve these costs in the overall context of this IRP process.

In the 2010 Base Rate Case, the Company may request, and the Commission may find it to be appropriate to approve a certified capacity cost recovery tariff, which would allow the recovery of these costs which are directly associated with the underlying and separately certified capacity costs. However, while the Company does not seek approval of that tariff in this IRP proceeding, it does request that the specified transmission, solar PV demonstration, and renewable costs be approved for later recovery using whatever recovery vehicle the Commission might deem appropriate at some later time.

1.6 THE DEMAND-SIDE PLAN

Georgia Power expects to achieve approximately 900 MW of demand reduction by 2013 through the implementation of existing and expanded DSM programs. This load reduction represents more than 5 percent of the Company's current load.

Georgia Power will continue the residential load management program, Power Credit, authorized by the Commission in Docket No. 6315-U and reauthorized by the Commission in Docket No. 13305-U. As a part of the 2007 IRP, the Commission approved the Company's five proposed DSM pilot programs and added the Refrigerator Recycling program. The Commission Order for the 2007 IRP also outlined specific questions for the DSM Working Group ("DSMWG") to address.

Between August 2007 and May 2008, the DSMWG met five times to address the questions outlined in the 2007 IRP Order. A report, filed on May 31, 2008, outlined the issues and findings and was accepted by the Commission as filed.

In July 2008, the Commission approved the Company's request for a rule waiver for the process of evaluating and developing DSM programs for this IRP. The Company worked closely with the DSMWG during the use of this "Top-Down Approach" to DSM program development, which resulted in a comprehensive analysis of potential DSM programs. The Company is proposing in this IRP to continue all current DSM programs, expand certain current DSM programs, and add two new DSM programs. The recommended DSM action plan includes certifying in Docket No. 31082 a total of nine programs that consists of five programs for residential customers, three for commercial customers, and one for industrial customers.

The Company is proposing modifications to the existing residential DSM tariff and creation of both a commercial and an industrial DSM tariff. These tariffs will collect all approved and certified program costs and the requested Additional Sum detailed further in the Certification Docket No. 31082.

Summary information for two alternative DSM cases is also included in this filing. One alternative case presents a potential set of DSM programs that can be economically developed in the event certain proposed federal legislation passes. The other alternative case represents the "Aggressive Case" sensitivity that was outlined in the revised DSM program development process that was approved by the Commission as a part of the IRP rules waiver request.

1.7 THE PRICING PLAN

The Company will continue its strategy of developing and promoting rates that give customers pricing signals that encourage peak demand reduction and load shifting. Innovative programs developed by Georgia Power (such as Real Time Pricing ("RTP"), Demand Plus Energy Credit ("DPEC") and Time of Use ("TOU")) have been effective in reducing the demand for electricity.

Georgia Power is making significant progress installing the Advanced Metering Infrastructure ("AMI") with over one million "smart" meters installed to date. The Company continues to leverage the AMI by promoting rates that send strong, clear pricing signals such as Time of Use-Residential Energy Only ("TOU-REO"). A key component of the promotion of TOU rates is customer education. The Company's promotions will focus on how customers can save money and energy by conserving use during or shifting loads from the on-peak time period.

Georgia Power proposed a pilot Time of Use-Fuel Cost Recovery ("TOU-FCR") rider in the fuel case filed in December 2009. As filed, TOU-FCR will be available only to TOU-REO customers on a voluntary basis. TOU-FCR will further strengthen price signals seen by customers on the TOU-REO rate.

1.8 THE ENVIRONMENTAL PLAN

The Environmental Compliance Strategy document included in Technical Appendix Volume 2 serves as a roadmap for compliance for Georgia Power and the other retail affiliates. This roadmap establishes a general direction but allows for individual decisions to be made based upon specific information available at the time. This approach is an absolute necessity in maintaining the flexibility to match a dynamic regulatory compliance environment with a variety of available compliance options. The Environmental Compliance Strategy document addresses recent environmental rulings and requirements and reflects the most recent strategy and cost estimates for incorporating these requirements.

In anticipation that the Company will seek, and the Commission may approve, a modified form of the current ECCR tariff, the Company believes that the costs which might be included in such an ECCR should be reviewed and considered in the overall context of this IRP. The costs which the Company seeks to have approved are more specifically described in the Selected Supporting Information section of Technical Appendix Volume 2. These costs are generally capital and operation and maintenance ("O&M") costs which are required to comply with federal and state laws and regulations.

1.9 RELIABILITY

In the short term, Georgia Power has sufficient resources to maintain an adequate planning reserve margin given anticipated demand of its customers and given the current regulations regarding electric generating units. Given the nature of forecasts and the uncertainties of future regulations, the Company will constantly evaluate its resource needs as they change and will respond as needed to ensure the reliability and economics of the Georgia Power system.

Georgia Power and the System include adequate reserve margins in their respective plans to ensure reliable and cost-effective service to their customers. However, the reliability of the entire southeastern United States region has an impact on Georgia Power because of the integrated nature of the electric system in this area. As part of the normal course of business, the Company monitors the needs and activities of power suppliers within the state and its neighbors. The Company works with these entities to ensure that any insufficiencies in the reserves of its neighbors, were they to occur, will not adversely affect Georgia Power's customers.

1.10 RESERVE MARGINS

After an analysis of load forecast and weather uncertainty as well as the current and near-term projected generation reliability of the System, the Company has selected a target reserve margin of 15 percent in the long term, which is near the minimum total cost but carries less risk than the absolute minimum cost point. For the short-term horizon, the Company will maintain a 13.5 percent planning reserve margin guideline, but may periodically review the availability and cost of resources in the market and adjust short-term resource procurement decisions accordingly.

The updates to certain key assumptions that affected the results of this Reserve Margin Study (included in Technical Appendix Volume 1) are as follows:

- The economic carrying cost of a CT in 2012 dollars increased. A higher CT cost results in a lower optimum reserve margin.
- The Southern Electric System average peak equivalent forced outage rate ("EFOR") has decreased since 2006. Average system peak season EFOR for the period of study applicable to the previous reserve margin study was 1.81 percent; for this study the average is 1.7 percent. Lower EFOR results in fewer projected reliability purchases and less expected unserved energy ("EUE"), which results in a lower optimum reserve margin.
- Operating reserve requirements were increased from 1,000 MW in the 2006 study to 1,250 MW in the 2009 study. Additionally, in previous studies, operating reserves were not maintained during occurrences of EUE. The current study maintains operating reserves at the prescribed level throughout all EUE events by

shedding firm load. This operating reserve requirement tends to increase the amount of EUE and leads to a higher optimum reserve margin.

1.11 THE DEMAND AND ENERGY FORECASTS

A twenty-year forecast of energy sales and peak demand was developed to meet the planning needs of Georgia Power. The Budget 2010 Load and Energy Forecast includes the retail classes of residential, commercial, industrial, MARTA, and governmental lighting, as well as the wholesale class, currently comprising only the city of Hampton.

A territorial peak demand of 17,985 MWs was set on August 9, 2007 for the Georgia Power service territory. The peak demand forecast for the Budget 2010 Load and Energy Forecast has been adjusted to account for the effects of RTP customers' response, expected cogeneration, the Distribution Efficiency Program, and high efficiency lighting.

A detailed discussion of the revised territorial energy and demand forecasts is set forth in the Selected Supporting Information section of Technical Appendix Volume 2.

1.12 GREEN ENERGY

Georgia Power initially received approval of the Green Energy Tariff in 2003. Subsequent to Commission approval of the 2007 IRP, the Company filed a Renewable Resource Action Plan and timetable that was approved in part by the Commission on October 16, 2007. Further Green Energy program modifications were approved by the Commission on September 16, 2008.

The Company currently offers Standard Green Energy at $3.50 per 100 kWh block; Premium Green Energy, containing at least 2 percent solar content for $4.50 per block; a Special Events Purchase Option, to meet customer needs by providing Green Energy for a single event through a one-time transaction; and a Large Volume Purchase Option, providing large quantities of lower cost green energy on a customer specific basis. The Company is currently working with the Commission Staff ("Staff") and interested stakeholders on a 100 percent solar option.

1.13 INTEGRATED RESOURCE PLAN

The Company's 2010 IRP includes the following:

- Purchase of 1,795 MW of capacity and energy certified by the Commission in Docket No. 25036-U on October 18, 2007, which will be available beginning June 1, 2010;
- Retirement of Plant McDonough Units 1 and 2 by 2012 and the addition of Units 4, 5, and 6 by 2012 for a net addition of approximately 2003 MW as certified by the Commission in Docket No. 24506-U;
- Addition of two new nuclear units at Plant Vogtle (Units 3 and 4) for a combined increase in capacity of approximately 1007 MW by 2017 as certified by the Commission in Docket No. 27800-U;
- Conversion of Plant Mitchell Unit 3 from coal to biomass as certified by the Commission in Docket No. 28158-U;
- A request for approval of transmission costs associated with certified capacity, costs of a portfolio of solar PV demonstration projects, and costs of other renewable projects approved in the 2007 IRP as shown in the Selected Supporting Information section of Technical Appendix Volume 2;
- A request for approval of capital and O&M costs for governmental imposed environmental mandates as shown in the Selected Supporting Information section of Technical Appendix Volume 2;
- Continuation of certain existing DSM Programs, expansion of certain existing DSM Programs, and addition of two new DSM Programs;
- Unit Retirement studies of the existing fleet of generating facilities that show the potential for significant retirements of coal-fired power plants under some scenario cases assuming certain carbon emissions prices; and
- Capacity Mix Studies that show optimal capacity resource additions for the base case IRP assuming current regulations and no carbon emissions prices as well as results from scenarios with alternative fuel price forecasts and carbon price assumptions.

The recommendations included in this IRP were analyzed with a matrix approach using multiple scenario cases that included varying fuel price forecasts and estimates of potential costs from future carbon legislation. Furthermore, the IRP was tested under a variety of sensitivity analyses to ensure that it will meet customer needs in a variety of possible changes in future conditions. The different assumptions used in the sensitivity analyses are detailed in Section 6.4.

1.14 TRANSMISSION PLANNING GUIDELINES

This IRP includes the Company's ten-year transmission plan, which identifies the transmission improvements needed (based upon current planning assumptions) to maintain a strong and reliable transmission system. The development of this plan is conducted in accordance with the System transmission planning guidelines and with the North American Electric Reliability Council ("NERC") planning standards. Along with the ten-year plan, Georgia Power has included a comprehensive and detailed bulk transmission plan of the Georgia Integrated Transmission System as required by the amended rules adopted by the Commission in Docket No. 25981-U.

1.15 CONCLUSION

The Company seeks approval of:

1) Its 2010 Integrated Resource Plan and the associated Action Plan;

2) Transmission costs associated with certified capacity, and costs of a portfolio of solar PV demonstration projects as shown in the Selected Supporting Information section of Technical Appendix Volume 2; and

3) Capital and O&M costs associated with governmental imposed environmental mandates, as shown in the Selected Supporting Information section of Technical Appendix Volume 2.

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2 – INTEGRATED RESOURCE PLANNING PROCESS OVERVIEW

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SECTION 2 - INTEGRATED RESOURCE PLANNING PROCESS OVERVIEW

The development of an IRP for Georgia Power is a part of a continuous planning process. Many different disciplines and areas of expertise from Georgia Power and Southern Company Services ("SCS") are incorporated in this planning process. This process provides for an orderly and reasoned framework under which both supply-side and demand-side option evaluations are compared on an equal basis to develop a plan that provides for reliable and economic electric energy to serve customers' needs over the planning horizon.

The Company developed a base case IRP using a reliable and economic combination of potential demand and supply-side generation resources to meet the needs of customers as determined in the base case load and energy forecast. This base case plan represents an evaluation of the planning period with current laws and regulations.

For the 2010 IRP, the Company is also presenting the results of "alternate" scenario planning cases that evaluate the impacts of four different fuel price forecasts and several estimates of the costs of potential carbon prices that could result from possible carbon legislation or regulation. Each scenario planning case is a separate and fully integrated resource plan and provides valuable insights into the potential impacts of different combinations of fuel prices and carbon prices over the planning period.

Federal climate change legislation, if passed, or climate change regulation, if promulgated, will have significant impact on national economic activity, fuel prices, and the electric utility industry. Given the differences in the electric generation fuel mix across the U.S., climate legislation is also predicted to have large and varying regional impacts, with particularly negative impacts for the southeastern U.S. due to its dependence on coal-fired electric generation. In order to evaluate these interactive and regional impacts, a national economic model was employed to evaluate the impacts of different fuel price forecasts and projections of carbon prices on national and regional economic activity.

This national economic model was also used to estimate the impacts of different carbon prices on the price of fuels, particularly natural gas, and to estimate the changes to the electric generation fleet across the U.S. that result from the scenario-specific prices of carbon and fuel prices. These impacts were then extended to develop specific load and energy forecasts for each scenario. These load and energy forecasts were then used as the basis for developing a reliable and economic combination of potential demand and supply-side generation resources to meet the needs of customers for each scenario.

2.1 CRITERIA FOR RESOURCE SELECTION

When a need for new capacity exists, the Company evaluates a combination of demand-side and supply-side resources to meet the need in an economical manner. The principal criterion for the development of the IRP is to maintain customer value — now and in the future. Customer value is increased when the benefits of the services provided to customers exceed the cost of those services.

The best IRP is one that provides a high level of customer value while anticipating a broad range of potential changes. Therefore, Georgia Power considers additional objectives in the development of the IRP. These include:

- **Flexibility** - Can the plan be altered if the future is different than expected?

- **Reliability** - Does the plan provide for adequate reliability of service for all customers?

- **Long-Term Viability** - Will the plan meet customer needs over the long term?

- **Environmental** - Does the plan consider environmental impacts?

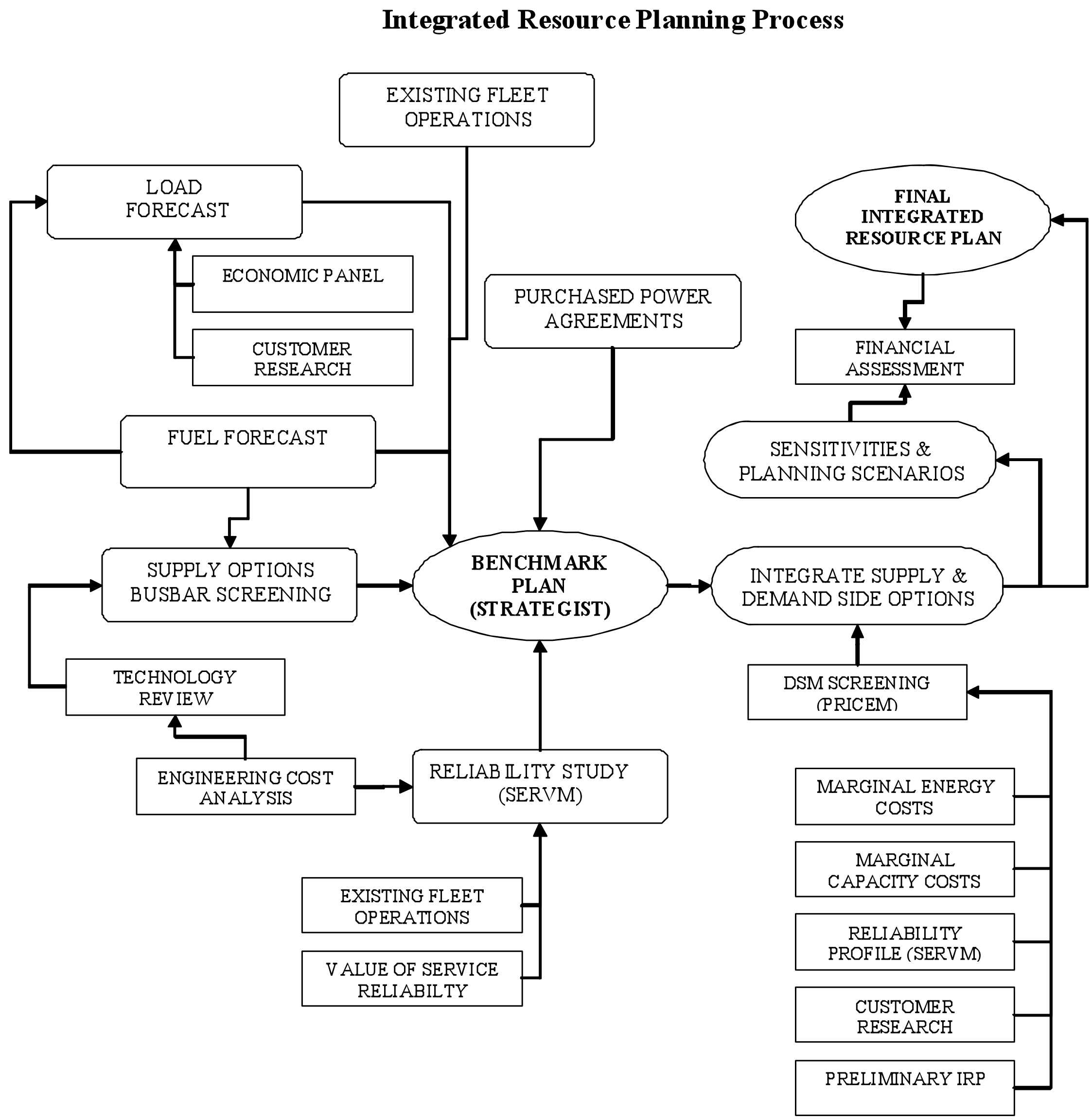
- **Risk** - Does the plan represent a reasonable balance between risk and cost?

- **Stockholder Value** - Will the plan provide stockholders with a fair return on their investment?

2.2 OUTLINE OF THE PROCESS

The detailed process by which the IRP is developed is shown in Figure 1, and the components of this process are described below. This process is an integrated process where both the supply-side and the demand-side programs are evaluated simultaneously rather than independently.

Figure 1 - Detailed Integrated Resource Planning Process



The result of this process is the addition of demand and supply-side options to serve customer needs in an economical manner considering reliability, flexibility, and risk. Georgia Power's IRP process includes inputs from: (1) the Fuel Forecast; (2) the Economic Forecast; (3) Generation Technology Screening; (4) the Load and Energy

Forecast; (5) the Target Reliability Study; (6) demand-side program assessments; (7) existing resource screenings; (8) the Technology Cost Development Study; (9) the mix integration; and (10) the financial analysis and review steps.

2.2.1 Development of the Benchmark Plan

The left portion of Figure 1 shows how various inputs, such as customer preferences, reliability standards, technology updates, economic projections, and the latest load and energy forecast, feed into the development of a benchmark supply-side plan. The development of these inputs is described below.

2.2.1.1 Data Inputs

Fuel Forecast — The System develops both short-term (current year plus two) and long-term fuel and allowance forecasts (year four and beyond). Short-term forecasts are updated monthly as part of the System's fuel budgeting process, and marginal pricing dispatch procedures. The short-term forecasts are overseen by SCS Fuel Services. The long-term forecasts are developed in early spring of each year for use in system planning activities. The long-term forecasts are overseen by the System's Planning Coordination Team. CRA International ("CRA") is the modeling vendor used by the System to develop the long-term forecasts. The development of the long-term forecasts is a highly collaborative effort between CRA and the System.

Economic Forecast — Moody's Economy.com's macroeconomic forecast is the basis for inflation and cost of capital estimates. Moody's Economy.com developed a forecast of economic variables and demographic statistics for the state of Georgia. Key descriptive variables from the economic and demographics forecast of Georgia were used to produce the Budget 2010 Load and Energy Forecast (see Technical Appendix Volume 2).

Generation Technology Qualitative and Economic Screening – Feasibility studies for 39 generation technologies were qualitatively screened by technology experts in SCS Research and Environmental Affairs. Various mature and emerging generating technologies were evaluated for the feasibility of deployment within the System. For all technologies determined to be viable, recommendations were made for further consideration by declaring the "*Status*" of the respective technologies as "retained for further screening". This process produced a select list of generating technology types that may be candidates for future plant additions.

Next, a preliminary, quantitative, economic and environmental screening evaluation was conducted utilizing a busbar life-cycle screening analysis. Busbar analysis compares total capital and operating costs of different types of generating technologies across a range of capacity factors. Busbar screening considers capital, fixed and variable O&M, fuels and environmental related costs and yields a comparison of the relative economics. The most promising technologies are subsequently reviewed in more detail producing a recommendation of those types of generating units that are likely to be good candidates for inclusion in developing the final supply-side plan.

Load and Energy Forecast — The load and energy forecast was started in the spring of 2009 and finalized in the fall of 2009. The load and energy forecasting process uses a combination of end-use and econometric analyses. The forecast is based on projections of economic growth, migration into the state, appliance efficiencies, competing fuel costs, and a variety of other projections. The principal sources of these projections are economic forecasting services, customer surveys, and computer models used by the Company.

The forecast process is explained in detail in Section 3 of this document and in Technical Appendix Volume 2.

Target Reliability Study — The retail operating companies currently use a 15 percent target reserve margin guideline for long-term resource planning. This guideline was developed using a combination of mathematical models and studies, industry experience, and system operations input, and was approved in the most recent IRPs. Economic evaluation is a key component of setting the reserve margin target. An updated recent target reliability study was recently completed for the 2010 IRP, and it affirmed the 15 percent longer-term planning reserve margin target.

Technology Cost Development Study — Current estimates are needed for cost, spending curves, emissions, and operating characteristics of the types of new generating units most likely to be added to the system. Aside from limited amounts of renewable generation, natural gas-fueled simple-cycle CT and CC units are the generating technologies likely to be added to the system in addition to new nuclear and coal-fired plants with carbon capture and sequestration. Also, the CT cost is included in the marginal capacity cost used in evaluating demand-side options, existing unit changes, and load building programs. These estimates are inputs into a computer model that utilizes dynamic programming techniques to develop an optimum schedule of the types of capacity needed throughout the planning period.

2.2.1.2 Mix Process

A key part of the benchmark plan in Figure 1 is the determination of the mix of generating capacity types that economically and reliably serves the projected customer load. The mix process combines all of the information represented by the arrows pointing to the benchmark plan. The mix process uses dynamic programming techniques to determine the least-cost combination of units that will meet reliability constraints.

One of the first steps in developing this portion of the IRP is a least-cost analysis that minimizes the net present value of the revenue requirements for the moderate (or base case) level of customer load in order to develop the benchmark plan.

The result of this effort is the creation of the benchmark plan. The preliminary supply-side plan will be used as the base plan for the demand-side integration process. The final supply-side plan (or base case) includes the results of the demand-side analysis (See Figure 1 above).

The key model used in the mix process is Strategist®. Strategist® employs a generation mix optimization module named PROVIEW™. (see Section 15, Attachment 15.1). Strategist® is used by approximately 70 other electric utilities. The major inputs of PROVIEW™ are: (1) future generating unit characteristics and capital cost, (2) the capital recovery rates necessary to recover investment cost, (3) capital cost escalation rates, and (4) a discount rate.

2.2.2 Assessment of Demand-Side Programs

Georgia Power identifies, screens, and assesses potential demand-side programs applicable to its service territory for inclusion in the IRP. This process uses a marginal cost approach to compare the costs with the benefits of each demand-side program. Generation capacity and energy, transmission, distribution, and other costs and benefits are evaluated. Also, technology availability, market characteristics, customer acceptance, and customer response are considered in estimating the potential success, impacts, and costs of the programs. The process is described more fully in Section 5.

2.2.3 Existing Resource Evaluation

Georgia Power analyzes potential increases in output from existing generating units using marginal cost techniques similar to those used to analyze demand-side programs. The model used to estimate marginal energy cost (PROSYM), is the source of the marginal energy cost used in the model used to evaluate DSM programs (PRICEM).

2.2.4 Integration and Development of the IRP

The integration step requires a re-examination of the need for generation additions identified in the benchmark plan as a result of including demand-side programs. After consideration of risk and uncertainty through sensitivity analyses and judgmental review, the 2010 IRP is finalized.

2.3 PLANNING SCENARIOS

In addition to the development of the base case, the Company used a scenario planning process to evaluate the full range of uncertainty for two of the most significant planning assumptions, fuel prices and future environmental requirements, specifically, carbon prices. Through the evaluation of alternative future possibilities for fuel and carbon prices, the Company is able to understand the interactive effects of these important variables as well as the impacts on economic growth in general and customer demands in specific. Furthermore, the planning scenarios allow the Company to consider a range of possibilities in the development of plans that are cost-effective across a wide variety of possible outcomes.

A key insight from the scenario planning analyses is that it is important to look at all the possible outcomes, not just the base case plan. The Company developed its action plan regarding long-lived decisions such as unit retirement studies, development of renewable energy resources and new supply-side generation including nuclear and coal with carbon capture and sequestration ("CCS").

Figure 2 below illustrates the planning scenarios evaluated during the development of the Company's IRP. Four possible fuel price forecasts were used as well as three possible carbon price cases ($0, $10, and $20 per ton of CO_2) along with a policy case of $30/ton.

Figure 2 - Planning Scenarios

	$0 CO2	$10 CO2	$20 CO2	$30 CO2
High Fuel				
Moderate with Volatility Fuel				
Moderate Fuel				
Low Fuel				

The Company developed this IRP and the resulting action plans based on a comprehensive review of the results of these planning scenarios. The Company will take actions to enable the option to develop new renewable energy resources and additional nuclear capacity beyond Plant Vogtle Units 3 and 4 in a timely manner.

3 – BUDGET 2010
LOAD AND ENERGY FORECAST

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SECTION 3 – BUDGET 2010 LOAD AND ENERGY FORECAST

3.1 GENERAL FORECASTING AND ECONOMICS OVERVIEW

The Budget 2010 Energy Sales and Peak Demand Forecast is for Georgia Power. Unless otherwise noted, all data, figures, and statistics include both Georgia Power and the former Savannah Electric and Power Company, which was merged into Georgia Power effective July 1, 2006.

The twenty-year forecast of energy sales and peak demand has been developed to meet the planning needs of the Company. The Budget 2010 Forecast includes the retail classes of residential, commercial, industrial, MARTA, and governmental lighting, as well as the wholesale class, currently comprising only the city of Hampton. The baseline forecast was started in the spring of 2009 and completed in the fall of 2009.

As with the nation as a whole, Georgia's economy has suffered from the recession that began in December 2007. Economic growth (as measured by real gross state product ("GSP")) averaged 1.2 percent per year between 2005 and 2008. This is far below the 3.1 percent average annual growth rate recorded from 2002-2005. The state has also lost 280,000 jobs since the previous employment peak in October 2007, and the unemployment rate – an average of 9.7 percent through November 2009 – is well above its pre-recession range of 4.5 percent to 5.5 percent.

The economy's uneven performance in the past few years has translated into similarly bumpy energy sales growth for Georgia Power. Weather normal energy sales for the residential, commercial, and industrial classes in 2009 were 3.5 percent less than in 2006. Residential sales were 0.3 percent lower in 2009 than in 2006; commercial sales increased 2.2 percent from 2006; and industrial sales have decreased 14.5 percent since 2006.

Although the past two years have been difficult for the state, demographic fundamentals such as population growth and household formation (which remain well above national norms), bode well for long-term economic growth. Projections of energy sales growth for the next several years assume that the economy will continue its recovery from the recession and that economic and demographic trends that were well established before the recession will, for the most part, return. Total energy sales are projected to increase over the 2009-2019 period.

3.2 FORECAST ASSUMPTIONS AND METHODS

The Budget 2010 forecast assumptions were developed through a joint effort of Georgia Power and SCS. The forecast was developed through careful consideration and methodical organization of key demographic and economic variables that have been demonstrated to be significant indicators of energy consumption. Major assumptions included the economic outlook for the U.S. and Georgia, energy prices, and market profiles for class end uses.

The economic forecast gives a description of the economy for the next 20 years and includes many elements of the economy, such as gross product, population, employment, commercial building square footage, and industrial production. The economic forecast for Budget 2010 was obtained from Moody's Economy.com, a national provider of economic data and forecasts.

