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January 29, 2016

GEORGIA POWER
A SOUTHERN COMPANY

Mr. Reece McAlister
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

RE: Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT; Docket No. 40161

Dear Mr. McAlister:

In accordance with O.C.G.A. §§ 46-3A-2 and 46-3A-3, and Georgia Public Service Commission (the "Commission") Rules 515-3-4.06 and 515-3-4-.08, Georgia Power Company hereby submits and makes application for approval of its 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT and Intercession City CT (the "2016 IRP and Decertification Application").

This filing contains certain information that is being filed under the Commission's trade secret rules as explained in the enclosed document regarding the basis for the assertion. Therefore, in addition to the trade secret document and per the Commission Staff's instructions, 14 copies and an electronic version of the redacted 2016 IRP and Decertification Application and supporting documentation are enclosed for public disclosure.

If you have any questions, please contact Ms. Cheryl Johnson at 404-506-6837.

Sincerely,

Kyle C. Leach
Director, Regulatory Affairs

Enclosure

Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT
Docket No. 40161

Main Document

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2016 INTEGRATED RESOURCE PLAN
TECHNICAL APPENDICES INDEX

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1 – SUMMARY OF 2016 INTEGRATED RESOURCE PLAN

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SECTION 1 - SUMMARY OF 2016 INTEGRATED RESOURCE PLAN

1.1 FOREWORD

This 2016 Integrated Resource Plan ("2016 IRP") is the ninth IRP filed by Georgia Power Company ("Georgia Power" or the "Company") since enactment of the Integrated Resource Planning Act in 1991, O.C.G.A. § 46-3A-1 et seq. ("IRP Act"), which requires the filing of such a plan every three years. In this 2016 IRP, the Company continues to chart a course into the energy future, taking proactive steps to capitalize on current market and regulatory conditions while also positioning the Company to respond to future developments, all for the benefit of customers. The 2016 IRP was developed through the Company's exhaustive planning process and has resulted in a comprehensive plan for continuing to provide customers with reliable electric service from a diverse portfolio of supply- and demand-side resources at rates below the national average.

This IRP continues the Company's commitment to providing its customers a diverse supply-side generating portfolio that provides reliable and cost-effective service to all customers. The Company's diverse fleet of supply-side generating resources—comprised of nuclear, natural gas, coal, oil, hydro, solar, wind, and biomass generation—provides significant benefit to customers and positions the Company to maximize value for customers in a wide variety of future economic and regulatory scenarios. Maintaining a diverse supply-side generating portfolio is critical given the inherent uncertainty of the future and the potential for rapid changes in the economic and regulatory landscape impacting energy supply. The plan proposed in this filing will provide compliance flexibility for the benefit of customers.

Georgia is now recognized as a national leader with respect to renewable resources. As a result of the collaborative approach taken by the Company and the Georgia Public Service Commission ("Commission"), Georgia Power will have nearly one gigawatt of solar generation capacity on its system by the end of 2016, representing one of the largest voluntary solar portfolios in the nation for an investor-owned utility. With new solar facilities planned or under construction across the state, Georgia is one of the fastest growing solar markets in the country. Georgia Power has also further diversified its renewable portfolio with purchases of biomass and wind generation. Georgia Power has nearly 500 megawatts ("MW") of power purchase agreements ("PPAs") with various biomass and landfill methane gas generators as well as PPAs totaling 250 MW for wind energy which began in January 2016.[1]

In this filing, the Company proposes the acquisition of an additional 525 MW of renewable resources utilizing market-based prices established through a competitive bidding process to provide energy savings to customers. This Renewable Energy Development Initiative ("REDI") would build on the market