The economic models used to produce both short and long-term energy and demand forecasts test a variety of economic and demographic variables as drivers of energy use. Retail prices for electricity and natural gas, for example, are drivers of energy use. The short-term forecasting models incorporate retail electricity prices, while the long-term models allow both electricity and gas prices to affect the purchasing decisions of customers. Price projections of the alternative fuels that energy consuming devices use to support a consumer need, business purpose, or industrial process are developed from internal processes so that device choice through consumer behavior can be modeled.

Weather, income, employment, historical load data, and industry standards for electrical equipment are among the other variables used in the forecasting models. Both the short-term and the long-term energy models are based on "normal" weather - the twenty-year average of Cooling Degree Days ("CDD") and Heating Degree Days ("HDD").

Short-term energy projections are based on linear regression models developed for the various energy classes except MARTA, which uses a trend model. The details of these regression models can be found in Section 4 of the Budget 2010 Load and Energy Forecast in Technical Appendix Volume 2.

The long-term models for the major classes are end-use models. The Residential End-Use Energy Planning System ("REEPS") model is used for the residential class, the Commercial End-Use Model ("COMMEND") is used for the commercial class, and the Industrial End-Use Forecasting Model ("INFORM") is used for the industrial class. These are discussed in greater detail in Section 4 of the Load and Energy Forecast included in Technical Appendix Volume 2.

Governmental lighting, MARTA, and wholesale sales forecasts are based on econometrics, time series methods, and information from Georgia Power field personnel.

The results of the short-term and long-term models are integrated into a unified forecast. In the Budget 2010 forecast, the short-term forecast results were used for 2010 through 2012 and long term forecast results were used for 2013 through 2029. Additional information on methodology can be found in Section 3 of the Budget 2010 Load and Energy Forecast in Technical Appendix Volume 2.

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4 – COMPARISON OF THE FORECAST WITH EXISTING RESOURCES

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SECTION 4 – COMPARISON OF THE FORECAST WITH EXISTING RESOURCES

4.1 SYSTEM AND GEORGIA POWER RESOURCES

The System carries reserves in order to maintain a desired level of reliability in the face of many uncertainties. The major uncertainties are load growth, weather, and generating unit outages. The current System long-term planning target reserve margin requirement is 15 percent of the total System load. In most years, the System operating companies peak at different times. This results in a lower System peak than the sum of each operating company's peak demands. Due to this load diversity, each operating company can carry lower reserves (approximately 14 percent) and still maintain the target planning reserve margin of 15 percent for the System. Georgia Power will provide an adequate and cost-effective level of reliability to its customers.

As a member of the System, Georgia Power shares reserves with the other operating companies. Therefore, the reserves available to meet Georgia Power's needs are best measured as the System reserves.

Georgia Power and the System have adequate reserves through 2015.

See Technical Appendix Volume 1 for additional details.

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5 – DEMAND-SIDE PLAN

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SECTION 5 - DEMAND-SIDE PLAN

This section summarizes the process used to assess demand-side resources for Georgia Power's 2010 IRP filing. Included in this section are:

- A review of significant events since the Company's 2007 IRP filing that are relevant to the assessment and screening of demand-side resources;
- A discussion of newly proposed or expanded current DSM programs and activities;
- A discussion of the regulatory treatment of DSM program costs and the Additional Sum; and
- A presentation of the economic results of DSM programs for this IRP.

The identification and evaluation of demand-side resources for inclusion in this IRP involves market considerations, such as customer acceptance and applicability, customer economics, and electric supply system economics. The process uses marginal electric supply costs in the analysis. The Company followed the process outlined in the IRP Rules Waiver approved by the Commission in July 2008 in Docket No. 24505-U which is discussed in more detail in later sections of this filing.

5.1 REVIEW OF SIGNIFICANT EVENTS SINCE PREVIOUS IRP FILING

Since the Company's January 2007 IRP filing, certain events have affected the screening of demand-side resources. These events are described below:

2007 IRP Filing Approval: In the 2007 IRP Order, the Commission approved the Company's five proposed DSM pilot programs and added the Refrigerator Recycling program. The 2007 IRP Order also outlined specific questions summarized below for the DSMWG to address in subsequent meetings:

- How Georgia Power calculated the Rate Impact Measure ("RIM") test;
- Consistency of the RIM test calculations with the California Standards Practice Manual;
- Whether to evaluate DSM at a program level or at a measure level; and
- Consider any other tools for evaluating DSM.

2007-2008 DSMWG Meetings: The Company met with the DSMWG five times during 2007 (August and September) and 2008 (March, April, and May) in order to address the questions outlined by the Commission from the 2007 IRP Order. A report was submitted to the Commission on May 31, 2008 that outlined the issues and findings. The report was accepted by the Commission as filed.

2008 Rules Waiver Approval: In July 2008, the Commission approved the Company's request for a waiver of certain IRP rules in Docket No. 24505-U. The Company requested that instead of complying with current Commission Rule 515-3-4-.04(4), it be allowed to utilize what has been referred to in the DSMWG meetings as the "Top-Down Approach." The Top-Down Approach is the converse of the current approach defined in the Commission Rule and focuses on program development as a starting point rather than measure level analysis as a starting point.

Specifically, the Company proposed the following steps for the Top-Down Approach in developing DSM programs for the 2010 IRP:

1. *Georgia Power, using an RFP process, will select a third party consultant to assist in the Technology Catalog update, research active programs nationally, and assist in developing proposed programs.*

2. *Georgia Power will utilize a technical and economic potential study for Georgia Power's service territory to assist in targeting DSM programs in the areas where the highest market potential exists. For the 2010 IRP, Georgia Power will use the 2007 AEEPA study.*

3. *Georgia Power, along with its consultant, will work closely with the DSMWG to update the Technology Catalog of DSM Measures. The starting point will be the 2007 IRP list of measures. Additional technologies will be added once Georgia Power's consultant is chosen and begins its work. Members of the DSMWG may also propose new measures to be added to the Technology Catalog.*

4. *Georgia Power, along with its consultant, will prepare a proposed program presentation for review by the DSMWG. Any other member of*

the DSMWG may propose programs as well. The DSMWG will meet to facilitate sufficient discussions on the programs to be evaluated.

5. *When appropriate and as part of the program evaluations, customer data/feedback will be collected and shared with the DSMWG. This could include information obtained from surveys, customer focus groups, Georgia Power Account Representatives, etc.*

6. *Once the Company determines which programs are to be analyzed, it will perform an economic screening of the programs in greater detail using the EnerSim and PRICEM models. The economic screening will include RIM, participants test ("PT"), total resource costs tests ("TRC"), and the Program Administrator Test for use in program evaluations. The results of the economic screening will be shared with the DSMWG for discussion.*

7. *Attempts to reach consensus and finalize all programs to be proposed for implementation in the 2010 IRP must be completed by mid 2009 in order to allow the Resource Planning group adequate time for inclusion in their process. Preliminary cost-effectiveness tests using PRICEM for revenue and avoided costs inputs will be developed for each program. These programs will be divided into programs that are passive (energy efficiency programs whose response is not controlled) versus active (demand response programs that are generally under dispatch control of the utility). Load reductions associated with passive programs will be used to adjust the load and energy forecast. Capacity associated with active programs will be modeled as resources. This information will be evaluated as two different system configurations with a base case without any new DSM (the base case would include the effects of continuation of existing DSM programs) and a Company DSM change case with both passive and active new DSM.*

8. *As part of the sensitivity analysis, the Company will also analyze at least one aggressive DSM change case developed with the assistance of the DSMWG. The aggressive DSM change case(s) could include technically viable and economically efficient DSM programs and resources that were not included in the Company DSM change case. The aggressive DSM*

change case(s) could also include higher penetrations of the DSM programs proposed in the Company DSM change case.

9. *The Company will use the difference in costs between the base case and the DSM change case configurations to determine the avoided generation cost impact of the DSM programs in each DSM change case. As the final step, the cost effectiveness tests mentioned in item 6 (above) will be calculated based on the inputs and adjustments from the system tools. Revenue impacts will be based on current rates and escalations based on the Company's financial projections adjusted for the DSM cost impacts. The avoided generation costs from the system tools and the avoided Transmission and Distribution ("T&D") revenue requirements as estimated by PRICEM will be used to calculate the benefits of the RIM, TRC and Program Administrator test for each DSM change case. The projected deadline for including new programs in the system planning process is mid 2009.*

Finally, the Company stated that the program evaluation process identified above will be conducted on a temporary basis in support of the 2010 IRP. The question of if, or when, to return to the former process will be determined by the Commission after the 2010 IRP proceeding. Georgia Power has fulfilled all of the requirements outlined in the nine step process above and recommends that the program level approach be continued for the 2013 IRP and all subsequent IRP filings.

Avoided Costs/Fuel Price Increases: Future estimated costs for fuel continue to be dynamic, and therefore, the avoided costs related to future supply-side resources are dynamic. The base case avoided costs for supply-side resources in the 2010 IRP have increased by about 20 percent from the 2007 IRP. Long term fuel price projections were developed for Southern Company by CRA with a 10-year rolling average escalation applied starting in year 21.

American Recovery and Reinvestment Act ("ARRA") of 2009: In February 2009, the ARRA was passed into law by Congress. The Act includes substantial funding for energy efficiency to be distributed to the states. Some details of the energy efficiency funding opportunities will be discussed in more detail in later sections of this chapter.

Georgia Power Organizational Change: As of December 2009, the Energy Efficiency and Regulatory Services group was created to manage the ever expanding needs related to energy efficiency programs. This group will have the overall responsibility of energy efficiency program design, implementation and evaluation. The new organization has advantages over the former matrix organization in that focus can be placed on meeting the program goals through one implementation and reporting structure without competing for resource time with other non-energy efficiency projects and responsibilities. Additionally, establishing this group will allow for more efficient overall management of program design and implementation activities.

5.2 DISCUSSION OF CURRENT DSM PROGRAMS

5.2.1 Continuation of the Certified Residential Load Management Program – Power Credit

The Power Credit program is a residential load control program that currently has approximately 51,000 participants. Some of the homes have more than one direct load control unit switch to control multiple Heating, Ventilation and Air Conditioning ("HVAC") units. The Power Credit program allows Georgia Power to cycle HVAC systems during periods of high system capacity constraints and high energy costs. HVAC energy is thereby shifted into off-peak periods with typically lower demands and energy costs. The program provides approximately 100 MW of load reduction at roughly 2 kW per unit controlled for single family homes. Although there have not been any participants in the Power Credit multifamily pilot program, the Power Credit program going forward will be open to interested multifamily properties.

The current communication system for the load control switches is a one-way low frequency radio receiver. Georgia Power's current service provider is phasing out its low frequency service. Georgia Power plans to move the Power Credit program communication protocol to a two-way communication system using its AMI communication system, which is being installed now with a completion date in the next few years. This change will require the replacement of all current one-way low frequency control units over the next three years (2010 – 2012), which will result in additional program costs in the range of $15 to $20 million for the three year implementation phase. These additional costs would be collected through the Residential DSM Tariff if approved by the Commission.

Georgia Power plans to perform a technology demonstration project to test different technologies that are capable of controlling HVAC units within the Company's current AMI FlexNet communication system. These tests will include outdoor unit controls as well as indoor thermostat control devices. After the testing is completed, the Company will select the most effective technology to meet the needs of the program at the most economical cost to ratepayers.

5.2.2 Continuation of the Weatherization Assistance for Low Income Customers Program

The Weatherization Assistance for Low Income Customers program began in January 1996. The program was designed to provide monetary assistance to Resource Services Ministries ("RSM") and the Georgia Environmental Facilities Authority ("GEFA") to augment their existing weatherization assistance efforts. As directed in the 2007 IRP Order, Georgia Power increased its funding of this program from $1.4 million to $2 million annually.

The program currently provides annual funding of $1.75 million to GEFA and $250,000 to RSM. Georgia Power plans to continue the funding of the Weatherization Assistance for Low Income Customers program at its current annual funding level of $2 million through December 31, 2013.

Additionally, GEFA will be receiving $124 million in financial funding for low income weatherization from the ARRA that it plans to distribute through its current community action agency framework. Georgia Power has offered to help GEFA with identifying customers qualifying for the assistance now that the qualification level has increased to 200 percent of the federal poverty level as outlined in the ARRA. Additionally the ARRA provides for a higher level of assistance per home, which is capped now at $6,500 for improvements, as opposed to the previous cap of $2,500 per home.

5.2.3 Energy Efficiency Information Programs

The energy efficiency information brochures and events assist customers in learning about using energy more efficiently. Specific program information costs are handled in the applicable program budgets and are included in that particular program's implementation plan found in the DSM certification application in Docket No. 31082.

Additionally, Georgia Power has increased its focus on using online information tools and social media, such as Twitter, to engage interested parties in energy efficiency discussions.

5.2.4 Energy Audits, Energy Efficiency Information Line and One-On-One Energy Efficiency Assistance

These activities provide day-to-day and one-on-one customized assistance to customers to help them better understand their energy usage and to identify energy efficiency opportunities. Additionally, in-home and on-line energy audits are offered to residential customers to assist them in identifying energy and money savings opportunities. Furthermore, about 30,000 to 35,000 calls a year are received through the Company's energy efficiency hotline from customers seeking energy efficiency advice. The one-on-one assistance is an ongoing activity that is typically focused on helping the Company's larger customers through its key account managers; however, it can be accomplished by virtually any employee in the Company with any customer.

5.2.5 Demand Response Tariffs

For many years Georgia Power has offered to its customers a menu of demand response tariffs, such as:

- **Real Time Pricing** ("RTP") charges customers marginal costs for incremental load – as prices increase, customers can respond by reducing their demand;
- **Demand Plus Energy Credit** ("DPEC") is an interruptible service tariff that provides customers with a demand credit for the potential demand reduction plus provides an energy credit when DPEC is called; and

- **Time of Use** ("TOU") tariffs provide customers with pricing signals during different periods of the day that closely reflect the marginal cost of the energy in the specific time period (peak and off-peak) and encourage customers to modify their usage accordingly.

5.2.6 Expansion of Current DSM Programs and Addition of New DSM Programs

The Company is requesting certification of the following DSM programs in its certification application filed concurrently with this IRP Docket No. 31082-U.

Residential Programs

- High Efficiency New Home program (formerly ENERGY STAR® New Home program)
- Residential Existing Homes program (formerly Home Performance with ENERGY STAR Program)
- Residential Lighting and Appliance program (formerly Residential Compact Fluorescent Light ("CFL") bulb program)
- Residential Refrigerator Recycling program
- Residential Water Heating program

High Efficiency New Home Program. This program focuses on a whole-house approach to improving the energy efficiency of new homes, promoting the installation of energy efficient measures in new home construction and improving the performance of participating homes to at least 15 percent above the International Residential Code ("IRC").

Details of the program are outlined in the ten-year Program Plan found in the certification application filed concurrently with this IRP.

The annual expected reductions and cost-effectiveness[1] of the steady state program are as follows:

Program	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Residential High Efficiency New Home	4,623	14,233,583	-$6,807,847	$31,178,555	$14,247,057	$37,986,402	$31,778,416	$0.030
Note: Economic test results are the NPV over the life of the measure.								

Residential Existing Homes Program. This program promotes a comprehensive, whole-house approach to improving the energy efficiency and comfort of existing homes. Georgia Power's program incorporates program elements of the federal Home Performance with ENERGY STAR ("HPwES") program, and market penetration estimates are based on experience from the pilot program for the past two years. Customer participation has been slow to start, but it is expected to increase, especially since there are a number of initiatives starting up as the result of federal funds from the ARRA.

Details of the program are outlined in the ten-year Program Plan found in the certification application filed concurrently with this IRP.

The annual expected reductions and cost effectiveness of the steady state program are as follows:

Program	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Residential Existing Homes	459	1,683,072	-$1,846,288	$454,800	$189,562	$2,301,087	$509,535	$0.095
Note: Economic test results are the NPV over the life of the measure.								

Residential Lighting and Appliance Program. This program promotes the purchase and installation of energy efficient equipment through customer education, retailer partnerships and sales training, and promotional giveaways of CFLs.

[1] Cost of Saved Energy, also referred to as Levelized Cost per kWh, is provided for each of the nine programs as requested by the DSMWG. This calculation only includes program costs; therefore it does not reflect the impact on revenue requirements or rates.

Details of the program are outlined in the ten-year Program Plan found in the certification application filed concurrently with this IRP.

The annual expected reductions and cost effectiveness of the steady state program are as follows:

Program	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Residential Lighting and Appliance	3,469	6,890,000	-$1,814,561	$1,348,962	$1,991,921	$3,163,522	$1,442,957	$0.053
Note: Economic test results are the NPV over the life of the measure.								

Residential Refrigerator Recycling Program. This program aims to eliminate inefficient or extraneous refrigerators in an environmentally safe manner and produce cost-effective long-term energy and peak demand savings. The program focuses on increasing residential customer awareness of the economic and environmental costs associated with running inefficient, older refrigerators/freezers. The program will provide cash incentives, free pickup and recycling for second refrigerators and/or freezers.

Details of the program are outlined in the ten-year Program Plan found in the certification application filed concurrently with this IRP.

The annual expected reductions and cost effectiveness of the steady state program are as follows:

Program	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Residential Refrigerator Recycling	697	4,900,332	-$2,472,199	$1,515,320	$1,354,834	$3,987,520	$1,597,798	$0.034
Note: Economic test results are the NPV over the life of the measure.								

Residential Water Heating Program. This program promotes energy efficient residential water heating practices through: 1) the identification of energy efficiency measures in existing water heating systems; 2) the installation of an electric water heater blanket and pipe insulation; and 3) the education of customers on the benefits of installing high efficiency water heating equipment.

Details of the program are outlined in the ten-year Program Plan found in the certification application filed concurrently with this IRP.

The annual expected reductions and cost effectiveness of the steady state program are as follows:

Program	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Residential Water Heating	108	618,250	-$506,290	$22,289	$203,104	$528,578	$39,668	$0.059
Note: Economic test results are the NPV over the life of the measure.								

Commercial Programs

- Commercial Audit program (formerly Commercial Tax Incentive program)
- Commercial Prescriptive Incentive program
- Commercial Custom Incentive program

Commercial Audit Program. This program, formerly referred to as the Commercial Tax Incentive Program in the Company's 2007 IRP filing and currently referred to as the Commercial and Industrial Technical Assistance Program by the DSMWG, adopts a market-based approach to help customers identify and implement energy efficiency measures. This is an extension of the existing Technical Assistance program in which Georgia Power offers technical services in the form of audits upon request to identify potential energy savings opportunities. The audits will focus on the three main energy intensive end uses in commercial facilities: lighting, HVAC and refrigeration and other process equipment.

Details of the program are outlined in the ten-year Program Plan found in the certification application filed concurrently with this IRP.

The annual expected reductions and cost effectiveness of the steady state program are as follows:

Program	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Commercial Audit Program	868	2,862,492	-$292,091	$2,267,622	$2,499,927	$2,559,712	$2,357,695	$0.017
Note: Economic test results are the NPV over the life of the measure.								

Commercial Prescriptive Incentive Program. This new program promotes the purchase of eligible high-efficiency equipment installed at qualifying customer facilities. Rebates offered through this program serve to reduce the incremental cost to upgrade to high-efficiency equipment over standard efficiency options.

Details of the program are outlined in the ten-year Program Plan found in the certification application filed concurrently with this IRP.

The annual reductions and expected cost effectiveness of the steady state program are as follows:

Program	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Commercial Prescriptive Incentive	13,566	34,340,225	$384,684	$27,924,023	$34,421,176	$27,539,339	$29,048,497	$0.013
Note: Economic test results are the NPV over the life of the measure.								

Commercial Custom Incentive Program. This program provides a platform for comprehensive energy efficiency projects normally in larger facilities that go beyond single measures and common efficiency practices. The program does not define a specific list of eligible measures but bases participation on the verifiable energy savings resulting from the measures implemented. Measurement and verification procedures will vary depending on the energy efficient products installed. The initial program offering will provide incentives for lighting improvements consistent with the tax incentives provided in the Energy Policy Act of 2005.

Details of the program are outlined in the ten-year Program Plan found in the certification application filed concurrently with this IRP.

The annual expected reductions and cost effectiveness of the steady state program are as follows:

Program	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Commercial Custom Incentive	20,691	76,855,371	$567,362	$70,379,364	$92,281,239	$69,812,003	$73,409,621	$0.004
Note: Economic test results are the NPV over the life of the measure.								

Industrial Programs

- Industrial Audit program

Industrial Audit Program. This program, formerly covered under the Commercial Tax Incentive Program and currently referred to as the Commercial and Industrial Technical Assistance Program, adopts a market-based approach to help customers identify and implement energy efficiency measures. This is an extension of the existing Technical Assistance program in which Georgia Power offers technical services in the form of audits upon request to identify potential energy savings opportunities. The audits focus on the two primary energy intensive end uses in industrial facilities: general building end uses, such as lighting and HVAC, and process equipment, such as motors, compressed air, and refrigeration.

Details of the program are outlined in the ten-year Program Plan found in the certification application filed concurrently with this IRP.

The annual expected reductions and cost effectiveness of the steady state program are as follows:

Program	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Industrial Audit	3,625	17,976,480	-$1,773,134	$12,385,350	$14,428,279	$14,158,483	$12,917,900	$0.009
Note: Economic test results are the NPV over the life of the measure.								

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Each of the ten-year DSM Program Plans allows for ongoing review and modification of program design features through its evaluation plan in an effort to maximize energy savings while being economically efficient. Any significant changes to program design in support of market conditions or program economics will be included with ongoing reports filed with the Commission, program evaluation filings, and/or IRP updates as needed.

5.2.7 Energy Efficiency Customer Awareness Campaign Approved in 2007 IRP

Georgia Power's Energy Efficiency Customer Awareness campaign promotes the benefits of energy efficiency to consumers and educates consumers about specific ways to save money and energy. The Commission approved budget for this activity is $4.4 million annually for years 2008 through 2010.

Georgia Power uses mass media channels to efficiently reach its customer base. Television, radio, print, internet, billboard and local office advertising are the primary channels being used. The Company has developed a number of online tools and has placed them on its website to enhance customers' learning about energy efficiency. Customers are invited to visit georgiapower.com to learn ways to save energy through general energy efficiency information, helpful tips and specific information about energy efficiency programs offered by Georgia Power. Social media channels are also being used and explored to engage consumers including Twitter, You Tube and blogs.

Georgia Power proposes that the annual budget for the Energy Efficiency Customer Awareness campaign activities remain at $4.4 million for the years 2011 through 2013.

5.3 DSM RESOURCE ASSESSMENT AND INITIAL COST EFFECTIVENESS SCREENING

5.3.1 Assessment and Screening Methodology

The assessment and screening methodology for DSM measures used in this IRP is different than the approach used in the Company's previous IRP filings. This new approach followed the nine step process outlined in the IRP rules waiver approved by the

Commission in July 2008 as previously referenced. The process included identifying DSM programs and measures with detailed input from the DSMWG. Additionally, economic evaluations were performed for each program that was passed to the economic screening to determine the program cost-effectiveness based on the standard benefit/cost tests required by the IRP rules. The required tests are RIM, which is a measure of fairness and equity; TRC, which is a measure of societal impact; and PT, which is a measure of the impact on a program participant. The Company also calculated the Program Administrator Cost Test ("PACT") and Societal Cost Test ("SCT") for each program as requested by the DSMWG. Unlike the 2007 IRP, no ranking of measures or programs by economic tests was required or performed.

The Company shared presentations related to DSM program design details with the DSMWG at multiple meetings in 2009. Some participants provided program plan suggestions and even full written program plans. Input from participants at the meetings and from these submittals was used in developing the list of programs to analyze. Consensus on programs to include in the analysis was reached with the DSMWG.

Some other differences from previous IRP filings are:

Program Level Approach

The Program Level Approach differs from the 2007 IRP process in that the Company did not assess the cost-effectiveness of individual measures as an initial step, as was done in past IRP filings. The Company focused its efforts on measures as part of programs developed with the help of the DSMWG, as outlined in the waiver. Twelve DSMWG meetings were held from September 2008 through December 2009 in support of the DSM analysis and proposed plan for this 2010 IRP filing. Each meeting contained, at a minimum, discussions related to program design and program economics. In addition, Georgia Power hosted an external website where the DSMWG members could post information for background review and program considerations to be included in program design discussions. Several individual members made postings to the website. Georgia Power reviewed all of the information that was posted and included program design ideas appropriate to the specific program plans.

PRICEM Economic Analysis

The PRICEM economic analysis in this IRP differs from prior IRP filings in that Georgia Power analyzed the DSM program cost-effectiveness using multiple scenarios that included various inputs into the PRICEM financial model as opposed to one PRICEM model, as was the case historically. The PRICEM models used represent a range of possible economic inputs across various fuel forecasts and projected costs of carbon legislation scenarios. The fuel levels vary from low to high with various levels of volatility and the carbon scenarios range from $0 per ton up to $20 per ton. These assumptions impact the underlying load and energy forecasts, which impact the mix of capacity and generation needs. This increased level of analysis provides for a significant increase in sensitivity analysis for the Company's DSM base case. Following is a matrix view of the fuel and scenarios that were used to develop the DSM financial model assumptions.

	Carbon Legislation		
Fuel	$0 / ton	$10/ ton	$20/ton
High			
Moderate w/Volatility			
Moderate			
Low			

In addition to the twelve scenarios evaluated by PRICEM with the fuel and carbon assumptions shown above, a base case was developed that is discussed in Section 2 of this filing. Summary economic results for all 13 scenarios is provided in Technical Appendix Volume 2.

Multiple DSM Case Approach

The multiple DSM case approach differs from prior IRP filings in that Georgia Power analyzed and filed three distinct cases for this IRP, two of which are required by the IRP rules. The first required case, herein referred to as Case 1, is Georgia Power's base case for which it seeks approval at this time. The second required case, herein referred to as Case 3, is an Aggressive Case sensitivity outlined in the nine step process approved by the Commission in July 2008. The Aggressive Case sensitivity was developed with suggestions from members of the DSMWG and includes a number of the programs outlined above with penetration rates intended to reach the consensus view of the DSMWG of one percent reductions per year (on average) ramping to a total of ten percent energy reductions in ten years. The third case is a legislative contingency case related to the pending federal legislation generally referred to as Waxman-Markey, which outlines a federal renewable electricity standard. These bills, if passed into law, would set targets for renewable generation and energy efficiency activities. In their current version, the bills do not allow energy efficiency activities to be counted toward the target until after the enactment date of the law, which if passed, will occur after the filing of this IRP. If federal legislation is passed that mandates higher energy efficiency targets, Georgia Power will re-evaluate its DSM program portfolio and return to the Commission for any required approvals.

DSM Program Economic Screening Policy

The Company is following the intent of the Commission economic screening policy outlined in the 2004 IRP Order, which requires the Company to offer a DSM plan that "minimize[s] upward pressure on rates and maximize[s] economic efficiency." The base case cost-effectiveness results presented herein are representative of modifications to current DSM programs for which the Company seeks certification in a concurrent docket. The base case DSM programs did not pass RIM, as was presented in the 2007 IRP filing, but in total represented a significant TRC benefit. The Aggressive Case sensitivity cost-effectiveness results presented herein, as developed through the nine step process approved by the Commission in July 2008, in no way represent the views of Georgia Power as a recommended DSM plan that should be approved by this Commission in the 2010 IRP filing or the concurrent certification filing due to the significant increase in customer's bills and poor economic efficiency. The Aggressive Case sensitivity includes programs from the base case at higher penetration and budget levels as well as additional programs and measures to help reach the one percent per year ramping up to ten percent cumulative over ten years. This higher level of market penetration in the Aggressive Case sensitivity ultimately results a rate impact of more than $250 million per year over the alternative supply-side resource plan. This plan would increase rates 13 times more than the Company's recommended plan while only increasing the economic efficiency (or TRC benefits) by about four times.

5.3.2 Data Development

In developing its list of DSM measures for inclusion in programs for initial screening, the Company conducted a comprehensive review of technical information sources for demand-side and energy-efficiency technologies. This review included evaluation of the Company's previous IRP filings, as well as reviews of new sources of information. Additional input was provided by the DSMWG members, some of whom represent many years of experience in DSM program development and implementation. Company representatives who work closely with Georgia Power's customers were also surveyed for their input. Information gathered was shared with the DSMWG in the program plan discussions.

5.3.2.1 Residential Technology

A total of 115 residential DSM measures within 12 programs were identified for economic screening. These measures provided potential energy savings through:

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

5.3.2.2 Commercial Technology

A total of 174 commercial DSM measures within 14 programs were identified for economic screening. These measures provide energy savings through:

- increased energy efficiency for electric equipment;
- electric space cooling and heating equipment;
- electric lighting;
- electric water heating; and
- heating and cooling savings resulting from improvements to the building's thermal shell.

Building type (where applicable), which is the type of customer operation, such as schools and offices; and construction type (where applicable), either new, existing, or both, were considered in the economic analysis.

5.3.2.3 Industrial Technology

A total of six industrial DSM measures within five programs were identified for economic screening. These measures provide energy savings through:

- electric space cooling and heating equipment;
- electric lighting;
- motors;
- compressed air; and
- refrigeration.

5.3.3 <u>Economic Screening</u>

Energy consumption and savings were calculated for all programs that were passed to the economic screening. Two main methods were used to calculate the energy consumption and savings potential for each measure:

1. The energy usage characteristics for weather-sensitive HVAC and thermal shell measures were calculated using an engineering simulation model ("EnerSim"). EnerSim is an hourly building energy simulation model used to predict energy consumption in buildings based on construction characteristics, insulation, occupancy, orientation, local weather, etc. It was used to generate all energy usage profiles for weather-sensitive end-uses examined in both residential and non-residential measures. EnerSim has been certified and approved by the US Department of Energy ("DOE") and is listed on their website as "Qualified Software." In addition to EnerSim, input from DSMWG experts was included in this step of the analysis process.

2. Energy usage for non-weather-sensitive end-uses was calculated using the EnerSim program, estimates of appliance energy usage from secondary sources listed above, and other end-use specific calculations. Input from DSMWG experts was included in this step of the analysis process as well.

Each potential end-use measure that was passed to the economic screening was then evaluated in an economic analysis model to determine its benefits and costs.

The Company used PRICEM, which is an economic analysis tool maintained by SCS, for a portion of this analysis. PRICEM produces estimates of the avoided utility costs and lost revenues over the life of the end-use equipment. Utility avoided costs include estimates of the supply-side capacity and environmental costs that can be avoided by each measure. The benefits derived were compared with the costs of making the improvement to determine the measure's cost-effectiveness.

The following cost-effectiveness tests were calculated for each measure (and subsequent programs): the PT, the RIM test, the TRC test, the PACT, and the SCT. Additionally, Cost of Saved Energy, also referred to as Levelized Cost per kWh, is provided for each of the nine programs as requested by the DSMWG and represents total program costs but does not include the lost revenues resulting from reduction in kWh sales.

5.3.3.1 Economic Screening of Residential Demand-Side Programs

Table 5.1 below summarizes the economic screening test results for the residential programs.

Table 5.1 - Residential Programs Economic Screening Results

Class	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Residential	9,357	28,325,238	-$13,680,517	$34,286,592	$17,753,145	$47,967,109	$35,135,041	$0.036

Note: Economic test results are the NPV over the life of the measure.

Further details behind the economic screening may be found in the certification application filed concurrently with this IRP.

5.3.3.2 Economic Screening of Commercial Demand-Side Programs

Table 5.2 below summarizes the economic screening test results for the commercial programs.

Table 5.2 – Commercial Programs Economic Screening Results

Class	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Commercial	35,125	114,058,088	$426,622	$100,337,676	$128,969,008	$99,911,054	$104,582,480	$0.007

Note: Economic test results are the NPV over the life of the measure.

Further details behind the economic screening may be found in the certification application filed concurrently with this IRP.

5.3.3.3 Economic Screening of Industrial Demand-Side Programs

Table 5.3 below summarizes the economic screening test results for the industrial programs.

Table 5.3 - Industrial Programs Economic Screening Results

Class	Capacity Reduction (kW)	Energy Reduction (kWh)	RIM Test	TRC Test	Program Administrator Test	Participants Test	Societal Test	Cost of Saved Energy
Industrial	3,625	17,976,480	-$2,006,467	$12,152,016	$14,194,946	$14,158,483	$12,684,567	$0.011

Note: Economic test results are the NPV over the life of the measure.

Further details behind the economic screening may be found in the certification application filed concurrently with this IRP.

5.4 DEMAND-SIDE PROGRAM DEVELOPMENT

5.4.1 Demand-Side Resource Policy

In the 2004 IRP filing Docket No. 17687-U, the Commission directed that proposed DSM Plans should minimize upward pressure on rates (negative RIM results) and maximize economic efficiency (positive TRC results). Additionally, the Commission directed that the cost/benefit analysis results of each initiative should use all three tests (PT, RIM and TRC test) and shall balance between economic efficiency (TRC benefits) and fairness and equity (RIM benefits/cost). This Commission policy continued in the

2007 IRP development and approval. The Company maintained this same philosophy in analyzing the programs for the 2010 IRP.

Consistent with the nine step process outlined in the IRP rules waiver approved by the Commission in August 2008, no measure or program economic ranking was done for the 2010 IRP program list.

5.4.2 10-Year DSM Program Plans

Using the Top-Down Approach discussed earlier allowed Georgia Power to dedicate time to develop ten-year program plans outlining the implementation details behind the individual programs. This differs from the 2007 IRP process in that the Company projected ten-year program plans instead of a three-year transition to steady state program plans. Each of the program plans are provided in the certification application filed concurrently with this IRP.

Included in each program plan are the following details:

- Program Summary – outlines the goals of the program and presents a logic model to graphically represent the relationships between activities and outcomes for the individual programs.
- Program Structure – outlines participant eligibility, home or facility eligibility, and specific measures and incentives where appropriate.
- Program Implementation – outlines the target market, key market players, as well as marketing and outreach plans.
- Program Operation – outlines the customer participation process and program administrative procedures.
- Program Evaluation – outlines the performance metrics, program budget, cost-effectiveness expectations, as well as an independent third-party evaluation plan.

Each program plan is provided in the certification filed concurrently with this IRP.

5.5 NEW PLANNED DEMAND RESPONSE TARIFFS

Load Acting As Contingency Reserves ("LAACR") Tariff

Over the last 18 months, Georgia Power worked with several interested customers, their consultants, and internal experts to develop a program to allow interruptible load to supplement the System's contingency reserve requirements. The potential LAACR Tariff is designed for large industrial customers that can provide a minimum of 5,000 kW of load reduction within ten minutes of notification. As planned, the program will hold load to the same standards as a resource when responding to contingency events, and will appropriately compensate the participant for the service. The Company is currently working with potential participants and is considering including a proposed LAACR tariff in Georgia Power's 2010 base rate case filing.

5.6 REGULATORY TREATMENT OF DSM PROGRAM COSTS AND THE ADDITIONAL SUM

Georgia Power is requesting in Docket No. 31082 that costs for all approved and certified DSM programs and activities be recovered through the existing Residential DSM tariff and two new DSM tariffs for Commercial and Industrial class customers. Georgia Power is also proposing in Docket No. 31082 the collection of an Additional Sum amount for certified DSM programs through these tariffs. These tariffs will be filed as part of the 2010 base rate case and would be implemented with any approved change of rates on January 1, 2011.

5.7 SUMMARY OF DSM CASES

CASE 1 – BASE CASE – GEORGIA POWER RECOMMENDED CASE

The energy efficiency programs for the Base Case being proposed in the 2010 IRP strikes a reasonable balance between the TRC test and the RIM test by achieving nearly $147 million in TRC benefits while minimizing the impact to rates to an estimated $15 million annually at steady state. The programs are primarily existing pilot programs with some modifications made using data gathered in the pilot phase and with input from the DSMWG, as well as two new programs. If approved, Georgia Power will continue to enhance these programs as more information becomes available relative to market penetration and customer feedback through an ongoing evaluation process. If approved and implemented, Georgia Power will keep the Commission fully informed of potential changes to program design.

Case 1 summary economics are provided in the DSM Program Documentation section of Technical Appendix Volume 2. As part of the nine step process, the Company agreed to calculate the generation avoided costs for its DSM change case using its system tool. The avoided generation costs for DSM Case 1 from the system tool were not significantly different than the avoided generation costs obtained from PRICEM. Also, the avoided generation costs for DSM Case 3 from the system tool were not significantly different than the avoided costs obtained from PRICEM.

CASE 2 – LEGISLATIVE CONTINGENCY CASE

The Legislative Contingency Case was developed as a sensitivity to the Company's DSM plan and is based on the expected additional requirements of potential federal legislation related to renewable energy, energy efficiency, and carbon reduction. Georgia Power presents the results of this case not as its recommended case but for informational purposes only. If federal legislation is passed that mandates higher energy efficiency targets, Georgia Power will re-evaluate its DSM program portfolio and return to the Commission for any required approvals.

Case 2 summary economics are provided in the DSM Program Documentation section of Technical Appendix Volume 2.

Georgia Power does not endorse the approval of Case 2. If Case 2 is implemented in the absence of legislation, the portfolio would put additional upward pressure on rates of approximately $55 million annually based on 2013 steady state calculations. Over the life of all programs within Case 2, rates would increase by more than $381 million relative to the supply-side option in the absence of legislation.

CASE 3 – AGGRESSIVE CASE SENSITIVITY

The Aggressive Case was developed to represent an aggressive DSM sensitivity and was developed with input from the DSMWG, as outlined in the nine step process approved in the IRP rules waiver in August 2008. It serves as a reference point for increased energy efficiency at very high costs to ratepayers. This higher level of market penetration in the Aggressive Case ultimately results in an annual rate impact of more than $250 million over the alternative supply-side resource plan, which is more than 13 times higher in increased rates over the Company's recommended plan while only increasing the economic efficiency (or TRC benefits) by about four times. This case is not recommended by Georgia Power.

Case 3 summary economics are provided in the DSM Program Documentation section of Technical Appendix Volume 2.

5.8 RECOMMENDED DSM ACTION PLAN

Georgia Power requests the Commission approve the following in this IRP:

- The five residential programs outlined above and detailed further in the certification application filed concurrently with this IRP;
- The three commercial programs outlined above and detailed further in the certification application filed concurrently with this IRP;
- The industrial program outlined above and detailed further in the certification application filed concurrently with this IRP; and
- Continuation of the program level approach outlined in the 2008 IRP rules waiver for analyzing DSM programs for the 2013 IRP.

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6 – SUPPLY-SIDE PLAN

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SECTION 6 - SUPPLY-SIDE PLAN

6.1 OVERVIEW

The supply-side benchmark planning process consists of the following steps:

- Assessing options at existing generation facilities;
- Evaluating power purchases;
- Assessing current and new electric generation technologies that may be available when new capacity is needed;
- Selecting the least-cost mix of capacity to develop the plan and the benchmark plan; and
- Evaluating the benchmark plan across a range of changing assumptions to assess risk, flexibility, and other considerations.

The benchmark plan is used throughout the IRP process, and cost-effective demand-side options are integrated with the benchmark plan to create the IRP. The IRP is the basis for evaluations of resource options until the next plan is completed.

6.2 EXISTING GENERATING PLANT OPTIONS

There are no current plans to re-power or modify the capacity of existing generating units, other than the retirement of Plant McDonough Units 1 and 2 and the Plant Mitchell Unit 3 biomass conversion discussed in Section 1. However, the Company has suspended further engineering and construction activity on the emission control projects at Plant Branch Units 1 and 2 and Plant Yates Units 6 and 7 until more information is available from the rulemaking and legislative process, thereby, mitigating the risk related to significant capital expenditures associated with those projects. The Company continues to review the economic feasibility of installing controls at Plant Branch Units 3 and 4. It is the Company's intent to continue to operate these units in the near-term and reevaluate the economics of installing emission controls on these units as more information becomes available.

6.2.1 <u>Blackstart CTs</u>

For transmission reliability purposes, certain generating units are designated as "Blackstart Restoration Resources." These units are either CTs or hydro units and are deemed critical to the reliability of the bulk electric system. Some of the blackstart CTs are more than 35 years old and it is increasingly more challenging to obtain spare parts for these units when repairs are required. The Company has very recently initiated a review and assessment of these resources in order to develop a Company-wide plan to determine any needed actions relative to these resources.

6.3 SUPPLY-SIDE OPTIONS

Based on current projections, the Company has adequate capacity reserves through 2015 so there is no plan to add capacity within the next three years in this IRP. The Company has suspended further engineering and construction of environmental controls at Plant Branch Units 1 and 2 and Plant Yates Units 6 and 7 as described below. The Company continues to review the economic feasibility of installing controls at Plant Branch Units 3 and 4. To maintain future reliability, the Company is restarting the 2015 RFP.

6.3.1 Environmental Controls at Plant Branch 1 and 2 and Plant Yates 6 and 7

Expected new environmental legislation and regulations that focus on coal-fired electricity generation impose significant uncertainty on the economic viability of some of Georgia Power Company's coal-fired generating units. The details of these activities are discussed in the Environmental Compliance Strategy. New legislation and regulation that will affect coal-fired power plants in Georgia, beyond the existing Georgia Multi-Pollutant Rule, include:

- current and continually changing regulation of sulfur dioxide and nitrogen oxides under the national ambient air quality standards rulemakings;
- new regulation of hazardous air pollutants under maximum achievable control technology requirements (HAPs MACT);
- new regulation of coal combustion by-products (CCB); and
- regulation of carbon dioxide (CO_2) emissions either through legislation or regulation.

Although the timing required to begin operation of controls to comply with the Georgia Multi-pollutant Rule is known, the final compliance deadlines for the other rulemakings are dependent on many legal and technical factors that are not completely known at this time. It is generally expected that the majority of these new rules will become final in the next two years and will require some level of compliance within the next five to seven years. Concerning the more significant new environmental requirements for HAPs MACT and CCB, proposed rules are expected in the spring of 2011 and final rules in late 2011. The ultimate outcome, timing and substance of CO_2 legislation and regulation are uncertain.

The potential impacts of these new requirements are individually significant and can range up to hundreds of millions of dollars per generating unit. However, the evaluations must look at the cumulative impacts of all the rules to capture all the expected costs and impacts on each unit.

The current scenario evaluations of the unit-specific impacts from these existing and new rulemakings have indicated that additional information which will be available in 2011 is needed to make the best decisions. Specifically, the economic viability evaluations for Plant Branch Units 1 and 2 and Plant Yates Units 6 and 7 indicate a need to wait for additional information prior to proceeding further with the controls required by the Georgia Multi-pollutant Rule. Therefore, work on the emission controls for these units has been suspended until 2011, at which time the construction of controls will resume or a determination will be made regarding an appropriate plan for those units and sites.

6.3.2 Restart the 2015 RFP

The Company will restart the 2015 RFP to protect reliability and maintain reserve margins in the event certain coal-fired units are unable to operate past 2014. The EGU HAPS MACT proposed rule has the potential to cause the retirement of approximately 1,200 MW or more of coal-fired capacity, which could result in a 2015 capacity need of approximately 1,000 MW. While the final rule has not been determined, it is contemplated that compliance would be required by about January 2015. Depending on the form of the final rule, certain of the Company's coal-fired power plants may be unable to operate either because controls will likely not be installed by the deadline or because it may be uneconomic to install the controls. Given the uncertainty and the significant amount of capacity at risk of retirement, the Company is restarting the 2015 RFP.

6.4 NEW GENERATING TECHNOLOGIES

The System continually evaluates conventional and emerging generating technologies as a starting point in developing a base supply-side plan. The objective is to assess their cost, status of development, cost uncertainties, environmental acceptability, fuel availability, construction lead times, and other factors.

The evaluation process:

- Identifies and reviews all conventional and new supply-side generation technologies;
- Performs a preliminary technology screening analysis based on technical, economic, environmental, and resource availability information;
- Performs a more detailed technology screening analysis of the options that passed the preliminary screening, which includes a busbar economic comparison of the candidate technologies;
- Projects the future cost and performance of the selected supply-side alternatives; and
- Identifies the technologies to be recommended for inclusion in the resource mix studies.

6.4.1 Preliminary Screening

The 2010 technology screening process identified 39 technologies for strategic assessment. They are listed in Section 16, Attachment 16.2 and Table 16.2.2. Also, see Table 18.2.1 in Section 18, for a description of the status of each technology considered and the screening decision made.

The strategic or qualitative assessment considered the stage of development of the technology, fuel availability, environmental impact, financial requirements, cost uncertainties, construction lead-time, and operating characteristics.

Many technologies from the initial list did not pass the preliminary screening due to their limited applicability to the territory (e.g., geothermal and wind) or their early stage of development (e.g., magnetohydrodynamics). Twenty-one technologies were carried forward for more detailed analysis (refer to Section 16, Attachment 16.2 and Table 16.2.3). See Section 10 for discussion regarding renewable generation options.

6.4.2 Detailed Screening

In order to pass through the second screening, a supply-side option must have desirable economic characteristics, as well as desirable environmental and other non-price characteristics.

To be economically attractive, an option must be among the lowest-cost options across a range of capacity factors. A busbar cost screening analysis is the common industry method used to determine the cost of operating a unit over a range of capacity factors. Busbar models combine the capital and operating costs of generating units so that the costs of operating units can be compared under various hours of annual operation. Also, busbar models provide an indication of the economic viability of one technology compared with others. However, it must be understood that busbar models have limited utility and their usefulness is primarily for screening level evaluations.

All data assumptions are shown in Table 11.2.1 in Technical Appendix Volume 1. A capital cost comparison and busbar curves are shown in Section 11, Figures 11.2.1 and 11.2.2 in Technical Appendix Volume 1, respectively.

Even though a technology may not be the absolute lowest-cost option, it may be a desirable alternative due to qualitative features, such as stage of development, ease of siting, modularity, short construction lead time, flexible operating characteristics, fuel diversity, or anticipated improvements that favorably impact the economics of the technology. These attributes are also considered in the detailed screening.

6.4.3 Nuclear Generation

Nuclear generation is included as a generating unit option in this IRP. The 2010 Generation Technology Data Book, included in Technical Appendix 1, provides the capital cost for pre-licensed nuclear generation.

6.4.4 Generation Mix Candidate Selections

The detailed economic results are used to determine likely candidates as representative capacity options in the base case resource mix studies. The base case technologies recommended include:

- CT, peaking;
- CC – "G", intermediate;
- Nuclear, base load; and
- Coal with carbon capture and sequestration, base load.

6.5 SUPPLY-SIDE PLAN

To develop a supply-side plan, the technologies that passed the detailed screening are further evaluated using the PROVIEW™ computer model to arrive at a benchmark plan. The key input assumptions are generating unit characteristics, fuel costs, reliability needs, financial costs and escalation rates. A summary of the PROVIEW™ model is in Section 16 of the Main Document.

6.5.1 Base Case Assumptions

Generating Unit Costs — The types of generating units used in developing the benchmark plan were base load coal and nuclear, intermediate load CC and peaking CT.

Fuel Costs — In the optimization process, the primary fuels used in the candidate units of the optimization are nuclear, coal, oil, and gas. Figure 3.7.1 in the Mix Study in Technical Appendix Volume 1 shows projections of nominal delivered costs of coal, residual oil, distillate oil, and natural gas based on heat content.

Reliability Needs — The supply-side plan is currently developed to meet a System planning target reserve margin of 15 percent. This margin was developed using a combination of economic studies, electric industry experience, and operator input. The economic analysis compares emergency purchase cost and customers' value of service [based on EUE cost] with the cost of adding capacity to avoid outages.

Financial Cost and Escalation - Long-term debt and common and preferred stock are issued to finance the construction of generating units. The returns demanded by the investment community are affected by perceptions of the inflation rate and business risks. The returns demanded by the investment community and the income tax rates affect the carrying cost of the investment, which can in turn affect the mix of capacity.

The Moody's Economy.com forecast is the basis of the financing and inflation cost estimates used in the planning process. For the mix analysis, an internally-developed average set of costs escalations was used. Discount analysis using the weighted average cost of capital is applied to place more emphasis on the near term. (More information on this topic is available in the Mix Study report in Technical Appendix Volume 1.) The financial parameters used in the mix process are also shown in Technical Appendix Volume 1.

6.5.2 Benchmark Plan Results

The optimization process utilizes the PROVIEW™ module of the production cost Strategist® model and determines the proper mix of capacity to serve a designated load. The results of this analysis indicate the proposed capacity additions. The capacity additions identified within this analysis serve as a guide for the type of capacity needed in a particular timeframe with the given assumptions. As prescribed by the Commission's rules and orders, a combination of self-owned generation and a competitive bidding process will be used for determining how the capacity needs are to be met.

The optimization process is essentially a trade-off between fixed costs and variable operating costs for the various generating unit options. Figure 6.4 in Technical Appendix Volume 1 depicts changes in energy mix by fuel source for the 2010–2029 planning period. As energy usage increases and no new coal-fueled generating units are added, the amount of energy supplied by oil and natural gas will increase. Figure 6.3 in Technical Appendix Volume 1 shows the portion of annual energy needs met by nuclear, coal and hydro units over the planning period 2010 - 2029. Table 6.3 in Technical Appendix Volume 1 shows the System Benchmark Capacity Plan.

6.5.3 Reference Case Sensitivities

The following sensitivities were performed in the development of the Company's IRP. These sensitivities are analyzed in detail in the System Mix Study found in the Technical Appendix Volume 1.

- Forecast of load:
    - Sensitivity 1 evaluates zero load growth from 2010 levels.
    - Sensitivities 2 and 3 evaluate higher and lower load growth.
- In-service dates of supply and demand resources:
    - Sensitivities 4 and 5 evaluate levels of demand-side options.
    - Sensitivities 12 through 28 evaluate the impacts of varying in-service dates and amounts of supply and demand resources through the scenario planning cases. In addition to separate fuel price forecasts and estimates of carbon prices, sensitivity cases 13 through 28 produce separate evaluations of the impacts on the load and energy forecasts, demand-side programs, unit retirements, and new supply-side resources.
- Unit availability:
    - Sensitivities 6 and 7 evaluate lower and higher forced outage rates.
- Fuel prices:
    - Sensitivities 13 through 28 evaluate the impacts of fuel prices through the scenario planning cases which have four separate fuel price forecasts combined with varying estimates of carbon prices to produce separate evaluations of the impacts on the load and energy forecasts, demand-side programs, unit retirements, and new supply side resources.
- Inflation in plant construction costs and costs of capital:
    - Sensitivity 8 incorporates a higher cost of capital assumption.
    - Sensitivities 9 and 10 analyze the impacts of doubling and tripling the construction cost escalation rates, respectively.
- Availability and costs of purchased power:
    - Sensitivity 11 evaluates the impacts of the availability and costs of purchased power.
- Pending federal or state legislation or regulation:
    - Sensitivities 13 through 28 evaluate the impacts of pending legislation or regulation through the scenario planning cases. The impacts of pending legislation or regulation can be analyzed by varying estimates of carbon and fuel prices. The scenario planning cases produce separate evaluations of these impacts on the load and energy forecasts, demand-side programs, unit retirements, and new supply side resources.
- Rate impact analysis:

- All of the sensitivities analyze the impacts on rates of the varying changes in assumptions. The rate impacts are included in the Financial Review in Technical Appendix Volume 2.

The Mix Study in Technical Appendix Volume 1 and Financial Review in Technical Appendix Volume 2 provide descriptions of these analyses and the impacts of each sensitivity analysis on:

- The timing, amounts, and types of new capacity needed to meet customers' needs;
- The costs associated with meeting the load growth on the system; and
- System marginal costs.

There are four major reasons to test the benchmark plan under different assumptions:

- To determine how well the plan will meet customer needs under a variety of different future outcomes;
- To determine if the plan should be altered to make it more flexible in meeting unforeseen changes;
- To build knowledge and intuition concerning the effect that different assumptions will have on the supply-side plan; and
- To identify and focus attention on additional studies to be performed.

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7 – INTEGRATION OF DEMAND-SIDE PROGRAMS INTO THE BENCHMARK SUPPLY-SIDE PLAN

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SECTION 7 - INTEGRATION OF DEMAND-SIDE PROGRAMS INTO THE BENCHMARK SUPPLY-SIDE PLAN

7.1 INTRODUCTION

In the integration step, those demand-side programs resulting from the DSM evaluation are integrated with the appropriate benchmark supply plan using the Strategist®/ PROVIEW™ model. This method ensures a cost-effective mix of demand-side and supply-side resources is selected, while acknowledging the limits of available demand-side resources.

7.2 DISTRIBUTING CAPACITY AMONG THE OPERATING COMPANIES

In order to make the full benefits of coordinated planning available to the System's operating companies, the mix optimization process is performed for all of the operating companies. For long-range planning purposes, the generating unit resources resulting from the mix process must then be distributed or allocated among the operating companies based on their particular needs and current resources. This planned distribution is performed through an analysis of each company's existing resources and energy needs. The actual resource selection is based on specific operating companies' needs instead of the planning assumptions. As the time for commitment to new capacity approaches, additional detailed studies are performed to identify the resources for meeting specific operating company requirements. The decision to acquire new generating capacity or demand-side resources will be made by the operating company based on studies of customer needs and the operational, cost, and financial assumptions specific to the operating company and the options available.

See Technical Appendix Volume 1 for additional details.

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8 – INTEGRATED RESOURCE PLAN

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SECTION 8 - INTEGRATED RESOURCE PLAN

8.1 OVERVIEW

The 2010 IRP projects that the demand for electricity by the Company's customers will continue to grow. Georgia Power must acquire a significant amount of new resources by 2029 in order to reliably serve these new requirements and replace units retired from generating service. The IRP recommends a cost-effective mix of supply-side and demand-side capacity resources to meet future requirements.

8.2 INTEGRATED RESOURCE PLAN

For the period of 2010 – 2014, Georgia Power has sufficient resources to meet customers' needs given the resources approved by the Commission in the 2007 IRP and subsequent filings, as described in preceeding sections. For the year 2015, the Company has a capacity need based on possible retirement of some existing coal generation due to the combination of possible carbon emission price, coal combustion by-product costs, and maximum achievable control technology rulemakings that are expected to be forthcoming. Therefore, to ensure reliability, the Company is restarting the 2015 RFP and is expected to make a decision regarding the amount of capacity to take from the RFP in 2011 once more information about the rulemakings is known.

The long-term plan for each of the scenario cases varies depending on the assumptions for that case. The Unit Retirement studies of the existing fleet of generating facilities show the potential for significant retirements of coal-fired power plants under certain scenario cases assuming carbon emissions prices and potential additional environmental rulemakings. For some of the scenario cases a mix of gas technologies (CTs and CCs) were selected through the planning period when capacity was needed to maintain reliability, meet growing customer needs, or for fuel-cost savings. In other scenario cases, nuclear and coal generation with carbon capture and sequestration ("CCS") were selected in addition to certain gas-fired generation during the planning period when capacity was needed to maintain reliability, meet growing customer needs, or for fuel-cost savings.

The IRP utilizes demand-side resources and acquires the proper mix of capacity through power purchases or self-owned resources (i.e. self-built and/or acquired from existing assets) in sufficient amounts to meet minimum System reliability criteria. The IRP (as shown in Table 8.1 in Technical Appendix Volume 1) shows the resource needs for the years 2010 – 2029 based on current environmental requirements and other base case assumptions. When Georgia Power acquires its resource needs through the RFP process, the actual generation technology purchased is dependent on what the market bids to the Company.

8.3 PLAN REVIEW BASED ON OTHER PLANNING OBJECTIVES

The IRP was reviewed based on the additional planning objectives listed below.

- **Flexibility** — Can the IRP be altered if the future is different than expected?

  Yes. In the near term, the IRP relies on demand-side programs, pricing tariffs, and short-term supply-side purchases when appropriate. Natural gas-fueled capacity proved to be the next supply-side resource needed under the analyses performed in the base case IRP while nuclear and coal with CCS are selected in certain scenario planning cases with carbon prices. The relatively short lead time (three years or less) required for a simple cycle CT and the utilization of short-term purchases will provide the flexibility to meet any uncertainties that may arise.

- **Long-Term Viability** — Will the IRP meet customer needs in the long term?

  Yes. The IRP adequately provides for needed capacity resources in the future and minimizes the need for rate increases. Some of the natural gas-fueled units are planned for optional operation on oil, if gas availability becomes a problem for short or long periods. There is flexibility to alter the plan as needed. Customers have the opportunity to participate in the demand-side program or pricing options that fit their individual needs. The IRP is a viable long-term plan under the current regulatory and operating environment.

- **Reliability** — Does the IRP meet customer needs for reliable service?

  Yes. The IRP holds System reliability at a level that balances the cost of outages and the cost of new generating capacity.

- **Environmental** — Does the IRP consider environmental impacts?

  Yes. The Company reviews and assesses pending rules, regulations and legislation in regards to environmental issues that may impact Georgia Power and Southern Company. The Company's Environmental Compliance Strategy Document is included in Technical Appendix Volume 2. Additional environmental sensitivities and their impact on the generation mix analysis is also included in the Mix Study in Technical Appendix Volume 1 and the Financial Review in Technical Appendix Volume 2.

  The IRP complies with all existing laws and regulations.

- **Risk** — Does the IRP represent a reasonable balance between reduced risk and cost?

  Yes. There is a risk that the load growth will be more or less than expected, and that the demand-side programs may not be well received or provide the projected load reductions. There also is risk that there will be more interest in DSM than currently experienced, decreasing the need for new capacity acquisitions. Finally, there is risk associated with uncertainty regarding expected environmental rulemakings and their potential impact on retirement of some existing resources. The plan balances this risk against cost to customers. The Financial Review included in Technical Appendix Volume 2 provides additional information regarding the business and financial risks associated with the IRP.

- **Stockholder Value** — Will the IRP provide stockholders with the opportunity to earn a fair return on their investment?

  Yes. The IRP process provides for a full review of the need to add new generation resources and the certification of resources chosen to fill those needs. This process provides shareholders with a greater level of certainty that their investments in these certified resources will result in the ability to earn a fair and reasonable return.

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9 – SUMMARY OF TRANSMISSION PLANNING

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SECTION 9 — SUMMARY OF TRANSMISSION PLANNING

9.1 TRANSMISSION PLANNING PRINCIPLES

The purpose of the transmission planning principles is to provide an overview of the standards and criteria that are used for transmission expansion and upgrade proposals. These principles are designed to help ensure the coordinated development of a reliable, efficient, and economical electric power system for the transmission of electricity for the long-term benefit of the transmission users. These principles also recognize that planning should be proactive in order to ensure timely system adjustments, upgrades, and expansions. The principles that apply to Georgia's transmission planning are as follows:

- Identify and recommend projects that are consistent with the Guidelines for Planning the Georgia Integrated Transmission System ("ITS") and the Guidelines for Planning the Southern Company Electric Transmission System;
- Identify and recommend projects that are consistent with the NERC Planning Standards and the SERC Supplement to the NERC Planning Standards;
- Minimize costs associated with the ITS expansion, giving appropriate consideration to system reliability;
- Identify projects with sufficient lead-time to provide for the timely construction of new transmission facilities;
- Recommend budget expenditures that recognize the financial capabilities and limitations of Georgia Power;
- Coordinate transmission system plans with the plans developed by the Transmission and Distribution ("T&D") Area and Distribution Planning groups, the T&D Planning Section, Distribution, Engineering, Land, Operations, Protection, other ITS members, other Company departments and the regions surrounding the Southeast to seek their active involvement in the project development and planning process;
- Coordinate transmission system plans with all ITS participants in an effort to enhance reliability and minimize associated costs; and
- Maintain adequate interconnections with neighboring utilities.

These principles provide guidance to planners and/or planning authorities that are called upon to explore existing issues and any future problems encountered in the transmission planning process.

9.2 10 YEAR TRANSMISSION PLAN

Georgia Power is a member of the ITS, which consists of the physical equipment necessary to transmit power from the generating plants and interconnection points to the local area distribution centers in most of Georgia. The ITS is jointly owned by Georgia Power, Georgia Transmission Corporation, MEAG Power and Dalton Utilities. Transmission planning embodies investment decisions required to maintain the ITS so that it can reliably and economically meet the power needs of the public. Justifications used in any such decisions are based on technical and economic evaluations of options that may be implemented to meet these needs.

Transmission Planning-East (TP-East) of the SCS Transmission Planning department is responsible for planning the transmission system for Georgia Power. TP-East, in conjunction with the other participants in the ITS and the interconnected neighboring utilities, develops a model of the transmission system for each year for ten years into the future. These planning models are used to identify transmission problems based on NERC and ITS planning guidelines and to evaluate alternative cost-effective solutions to the problems. Investment decisions must accommodate the fact that future load levels and generation plans are uncertain. This ensures that the planning process does not have to start anew each time a change is made.

All Transmission Planning information is provided in Technical Appendix Volume 3 per the Commission's 2007 IRP Order and the amended rules adopted by the Commission in Docket No. 25981-U.

10 – RENEWABLE RESOURCES

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SECTION 10 – RENEWABLE RESOURCES

10.1 RENEWABLE RESOURCES OVERVIEW

Georgia Power continues to encourage the development of cost-effective renewable energy resources. The Company has expanded the purchases of renewable energy to meet increasing customer demand for its Green Energy Program and has proposed changes to its Renewable and Non-Renewable Tariff (“RNR”). The Company continues to purchase capacity and energy from Qualifying Facilities (“QFs”). Furthermore, Georgia Power and Southern Company are conducting significant research into renewable energy sources suitable for its service territory, including research into biomass, solar, wind, and hydro resources.

The Company continues to pursue various options in order to develop up to three cost-effective renewable projects with capacity of 30 MWs or less. The Company has evaluated several renewable energy projects and continues to work toward development of cost-effective projects. The sources of renewable energy for potential Company projects include landfill methane gas, digester methane gas, wood biomass, and solar energy. The potential projects are being proposed by independent power producers as well as by Georgia Power customers. Currently, the Company has not committed to any specific projects.

Landfill methane gas projects appear to have the best potential for meeting the cost-effectiveness criteria. The Company has completed several site specific evaluations and is negotiating with landfill owners.

10.2 GREEN ENERGY PROGRAM

The Commission approved Georgia Power’s Green Energy Program (“Program”) on July 15, 2003. This order approved both the Green Energy (“GE”) tariff for the sale of Green Energy, and the RNR tariff for the purchase of Green Energy. After the Company contracted with DeKalb County for the output from the Seminole Landfill generator, the Program’s main energy supply resource, the Company began billing customers in October 2006.

Subsequent to the 2007 IRP Order, the Company filed a Renewable Resource Action Plan and Time Table, which introduced the concept of a Large Volume Renewable Energy Program for customers who wanted to purchase renewable energy in large quantities. On October 16, 2007, the Commission issued an order adopting in part the Company's Renewable Resource Action Plan and Time Table. This order deferred a decision on the Large Volume Renewable Energy Program to allow for meetings with stakeholders and Commission Staff to collaborate on a final program design.

The Company initiated a process to allow all stakeholders the opportunity to provide feedback on the proposed Large Volume Program design. The predominant theme from stakeholders was not to create a separate Large Volume Program, but to modify the existing Green Energy Program to include a Large Volume Option. The Company accepted these suggestions and modified the proposed program design. As a result of this collaborative effort, the Company filed a petition for modification of its Green Energy Program, including the Large Volume Purchase Option, on August 29, 2008.

The modified Program design included four options through which customers could purchase Green Energy:

- Standard Green Energy, with a price drop from \$4.50 per 100 kWh block to \$3.50 per block;
- Premium Green Energy, containing at least two percent solar content for \$4.50 per block;
- A Special Events Purchase Option, to meet customer needs by providing Green Energy for a single event through a one-time transaction; and
- The Large Volume Purchase Option, providing large quantities of green energy on a customer specific basis.

Other program changes in the filing included a modification in the resource criteria to the Green-e National Standard (the Program received Green-e certification in March, 2008) and several program accounting changes. The program modifications were approved by the Commission on September 16, 2008, and the Company implemented the Program changes soon thereafter.

The modified program with added customer options has been well received. The Large Volume Purchase Option in particular has enjoyed great success. As of September 2009, the most recently available data from the Company's Quarterly Green Energy Report, five customers were participating in the Large Volume Purchase Option buying over 1.5 million kWh's of Green Energy per month. Adding these five large volume customers has nearly doubled the amount of Green Energy sold through the program over the prior year. Additionally, the Company recently signed another Large Volume Purchase Option agreement that will add another 6.7 million kWh's annually to program sales. The Large Volume Green Energy concept, with input from stakeholders and leadership from the Commission and Staff, is a prime example of how Georgia Power is meeting customers' needs for renewable energy options.

A significant marketing effort is underway to increase participation for all the products in the program. As part of the Commission decision to raise the capacity cap for the RNR tariff (to be discussed in detail in the next section), the Company is working with interested stakeholders on a cooperative marketing campaign that may add to customer enrollments in the Green Energy Program. The Company is also conducting a traditional marketing campaign through direct mail as part of overall efforts to grow participation.

On November 19, 2009, the Commission requested the Company and Staff develop a product offering 100 percent solar energy for Commission review. The Company and Staff worked together and on December 18, 2009, the Company filed a petition for modification to the Green Energy Program, which included a 100 percent solar option priced at $12.00 per 100 kWh block. The Company will continue to work with the Commission, Staff, and interested stakeholders in the final design and implementation of this new product.

In summary, Georgia Power's Green Energy Program is robust and growing. Georgia Power is conducting an RFP for additional renewable energy resources to meet the growing customer demand. The Company has been responsive to customer needs and now offers Green Energy products to satisfy a variety of customers. Through the program design which allows interested customers to support renewable energy without impacting non-participants, the Company is gaining experience in purchasing renewable energy and is stimulating the growth of renewable resources in the region.

10.3 RNR AND DISTRIBUTED GENERATION ENERGY PURCHASES

The RNR tariff was approved as part of the Green Energy Program in 2003. Georgia Power purchases a portion of its renewable energy from distributed generation resources through the RNR tariff. The tariff provides a means for Georgia Power to comply with the Georgia Cogeneration and Distributed Generation Act of 2001, and allows for the purchase of this energy at avoided energy cost in compliance with the final order in the Public Utility Regulatory Policies Act ("PURPA") avoided cost Docket No. 4822-U. Pursuant to Docket No. 16573-U, the Company purchases energy from solar resources through the single-directional metering option of the RNR-5 tariff at a preset price – currently 18.31¢ per kWh.

At the inception of the RNR tariff, a total capacity cap of 500 kW was established for these solar purchases. As of May 2009, the Company had executed contracts for capacity that reached the 500 kW cap. On August 4, 2009, the Commission, as part of Docket No. 16573-U, increased the capacity available for the preset solar price by 1,000 kW to a total of 1,500 kW. Since that time, Georgia Power has executed additional contracts to fill the new capacity and continues to maintain a significant waiting list for this premium pricing.

Georgia Power recognizes the role that the premium pricing available through RNR plays in stimulating the solar energy market in Georgia. Without a guaranteed price that includes a significant premium above Georgia Power's avoided energy cost, many solar projects would not be viable. It is in this light that the Company proposes to raise the capacity cap by 1,000 kW for the premium pricing through RNR to 2,500 kW. These costs will be included in the program, and are not projected to put upward rate pressure on non-participants.

Currently, solar resources from existing RNR contracts provide more than enough solar energy to satisfy demand from sales of the Premium Green Energy product. However, the Company's current marketing efforts, as well as the pending 100 percent solar product option for interested customers, may increase the demand for solar from the Green Energy Program.

The concept of paying a higher price for solar resources was introduced and approved as part of the original Green Energy Program filing in July 2003. The original price was set at 15¢ per kWh. In the Order Adopting the Revised Tariffs on September 5, 2006, the Commission directed Georgia Power to adjust the payment for solar photovoltaic energy to 17.74¢ per kWh, and to index the payment going forward to the avoided energy cost filed in Docket No. 4822-U such that the price is adjusted annually based on increases or decreases in the projected avoided energy cost for the current year over the previous year estimate. The 17.74¢ per kWh price represented a premium over the Company's avoided energy cost of approximately 13¢ per kWh.

In order to mitigate the financial impact of the additional solar energy purchases to the Green Energy Program, the Company now proposes to de-link from the Company's projected avoided costs the premium purchase price offered for solar through the RNR tariff, currently at 18.31¢ per kWh. Current market conditions, specifically the significant interest in supplying solar at the current RNR tariff price of 18.31¢ per kWh, indicate that it may be possible to continue to stimulate the solar market in Georgia by offering a lower price for solar energy through RNR. Additionally, the prices for solar generating equipment and installation are decreasing, while Georgia Power's avoided costs are projected to rise. It is for these reasons the Company proposes to fix the price for the single-directional metering option through RNR at the time of the Company's next avoided cost filing. The new price will be based on the "Annual All Hours" avoided energy cost estimate and will thereafter be based on solar equipment market conditions, not the Company's avoided costs. The Company, working with Commission Staff, will evaluate the solar price offering annually based on market conditions, and a solar production cost index. The Company will periodically propose a new "Solar Purchase Price" for premium purchases through the RNR tariff that will apply to the term of any new contracts.

As part of the development of the "Solar Purchase Price" the Company will work with Staff to consider the merits of valuing the capacity benefit provided by distributed solar generating resources. Factors such as time of day and season of energy production, expected availability, and the future capacity needs for the Company will be considered in this process. The methodology for determining the capacity benefit will be consistent with existing Commission policies.

The premium pricing for the purchase of solar energy through the RNR tariff is important to the development of the solar market in Georgia. Additionally, the Green Energy Program depends upon this solar energy to supply the program needs. The proposed modifications to the RNR tariff will allow the Company to purchase more solar energy at a premium price and continue to stimulate the solar energy industry in Georgia.

10.4 COMMUNITY SUPPORTED PROJECT-SPECIFIC ENROLLMENTS AND RNR CAPACITY EXCEPTIONS

A recurring theme heard from solar developers in Georgia is to offer the ability for customers to purchase Green Energy and directly support a specific renewable energy facility. That is, for customers buying Green Energy to know that the money they are spending is going toward direct support of a project in their community or a project that they are familiar with. Based on this request, the Company is proposing a methodology to track customers who wish to support a specific renewable generating facility with their program participation. This method would allow developers to solicit community support for particular projects. Once enough customers had subscribed through the green energy program having been identified as supporters of a specific project, that project could be granted an exemption to the RNR cap equal to the amount of additional capacity generated from the community supported sales. These projects then could qualify for the premium pricing available through the single-directional metering option. The modifications to the RNR cap would be made by the Company on a customer-specific basis with review by the Commission.

10.5 SOLAR OVERVIEW

Over the last 24 months, the costs of solar photovoltaic ("PV") cells and systems have continued to decline. The cost reductions are a direct result of increased global production capacity and demand, reduction in raw material costs, and an eight year federal tax credit extension that was implemented in 2009. In the state of Georgia, interest in solar as an energy supply option has also increased. One significant reason is the RNR tariff offered by Georgia Power. The popularity of this optional tariff has served as an additional market driver, which has made distributed solar systems attractive to a larger segment of customers.

These changes in market conditions have generated a significant amount of interest and questions about distributed solar systems from customers. In response to this interest, Georgia Power established a series of educational web pages to help answer questions and to assist customers in evaluating the technical and economic feasibility of solar systems located at customer sites. The Company also established a "solar hotline" telephone number, where customers who have specific questions that go beyond the web content can speak to a knowledgeable Georgia Power employee for answers to those questions. If the questions are beyond the scope of the "hotline" employee's knowledge, the customer is directed to the appropriate internal or external resources to assist them. As of this IRP filing, the Company has received thousands of visits to the solar website and logged over nine hundred customer inquires to the hotline.

10.5.1 Solar PV Demonstration and Pilot Projects

There are two demonstrations underway within Southern Company's footprint. The first is located on the roof of the Georgia Power Headquarters Building in Atlanta, Georgia. The objective of this pilot-scale demonstration is to compare the performance and reliability of different commercially available PV technologies. Five technologies were installed by the end of the summer of 2009. The remaining two systems are scheduled for installation before the end of February 2010. Once all technologies are commissioned, the Company will begin an evaluation determining which technologies are most suited for the unique climate conditions of the southeastern United States. This evaluation will last a minimum of 12 months. The demonstration project has already served as an educational platform for customers who are in the process of evaluating solar projects. Georgia Power has hosted informational meetings for the Atlanta Braves, MARTA, and Atlanta Spirit, along with other key solar stakeholders. The Company has also established a solar dashboard on the internet where stakeholders can see near real-time (15 minute intervals) and historical production data for each of the technologies, along with associated weather data from the project's weather station. Georgia Power will publish preliminary observations of technology performance in various climate conditions before the fourth quarter of 2011.

The second demonstration project will be located on the rooftop of the Alabama Power Headquarters Building in Birmingham, Alabama. The objective of this pilot-scale demonstration is to gain experience with micro-inverters being used on different commercially available solar PV technologies. Equipment has been received and it should be installed during the first quarter of 2010. This project is being conducted in conjunction with the Electric Power Research Institute ("EPRI").

10.5.2 Solar Demonstration

PV module costs have declined over the past five years, with module costs projected to further decrease over the next three to five years as global production capacity increases. While small rooftop PV systems remain at a significant premium, larger systems can be installed at a much lower cost per unit of output.

Larger systems take advantage of economies of scale in project siting, procurement, construction, and maintenance. These systems can also take advantage of more cost-effective tracking technologies. These tracking systems, which allow the solar cells to follow the sun throughout the day, can increase the capacity factor by up to thirty percent and can generate more energy in peak periods verses the fixed-mounted rooftop systems.

Georgia Power proposes to implement a portfolio of solar PV demonstration projects. The objective of this demonstration would be to enhance Georgia Power expertise in developing solar projects. This demonstration would allow the Company to evaluate completely developed solar projects that include siting, procurement, construction, performance and maintenance. The total demonstration project portfolio would not exceed 2.5 MW of capacity. The costs for this demonstration project portfolio would not exceed the preset "Solar Purchase Price" established in the RNR tariff, which includes the current market price for solar energy in Georgia. The Company has included these costs for approval in the Selected Supporting Information section of Technical Appendix Volume 2.

This portfolio of projects would allow the Company to evaluate a variety of solar technologies, and to evaluate how some of these technologies increase capacity factor and shift production to peak periods of the day. This research effort would also help the Company identify vendors with whom Georgia Power could establish partnerships in the event a larger solar program is needed to meet federal or state compliance standards.

10.5.3 Solar Augmented Steam Cycle – Coal and Natural Gas

Southern Company participated in two supplemental solar projects with EPRI from 2008 to 2010. These paper studies involved assessing the economics and feasibility of adding steam generated by a solar thermal field to a conventional fossil fuel-powered steam cycle, either to offset some of the fossil fuel required to generate electric power or boost plant power output. These were computer simulation projects and the parameters entered came from actual coal and natural gas plants. The final reports are available to participants of the supplemental projects.

10.5.4 Solar Water Heating Demonstration Projects

Eighty-gallon propylene glycol solar water heating systems were installed at four residences in Pensacola, FL; Saraland, AL; Bainbridge, GA; and Long Beach, MS. The objective of this project is to generate performance, reliability, and cost information sufficient to quantify the economics and technical viability of solar hot water heating applications across Southern Company's service territory. The last of the four systems was installed during the summer of 2009 and data review has begun for all four sites. Data will be collected after two years of operation and a final report will be written at the end of the test period.

10.6 BIOMASS OVERVIEW

10.6.1 Plant Mitchell Unit 3 Biomass Conversion

On March 17, 2009, the Commission approved the conversion of Plant Mitchell Unit 3 into a biomass facility. Fuel for the Mitchell biomass unit will be wood chips or other biomass and will consist primarily of un-merchantable wood, harvest residues, whole chipped trees, mill residues and peanut or pecan hulls. The Commission approved conversion of the unit in June 2012.

The conversion of Plant Mitchell Unit 3 to biomass is a significant part of the company's renewable resource plan. However, Georgia Power has decided to delay capital spending for the Plant Mitchell biomass project at least until the Environmental Protection Agency ("EPA") issues its proposed rules regarding industrial boiler emissions. In 2008, when the Company proposed the conversion, the EPA was expected to release a proposed Industrial Boiler Maximum Achievable Control Technology ("IB MACT") environmental rule in the summer of 2009. To date, the proposed IB MACT rule has not been released. This rule would likely affect biomass boilers like the one being planned for Plant Mitchell and is now expected to be released in 2010. The Company plans to propose an amended project plan subsequent to the EPA release of the proposed rule.

Once the new EPA rules are better defined, Georgia Power will evaluate the potential impact they might have on the conversion project at Plant Mitchell. The company plans to study other boiler technologies to prepare for the possibility the rules may significantly impact the cost of the biomass boiler conversion currently planned for the plant. For the 2010 IRP Mix Study, Plant Mitchell Unit 3 is modeled as converting to biomass.

From a regulatory perspective, coal combustion by-products (including coal ash and Flue Gas Desulfurization (FGD) gypsum) are currently treated as non-hazardous materials by EPA and the states. This applies to disposal as well as the numerous beneficial uses for these materials. At this point, the EPA is considering a different regulatory framework for these coal combustion materials, which could possibly extend to biomass ash. Possible scenarios include non-hazardous or hazardous, with perhaps even a hybrid designation which could treat disposed materials as hazardous while exempting some beneficial uses. The EPA has not issued a proposed rule yet, but is expected to do so in the first quarter of 2010. Ultimately, any final designation other than non-hazardous would likely have a severe impact on plant operations and costs, as well as the ability to maintain beneficial uses.

10.6.2 Biomass Co-firing

The scope of Southern Company's biomass testing program has included investigation of co-firing various types of biomass at existing pulverized coal power plants. With increased fuel costs, the lowest cost options of renewable energy generation were sought. In response, several studies have been conducted by Southern Company and Georgia Power regarding the feasibility and cost-effectiveness of different co-firing technologies.

In general, there are two forms of co-firing. Co-milling involves treating the biomass as if it were coal, mixing the material with the coal and passing it through the coal handling system and coal burners. The other technology is direct injection, in which the biomass is processed to a fine sawdust-like material and blown directly into the furnace through its own dedicated burners or with the coal through existing burners. Co-milling requires less capital but is limited to only low percentages of biomass. Its success depends on the individual power plant design, on the form of biomass as fuel, and on the percentage co-fired. The maximum co-milling energy percentage will typically be about to one to five percent by energy input. In testing at Southern Company plants, sawdust and sander dust worked fairly well, as did finely chipped tree trimming waste. Less success was achieved with large wood chips due to their fibrous nature. Smaller wood chips, 1/2 inch or less in fiber length, worked better than the larger chips, but not quite as well as sawdust.

Direct injection is generally capable of co-firing higher percentages of biomass. It is possible to achieve 10 to 20 percent co-firing by the direct injection method. However, capital equipment is required and the biomass (wood or grass) must be reduced to a small size, which can further add to costs. However, fairly promising results have been obtained in Southern Company power plant tests conducted on direct injection of switchgrass.

In addition to the biomass handling, feeding, and capital cost issues mentioned above, there are other key technical hurdles that must be overcome before biomass could be co-fired on a significant scale. Biomass materials have concentrations of certain minerals that are potentially adverse to operation of pollution control equipment located at many of the Company's power plants. Southern Company is currently pursuing research and development ("R&D") to better define the harmful effects of these minerals. Furthermore, many plants sell, rather than store, their fly ash for use in the concrete industry. However, the American Society for Testing and Materials ("ASTM") International specifications for fly ash in cement do not recognize anything but fly ash from coal. As a result, there are serious concerns about the ability to sell fly ash that contains wood ash. Southern Company is pursuing a study with Georgia Tech to determine the differences in coal only ash and biomass co-fired ash as is discussed more fully below.

The current financial projections show that co-firing biomass can be economical with conventional coal-based power generation in certain situations. Because a given volume of biomass contains much less energy than the same volume of coal, the transportation costs for biomass versus coal are much greater. This not only adversely affects the economics of biomass power generation, but also limits the amount of biomass that can be transported to a given location. The Company estimates that Georgia Power could realistically co-fire biomass in the range of 30 to 80 MW at selected units.

Southern Company will continue to conduct a significant R&D program in biomass co-firing with the goal of solving the key technical issues and improving the economics. Southern Company is actively engaged in addressing the technical issues and economic barriers that will permit increased use of this native resource for future power generation.

Southern Company recently completed a series of small (1/2 inch and less) wood chip co-milling tests. The tests were conducted at two Mississippi Power units, five Alabama Power units, and one Georgia Power unit. The project explored the feasibility of using woody biomass as an energy source by blending it with coal and sending the fuel mix through the existing fuel handling system. The overall percentages of woody biomass that could be co-milled ranged from zero to three percent by energy. This number is lower than initially expected and is greatly influenced by excess pulverizer capacity, pulverizer type and fuel moisture. Additional co-milling studies will be performed with wood pellets as the fuel type at an Alabama Power unit in the near future.

10.6.3 Coal to Biomass Conversion Feasibility Studies

Southern Company is continuing work on feasibility studies to understand the technical, environmental, and cost issues associated with retrofitting pulverized coal units for woody biomass firing. The studies will define the required equipment modifications, performance, environmental emissions, and costs associated with retrofitting coal units. EPRI is collaborating with SCS in co-funding some studies. Comprehensive financial analyses will be performed to determine the economic viability of the biomass conversions. The Plant Mitchell study was completed in 2008 and studies at multiple Mississippi Power, Alabama Power, Gulf Power, and Georgia Power plants continue.

Georgia Power is in the process of considering the technical and economic feasibility of converting certain coal units to woody biomass units. The economic feasibility of converting any of these units may depend on the outcome of potential regulatory or legislative changes (e.g., the EPA's new Industrial Boiler Maximum Allowable Control (MACT) Technology rule that is expected in 2010, the EPA's Electric Generating Unit (EGU) Hazardous Air Pollutants (HAPs) MACT rule expected in 2011, Renewable Electricity Standard (RES) legislation, and climate change legislation). Therefore, the Company will continue to review these types of regulatory and legislative changes as it considers further analysis and development of biomass conversions. If the Company concludes that one or more of the units under consideration appears technically and economically feasible, it may perform more detailed analysis and may submit an application for certification of the biomass conversion to the Commission, as it did with Plant Mitchell Unit 3.

10.6.4 Advanced Biomass Gasification

Utility studies have determined that pressurized biomass gasification for power generation in large-scale (i.e., greater than 50 MW) CC applications can be competitive when compared to other low-cost renewable options. However, there are significant technical issues associated with feeding biomass and with subsequent cleanup of the synthesis gas ("syngas"). These technical challenges will be addressed in collaborative research projects to develop biomass gasification as a power generation option. Bench-scale work is underway at the University of North Dakota Energy & Environmental Research Center ("EERC") and at Auburn University on a 150 psi lab scale gasifier.

The National Carbon Capture Center ("NCCC") (formerly the Power Systems Development Facility), managed and operated by Southern Company on behalf of the U.S. Department of Energy ("DOE"), is also working on biomass gasification at blends up to 20 percent by mass. A "proof-of-concept" demonstration will be conducted at the NCCC. The project will test the properties of biomass feedstocks; research pretreatment technologies that improve biomass handling properties; identify biomass preparation and feed schemes, including advanced feeders, to assure reliable pressurized biomass feed injection; and evaluate various process schemes that manage feeder reliability, ash handling and chemistry, corrosion, and tar formation. The gasifier will be operated in co-feed (coal and biomass), air-blown mode to represent power generation process conditions. Emissions and performance of the gasifier and several downstream syngas cleanup systems will also be documented during these tests.

10.6.5 Biomass Direct Injection Study

Southern Company and Georgia Power are working to develop a better understanding of the technical, environmental, and cost issues associated with co-firing up to 10 percent biomass by energy through direct injection on a Georgia Power coal unit. The study will define the required additional equipment, equipment modifications, performance, environmental emissions, and costs associated with adding the biomass direct injection system to the coal unit. KEMA is the Company's contractor for the study. KEMA will also assess the impacts of co-firing up to 10 percent biomass by energy on downstream emission control equipment.

10.6.6 <u>Biomass Co-Milled Ash Study with Georgia Tech</u>

Currently ASTM recognizes ash exclusively from the combustion of coal for use in concrete and other beneficial use applications. Southern Company has teamed with Georgia Tech to analyze different blended coal and biomass ash mixes to determine the differences in coal only fly ash and co-fired fly ash. Hopefully with acceptable results Southern Company and Georgia Tech will convince ASTM to allow a certain percentage of biomass ash with the coal ash in beneficial uses.

10.6.7 <u>Biomass Effects on Downstream Equipment</u>

Beginning in 2010 Southern Company plans to join an EPRI consortium to look at downstream effects of co-firing 10 percent by energy biomass on a coal-fired unit. The collaborative study will be done on the AES Greenidge Station in Dresden, NY. Currently, Greenidge is the only coal-fired unit in the US with a robust 10 percent direct injection biomass system with plans to run continuously. EPRI will try to determine the effect on Selective Catalytic Reduction ("SCR") catalyst de-activation, boiler tube corrosion and other areas. The study will likely last at least six months.

10.6.8 <u>Torrefied Wood Assessment and Test</u>

Southern Company has entered a collaborative agreement to study the feasibility of torrefied wood as a biomass co-milling fuel for higher percentage co-milling. Torrefied wood is wood that has been turned into a brittle char like material under heat with limited oxygen. Torrefied wood retains over 90 percent of its energy value but loses moisture, becomes more brittle and also becomes hydrophobic meaning it can be stored outside. The end product has many properties similar to coal. The collaborative research with Centre for Energy Advancement through Technological Innovation ("CEATI") International looked at various torrefied wood producers and the maturity of their technology. Southern Company plans to test this material once commercial quantities become available.

10.6.9 <u>Woody Biomass Fuel Supply</u>

The state of Georgia and the southeast have an abundance of forestry and woody biomass resources available for energy use, as evidenced, for example, by fuel studies for Plant Mitchell, as well as data produced by the Georgia Forestry Commission and the U.S. Forest Service. Georgia leads the nation with over 24 million acres of commercial timberland covering two-thirds of the state. The state forests play a vital role in the state's economy and overall quality of life. Data from the Georgia Forestry Commission ("GFC") suggest that, statewide, there is approximately 70 million green tons of wood growth per year produced by a base of about 2 billion tons of standing timber. A GFC study suggests there are about 30 million green tons per year of available, unused woody biomass. Considering the likely demand for this available supply from other potential users (expanding forest products businesses, wood pellet manufacturers, cellulose to ethanol projects, and biomass power plants) and considering that some portion of the available woody biomass is not cost-effective to gather and transport, the Company believes that if required by a federal RES, and with substantial renewable energy credits ("RECs") under a federal RES, it may be possible for Georgia Power to develop several hundred MWs of cost-effective woody biomass generation capacity. This total could potentially include co-firing opportunities, conversions or green-field facilities. Site-specific feasibility studies (e.g., wood fuel study, traffic study, technical feasibility, economic feasibility study, and environmental study) would be necessary to determine the viability of individual projects.

10.7 WIND ENERGY

Georgia Power and Southern Company are studying the feasibility of locating wind turbines off the coasts of Georgia and Florida.

10.7.1 Georgia Coast Offshore Wind Feasibility Study

Southern Company and Georgia Tech's Strategic Energy Institute collaborated on a study of the feasibility of locating wind turbines off the coast of Savannah, Georgia. The goal of the project was to determine if offshore wind power is an efficient and cost-effective renewable energy option for power generation. Design and conceptual engineering for the project was completed using technical expertise from both Georgia Tech and Southern Company. The study evaluated various technology options for wind turbines, platforms/foundations, submarine cabling, and grid interconnection. Detailed analyses of a site location and environmental regulations and jurisdictions, including permitting requirements, were also performed. A final report was completed in early 2007.

10.7.2 <u>Florida Gulf Coast Wind Meteorological Tower</u>

A meteorological tower was installed at Navarre Beach, FL, to examine the wind speeds along the Gulf Coast and their potential to match the utility load profile. The site on which the tower was installed is a strip of beach between the Gulf of Mexico and the Intracoastal Waterway. After the tower was installed in September 2009, data began being collected at three different heights (40, 50, and 60 meters).

10.8 INCREMENTAL HYDRO

Georgia Power and Southern Company continue to research opportunities for incremental hydro resources. Incremental hydro refers to the incremental energy and in some cases, incremental capacity obtained by upgrading existing hydro facilities. Upgrades to existing facilities are usually site specific and could range from replacing worn out equipment (such as a turbine runner) to replacing the entire powerhouse or installing a new powerhouse in an underutilized impoundment. Engineering studies have recently been completed to assess the feasibility and cost of upgrading certain Georgia Power hydro resources. Economic studies will subsequently be completed to determine the timing and/or conditions appropriate for implementing any of the upgrades. If appropriate, the Company would bring such projects before the Commission for approval prior to starting construction.

11 – ADVANCED CLEAN COAL TECHNOLOGIES

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SECTION 11 – ADVANCED CLEAN COAL TECHNOLOGIES

11.1 ADVANCED COAL GASIFICATION AND THE NATIONAL CARBON CAPTURE CENTER ("NCCC")

Southern Company remains active in the development of integrated gasification combined cycle ("IGCC") technology at the NCCC (formerly the Power Systems Development Facility) in Wilsonville, AL, and with planned commercial-scale IGCC projects. The NCCC, operated by Southern Company for the DOE, was established as a research center designed to test advanced coal-based electric power technologies, including gasification, combustion, and gas cleanup processes. The NCCC was originally conceived as the premier advanced coal power generation research and development facility in the world, and it has fulfilled this expectation. Its scope has recently been expanded to include technologies for carbon capture. The facility serves as a unique, highly flexible test center where the technologies being tested are exposed to the requirements and rigors of real plant operating conditions while producing data that can be scaled-up with confidence for commercial demonstration. Integrated operation allows the effects of system interactions to be understood; interactions that can typically be missed in unintegrated pilot-scale testing. The engineering-scale of the NCCC also allows the maintenance, safety, and reliability issues of a technology to be investigated at a cost that is far lower than the cost of commercial-scale testing. In addition to developing a new gasifier system, the NCCC has provided test support to a variety of technologies and components, including the following: syngas cleanup techniques for removal of hazardous pollutants or other emissions; high-efficiency filter elements to remove dust from high-temperature, high-pressure syngas and flue gas; safeguard devices that effectively isolate filters in the event of failure; planar solid oxide fuel cells operating on syngas; innovative coal feed and ash removal systems; and innovative sensor and gas analysis techniques. The successful work done at the NCCC has led to the planned commercial scale demonstrations of the Transport Reactor Integrated Gasification ("TRIG™") system at Kemper County, Mississippi and in China. TRIG™ is an advanced IGCC technology that produces electricity with lower emissions than traditional coal power plants.

KBR and Southern Company will provide Beijing Guoneng Yinghui Clean Energy Engineering Co., Ltd. with licensing, engineering services and proprietary equipment for the implementation of TRIG™ technology at a power plant operated by Dongguan

Tianming Electric Power Co., Ltd. ("Dongguan TMEP") in the Guandong Province of the Peoples Republic of China. At the Dongguan TMEP facility, TRIG™ technology will be added to an existing gas turbine CC plant so that it can use clean synthesis gas from coal rather than fuel oil as its fuel for generating electricity. The plant is scheduled for completion in 2011.

Mississippi Power has proposed building a TRIG™ power plant in Kemper County, Mississippi, that will capture 65 percent of CO_2 emissions. The Kemper County IGCC facility will be equivalent to a new natural gas CC generation resource with respect to CO_2 emissions and will use Mississippi lignite. Pending Mississippi Public Service Commission approval, construction will begin in 2010. The proposed generation station is a 585-megawatt power plant that would begin commercial operation in 2014.

Advanced gasification and combustion technologies for power generation that can be equipped with more cost-effective CO_2 capture technology are needed for the clean and efficient use of the nation's abundant coal reserves. Capturing and sequestering CO_2 from coal-fueled power plants will be a vital part of any strategy to reduce CO_2 emissions. The NCCC has been established to respond to the need for developing cost-effective CO_2 capture technology for coal fueled power generation. The future focus of the NCCC is to conduct sufficient R&D to advance emerging CO_2 control technologies to commercial scale for effective integration into either IGCC or advanced combustion processes. Developing technology options that will reduce CO_2 emissions is a primary goal for future work at NCCC. Cost-effective technologies applicable to both gasification and combustion-based power generation are needed and will be evaluated. Many technologies are under consideration and are being screened in collaboration with DOE and industrial partners. In order to provide a test-bed for technology development, the NCCC has designed and is installing flexible infrastructure capable of supporting the testing of multiple test modules from various technology developers that will allow development of CO_2 capture R&D concepts using coal-derived syngas and flue gas in an industrial setting.

The NCCC is proposing a broad array of technology development activities. The flexibility and scale of the NCCC is well suited to test CO_2 capture technologies. The NCCC can test multiple projects in parallel with a wide range of test equipment sizes leading up to pre-commercial equipment sufficient to guide the design of full commercial scale power plants. The technologies developed at the NCCC will include pre-combustion CO_2 capture, post-combustion CO_2 capture, and oxy-combustion.

In order to develop a cost-effective advanced coal power plant with CO_2 capture, all process blocks within the power plant must be optimized in addition to the capture block. Including CO_2 capture in an advanced coal power plant will increase the plant's cost of producing electricity, so opportunities to reduce cost in every part of the process will be explored. Although highest priority will be given to low-cost CO_2 capture process development, projects that reduce overall process capital and operating costs will also be included in the NCCC test plan to partially offset incremental cost increases due to the addition of CO_2 capture. These cost reduction projects include technology development for syngas cleanup, particulate control, fuel cells, sensors and controls, materials, and feeders. The NCCC will provide a test-bed for scale-up of DOE funded R&D projects as they become available.

The NCCC is a cornerstone for the United States leadership in advanced CO_2 capture technology development. Technologies developed at the NCCC can be scaled directly to commercial sized equipment and can be properly integrated with government or industry funded demonstrations or commercial projects. The NCCC can lead the way to lower cost CO_2 capture technologies and enable coal-based power generation to remain a key contributor to providing affordable, reliable and clean power generation for years to come.

11.2 SOUTHERN COMPANY CARBON CAPTURE AND SEQUESTRATION

The two post-combustion CO_2 capture technologies that Southern Company considers to be the most promising for near-term deployment on existing units at a commercial scale are Alstom's Chilled Ammonia Process ("CAP") and MHI's Kansai Mitsubishi Carbon Dioxide Recovery Process ("KM-CDR") process using KS-1 solvent. Southern Company is investigating both of these technologies. Plans for deployment of post-combustion carbon capture systems to be retrofitted on the existing coal-fired fleet must consider the cost and heat rate penalties associated with these processes.

Southern Company is co-funding, through EPRI, a five MW demonstration of the CAP technology at We Energies' Pleasant Prairie Power Plant (P4). Accomplishments of the

CAP demonstration to date include the integration of several unit operations into a complete process, high levels of CO_2 removal (84 percent), a high purity CO_2 stream, low ammonia emissions and regeneration at pressure. Energy use has been, as predicted, at 29 percent of gross heat input, which is a 41 percent increase in heat rate. Operating challenges include the prevention of solids formation in plate and frame heat exchangers and other components. Ammonia reagent recovery has been constrained by stripper limitations and elevated losses in the blowdown stream. The demonstration process has not achieved long-term operation or high ammonia solution concentration. None of these challenges is considered insurmountable and the P4 pilot is to be followed by a 30 MW demonstration at AEP Mountaineer that is already under construction.

Southern Company is also developing a 25 MW pilot scale demonstration of the KM-CDR process jointly with Mitsubishi, DOE, EPRI and other co-funders at Alabama Power's Plant Barry Unit 5. This plant will capture and sequester CO_2 at a rate of 500 tons per day for three years beginning in 2011. Predictions include a parasitic power load of 22 percent which corresponds to a 28 percent increase in heat rate.

The 25 MW CCS demonstration, which will enter its construction phase in 2010, is already finding design innovations that will reduce the parasitic power required to operate the advanced amine capture process. Following startup in 2011, the facility will capture and sequester up to 150,000 metric tons per year of CO_2 emissions. The goal of the project is to demonstrate on coal-fired flue gas CO_2 capture and purification, pipeline transportation, and ultimate sequestration in deep geologic saline formations near the plant. Southern Company's share of the $175 million total project is $57.4 million, which will be allocated among the operating companies of Southern Company across the 2009 - 2015 project duration. For 2010, Southern Company's share is $24 million with GPC providing approximately $10.2 million of this amount.

On December 3, 2009, DOE selected for negotiations a proposed 160 MW CCS demonstration at Plant Barry. In addition to the Barry project, the AEP similar-scale demonstration of chilled ammonia CCS and the Texas Clean Energy IGCC projects were selected. Negotiations for the 160 MW demonstration, including project costs, are still underway.

12 – HYDRO ELECTRIC OPERATION AND RELICENSING

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SECTION 12 – HYDRO ELECTRIC OPERATION AND RE-LICENSING

12.1 FOREWORD

Georgia Power operates 19 Hydro Electric Facilities and has an ownership interest in a 20th with a total of 75 generating units in Georgia. All but two (2) of these facilities (Barnett Shoals and Estatoah) are licensed under the Federal Power Act. These facilities provide 1090 MW of capacity and have provided approximately 2,269,000 MWh of energy over the 20-year period from 1989 to 2008 to the customers of Georgia. The following information details the re-licensing dates, schedules, requirements and estimated risk of environmental challenges to continued operation associated with these facilities.

12.2 GEORGIA POWER HYDRO PLANT RE-LICENSING SCHEDULE

The following description applies to relicensing proceedings that will be ongoing over the next twenty years.

Morgan Falls

The Federal Energy Regulatory Commission ("FERC") issued a new license for Morgan Falls effective March 1, 2009. There were no changes to the current operations of the plant. The relicensing resulted in about $600,000 of environmental enhancements occurring primarily between 2009-2011.

Bartletts Ferry

License Expires 12/14/2014

The Notice of Intent to File Re-license Application was submitted in May 2009. Consultation with stakeholders will continue until December 2012, when Georgia Power will file its license application with FERC. FERC will issue a new license by December 2014 that will likely include environmental enhancements. The scope of these potential enhancements is unknown at this time, but can be better defined in the next IRP.

Expected Costs of Relicensing Bartletts Ferry:

2009: $500,000

2010: $1,000,000

2011: $1,000,000
2012: $1,000,000
2013: $600,000
2014: $400,000
========
Total: $4,500,000

<u>**Wallace Dam**</u>
License Expires 6/01/2020
The Re-license process is scheduled to start in 2013; a Notice of Intent to File Re-license Application must be filed prior to June 1, 2015.

Expected Costs of Relicensing Wallace Dam:
2014: $500,000
2015: $1,000,000
The remaining years have not been budgeted but are expected to be of similar magnitude.

<u>**Langdale, Riverview, and Lloyd Shoals Projects**</u>
License Expires 1/01/2024
The Re-license process is scheduled to start in 2017; a Notice of Intent to File Re-license Application must be filed prior to January 1, 2019.

<u>**Rocky Mountain Pumped Storage Project**</u> **(Co-owned and Jointly Licensed with Oglethorpe Power)**
License Expires 1/01/2027
The Re-license process is scheduled to start in 2020; a Notice of Intent to File Re-license Application must be filed prior to January 1, 2022.

<u>**Barnett Shoals**</u> (Leased/Unlicensed)
Based on the results of an economic study, Georgia Power will not renew the current lease upon its expiration on May 1, 2010. Barnett Shoals represents only 2.8 MW of Georgia Power capacity and approximately 5,800 MWh of annual generation, so there will be very little impact to the utility upon non-renewal.

12.3 REQUIREMENTS AND RISK TO RE-LICENSING

Requirements

During relicensing, requirements may be imposed by FERC (resulting from input from federal and state agencies, non-governmental organizations, and other stakeholders). Georgia Power is not currently considering any changes to its operations for the large upcoming relicensing proceedings at Bartletts Ferry and Wallace Dam.

Outside of the FERC relicensing proceeding, requirements may be imposed during a license term by the U.S. Fish and Wildlife Service, U.S. Forest Service, or National Park Service through prescriptive authority under the Federal Power Act or by state agencies under Section 401 permits of the Clean Water Act.

Any of these potential requirements can lead to the following impacts or risk to the Company's continued operation of hydro projects.

Risk

Loss of generation and/or capacity from:

- Increased minimum flows;
- Seasonal limits on generation;
- Increased water withdrawals;
- Limits on reservoir fluctuations; or
- Dam Removal (less likely for larger hydro projects).

Reduction in peaking capability, reliability, ancillary services (e.g., voltage control), and operational flexibility from:

- Imposed ramping rates; or
- Modifications to current operational regimes.

Increased capital investments arising from:

- Installation of fish passage facilities;
- Installation of environmental enhancement facilities (e.g., dissolved oxygen);
- Installation of additional recreation facilities;
- Shoreline changes;
- Habitat enhancement;

1) Monitoring and surveillance of environmental parameters; or
2) Replacement of capacity/energy.

13 – ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

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SECTION 13 — ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

13.1 OVERVIEW OF THE ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

The Energy Independence and Security Act of 2007 ("EISA") required the Commission to consider four new PURPA standards. The Commission first addressed the new standards in Docket No. 30041-U. In its final order in that docket, the Commission concluded that the new standards should be considered in the Company's 2010 IRP.

Under PURPA, prior actions by the General Assembly or the Commission ("prior state action") can suffice for compliance with PURPA's mandate to consider these four new standards. Given prior actions by the General Assembly and the Commission, no further action is required with respect to these four new standards.

13.2 ANALYSIS OF FOUR STANDARDS CONTAINED IN EISA

13.2.1 <u>EISA Standard 16</u>

(16) Integrated resource planning. Each electric utility shall—

(A) integrate energy efficiency resources into utility, State, and regional plans; and
(B) adopt policies establishing cost-effective energy efficiency as a priority resource.

<u>Prior State Action</u>

The Georgia General Assembly has implemented a comparable standard, and the Commission has considered and implemented a comparable standard.

<u>Summary</u>

The General Assembly adopted the Integrated Resource Planning Act in 1991, codified at O.C.G.A. § 46-3A-1 *et seq* (the "IRP Act"). Pursuant to this statutory scheme, every third year, the Commission reviews the Company's plans to integrate energy efficiency into the Company's overall resource portfolio and also evaluates a range of energy efficiency measures.

Description

Georgia's IRP Act describes energy efficiency as being part of an IRP and therefore "integrates" energy efficiency into the IRP and "establish[es] cost-effective energy efficiency as a priority resource." Specifically, O.C.G.A. § 46-3A-2 indicates that the Commission must determine whether the IRP "adequately demonstrates the economic, environmental, and other benefits to the state and to customers of the utility, associated with . . . (A) Improvements in energy efficiency . . . ." Similarly, the Commission rules point to the importance of energy efficiency measures: "[i]n IRP, all resources reasonably available to reliably meet future energy service demands are considered by the utility on a fair and consistent basis. These options include, but are not limited to . . . (e) options that reduce demands for utility-supplied power and energy through energy efficiency…." Commission Rule 515-3-4-.02 (25).

In its IRP, Georgia Power integrates energy efficiency resources into its overall resource plans and has adopted policies establishing cost-effective energy efficiency programs as a priority resource. Since its initial IRP filing in 1992, Georgia Power has implemented numerous energy efficiency and DSM programs. Most recently, as part of the Company's 2007 IRP, the Commission approved a wide range of energy efficiency and DSM programs. Six new DSM programs were approved on a pilot program basis: (1) the Power Credit Multifamily Program; (2) the Programmable Thermostat with Home Performance with ENERGY STAR Program; (3) the Compact Fluorescent Light Bulb Program; (4) the Electric Water Heater Insulation Program; (5) the Commercial Tax Incentive Program; and (6) the Refrigerator and Freezer Recycling Program. The Commission also approved a series of commitments from the Company involving end-use energy efficiency. Finally, the Commission approved an award of an "additional sum" pursuant to O.C.G.A. § 46-3A-9 for the Company's certified Power Credit Single Family program.

The DSMWG was formed by the Commission during the 2004 IRP and was tasked with developing a proposed DSM Plan for residential and commercial customers for the Commission's consideration. The DSMWG provides yet another avenue for the Commission to analyze and assess the most effective means of utilizing energy efficiency and DSM programs. The Commission reconvened the DSMWG during the 2007 IRP and the group continued to have regular meetings in preparation for the 2010 IRP.

Going forward, Georgia Power expects to spend approximately $500 million on 18 DSM programs over the next decade to achieve considerable demand reduction.

13.2.2 EISA Standard 17

(17) Rate design modifications to promote energy efficiency investments.

(A) In general. The rates allowed to be charged by any electric utility shall—

(i) align utility incentives with the delivery of cost-effective energy efficiency; and

(ii) promote energy efficiency investments.

(B) Policy options. In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider—

(i) removing the throughput incentive and other regulatory and management disincentives to energy efficiency;

(ii) providing utility incentives for the successful management of energy efficiency programs;

(iii) including the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;

(iv) adopting rate designs that encourage energy efficiency for each customer class;

(v) allowing timely recovery of energy efficiency-related costs; and

(vi) offering home energy audits, offering demand response programs, publicizing the financial and environmental benefits associated with making home energy efficiency improvements, and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.

Prior State Action

The Georgia General Assembly has implemented a comparable standard, and the Commission has considered and implemented a comparable standard.

Summary

Pursuant to Georgia's IRP statutes and the Commission's general oversight, the Company has aggressively pursued cost-effective energy efficiency measures and has been encouraged to do so through various rate recovery measures. To the extent necessary, the Commission has reviewed and approved such programs prior to implementation. In addition, the Company has implemented, under the oversight of the Commission, a number of rate designs and other programs that serve to encourage energy efficiency.

Description

Georgia Power recovers, through its rates, all of the costs associated with the various energy efficiency and DSM programs discussed above. All such programs are evaluated using various economic tests in order to assure that neither the Company nor its customers are negatively impacted by the program. Furthermore, the IRP Act encourages energy efficiency through the rate recovery established for certified demand-side capacity options. O.C.G.A. § 46-3A-9 states that "[t]he approved or actual cost, whichever is less, of any certificated demand-side capacity option shall be recovered by the utility in rates, along with an additional sum as determined by the commission to encourage the development of such resources." The "additional sum" provided in O.C.G.A. § 46-3A-9 adequately aligns Georgia Power's financial incentives with efficient energy use. As discussed above, the Commission has previously allowed recovery to Georgia Power pursuant to this statute.

Georgia Power currently operates under a three year accounting order agreement with the Commission. Under the terms of the current accounting order, Georgia Power's rates and revenue allowances are subject to a full base rate filing at the end of the three year term to reflect current conditions. In addition, the accounting order allows for the possibility of annual rate adjustments if earnings vary outside a stipulated return on equity ("ROE") band. This accounting order arrangement greatly reduces regulatory and management disincentives for energy efficiency.

Additionally, in Georgia Power's 2007 rate case, the Commission approved the "Demand-side Management Residential Rider" or DSM-R-1 that allows for collection of projected program costs and an additional sum amount for the certified Power Credit program. This rider grants to the Company "timely recovery" of its DSM costs, thereby encouraging such energy efficiency measures.

The Company also offers a number of tariffs that serve to promote energy efficiency to its customers. Both the RTP products and the TOU rates offered by the Company are examples of rate designs offered by Georgia Power and approved by the Commission that serve to encourage energy efficiency among all customer classes. In order to promote energy efficiency during times of peak usage, the Company also incorporates seasonality in its rate design. Georgia Power has a summer peak load and the seasonal rate design has been implemented to charge more in the summer months when more expensive generating units are needed in order to meet higher loads. The higher summertime rates promote energy efficiency measures that reduce summertime load or shift that load to off peak seasons. Moreover, within the residential summertime rate structure, rates increase with increased usage. This provides an additional rate incentive for customers to take actions to improve the efficiency of their electricity usage.

The DSMWG, as previously mentioned, serves as a tool by which the Commission and various participants have collaborated in order to analyze energy efficiency programs and DSM initiatives. The Company and the Commission also work with customer groups to actively encourage and initiate new energy conservation and energy efficiency programs. Georgia Power has developed a number of programs that provide educational material and information related to incentives and financing to help program participants select appropriate energy efficiency improvements. The Company has been offering in-home energy audits for more than 15 years, and the number of audits administered has averaged around 4,000 per year for the past two years. Additionally, the Company provides an on-line audit tool for customers, with about 1,400 on-line audits completed per year for the past two years. The Company has an energy efficiency toll-free number, which has received approximately 40,000 calls per year for the past two years, and the Company has spent approximately $4.4 million annually on an Energy Efficiency Consumer Awareness Campaign. The Company recently developed informational material entitled "Homeowner's Tax Incentive Overview" that is being used by Company representatives to assist customers in learning about what tax incentives might be available to them.

Finally, the Company also offers two separate demand response programs: the Power Credit Program and the Demand Plus Energy Credit rider. The Company, under the Commission's supervision, has been permitted to recover the costs associated with such programs.

13.2.3 <u>EISA Standard 18</u>

(18) Consideration of smart grid investments.

(A) In general Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of the State demonstrate to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including—

(i) total costs;

(ii) cost-effectiveness;

(iii) improved reliability;

(iv) security;

(v) system performance; and

(vi) societal benefit.

(B) Rate recovery. Each State shall consider authorizing each electric utility of the State to recover from ratepayers any capital, operating expenditure, or other costs of the electric utility relating to the deployment of a qualified smart grid system, including a reasonable rate of return on the capital expenditures of the electric utility for the deployment of the qualified smart grid system.

(C) Obsolete equipment. Each State shall consider authorizing any electric utility or other party of the State to deploy a qualified smart grid system to recover in a timely manner the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.

<u>Prior State Action</u>

The Commission has considered and implemented a comparable standard.

Summary

Under the supervision of the Commission, Georgia Power has incorporated smart grid technologies throughout its electric system and will continue to do so to the extent such technologies prove cost-effective. All prudently incurred costs are recovered through rates.

Description

The characteristics of a Smart Grid, as described in Title XIII of the EISA 2007, include:

- Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
- Dynamic optimization of grid operations and resources, with full cyber security.
- Deployment of “smart” technologies for metering, communications concerning grid operations and status, and distribution automation.

Georgia Power has and will continue to utilize smart grid technology to the greatest extent possible. Supervisory Control and Data Acquisition (“SCADA”) has been installed on over 90 percent of the transmission and distribution system. Intelligent devices such as digital relays are also deployed throughout the system. Robust communication systems between line and substation devices and the control centers provide optimal utilization of the system. Similarly, intelligent automated line devices such as reclosers, regulators, and switches are deployed over much of the system.

One of the most significant smart grid initiatives undertaken by Georgia Power and approved by the Commission is the deployment of AMI meters to all customers. The AMI meters will allow the Company to assist customers in more fully understanding their cost of electricity, usage patterns and other information related to their electricity consumption. AMI meters have the additional benefit of reducing overall costs as compared with traditional meters, making them very cost-effective. Georgia Power is allowed to recover the costs of the AMI meter through its rates. The current plan is for a six-year deployment process for the AMI meters. One million AMI meters have been installed by January 2010. The remaining 1.5 million AMI meters are planned for installation by the end of 2012.

All such smart grid initiatives undertaken by Georgia Power are analyzed based on total cost, cost-effectiveness, reliability, security, system performance and overall benefit. The initial cost of smart grid systems is usually greater than traditional T&D systems. Therefore, Georgia Power considers and selects smart grid technologies for new investments when there is sufficient current or future benefit to customers or society at large to overcome the increased cost. The Commission has reviewed smart grid related costs and, after balancing a broad range of factors, has allowed recovery to the extent such recovery is in the public interest. More generally, the Company always analyzes its investments in any grid-related technology in order to determine what equipment will most effectively and prudently fulfill the needed purpose. The Commission regulates the cost recovery of all such capital expenditures and, to the extent needed, reviews all such expenditures, based on a variety of factors, in order to determine whether such expenditures are in the public interest.

13.2.4 <u>EISA Standard 19</u>

(19) Smart grid information

(A) Standard. All electricity purchasers shall be provided direct access, in written or electronic machine-readable form as appropriate, to information from their electricity provider as provided in subparagraph (B).

(B) Information. Information provided under this section, to the extent practicable, shall include:

(i) Prices. Purchasers and other interested persons shall be provided with information on—

(I) time-based electricity prices in the wholesale electricity market; and

(II) time-based electricity retail prices or rates that are available to the purchasers.

(ii) Usage. Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them

(iii) Intervals and projections. Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.

(iv) Sources. Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.

(C) Access. Purchasers shall be able to access their own information at any time through the Internet and on other means of communication elected by that utility for Smart Grid applications. Other interested persons shall be able to access information not specific to any purchaser through the Internet. Information specific to any purchaser shall be provided solely to that purchaser.

Prior State Action

The Commission has considered and implemented a comparable standard.

Summary

Georgia Power has adopted a number of programs through which customers are able to gain access to information regarding their usage. Full deployment of AMI meters will likely make such access possible for even more consumers.

Description

Georgia Power has adopted a number of tools by which customers are able to access a wealth of information regarding the electricity purchases that each makes. Customers participating in Georgia Power's RTP program receive either day-ahead or hour-ahead prices reflecting marginal cost price signals based on system operating costs.

Georgia Power's commercial and industrial customers can access information about their power use directly through the internet using Georgia Power's EnergyDirect product. EnergyDirect includes powerful tools to analyze the effect of operating decisions on a customer's energy consumption and costs to help them make informed decisions about energy use. Through the use of interval recording meters, the Company is able to provide RTP and TOU products to its commercial and industrial customers. Such interval recording meters allow the Company and customers to track energy usage on a real time basis.

As discussed above, Georgia Power's AMI deployment is a major step towards more customer access to electricity information. Georgia Power anticipates that once the AMI meters are fully deployed, it will be able to offer customers additional programs using the meters, including allowing customers to view their energy usage online as well as additional innovative rate options. As AMI is deployed, Georgia Power is actively marketing TOU pricing to its residential customers. The Company will continue to work with the Commission in order to ensure that the AMI meters are optimally utilized to provide a full range of information to consumers.

14 – WHOLESALE GENERATION

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SECTION 14 – WHOLESALE GENERATION

14.1 OVERVIEW

The Company has offered certain wholesale capacity blocks to the retail jurisdiction through Docket No. 26550-U. The recent decisions on returning wholesale capacity to retail as well as the potential for additional offers to retail of wholesale capacity blocks is described below. Furthermore, the Company is considering additional potential long-term requirements service agreements with certain wholesale customers as described below.

14.2 BLOCKS 5 & 6 AND SCHERER UNIT 3

In 2008, under Docket No. 26550-U, the Company agreed to offer certain wholesale capacity blocks to the retail jurisdiction. On March 31, 2009, the Company made the first of its offers to retail, 178 MW of wholesale blocks 5 and 6 and approximately 78 MW of Scherer Unit 3. Blocks 5 and 6 consist of oil-fired generating units used as peaking capacity. Scherer Unit 3 is a base-load coal-fired unit.

On July 27, 2009, the Commission issued an order accepting the blocks 5 and 6 offer of 178 MW. Portions of the blocks 5 and 6 capacity will become available to retail at different times as the existing wholesale contracts expire. On January 1, 2011, 33 MW will become available to retail, followed by an additional 51 MW on October 1, 2011. On January 1, 2015, an additional 34 MW will become available to retail, followed by an additional 60 MW on January 1, 2016. The 178 MW of blocks 5 and 6 will remain in retail rate base until the end of the assets' lives.

On September 15, 2009, the Commission issued an order approving acceptance of approximately 78 MW of Scherer Unit 3. Approximately 54 MW will become available to retail on January 1, 2016, with the additional 24 MW on June 1, 2016. The approximately 78 MW Scherer Unit 3 resource will remain in retail rate base for 15 years (until 2031).

On October 7, 2009, the Company filed for application for certification of the blocks 5 and 6 and Scherer Unit 3 resources. The Commission is scheduled to render its decision on February 18, 2010.

14.3 BLOCK 1

Contemporaneous with this IRP filing, also in Docket No. 26550-U, the Company is offering wholesale Block 1 to the retail jurisdiction. Block 1 consists of 250 MW of coal-fired capacity. The capacity will become available to serve the retail jurisdiction on April 1, 2016.

14.4 BLOCKS 2 - 4

Also under Docket No. 26550-U, the Company is in discussions with wholesale customers and may be in position to offer 312 MW of coal-fired capacity represented by a portion of Blocks 2-4 to the retail jurisdiction in early 2010. The capacity could become available on January 1, 2015.

14.5 WHOLESALE REQUIREMENTS CONTRACTS

The Company currently provides requirements service to the city of Hampton. As a result, Hampton's load and generation need is fully integrated into the Company's resource planning process, as required by Commission rules.

The Company is considering additional potential long-term requirements service agreements with other wholesale customers. The Company may provide requirements service under additional long term agreements (e.g., 20-30 years).

The requirements agreements would involve joint integrated long-term planning of wholesale and retail loads and generation resources. The customers' load and generation resources would be combined with Company load resources for planning as well as generation commitment and dispatch, thereby resulting in greater economies of scale benefits. The Company would own (or purchase) new incremental generation required to serve its total load, including the wholesale requirements obligations. Any proposals would be subject to Commission approval of the IRP, which includes the subject requirements load.

The benefits of additional long-term requirements agreements include joint planning of generation and transmission capacity as well as economies of scale resulting in capacity and energy savings.

15 – ACTION PLAN

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SECTION 15 - ACTION PLAN

The Company's action plan is as follows:

- Build, operate, and maintain the necessary generation, transmission, and distribution infrastructure to serve the growing needs of Georgia;

- Maintain long-term system planning reserve margin target of 15 percent;

- Continue to implement and develop all transmission and distribution projects necessary to ensure adequate reliability to the customers in the state of Georgia.

- Meet all environmental requirements.

- Continue certain existing DSM programs, expand certain existing DSM programs, and implement two new DSM programs.

- Request continuation of the program level approach outlined in the 2008 IRP rules waiver for analyzing DSM programs for the 2013 IRP.

- Certify nine DSM programs in Docket No. 31082.

- Request Additional Sum for DSM programs in Docket No. 31082.

- Continue to provide customer information on cost-effective energy saving options that are available in the market and provide customer specific information as required.

- Utilize Qualified Facility contracts and continue to encourage additional resources in compliance with PURPA and the Commission's Avoided Cost Order, Docket No. 4822-U.

- Continue to market the Green Energy Program and proceed with procurement of additional green resources as needed for the program.

- Consider retirement of certain additional coal units if they prove uneconomic based on outcome of HAPS MACT and CCB rulemaking proceedings.

- Delay the conversion of Plant Mitchell Unit 3 from coal to biomass operations pending issuance of draft boiler MACT rules.

- Suspend work on emission controls for Units 6 and 7 at Plant Yates and Units 1 and 2 at Plant Branch until more information is available from the rulemaking and legislative process. Continue review of decision to install controls at Plant Branch Units 3 and 4.

- Restart the 2015 RFP.

- Request approval of transmission costs associated with certified capacity, costs of a portfolio of solar PV demonstration projects, and costs of renewable projects approved in the 2007 IRP;

- Request approval of capital and O&M costs for governmental imposed environmental mandates;

- Continue to promote and expand the TOU-REO rate for residential customers as the AMI network becomes available. Introduce TOU-FCR as an option for these customers to strengthen the price signal.

- Implement changes to RNR and the Solar Demonstration projects identified in the Renewable Resources Section.

- Take actions to enable the option for additional renewable energy resources beyond the conversion of Plant Mitchell Unit 3 from coal to biomass.

- Take actions to enable the option for additional nuclear capacity beyond Plant Vogtle Units 3 and 4.

16 – ATTACHMENTS

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SECTION 16 – ATTACHMENTS

ATTACHMENT 16.1 - MAJOR MODELS USED IN IRP

Economic Model

Georgia Power Company's econometric forecasting models (see below) use forecasts of various key economic and demographic variables for the state of Georgia. These forecasts are developed by Moody's Economy.com, whose large-scale macroeconometric models produce economic and demographic forecasts for the U.S. and for the state of Georgia. Moody's Economy.com's models are proprietary.

Residential End-Use Energy Planning System

REEPS is an end-use model that is used to develop a long-term energy forecast of the residential sector. REEPS was developed under an EPRI contract in conjunction with Regional Economic Research, Inc.

Commercial End-Use Model

COMMEND is an end-use model that is used to develop a long-term energy forecast of the commercial sector. COMMEND was developed under an EPRI contract in conjunction with Regional Economic Research, Inc.

Industrial End-Use Forecasting Model

INFORM is an end-use model that is used to develop a long-term energy forecast of the industrial sector. INFORM was developed under an EPRI contract in conjunction with Regional Economic Research, Inc.

Econometric Forecasting Models

Various econometric forecasting models are used to estimate the relationships between economic and demographic variables and energy use and demand. These models use ordinary least squares regression techniques.

Hourly Electric Load Model (HELM)

HELM is a peak demand model that produces a forecast of peak demand using forecasted class energy, historical class load shapes and corresponding weather, and a description of typical (normal) weather.

SERVM

The Strategic Energy Risk Evaluation Model (SERVM) is a generation reliability model developed by the System in conjunction with an outside consulting firm to evaluate reliability.

SERVM is an hourly, chronological model using Monte Carlo techniques. Random numbers are used to schedule outages based on historical failure and repair time data for the system units. The model executes beginning with 1 A.M. on January 1, committing units, tracking available hydro energy, operating pumped storage units, and calling interruptible load as needed, recording the calls.

The annual processing is performed typically 400 times with the results averaged. This evaluation is performed for each weather-hydro year chosen for the study, typically the previous 40 years.

Useful information provided by SERVM includes:

- Expected unserved energy – the amount of energy that cannot be served due to generating capacity shortages;

- Loss of load hours – the number of hours in which some load is not served, with statistics concerning distribution throughout the year; and

- Interruptible load – the number of times that interruptible load is called, with statistics concerning distribution throughout the year.

SERVM is a major tool providing input for numerous studies. It is used in: 1) developing the target reserve margin; 2) developing interruptible service riders; 3) developing real time pricing tariffs; 4) developing loss of load hour tables in PRICEM; and 5) developing incremental capacity equivalent (ICE) factors.

PROSYM

PROSYM is used to estimate marginal energy cost for use in various models and analyses. It is also used to project marginal sulfur dioxide ("SO_2") allowance costs. PROSYM is an hourly model that utilizes Monte-Carlo techniques to randomly simulate the unit forced outages.

The useful information that can be gathered from PROSYM includes:

- Projections of marginal energy cost by hour for 20 years into the future;
- Projections of the SO_2 marginal cost of serving an additional block of load; and
- The cost effects of changing the characteristics of individual units, such as changing heat rates, station service requirements, or similar factors.

PROSYM supplies important data to many studies. It is or has been used in: (1) determining the worth of improving existing units; (2) developing the marginal energy cost for use in PRICEM and elsewhere; and (3) developing the SO_2 marginal cost for use in PRICEM.

REVREQ

REVREQ is a financial program used to convert capital expenditures into annual revenue requirements. It incorporates projections of the costs of capital, tax rates, and depreciation rates.

The useful information that can be gathered from REVREQ includes:

- Annual revenue requirements necessary to earn a return on and return of the investment;
- Net present value of revenue requirements; and
- Levelized fixed charge rates.

REVREQ provides a key calculation for numerous studies. It is or has been used in: (1) calculating revenue requirements streams for PRICEM; (2) calculating the economic carrying cost rates and net present value of revenue requirements for many studies including for example for use in Strategist®/ PROVIEW™.

Strategist®/ PROVIEW™

PROVIEW™ is a generation planning optimization module of the Strategist® production cost model. It uses dynamic programming techniques to calculate the total capital and operating costs for hundreds of combinations of generating units. It calculates the minimum cost combination of units.

The useful information that can be gathered from Strategist®/PROVIEW™ includes:

- Least cost combination of generating unit additions by year;
- Additional cost of generation expansion plans that are not the least-cost plan; and
- Estimates of fuel use by fuel type.

PROVIEW™ is the basis of the benchmark plan. Sensitivity analyses performed through Strategist®/PROVIEW™ provide information for developing a combination of generating units that will provide a good combination of flexibility, risk reduction, and other considerations. Strategist® is used to integrate the supply-side options and the demand-side programs to produce the IRP. Strategist®/PROVIEW™ are also used to evaluate bids received in the competitive bidding process.

PRICEM

The Profitability Reliability Incremental Cost Evaluation Model ("PRICEM") is a spreadsheet-based marginal cost model designed to predict change in revenue requirements and other effects attributable to changes in loads and/or revenues. PRICEM was developed by the System and takes data from other major models, combining them in a single spreadsheet to provide for quick, yet relatively detailed, evaluations of options. Data inputs are consistent with inputs to Strategist™/PROVIEW™ and as such are taken from: (1) revenue requirements streams from REVREQ, (2) marginal energy cost from PROSYM, (3) ICE factors from SERVM, and (4) Generation Technology Data Book assumptions.

PRICEM models the year with 864 load points and uses the peaker method, a technique allowing the total of generating capacity cost and energy cost to be estimated with peaking capacity and marginal energy cost. The peaker method allows for quick screening of many alternatives. Useful information that can be gathered from PRICEM includes:

- RIM - A net present value calculation of the total benefits and total costs over the life of the program; and
- Predictions of the amount of generating capacity needed to maintain System reliability after a change in interruptible or firm loads.

EnerSim

EnerSim is a comprehensive tool for complex building energy analysis. It has the ability to analyze different types of HVAC systems, HVAC equipment, operations based on design capacity, and part-load performance on total annual energy usage.

EnerSim calculates internal heat from lighting, applications, appliances, and people during occupied and unoccupied hours. The programs use these calculations to estimate annual energy usage. Building load information is calculated and then weather data is used to create a file with the building's hourly usage patterns. RateSim, the rate analysis tool, uses the hourly file to calculate monthly energy bills. RateSim also creates a profile of energy consumption in the format required for use in PRICEM. Heat pumps, air conditioners, electric resistance heat and solar loads are modeled using the ASHRAE Handbook-Fundamentals.

EnerSim is used to calculate the building energy load profiles of weather-sensitive energy efficiency measures, such as heating and cooling equipment upgrades, and insulation and weatherization improvements.

ATTACHMENT 16.2 - TECHNOLOGY SCREENING

Table 16.2.1 TECHNOLOGY SCREENING

Technology	Description	Status
1. Subcritical Pulverized Coal (Conventional Pulverized Coal)	This technology is mature with a large number of units on the system. New units would include the latest emission control systems to ensure compliance with all applicable environmental regulations and permit requirements.	**RETAINED** for further screening.
2. Supercritical Pulverized Coal	This technology is mature with several units on the system. Environmental performance would be similar to subcritical pulverized coal.	**RETAINED** for further screening.
3. Advanced Pulverized Coal	This technology involves the evolution of coal-fueled generation to slightly more extreme steam conditions than supercritical conditions for higher thermal efficiency. It also includes design for flexible operation, including the maintenance of higher efficiencies at partial loads. Many of these advanced features will gradually be incorporated into new base load coal-fueled capacity as they are made available through U.S. and international research efforts. The environmental performance would be similar to subcritical pulverized coal. Material capabilities limit the practical design of this unit, though currently there are operating designs that exceed supercritical limits (main steam conditions around 3600psia and 1100F).	**RETAINED** for further screening.
4. Ultrasupercritical Pulverized Coal (USC)	This technology represents the targeted design of current US and international USC research and embodies coal-fueled generation to steam conditions higher than that achieved by existing advanced pulverized coal technology for even higher thermal efficiency (main steam conditions approaching 5000psia and 1400F). The environmental performance would be similar to sub critical pulverized coal. Material capabilities currently limit the design of this unit.	Dropped from further screening due to low level of development maturity.

Technology	Description	Status
5. Atmospheric Fluidized Bed Combustion (AFBC)	This technology includes both bubbling bed designs and circulating bed designs. AFBC technologies have the potential for sulfur removal without add-on flue gas scrubbers. AFBC is currently better suited to industrial cogeneration and is probably the technology of choice for low grade, high ash coals and are typically limited to 300MW in size. When combined with future supercritical materials, AFBC economics may improve.	Dropped from further screening due to economic reasons.
6. Pressurized Fluidized Bed Combustion (PFBC)	These plants could be produced as modular factory assembled units, but there are reliability concerns with particulate removal at high temperature and pressure, possible corrosion and erosion in the bed, and uncertainties with the cost of large pressure vessels. Vendors have recently stopped marketing and development efforts of PFBC.	Dropped due to lack of commercial development.
7. Topping PFBC	In this concept, the coal feed is partially gasified to produce a low-Btu fuel gas, and the residual char is burned in a PFBC combustor. The flue gas is used as the oxidant to burn the fuel gas and raise the gas turbine inlet temperature to 2,750º F. Vendors have recently stopped marketing and development efforts of TPFBC.	Dropped due to lack of commercial development.
8. Oxygen-Blown IGCC	This concept has potential for modularity, staged construction, and improved efficiency and environmental performance over pulverized coal-firing. Capital cost is an important concern of the technology and the use of advanced turbines is necessary for further efficiency improvement. Southern Company has constructed a power system test facility in conjunction with DOE to refine IGCC. Based on most current studies of CO_2 capture for a coal-fueled power plant, IGCC has a cost advantage over pulverized coal because the CO_2 in the gas stream is much more concentrated and at a higher pressure.	**RETAINED** for further screening.
9. Air-Blown Integrated Coal Gasification Combined	This technology is based on an advanced concept using an air blown transport	**RETAINED** for further screening.

Technology	Description	Status
Cycle	gasifier and associated combustor. Air blown IGCC offers lower capital costs and higher efficiency compared to oxygen blown IGCC. The first commercial scale demonstration of the technology is expected to begin operation by 2012 in China. Further improvements to the technology are being evaluated at the NCCC facility operated at Southern Company in conjuction with the DOE that have the potential for lower capital cost and higher efficiency.	
10. Non-Integrated Coal Gasification Combined Cycle	This concept holds promise for modularity and staged construction. Capital cost is an important concern of the technology and the development of advanced turbines is necessary for further efficiency improvement.	Dropped from further screening because the integrated version would be more cost-effective and efficient.
11. Integrated Gasification Fuel Cell Combined Cycle	This is a future concept that depends on the development of advanced fuel cells that would be substituted for combustion turbines in the gasification combined-cycle plant to provide high efficiency and extremely low environmental emissions. The commercialization of this concept is still uncertain given its dependence on the development of several advanced technology concepts.	Dropped from further screening due to its low level of development and high degree of uncertainty with cost projections.
12. Magnetohydrodynamics (MHD)	MHD appeal is high efficiency and inherent SO_2, nitrogen oxide ("NOx"), and particulate control. The key developmental component is the MHD generator, in which a conducting exhaust gas from the combustion of coal along with seed material is passed thorough a magnetic field to produce DC electricity. The bottoming cycle is a conventional boiler and steam turbine. However, progress with MHD remains slow to stagnant and conceptual estimates indicate very high cost.	Dropped from further screening due to the level of development and cost uncertainties.
13. CT (Conventional/ Advanced)	Many conventional units exist on the system. The technology is mature, but advanced designs offer even higher turbine	**RETAINED** for further screening.

Technology	Description	Status
	inlet temperatures for improved efficiencies. The increasing turbine temperatures will open new reliability questions. CTs can be applied as peaking capacity and in combined cycle plants using natural gas or oil. Advancements are being closely monitored. State-of-the-art combustion NOx control systems will be incorporated in the designs.	
14. CC (Conventional/Advanced)	Units are in operation on the system and the technology is mature. Future designs using more state-of-the-art CTs will offer better economies (see CTs above). Vendors are now offering new CT designs with increased turbine inlet temperatures for improved CC efficiencies. State-of-the-art NOx control systems will be incorporated for environmental compliance. A number of advanced CT based cycles such as the CHAT, HAI, and Kalina cycles have the potential for higher thermal efficiencies, however they have not been commercially demonstrated.	**RETAINED** for further screening.
15. Phosphoric Acid Fuel Cells	Phosphoric acid electrolyte systems using natural gas are the most mature fuel cell technology, but are not economical unless further reductions in capital cost and improvements in reliability can be achieved. Capital cost of this technology is not expected to change dramatically in the future. Attractive features include modular construction, low environmental impact, siting flexibility, and high efficiencies at small sizes.	Dropped from further screening since the advanced fuel cells are expected to have more attractive economics and performance.
16. Advanced High Temperature Fuel Cells - Molten Carbonate Fuel Cell (MCFC) and Solid Oxide Fuel Cell (SOFC)	Fuel cells using molten carbonate or solid oxide electrolyte may be more attractive than the phosphoric acid or PEM fuel cell. Since these fuel cells are operated at high temperatures (600-1000˚C), the incentives include higher efficiencies; more flexible and simplified fuel processing and use of inexpensive catalyst. Also, by-producing heat at these high temperatures, there are more applications than phosphoric acid systems, such as cogeneration and	**RETAINED** for further screening.

Technology	Description	Status
	incorporation of a bottoming cycle. These fuel cells also have potential for use with coal gasification in integrated gasification fuel cell power plants. Cost, material selection under high temperature operation, and cell durability remain important issues. MCFC is being commercialized now at a cost between $2,500-$3,500/KW, though indications are that costs are decreasing. Fuel Cell Energy is the only commercializer in the US for MCFC technology. SOFC is also moving up on the technology maturity curve, but they are at least a couple years behind the MCFC. However, their long term cost projection is lower than that of MCFC. Rolls Royce has expanded their SOFC development and is planning a commercial installation in late 2010 or early 2011. Environmental characteristics are expected to be excellent for all fuel cell technologies.	
17. Fuel Cell CC	See Advanced Fuel Cells. By-product heat from MCFC or SOFC can be used in bottoming cycles to produce additional power. Siemens demonstrated a pressurized 220 KW SOFC/MT hybrid in Ca. and achieved 52 percent efficiency even though the system was not optimized. FuelCell Energy is also testing a atmospheric MCFC/MT hybrid system. DOE Vision 21 power plant highlights such system at efficiency of 60-70 percent (80-90 percent with thermal) with 0 air pollutants and CO_2 (with sequestration) by 2015. The costs from such a system should be at par with market rate.	**RETAINED** for further screening.
18. Reciprocating Engines / Microturbines	Diesel or gas fired generators and microturbines could potentially have economics competitive with combustion turbines at very low capacity factors and for dispersed applications. There are environmental concerns due to relatively high emission rates for certain pollutants when burning diesel fuel.	Dropped from further screening since the applications for dispersed generation are very site-and customer-specific.

Technology	Description	Status
19. Pumped Storage Hydroelectric	Southern Company currently applies this technology on its system. There is uncertainty in initial construction costs that are extremely site-specific, and long lead times are susceptible to project delays. Facilities of this type must deal with environmental issues related to land use and the availability of the water source. This is the most mature storage technology available.	**RETAINED** for further screening.
20. Underground Pumped Storage Hydroelectric (UPH)	Underground pumped storage hydro could avert the environmental and licensing problems of conventional above ground facilities. The high excavation costs and long lead times of UPH significantly reduce its attractiveness. A potential future project site is being developed for Wiscasset, Maine, though nothing has been constructed at this time.	Dropped from further screening due to high cost and stage of technology development.
21. Compressed Air Energy Storage (CAES)	CAES plant hardware is commercially available. The first CAES (290 MW) plant was constructed in Germany in 1978. A 100 MW plant was constructed by Alabama Electric Cooperative and began commercial operation in June 1991 and is an integral part of AEC dispatch. There are several design configurations for new advanced CAES plants (typically coupled with a standard CT), utilizing either above ground (low MW) or below ground (high MW) energy storage options. The potential for large scale energy storage depends on suitable geology for constructing the air storage reservoir. The preferred geology for Southern Company would be salt dome sites in Mississippi and Alabama. CAES has the potential for better local environmental characteristics than pumped hydro. Brine disposal may be an environmental concern during reservoir construction.	**RETAINED** for further screening.
22. Lead/Acid and Advanced Batteries (Load Leveling, UPS)	Lead/acid technology is mature, but life at elevated operating temperature with heavy duty cycles is of concern. Advanced batteries are being developed to achieve	**RETAINED** for further screening. (advanced battery)

Technology	Description	Status
	higher energy and/or power density, higher reliability, lower maintenance and longer life at a cost that can be competitive to conventional lead acid batteries. Potential applications include load management/peak shaving applications to defer the power plant construction for peaking capacity and backup power for T&D substations. Environmental impact on the local area is expected to be very low when the charging source is not considered.	
23. Flywheel Energy Storage	Flywheels store mechanical energy, with the amount dependent on the inertia and rotational speed of the flywheel. Southern Company has demonstrated flywheel feasibility in short term ride-through for power quality (PQ) applications with very good success, but systems for high energy storage applications for peak shaving and/or load leveling are still undeveloped. Acceptable total system costs have been achieved with the PQ units and the ability to integrate the mechanical and power electronic components have been demonstrated. Monitoring of activity in the MW class systems continue and further cost reductions for composite materials, magnetic bearings, and power electronics will improve the chances for future electrical energy storage applications.	Dropped from further screening due to the early status of development and better suitability for dispersed generation applications.
24. Nuclear Advanced Light Water Reactor – Evolutionary	These plants are similar in design to Hatch, Farley and Vogtle but incorporate many evolutionary improvements in areas such as controls, systems, materials, construction techniques, and a streamlined regulatory approval process. Plants in this category include the Advanced Boiling Water Reactor (“ABWR”) by GE and Toshiba, Advanced Pressurized Water Reactor (“APWR”) by Mitsubishi and the European Pressurized Water Reactor (“EPR”) by Areva. ABWRs are in operation in Japan, and are under consideration for several sites in the US. The APWR has been discussed for several US sites, but no	**RETAINED** for further screening.

Technology	Description	Status
	license applications have been submitted to date. The EPR design is being built in Europe, and a modified version has been submitted for certification in the US. The evolutionary designs have the same environmental characteristics as the current fleet of light water reactors.	
25. Nuclear Advanced Light Water Reactor – Passive	Southern Company has made a commitment to this technology as evidenced by the 2008 Engineering, Procurement and Construction contract between Georgia Power and the Westinghouse-Shaw Consortium to construct two AP1000 (1000 MWe) nuclear units at the Vogtle site for commercial operation in 2016 and 2017. In addition to the Westinghouse AP1000 design, this category includes the ESBWR, a passive BWR design under development by GE. The ESBWR is lagging behind the AP1000 in terms of NRC certification. Both the ESBWR and AP1000 are receiving NuStart and DOE support. Westinghouse is also considering development of a larger passive plant, possibly an AP1600 (1600 MW). The current passive designs have the same environmental characteristics as the current fleet of light water reactors.	**RETAINED** for further screening.
26. Nuclear Advanced Light Water Reactor – Modular	The economics of the smaller advanced modular reactor designs, such as the B&W m Power (approximately 125 MW) are unclear. Additionally, these designs are years behind the evolutionary and passive plants in terms of both design development and licensing. They are expected to have the same environmental characteristics as other nuclear options.	Dropped from further screening due to development status.
27. Solar Thermal Parabolic Trough	Solar technologies based on focusing the sun's energy to heat a working fluid work most effectively in direct sunlight. Diffuse solar insolation due to clouds and haze in the Southeast reduces the value of most solar thermal applications, and the high	**RETAINED** for further screening.

Technology	Description	Status
	capital cost and large land area requirements are significant concerns. The technology has good environmental characteristics. One potential application of this technology is to use the steam that can be generated from this technology to augment the steam generated from a conventional fossil power plant giving a lower-cost method of utilizing solar energy to power.	
28. Solar PV	Research continues to increase efficiency and reduce cost. Issues include the site specific solar insolation resource and large land area requirements. There are some limits to applicability in the southeastern U.S. Breakthroughs in PV technology could make this a very attractive alternative. The technology has excellent environmental aspects.	**RETAINED** for further screening.
29. Wind Power	Available wind resources in the southeastern U.S. are not adequate to support significant utility scale use of this technology. Advanced wind turbines that can utilize lower wind speeds could increase potential.	**RETAINED** for further screening.
30. Municipal Solid Waste ("MSW")	MSW generation has been used in some locales where landfills are too expensive or environmentally unacceptable. Thus, it has some potential but is highly site-specific and limited in ultimate quantity.	Dropped from further screening due to limited interest and high level of environmental concern.
31. Dedicated Biomass (wood, etc)	Biomass (wood, wood waste, agricultural residues) is widely available in the Southeast. A dedicated biomass-fired power plant of 50MW to 100MW in size is feasible. Major consideration is obtaining fuel under a long-term contract at a reasonable (and low) price. The plant may rely on gasification of biomass, followed by a CT to convert the gas to electricity. Raw biomass tends to have a high transportation cost, due to its low energy-density in raw form. This places an upper limit on the size of a dedicated biomass-	**RETAINED** for further screening.

Technology	Description	Status
	consuming power plant.	
32. Co-fired Biomass or Wood Waste	Cofiring of switchgrass and wood waste has been demonstrated at several System power stations. Co-firing of these materials is now routine in AL and MS, for green power pricing programs. Cofiring at up to 10 percent is probably the upper limit. Co-firing at high levels is potentially detrimental to SCR emission reduction system catalysts.	**RETAINED** for further screening. (refer to technology 1).
33. Landfill Gas	Capped landfills produce methane gas through anaerobic digestion of the landfill contents. The gas has about half the energy of natural gas per cubic foot and can be burned in engines or co-fired in natural gas boilers or turbines. Many environmental advantages with possible economic viability are present. A single large landfill may provide gas for 7MW max.	**RETAINED** for further screening.
34. Geothermal	Geothermal resources in the southeastern U.S. are not adequate to support utility scale of this technology.	Dropped from further screening due to limited applicability in Georgia Power's and Southern Company's territory.
35. Solar Stirling Dish	The Dish Stirling engine operates as an externally heated piston-driven prime mover. In a solar Stirling dish system, a dish is used to capture and focus sunlight to provide heat for the Stirling engine. As with the parabolic trough and other reflector systems, diffuse solar insolation due to clouds and haze in the Southeast greatly reduces the effectiveness and value of solar Stirling dish. This technology has good environmental characteristics, but applicability is very limited in southeastern U.S.	Dropped due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
36. Solar Central Receiver Technology	This technology is commonly referred to as a "power tower", where an array of mirrors is focused on a specific area on a tower that contains a receiver (boiler) where steam is	Dropped due to cost uncertainties, level of development, and

Technology	Description	Status
	made directly. It works most effectively in direct sunlight. Diffuse solar insolation due to clouds and haze in the Southeast reduces its value, and the high capital cost and large land area requirements are significant concerns. This technology has good environmental characteristics.	limited applicability in Georgia Power's and Southern Company's territory.
37. Compact Linear Fresnel Reflector	Rows of solar collectors reflect solar radiation onto a linear receiver above the solar field in which pressurized water is converted into steam. It works most effectively in direct sunlight. Diffuse solar insolation due to clouds and haze in the Southeast reduces its value, and the high capital cost and large land area requirements are significant concerns. This technology exhibits good environmental characteristics.	Dropped due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
38. Ocean Energy & Hydrokinetic Generation	Ocean energy and hydrokinetic generation includes power generation from waves, ocean current, tides, and river current. Specific research has begun to be conducted in these areas defining the resources and developing technologies that can utilize these resources. They have the potential to negatively affect estuarine environments.	**RETAINED** for further screening (hydrokinetic only). Ocean energy dropped due to cost, level of development, lack of sites, and environmental considerations.
39. Ocean Thermal Generation	The temperature difference between surface and deep ocean waters can be used to drive an ammonia or other low-temperature power cycle to produce power. In most situations, tropical locations with deep ocean near shore are sought. There are environmental concerns with releasing cold bottom water at the ocean surface and with the potential for ammonia release.	Dropped due to cost uncertainties, level of development, lack of good sites in Georgia Power's and Southern Company's territory, as well as potential environmental considerations.

Table 16.2.2 Candidate Technologies

COAL-FUELED	LIQUID/GAS FUELED (CONTINUED)
Subcritical Pulverized Coal (2400 psi) Supercritical Pulverized Coal (3500 psi) Advanced Pulverized Coal Ultrasupercritical Pulverized Coal Atmospheric Fluidized Bed Combustion Bubbling Bed Circulating Bed Pressurized Fluidized Bed Combustion Bubbling Bed Circulating Bed Advanced Topping Circulating FBC Integrated Gasification Combined Cycle Oxygen-Blown Advanced Air-Blown Non-Integrated Coal Gasification Combined Cycle Integrated Gasification Fuel Cell Combined Cycle Magnetohydrodynamics (MHD) **LIQUID/GAS FUELED** Combustion Turbine Conventional Combustion Turbine Advanced Aeroderivative – Simple Cycle Combined Cycle Conventional Heavy Oil-fired Combined Cycle Advanced G/H technologies Inlet Air Chilling Kalina Cycle Cascaded Humidified Adv. Turbine (CHAT) Humidified Air Injection (HAI)	Phosphoric Acid Fuel Cell Advanced Fuel Cells Fuel Cell Combined Cycle Diesel Generator **ENERGY STORAGE** Pumped Hydro Underground Pumped Hydro Lead Acid Battery Advanced Battery Flywheel Compressed Air Energy Storage **NUCLEAR** Advanced LWR Evolutionary Advanced LWR Passive Advanced LWR Modular **RENEWABLES** Solar Thermal Parabolic Trough Photovoltaics Wind Power Municipal Solid Waste Biomass (Wood, etc.) (Dedicated/co-firing) Landfill gas Geothermal Solar Dish Stirling Solar Central Receiver Compact Linear Fresnel Reflector Ocean Wave and Hydrokinetics Ocean Thermal Generation

Table 16.2.3 Technologies Selected for Further Screening

COAL-FUELED:	**ENERGY STORAGE:**
Conv. Pulverized Coal (Subcritical)	Pumped Hydro
Conv. Pulverized Coal (Supercritical)	Compressed Air Energy Storage
Advanced Pulverized Coal	Advanced Battery
Oxygen-Blown IGCC	
Air-Blown IGCC	**NUCLEAR:**
	Advanced LWR - Evolutionary
GAS-FUELED:	Passive Safety Advanced LWR
Combustion Turbine Conventional	
Combustion Turbine Advanced	**RENEWABLES:**
Combined Cycle Conventional	Solar Thermal Parabolic Trough
Combined Cycle Advanced	Photovoltaics
501G / H	Wind Power
Advanced Fuel Cell	Dedicated Biomass
FCCC	Co-fired Wood Waste
	Landfill Gas
	Hydrokinetic

ATTACHMENT 16.3 - SUMMARY OF THE SYSTEM POOLING ARRANGEMENT

Introduction

Georgia Power Company is a member of the Southern electric system (SES), which consists of, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company ("Operating Companies"). The Operating Companies function as a single, integrated public-utility system through adherence to the Southern Company System Intercompany Interchange Contract (IIC), an agreement on file with the Federal Energy Regulatory Commission (FERC). Southern Company Services, Inc. (SCS) acts as agent for the Operating Companies in the administration of the IIC. The term of the IIC provides for the agreement to continue in effect from year-to-year after the effective date subject to termination at any time by mutual agreement of all the Operating Companies or subject to termination by an individual Operating Company by giving five years advance written notice.

The IIC provides a framework whereby the generating resources of the Operating Companies are operated in a coordinated and integrated fashion to economically serve their aggregate firm obligations, as well as to engage in shorter term transactions in the wholesale markets. Using traditional concepts of economic dispatch, the Pool deploys available generation to satisfy the aggregate obligations of the system at any given time in a reliable and economic fashion. The IIC also provides for coordinated planning between the Operating Companies and for the sharing of temporary surpluses and deficits of capacity. The IIC ensures that the after-the-fact accounting associated with joint system dispatch (energy) and reserve sharing (capacity) is handled in accordance with the principles set forth in that agreement. It should be noted that the coordinated planning process for the four traditional (retail) companies (Mississippi Power, Alabama Power, Georgia Power and Gulf Power) has been functionally separated from the planning process for Southern Power in the latest IIC. This functional separation does not change the manner in which the other four Operating Companies have traditionally conducted coordinated planning.

Relationship of the Operating Companies under the IIC

The Southern Company Pool is a coordinated Pool, not a centralized Pool. Although the generating facilities of each Operating Company are committed to a centralized economic dispatch, each individual Operating Company retains the right and the responsibility for providing the generation and transmission facilities necessary to meet the requirements of its customers. Each Operating Company has its own management that reports to its own board of directors, with the management and the board of directors of each Operating Company being directly responsible for making the decisions that affect that Operating Company and its customers. They are also responsible for working with local regulators and adhering to the requirements of state law.

Accordingly, each Operating Company has its own distinct characteristics in regard to types of generation and load. For example, Alabama Power, Georgia Power and Southern Power bring hydroelectric and nuclear generating capacity to the Pool, while the other Operating Companies do not. Similarly, the load characteristics of the Operating Companies vary due to the types of customers each brings to the Pool. The differing economies within each Operating Company territory and/or customer base lead to different load growth rates and load shapes for each Operating Company.

The IIC provides for an Operating Committee that consists of one representative of each Operating Company and SCS, with the SCS representative acting as a non-voting Chairman. The functional separation of certain activities of Southern Power restricts the participation of its Operating Committee member in some matters (such as discussions and recommendations involving the coordinated planning of the four retail Operating Companies). A unanimous vote of the five Operating Company members is required in order to change the IIC.

Interconnections

The Operating Companies are interconnected with 12 non-associated utilities through 61 different transmission facilities. These transmission lines are operated at voltages of 46 kV, 69 kV, 115 kV, 161 kV, 230 kV and 500 kV, and include facilities that are operated normally open. The non-associated utilities with which the SES is interconnected are shown in Table 16.3.1 below.

Table 16.3.1 – Non-associated Utilities

Florida Power & Light Company	Progress Energy - Florida
JEA	City of Tallahassee
Duke Energy Corporation	South Carolina Electric & Gas Company
Tennessee Valley Authority	South Carolina Public Service Authority
Entergy Corporation	Crisp County Power Commission
PowerSouth Energy Cooperative	South Mississippi Electric Power Association.

<u>Basic Principles of the IIC</u>

The basic principles of the IIC can be summarized as follows.

1. Each Operating Company submits its load and generation to the Pool for joint commitment and economic dispatch.
2. Energy Principles
   a. Each Operating Company retains its lowest cost resources to serve its customers.
   b. An Operating Company's excess energy is then made available to the other Operating Companies to serve their customers.
   c. An Operating Company is entitled to buy energy from the Pool if the cost is lower than energy from its own resources.
   d. Energy in excess of that necessary to serve the Operating Companies' customers is marketed by the Pool to the wholesale markets.
3. The IIC provides for coordinated planning among the retail Operating Companies and for the sharing among all Operating Companies of temporary surpluses and deficits of capacity.

4. Under the IIC, each Operating Company shares in the benefits and pays its share of the costs resulting from their coordinated operations.

Participation in the Southern Company Pool provides benefits to the Operating Companies and to their customers. This not only enhances GPC's ability to provide reliable, low-cost electric service to its customers but also to achieve economies of scale in any required investments. Benefits of Pool participation include:

(a) Staggering construction of new generating facilities so that each retail Operating Company can construct and install the optimum sized generating facilities while utilizing economies of scale;

(b) Sharing temporary surpluses and deficits of generating capacity that can arise as a result of coordinated planning or other circumstances (e.g., staggered construction schedules, variations in load patterns, load forecast uncertainties, etc.);

(c) Coordinating scheduled maintenance to provide greater flexibility, including major maintenance requiring relatively long unit outages, as well as mitigating the cost impact (to customers) of these required outages;

(d) Carrying a lower generation planning reserve margin (due primarily to system load diversity), which enables each Operating Company to have a lower investment in generating resources;

(e) Providing reliable service with shared operating reserve requirements (which puts downward pressure on fuel costs);

(f) Access to lower cost energy from other Operating Companies;

(g) Enhanced reliability of electric service through the use of transmission interconnections to provide backup service in case of emergencies as well as providing the ability to import lower cost energy when available; and,

(h) Acting as a Pool (instead of individual Operating Companies) to identify shorter term purchase and sale opportunities in the wholesale markets that may be available from time to time.

Basic Operation of the IIC

The concept of economic dispatch, which seeks to minimize the total system production cost, is one of the major benefits of the Pool. The generating assets of all the Operating Companies in the Pool are committed and dispatched as a common system without regard to the ownership of each generating facility. Subject to operational constraints and reliability considerations, the lowest cost generation assets are dispatched during each hour to meet the total needs of the customers of all the Operating Companies. The goal of this process is to ensure that the lowest cost energy is produced every hour. It also should be noted that each Operating Company retains its lowest cost generation to serve that Operating Company's customers.

The Pool also interfaces with the wholesale markets on behalf of the Operating Companies for both sales and purchases. When the Pool has excess power available, it will pursue wholesale sales opportunities for which there is a reasonable expectation that the transaction will result in positive net margin for the Operating Companies. There are two primary reasons for the Pool to seek purchase opportunities: (1) economics; and (2) reliability. The Pool will pursue purchase opportunities from the wholesale markets if such purchases are expected to be more economical than system resources (again, subject to operational constraints and system reliability). In the event the Pool experiences reliability challenges, then the Pool may seek purchases in response to such operating conditions.

Reserve Sharing

As noted in the introduction, the IIC contains capacity provisions, commonly referred to as "reserve sharing", that provide for a sharing of temporary generating capacity surpluses and deficits that are a result of coordinated planning or other circumstances. As participants in the coordinated operation of the integrated electric system, each Operating Company enjoys the same level of service reliability. In any given month, however, one or more Operating Companies will have a temporary surplus or deficit of capacity relative to the overall level of actual system reserves. Consistent with the goal of sharing in the benefits and burdens of the coordinated and integrated electric system, the reserve sharing provisions of the IIC provide for the equitable allocation of such temporary surplus or deficit capacity. The resulting purchase and sale of capacity is transacted on a monthly basis.

Reserve sharing is determined by comparing each Operating Company's load responsibility with its respective capacity resources recognized through the coordinated planning process. The Operating Companies must own or purchase sufficient capacity (including capacity available for load service and that which is unavailable due to forced outage, partial outage, and maintenance outage) needed to reliably serve their respective load responsibilities. Capacity above that amount is considered reserve capacity, and each Operating Company is responsible for a portion of such reserve capacity based upon historical peak load ratios. If an Operating Company's reserve capacity is less than its reserve responsibility, that Operating Company will make reserve sharing payments under the IIC for the month

Each Operating Company develops an annual charge (payments are based on monthly capacity worth) based upon the cost of its most recently installed or purchased peaking resource(s). The Operating Companies that are "selling" capacity to the Pool will receive a payment from the Pool based upon their respective capacity rates. The Operating Companies that are "buying" capacity from the Pool will make payments to the Pool based upon the weighted average of the capacity rates of the "selling" Operating

Companies   In this way, all the buying Operating Companies pay the same composite cost in a given month for reserve sharing purposes. By definition, the amount by which one or more Operating Companies are "short" (make payments) will be equal to the amount by which one or more Operating Companies are "long" (receive payments).

Energy Transactions

Energy transactions within the Pool are accounted for on an hour-to-hour basis, with the accounting occurring after-the-fact utilizing the actual flows among the operating companies.

The actual real-time operation of the system is based upon the concept of economic energy dispatch, which through on-line computer control assures that available generation is dispatched so as to choose the most economical generation available to serve the total System obligation at any given time. An adequate set of lowest-cost generating resources is committed in advance to meet the total System obligation, with due regard for generation requirements associated with service area protection, voltage control, unit protection, and other operating limitations considerations.

For billing purposes under the IIC, each operating company is deemed to have retained its lowest-cost energy resources (most notably hydro and nuclear) to serve its own territorial customers, plus whichever of its resources that may have been operating outside of economic dispatch for purposes of service area protection or voltage control. To the extent an operating company's generation exceeds its own load obligations, that energy is sold to the pool under the IIC. If an operating company's generation is not equal to or greater than its own load obligations, the difference is purchased from the pool. The energy rate for energy sold to or purchased from the pool by each operating company is referred to as the Associated Interchange Energy Rate and represents the incremental System cost of serving the Operating Companies' aggregate firm obligations. Under the IIC, the determination of which operating companies are buying from and which are selling to the pool is made on an hourly basis, and an invoice that accounts for these energy transactions is rendered monthly.

Peak-Period Load Ratios

Peak-Period Load Ratios are utilized in the allocation of certain energy and capacity transactions by the Pool with non-associated systems, hydro regulation energy losses, increases in cost due to hydro regulation, and other allocations provided for in the IIC and the Manual to the IIC.

The Peak-Period Load Ratios for each contract year are based upon the prior year's actual peak period energy in the months of June, July, and August for each Operating Company. The peak period is defined to be the 14 hours between 7:00 a.m. and 9:00 p.m. of each weekday, excluding holidays. The System peak-period energy is equal to the sum of all the Operating Companies' peak period energy.

The Peak-Period Load Ratios are determined by dividing each Operating Company's summation of the June, July, and August actual weekday peak-period energy loads by the total System June, July and August actual weekday peak-period energy loads.

ATTACHMENT 16.4 - RESEARCH ACTIVITIES

Research Projects

Georgia Power, both individually and in coordination with the other members of the Southern Electric System, is involved in a wide range of research projects. These projects can be categorized into four major strategic areas: Environmental Issues, Energy Supply Research, Customer Technologies, and Research & Environmental Management. Each of these areas is composed of a number of groups of programs. The following discussions will concentrate on these groupings rather than each single program.

Environmental Issues

Environmental Policy Analysis – Provide scientific and economic analyses of policy options, legislation, and international initiatives as well as recommendations for actions to achieve environmental goals.

Environmental Regulation – Seek to enable and encourage regulatory agencies to set and achieve environmental regulatory goals that are in concert with legislative mandates and that minimize compliance costs.

Regulatory Implementation Program – Provide analyses necessary to minimize the cost of complying with environmental requirements

Environmental Compliance Strategies and Permitting Program – Develop, maintain and coordinate the implementation of a system-wide, cost effective environmental compliance strategy and provide direct technical support for all clean air implementation activities. This program also seeks environmental permits that clearly meet the intent of regulations and carry out Southern Company's environmental commitment while balancing operating flexibility, schedules, and cost.

Environmental Sciences Research Program – Develop information related to environmental effects of the company's operations to support company efforts to make sound science available for environmental regulatory policy decisions.

Environmental Stewardship Program – Develop, implement, and coordinate a comprehensive, integrated environmental stewardship initiative and the program as a whole; establish and maintain a professional and productive relationship with interested stakeholders; and conduct productive, two-way communications with internal and external stakeholders regarding environmental issues.

Energy Supply Research

Emissions Control Program – Conduct research and provide information on new technologies that will minimize compliance costs related to current and future power plant emissions.

Fuels and Combustion By-Products – Develop methods for reducing fuel-related costs while addressing environmental and waste-disposal concerns.

Plant Enhancements Program – Develop improvements to existing generation facilities through advanced technologies that either reduce costs or increase performance.

Gas Turbines, CCs, and Supply Options – Provide assessments of mature and emerging generation technologies to support the system planning function of the company.

Renewable Energy Program – Evaluate new and existing renewable resources to determine low-cost renewable energy options.

NCCC (formerly Power Systems Development Facility Program) – Research coal-based power generation technologies that will competitively produce electricity while meeting all environmental requirements.

Customer Technologies

Industrial Technologies Program – Attempt to identify and deliver new technologies that add value to our existing products and services for our industrial customers.

Residential and Commercial Technologies Program - Attempt to identify and deliver new technologies that add value to our existing products and services for our residential and commercial customers.

Electric Transportation Program – Develop strategies for the appropriate and efficient deployment of supporting charging infrastructure for fleet, industrial, public transportation, and consumer electric vehicles.

Distributed Resources Program – Research, develop, demonstrate, and plan the implementation of distributed utility technology products.

Research and Environmental Management

This area includes strategic planning, budgeting, and administration for the Research and Environmental Affairs department. The area is responsible for assisting both in-house research programs and leveraging external research programs such as EPRI.

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National Land Cover Database Zone 55 Land Cover Layer

Metadata also available as

Metadata:

Identification_Information:
Citation:
Citation_Information:
Originator: U.S. Geological Survey
Publication_Date: 20030901
Title: National Land Cover Database Zone 55 Land Cover Layer
Edition: 1.0
Geospatial_Data_Presentation_Form: remote-sensing image
Series_Information:
Series_Name: None
Issue_Identification: None
Publication_Information:
Publication_Place: Sioux Falls, SD
Publisher: U.S. Geological Survey
Other_Citation_Details:
References:Homer, C., C. Huang, L. Yang, B. Wylie and M. Coan, 2004. Development of a 2001 national land cover database for the United States. Photogrammetric Engineering and Remote Sensing Vol.70,No.7,pp 829-840 or online at www.mrlc.gov/publications.The USGS acknowledges the support of SEGAP in development of data in this zone.
Online_Linkage: <http://www.mrlc.gov>
Description:
Abstract:

The National Land Cover Database 2001 land cover layer for mapping zone 55 was produced through a cooperative project conducted by the Multi-Resolution Land Characteristics (MRLC) Consortium. The MRLC Consortium is a partnership of federal

agencies (www.mrlc.gov), consisting of the U.S. Geological Survey (USGS), the National Oceanic and Atmospheric Administration (NOAA), the U.S. Environmental Protection Agency (EPA), the U.S. Department of Agriculture (USDA), the U.S. Forest Service (USFS), the National Park Service (NPS), the U.S. Fish and Wildlife Service (FWS), the Bureau of Land Management (BLM) and the USDA Natural Resources Conservation Service (NRCS). One of the primary goals of the project is to generate a current, consistent, seamless, and accurate National Land cover Database (NLCD) circa 2001 for the United States at medium spatial resolution. This landcover map and all documents pertaining to it are considered "provisional" until a formal accuracy assessment can be conducted. For a detailed definition and discussion on MRLC and the NLCD 2001 products, refer to Homer et al. (2004) and <http://www.mrlc.gov/mrlc2k.asp>.

The NLCD 2001 is created by partitioning the U.S. into mapping zones. A total of 66 mapping zones were delineated within the conterminous U.S. based on ecoregion and geographical characteristics, edge matching features and the size requirement of Landsat mosaics. Mapping zone 55 encompasses whole or portions of several states, including the states of Georgia and Florida. Questions about the NLCD mapping zone 55 can be directed to the NLCD 2001 land cover mapping team at the USGS/EROS, Sioux Falls, SD (605) 594-6151 or mrlc@usgs.gov.

Purpose:
The goal of this project is to provide the Nation with complete, current and consistent public domain information on its land use and land cover.
Supplemental_Information:
Corner Coordinates (center of pixel, projection meters)Upper Left Corner: 1017660 meters(X), 1259430 meters(Y)Lower Right Corner: 1486830 meters(X), 729690 meters(Y)Spatial-specific information not available
Time_Period_of_Content:
Time_Period_Information:
Range_of_Dates/Times:
Beginning_Date: 19991023
Ending_Date: 20030124
Currentness_Reference: ground condition
Status:
Progress: In work
Maintenance_and_Update_Frequency: As needed
Spatial_Domain:
Bounding_Coordinates:
West_Bounding_Coordinate:-82.0661233437757
East_Bounding_Coordinate:-81.4416524119572
*North_Bounding_Coordinate:*33.4190690692362
*South_Bounding_Coordinate:*32.8582535780573
Keywords:
Theme:
Theme_Keyword_Thesaurus: None

Theme_Keyword: Land Cover
Theme_Keyword: GIS
Theme_Keyword: U.S. Geological Survey
Theme_Keyword: USGS
Theme_Keyword: digital spatial data
Theme:
Theme_Keyword_Thesaurus: ISO 19115 Category
Theme_Keyword: imagery
Theme_Keyword: Base Maps
Theme_Keyword: Earth Cover
Theme_Keyword: SEGAP
Theme_Keyword: GAP
Place:
Place_Keyword_Thesaurus:
U.S. Department of Commerce, 1995, Countries, dependencies, areas of special sovereignty, and their principal administrative divisions, Federal Information Processing Standard 10-4,): Washington, D.C., National Institute of Standards and Technology
Place_Keyword: United States
Place_Keyword: U.S.
Place_Keyword: US
Place:
Place_Keyword_Thesaurus: None
Place_Keyword: zone 55
Place:
Place_Keyword_Thesaurus:
U.S. Department of Commerce, 1987, Codes for the identification of the States, the District of Columbia and the outlying areas of the United States, and associated areas (Federal Information Processing Standard 5-2): Washington, D.C., National Institute of Standards and Technology
Place_Keyword: GA
Place_Keyword: Georgia
Place_Keyword: FL
Place_Keyword: Florida
Access_Constraints: None
Use_Constraints: None
Point_of_Contact:
Contact_Information:
Contact_Organization_Primary:
Contact_Organization: U.S. Geological Survey
Contact_Position: Customer Services Representative
Contact_Address:
Address_Type: mailing and physical address
Address: USGS/EROS
Address: 47914 252nd Street
City: Sioux Falls
State_or_Province: SD

Postal_Code: 57198-0001
Country: USA
Contact_Voice_Telephone: 605/594-6151
Contact_TDD/TTY_Telephone: 605/594-6933
Contact_Facsimile_Telephone: 605/594-6589
Contact_Electronic_Mail_Address: custserv@usgs.gov
Hours_of_Service: 0800 - 1600 CT, M - F (-6h CST/-5h CDT GMT)
Contact_Instructions:
The USGS point of contact is for questions relating to the data display and download from this web site. For questions regarding data content and quality, refer to:<http://www.mrlc.gov/mrlc2k.asp> or email: mrlc@usgs.gov

Data_Set_Credit: U.S. Geological Survey
Security_Information:
Security_Classification_System: None
Security_Classification: Unclassified
Security_Handling_Description: N/A
Native_Data_Set_Environment:
Microsoft Windows 2000 Version 5.1 (Build 2600) Service Pack 1; ESRI ArcCatalog 9.0.0.535

Data_Quality_Information:
Attribute_Accuracy:
Attribute_Accuracy_Report:
The information on data quality for mapping zone 55 was generated by the Decision Tree algorithm that conducts a cross-validation for assessing classification and prediction reliability. No formal independent accuracy assessment of mapping zone 55 land cover has been made. The regression tree algorithm employed in NLCD 2001 mapping offers a cross-validation option for assessing classification and prediction reliability. Cross-validation can provide relatively reliable estimates for land cover predictions if the reference data used for cross-validation are collected based on a statistically valid sampling design. For mapping zone 55 land cover modeling, a 10-fold cross-validation was conducted by dividing the entire training data set into 10 subsets of equal size. For each model run, an accuracy estimate was derived using one subset to evaluate the model prediction (with the model developed using the remaining training samples). This process was repeated 10 times. After all 10 runs, an average value of all accuracy estimates from the 10 runs were computed. Users should be cautioned that these cross-validation results provide users with only first-order estimates of data quality, and should not be considered a formal accuracy assessment. This landcover map and all documents pertaining to it are considered "provisional " until a formal accuracy assessment can be conducted.
Quantitative_Attribute_Accuracy_Assessment:
Attribute_Accuracy_Value: 72
Attribute_Accuracy_Explanation:
The above listed value is the overall accuracy obtained for the land cover data using a cross-validation estimate from the decision tree model. This document and the described landcover map are considered "provisional" until a formal accuracy assessment is completed. The U.S. Geological Survey can make no guarantee as to the accuracy or

completeness of this information, and it is provided with the understanding that it is not guaranteed to be correct or complete. Conclusions drawn from this information are the responsibility of the user.

Logical_Consistency_Report:

The NLCD 2001 database for mapping zone 55 consists of three main data products including: (1) per pixel classified land-cover data (2) sub-pixel percent imperviousness and (3) sub-pixel percent tree canopy density. The land-cover database also includes three additional metadata layers that provide users a spatial node map of the land cover classification. The three layers are: (a) a spatial node map of the land cover classification, (b) a spatial confidence map of the land cover classification, and, (c) a text file of logical statements related to the land cover classification.

Conceptually, the descriptive tree is a classification tree generated by using the final minimum-map- unit land cover product (1 acre) as training data, and Landsat and other ancillary data as predictors. The goal of the descriptive tree is to summarize the effects of boosted trees (10 sequential classification trees) into a single condensed decision tree that can be used as a diagnostic tool for the classification process. This descriptive tree can be used to assess the relative importance of each of the input data sets on each land cover class. Such information may also be useful to customize the minimum-mapping-unit classification to meet a user's specific needs through raster modeling. Descriptive trees usually capture 60 to 80% of the information from the original land cover data.

The leaf or terminal nodes of the descriptive tree are assigned to sequential numbers (called node numbers) and mapped across the entire mapping zone on a pixel-by-pixel basis. These node numbers can then be matched with the various conditional statements associated with each respective terminal node. This spatial layer appears similar to a cluster map, but is the result of a supervised classification - not an unsupervised clustering. This node map can potentially be used as input by users to customize NLCD land cover, by linking the spatial extent of an individual node with the rules of the conditional statement.

The Land Cover spatial classification confidence data layer is provided to users to help determine the per-pixel spatial confidence of the NLCD 2001 land cover prediction from the descriptive tree. The C5 algorithm produces an estimate (a value between 0% and 100%) that indicates the confidence of rule predictions at each node based on the training data. This spatial confidence map should be considered as only one indicator of relative reliability of the land cover classification, rather than a precise estimate. Users should be aware that this estimate is made based on only training data, and is derived from a generalized descriptive decision tree that reproduces the final land cover data. However, this layer provides valuable insight for a user to determine the risk or confidence they choose to place in each pixel of land cover.

A logic statement from a descriptive tree classification describes each classification rule for each classified pixel. An example of the logic statement follows:

IF tasseled-cap wetness > 140 and imperviousness = 0 and canopy density < 4, then classify as Water

This logic file can be used in combination with the spatial node map to identify classification logic and allow modifications of the classification based on user's knowledge and/or additional data sets.

Additional information may be found at <http://www.mrlc.gov/mrlc2k_nlcd.asp>.

Completeness_Report:
This NLCD product of mapping zone 55 Land Cover layer is the version dated 03/01/2006.
Positional_Accuracy:
Horizontal_Positional_Accuracy:
Horizontal_Positional_Accuracy_Report: N/A
Vertical_Positional_Accuracy:
Vertical_Positional_Accuracy_Report: N/A
Lineage:
Process_Step:
Process_Description:
The land cover classification was achieved by use of a classification and decision tree method (DT) using a combination of Landsat imagery and ancillary data. The decision rules were generated with See5, which implements a gain ratio criterion in tree development and pruning (Quinlan, 1993). See5 also implemented several advanced features that can aid and improve land cover classification, including boosting and cross-validation. Boosting is a technique for improving classification accuracy, while cross-validation can provide certain level of estimation regarding the land cover classification quality. In addition, See5 can generate a confidence estimate for each classified pixel and record the associated classification logic in a text file that can be readily interpreted and incorporated into a metadata system. A hierarchical approach was implemented for mapping zone 55 in which logical groupings of pixels were recognized throughout the classification process. Once reference data were collected and labeled, a forest/non-forest layer was produced. From the group of forest pixels, deciduous woody wetland pixels were pulled out via unsupervised classification and the remaining pixels were classified with the CART method to populate the remainder of the woody wetland class, upland evergreen, and shrub classes. For the non-forest pixels, water and emergent wetland pixels were mapped with CART and separated from the remaining non-forest pixels. Those remaining pixels were classified to pasture, row crop, and grassland. Areas underneath the clouds and associated shadows were generally misclassified as row crop and water/wetland respectively. To correct for this, we created a mask for clouds and cloud shadows then replaced the pixels beneath the cloud mask with classified pixels from a separate thematic map generated without the leaf on imagery as an input. To develop adequate training data for land cover mapping, DOQQ's with a nominal spatial resolution of 1-m were used as reference imagery. We generated a stratified random reference point set and labeled the points based on interpretation of high-resolution Digital Orthophoto Quarter Quadrangles (DOQQ), Landsat TM imagery, and National

Wetland Inventory data layers. Coastal area and mines/barren land masks were created by defining areas of interest (AOI) where selected classes did not have any representation in the reference point set. The coastal and mines/barren masks were used to facilitate the mapping of sandy beaches and unconsolidated shore and barren areas associated with mining operations and non-vegetated areas of field research and military installations respectively. These masks were necessary to decrease the confusion among these "barren" land covers and the agriculture fields that were lacking vegetative cover in all three imagery mosaics.Acquisition dates of Landsat ETM+ (TM) scenes used for land cover classification in zone 55 are as follows:
SPRING-
Index 1 for Path 16/Row 38 on 02/17/02 = Scene_ID 7016038000204850
Index 1 for Path 16/Row 39 on 02/17/02 = Scene_ID 7016039000204850
Index 1 for Path 16/Row 40 on 02/17/02 = Scene_ID 7016040000204850
Index 2 for Path 17/Row 37 on 02/24/02 = Scene_ID 7017037000205550
Index 2 for Path 17/Row 38 on 02/24/02 = Scene_ID 7017038000205550
Index 2 for Path 17/Row 39 on 02/24/02 = Scene_ID 7017039000205550
Index 2 for Path 17/Row 40 on 02/24/02 = Scene_ID 7017040000205550
Index 3 for Path 18/Row 37 on 12/24/99 = Scene_ID 7018037009935850
Index 3 for Path 18/Row 38 on 12/24/99 = Scene_ID 7018038009935850
Index 4 for Path 18/Row 39 on 02/10/00 = Scene_ID 7018039000004150
Index 5 for Path 19/Row 37 on 01/24/03 = Scene_ID 7019037000302450
Index 5 for Path 19/Row 38 on 01/24/03 = Scene_ID 7019038000302450
Index 6 for Path 19/Row 39 on 01/08/03 = Scene_ID 7019039000300850
LEAF ON (Summer)-
Index 1 for Path 16/Row 38 on 05/24/02 = Scene_ID 7016038000214450
Index 2 for Path 16/Row 39 on 04/27/01 = Scene_ID 5016039000111710
Index 3 for Path 16/Row 40 on 04/03/01 = Scene_ID 7016040000109350
Index 4 for Path 17/Row 37 on 06/10/00 = Scene_ID 7017037000016250
Index 5 for Path 17/Row 38 on 05/09/00 = Scene_ID 7017038000013050
Index 6 for Path 17/Row 39 on 06/16/02 = Scene_ID 7017039000216750
Index 7 for Path 17/Row 40 on 03/28/02 = Scene_ID 7017040000208750
Index 8 for Path 18/Row 37 on 04/30/00 = Scene_ID 7018037000012150
Index 8 for Path 18/Row 38 on 04/30/00 = Scene_ID 7018038000012150
Index 9 for Path 18/Row 39 on 06/01/00 = Scene_ID 7018039000015350
Index10 for Path 19/Row 37 on 05/18/01 = Scene_ID 5019037000113810
Index10 for Path 19/Row 38 on 05/18/01 = Scene_ID 5019038000113810
Index11 for Path 19/Row 39 on 07/16/02 = Scene_ID 7019039000219750
LEAF-OFF (Fall)-
Index 1 for Path 16/Row 38 on 10/23/99 = Scene_ID 7016038009929650
Index 2 for Path 16/Row 39 on 11/10/00 = Scene_ID 7016039000031550
Index 3 for Path 16/Row 40 on 08/25/01 = Scene_ID 7016040000123750
Index 4 for Path 17/Row 37 on 10/03/01 = Scene_ID 7017037000127650
Index 4 for Path 17/Row 38 on 10/03/01 = Scene_ID 7017038000127650
Index 5 for Path 17/Row 39 on 10/16/00 = Scene_ID 7017039000029050
Index 5 for Path 17/Row 40 on 10/16/00 = Scene_ID 7017040000029050
Index 6 for Path 18/Row 37 on 10/26/01 = Scene_ID 7018037000129950

Index 7 for Path 18/Row 38 on 10/02/01 = Scene_ID 5018038000127510
Index 7 for Path 18/Row 39 on 10/02/01 = Scene_ID 5018039000127510
Index 8 for Path 19/Row 37 on 10/01/01 = Scene_ID 7019037000127450
Index 8 for Path 19/Row 38 on 10/01/01 = Scene_ID 7019038000127450
Index 8 for Path 19/Row 39 on 10/01/01 = Scene_ID 7019039000127450

Landsat data and ancillary data used for the land cover prediction -

Data Type of DEM composed of 1 band of Continuous Variable Type.

Data Type of Slope composed of 1 band of Continuous Variable Type.

Data Type of Aspect composed of 1 band of Categorical Variable Type.

Data type of Position Index composed of 1 band of Continuous Variable Type.

Source_Used_Citation_Abbreviation: Landsat ETM, DOQQ, USDA, FIA, DEM, National Center,EROS, IKONOS
Process_Date: Unknown
Source_Produced_Citation_Abbreviation: USGS NLCD
Process_Contact:
Contact_Information:
Contact_Organization_Primary:
Contact_Organization: USGS EROS NLCD 2001 - SE GAP
Contact_Position: Customer Service Representative
Contact_Address:
Address_Type: mailing and physical address
Address: USGS EROS
Address: 47914 252nd Street
City: Sioux Falls
State_or_Province: SD
Postal_Code: 57198
Country: USA
Contact_Voice_Telephone: 605-594-6151
Contact_TDD/TTY_Telephone: NA
Contact_Facsimile_Telephone: 605-594-6589
Contact_Electronic_Mail_Address: custserv@usgs.gov
Hours_of_Service: 0800 - 1600 CT, M - F (-6h CST/-5h CDT GMT)

Spatial_Data_Organization_Information:
Direct_Spatial_Reference_Method: Raster
Raster_Object_Information:
Raster_Object_Type: Pixel
Row_Count: 1858
Column_Count: 1671
Vertical_Count: 1

Spatial_Reference_Information:
Horizontal_Coordinate_System_Definition:
Planar:
Map_Projection:
Map_Projection_Name: Albers Conical Equal Area
Albers_Conical_Equal_Area:
Standard_Parallel: 29.500000
Standard_Parallel: 45.500000
Longitude_of_Central_Meridian: -96.000000
Latitude_of_Projection_Origin: 23.000000
False_Easting: 0.000000
False_Northing: 0.000000
Planar_Coordinate_Information:
Planar_Coordinate_Encoding_Method: row and column
Coordinate_Representation:
Abscissa_Resolution: 30.000000
Ordinate_Resolution: 30.000000
Planar_Distance_Units: meters
Geodetic_Model:
Horizontal_Datum_Name: North American Datum of 1983
Ellipsoid_Name: Geodetic Reference System 80
Semi-major_Axis: 6378137.000000
Denominator_of_Flattening_Ratio: 298.257222

Entity_and_Attribute_Information:
Detailed_Description:
Entity_Type:
Entity_Type_Label: Layer_1
Entity_Type_Definition: NLDC Land Cover Layer
Entity_Type_Definition_Source: National Land Cover Database 2001
Attribute:
Attribute_Label: ObjectID
Attribute_Definition: Internal feature number
Attribute_Definition_Source: ESRI
Attribute_Domain_Values:
Unrepresentable_Domain:
Sequential unique whole numbers that are automatically generated.
Attribute:
Attribute_Label: Count
Attribute_Definition:
A nominal integer value that designates the number of pixels that have each value in the file; histogram column in ERDAS Imagine raster attributes table
Attribute_Definition_Source: NLCD 2001
Attribute_Domain_Values:
Unrepresentable_Domain: Integer

Attribute:
Attribute_Label: Value
Attribute_Definition:
Land Cover Class Code Value. Class definitions marked with an asterisk (*) are Coastal NLCD Classes only.
Attribute_Definition_Source: NLCD 2001
Attribute_Domain_Values:
Enumerated_Domain:
Enumerated_Domain_Value: 1
Enumerated_Domain_Value_Definition: No data value, Alaska zones only
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 11
Enumerated_Domain_Value_Definition:
Open Water - All areas of open water, generally with less than 25% cover or vegetation or soil
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 12
Enumerated_Domain_Value_Definition:
Perennial Ice/Snow - All areas characterized by a perennial cover of ice and/or snow, generally greater than 25% of total cover.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 21
Enumerated_Domain_Value_Definition:
Developed, Open Space - Includes areas with a mixture of some constructed materials, but mostly vegetation in the form of lawn grasses. Impervious surfaces account for less than 20 percent of total cover. These areas most commonly include large-lot single-family housing units, parks, golf courses, and vegetation planted in developed settings for recreation, erosion control, or aesthetic purposes
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 22
Enumerated_Domain_Value_Definition:
Developed, Low Intensity -Includes areas with a mixture of constructed materials and vegetation. Impervious surfaces account for 20-49 percent of total cover. These areas most commonly include single-family housing units.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 23

Enumerated_Domain_Value_Definition:
Developed, Medium Intensity - Includes areas with a mixture of constructed materials and vegetation. Impervious surfaces account for 50-79 percent of the total cover. These areas most commonly include single-family housing units.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 24
Enumerated_Domain_Value_Definition:
Developed, High Intensity - Includes highly developed areas where people reside or work in high numbers. Examples include apartment complexes, row houses and commercial/industrial. Impervious surfaces account for 80 to100 percent of the total cover.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 31
Enumerated_Domain_Value_Definition:
Barren Land (Rock/Sand/Clay) - Barren areas of bedrock, desert pavement, scarps, talus, slides, volcanic material, glacial debris, sand dunes, strip mines, gravel pits and other accumulations of earthen material. Generally, vegetation accounts for less than 15% of total cover.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 32
Enumerated_Domain_Value_Definition:
Unconsolidated Shore* - Unconsolidated material such as silt, sand, or gravel that is subject to inundation and redistribution due to the action of water. Characterized by substrates lacking vegetation except for pioneering plants that become established during brief periods when growing conditions are favorable. Erosion and deposition by waves and currents produce a number of landforms representing this class.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 41
Enumerated_Domain_Value_Definition:
Deciduous Forest - Areas dominated by trees generally greater than 5 meters tall, and greater than 20% of total vegetation cover. More than 75 percent of the tree species shed foliage simultaneously in response to seasonal change.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 42
Enumerated_Domain_Value_Definition:

Evergreen Forest - Areas dominated by trees generally greater than 5 meters tall, and greater than 20% of total vegetation cover. More than 75 percent of the tree species maintain their leaves all year. Canopy is never without green foliage.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 43
Enumerated_Domain_Value_Definition:
Mixed Forest - Areas dominated by trees generally greater than 5 meters tall, and greater than 20% of total vegetation cover. Neither deciduous nor evergreen species are greater than 75 percent of total tree cover.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 51
Enumerated_Domain_Value_Definition:
Dwarf Scrub - Alaska only areas dominated by shrubs less than 20 centimeters tall with shrub canopy typically greater than 20% of total vegetation. This type is often co-associated with grasses, sedges, herbs, and non-vascular vegetation.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 52
Enumerated_Domain_Value_Definition:
Shrub/Scrub - Areas dominated by shrubs; less than 5 meters tall with shrub canopy typically greater than 20% of total vegetation. This class includes true shrubs, young trees in an early successional stage or trees stunted from environmental conditions.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 71
Enumerated_Domain_Value_Definition:
Grassland/Herbaceous - Areas dominated by grammanoid or herbaceous vegetation, generally greater than 80% of total vegetation. These areas are not subject to intensive management such as tilling, but can be utilized for grazing.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 72
Enumerated_Domain_Value_Definition:
Sedge/Herbaceous - Alaska only areas dominated by sedges and forbs, generally greater than 80% of total vegetation. This type can occur with significant other grasses or other grass like plants, and includes sedge tundra, and sedge tussock tundra.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:

Enumerated_Domain_Value: 73
Enumerated_Domain_Value_Definition:
Lichens - Alaska only areas dominated by fruticose or foliose lichens generally greater than 80% of total vegetation.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 74
Enumerated_Domain_Value_Definition:
Moss- Alaska only areas dominated by mosses, generally greater than 80% of total vegetation.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 81
Enumerated_Domain_Value_Definition:
Pasture/Hay - Areas of grasses, legumes, or grass-legume mixtures planted for livestock grazing or the production of seed or hay crops, typically on a perennial cycle. Pasture/hay vegetation accounts for greater than 20 percent of total vegetation.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 82
Enumerated_Domain_Value_Definition:
Cultivated Crops - Areas used for the production of annual crops, such as corn, soybeans, vegetables, tobacco, and cotton, and also perennial woody crops such as orchards and vineyards. Crop vegetation accounts for greater than 20 percent of total vegetation. This class also includes all land being actively tilled.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 90
Enumerated_Domain_Value_Definition:
Woody Wetlands - Areas where forest or shrub land vegetation accounts for greater than 20 percent of vegetative cover and the soil or substrate is periodically saturated with or covered with water.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 91
Enumerated_Domain_Value_Definition:
Palustrine Forested Wetland* -Includes all tidal and non-tidal wetlands dominated by woody vegetation greater than or equal to 5 meters in height and all such wetlands that occur in tidal areas in which salinity due to ocean-derived salts is below 0.5 percent. Total vegetation coverage is greater than 20 percent.

Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 92
Enumerated_Domain_Value_Definition:
Palustrine Scrub/Shrub Wetland* - Includes all tidal and non-tidal wetlands dominated by woody vegetation less than 5 meters in height, and all such wetlands that occur in tidal areas in which salinity due to ocean-derived salts is below 0.5 percent. Total vegetation coverage is greater than 20 percent. The species present could be true shrubs, young trees and shrubs or trees that are small or stunted due to environmental conditions.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 93
Enumerated_Domain_Value_Definition:
Estuarine Forested Wetland* - Includes all tidal wetlands dominated by woody vegetation greater than or equal to 5 meters in height, and all such wetlands that occur in tidal areas in which salinity due to ocean-derived salts is equal to or greater than 0.5 percent. Total vegetation coverage is greater than 20 percent.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 94
Enumerated_Domain_Value_Definition:
Estuarine Scrub/Shrub Wetland* - Includes all tidal wetlands dominated by woody vegetation less than 5 meters in height, and all such wetlands that occur in tidal areas in which salinity due to ocean-derived salts is equal to or greater than 0.5 percent. Total vegetation coverage is greater than 20 percent.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 95
Enumerated_Domain_Value_Definition:
Emergent Herbaceous Wetlands - Areas where perennial herbaceous vegetation accounts for greater than 80 percent of vegetative cover and the soil or substrate is periodically saturated with or covered with water.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 96
Enumerated_Domain_Value_Definition:
Palustrine Emergent Wetland (Persistent)* - Includes all tidal and non-tidal wetlands dominated by persistent emergent vascular plants, emergent mosses or lichens, and all such wetlands that occur in tidal areas in which salinity due to ocean-derived salts is below 0.5 percent. Plants generally remain standing until the next growing season.

Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 97
Enumerated_Domain_Value_Definition:
Estuarine Emergent Wetland* - Includes all tidal wetlands dominated by erect, rooted, herbaceous hydrophytes (excluding mosses and lichens) and all such wetlands that occur in tidal areas in which salinity due to ocean-derived salts is equal to or greater than 0.5 percent and that are present for most of the growing season in most years. Perennial plants usually dominate these wetlands.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 98
Enumerated_Domain_Value_Definition:
Palustrine Aquatic Bed* - The Palustrine Aquatic Bed class includes tidal and nontidal wetlands and deepwater habitats in which salinity due to ocean-derived salts is below 0.5 percent and which are dominated by plants that grow and form a continuous cover principally on or at the surface of the water. These include algal mats, detached floating mats, and rooted vascular plant assemblages.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Enumerated_Domain:
Enumerated_Domain_Value: 99
Enumerated_Domain_Value_Definition:
Estuarine Aquatic Bed* - Includes tidal wetlands and deepwater habitats in which salinity due to ocean-derived salts is equal to or greater than 0.5 percent and which are dominated by plants that grow and form a continuous cover principally on or at the surface of the water. These include algal mats, kelp beds, and rooted vascular plant assemblages.
Enumerated_Domain_Value_Definition_Source: NLCD 2001 land cover class descriptions
Attribute:
Attribute_Label: Red
Attribute_Definition:
Red color code for RGB slice by value for canopy image display purposes. The value is arbitrarily assigned by the display software package, unless defined by user. Standard user defined ramp for NLCD project is start color light gray, end color red.
Attribute_Definition_Source: NLCD 2001
Attribute_Domain_Values:
Range_Domain:
Range_Domain_Minimum: 0
Range_Domain_Maximum: 100
Attribute_Units_of_Measure: CSS Color Value Percentage
Attribute_Measurement_Resolution: 0.1
Attribute:
Attribute_Label: Green

Attribute_Definition:
Green color code for RGB slice by value for canopy image display purposes. The value is arbitrarily assigned by the display software package, unless defined by user. Standard user defined ramp for NLCD project is start color light gray, end color red.
Attribute_Definition_Source: NLCD 2001
Attribute_Domain_Values:
Range_Domain:
Range_Domain_Minimum: 0
Range_Domain_Maximum: 100
Attribute_Units_of_Measure: CSS Color Value Percentage
Attribute_Measurement_Resolution: 0.1
Attribute:
Attribute_Label: Blue
Attribute_Definition:
Blue color code for RGB slice by value for canopy image display purposes. The value is arbitrarily assigned by the display software package, unless defined by user. Standard user defined ramp for NLCD project is start color light gray, end color red.
Attribute_Definition_Source: NLCD 2001
Attribute_Domain_Values:
Range_Domain:
Range_Domain_Minimum: 0
Range_Domain_Maximum: 100
Attribute_Units_of_Measure: CSS Color Value Percentage
Attribute_Measurement_Resolution: 0.1
Attribute:
Attribute_Label: Opacity
Attribute_Definition:
A measure of how opaque, or solid, a color is displayed in a layer.
Attribute_Definition_Source: NLCD 2001
Attribute_Domain_Values:
Range_Domain:
Range_Domain_Minimum: 0
Range_Domain_Maximum: 100
Attribute_Units_of_Measure: Percentage
Attribute_Measurement_Resolution: 0.1
Overview_Description:
Entity_and_Attribute_Overview:
Attributes defined by USGS and ESRI.
Class Red Green Blue
0 0.000000000 0.000000000 0.000000000
1 0.000000000 1.000000000 0.000000000
11 0.325490196 0.462745098 0.662745098
12 0.854901961 0.913725490 1.000000000
21 0.913725490 0.819607843 0.815686275
22 0.890196078 0.615686275 0.545098039
23 0.976470588 0.000000000 0.000000000

24 0.705882353 0.000000000 0.000000000
31 0.741176471 0.725490196 0.670588235
32 1.000000000 1.000000000 1.000000000
41 0.443137255 0.701960784 0.419607843
42 0.137254902 0.423529412 0.231372549
43 0.752941176 0.827450980 0.607843137
51 0.694117647 0.588235294 0.235294118
52 0.835294118 0.764705882 0.533333333
71 0.925490196 0.925490196 0.796078431
72 0.823529412 0.823529412 0.505882353
73 0.635294118 0.796078431 0.321568627
74 0.513725490 0.725490196 0.619607843
81 0.901960784 0.882352941 0.282352941
82 0.709803922 0.486274510 0.200000000
90 0.760784314 0.878431373 0.949019608
95 0.486274510 0.674509804 0.772549020
Entity_and_Attribute_Detail_Citation:
Attribute accuracy is described, where present, with each attribute defined in the Entity and Attribute Section. Note: To ensure all areas of mapping zone 55 are completely covered, a 3,000 meter (100 Landsat pixels) buffer was added to the boundary of mapping zone 55.

Distribution_Information:
Distributor:
Contact_Information:
Contact_Organization_Primary:
Contact_Organization: U.S. Geological Survey
Contact_Position: Customer Service Representative
Contact_Address:
Address_Type: mailing and physical address
Address: USGS/EROS
Address: 47914 252nd Street
City: Sioux Falls
State_or_Province: SD
Postal_Code: 57198-0001
Country: USA
Contact_Voice_Telephone: 605/594-6151
Contact_TDD/TTY_Telephone: 605/594-6933
Contact_Facsimile_Telephone: 605/594-6589
Contact_Electronic_Mail_Address: custserv@usgs.gov
Hours_of_Service: 0800 - 1600 CT, M - F (-6h CST/-5h CDT GMT)
Contact_Instructions:
The USGS point of contact is for questions relating to the data display and download from this web site. Questions about the NLCD mapping zone 55 can be directed to the NLCD 2001 land cover mapping team at the USGS/EROS, Sioux Falls, SD (605) 594-6151 or mrlc@usgs.gov.

Resource_Description: Downloadable data
Distribution_Liability:
Although these data have been processed successfully on a computer system at the USGS, no warranty expressed or implied is made by the USGS regarding the use of the data on any other system, nor does the act of distribution constitute any such warranty. Data may have been compiled from various outside sources. Spatial information may not meet National Map Accuracy Standards. This information may be updated without notification. The USGS shall not be liable for any activity involving these data, installation, fitness of the data for a particular purpose, its use, or analyses results.
Standard_Order_Process:
Digital_Form:
Digital_Transfer_Information:
Format_Name: Arc/Info Export Format and/or ArcView Shapefile
Format_Version_Number: ArcGIS 9.0
Format_Specification: ASCII
Transfer_Size: 0.001
Digital_Transfer_Option:
Online_Option:
Computer_Contact_Information:
Network_Address:
Network_Resource_Name: <http://seamless.usgs.gov>
Access_Instructions:
The URL <http://seamless.usgs.gov> provides a map interface that allows for data downloads within a customer defined area of interest. Zoom tools are available that can be used to investigate areas of interest on the map interface. The download tool allows the customer to capture layers from the map, utilizing the Seamless Data Distribution System process for downloading. A request summary page is then generated with the download layers listed. By clicking the "download" button on the summary page, a zipped file will be generated that can be saved on the customer's computer. The file can then be unzipped and imported into various user software applications.
Online_Computer_and_Operating_System: Not available for dissemination
Fees: None
Ordering_Instructions: Contact Customer Services
Turnaround: Variable
Custom_Order_Process: Contact Customer Services Representative
Technical_Prerequisites:
ESRI ArcMap Suite and/or Arc/Info software, and supporting operating systems.

Metadata_Reference_Information:
Metadata_Date: 20060307
Metadata_Contact:
Contact_Information:
Contact_Organization_Primary:
Contact_Organization: U.S. Geological Survey
Contact_Position: Customer Services Representative
Contact_Address:

Address_Type: mailing and physical address
Address: USGS/EROS
Address: 47914 252nd Street
City: Sioux Falls
State_or_Province: SD
Postal_Code: 57198-0001
Country: USA
Contact_Voice_Telephone: 605/594-6151
Contact_TDD/TTY_Telephone: 605/594-6933
Contact_Facsimile_Telephone: 605/594-6589
Contact_Electronic_Mail_Address: custserv@usgs.gov
Hours_of_Service: 0800 - 1600 CT, M - F (-6h CST/-5h CDT GMT)
Metadata_Standard_Name: FGDC Content Standards for Digital Geospatial Metadata
Metadata_Standard_Version: FGDC-STD-001-1998
Metadata_Time_Convention: local time
Metadata_Access_Constraints: None
Metadata_Use_Constraints: None
Metadata_Security_Information:
Metadata_Security_Classification_System: None
Metadata_Security_Classification: None
Metadata_Security_Handling_Description: None
Metadata_Extensions:
Online_Linkage: <http://www.esri.com/metadata/esriprof80.html>
Profile_Name: ESRI Metadata Profile

Generated by mp version 2.8.6 on Tue Mar 07 08:48:31 2006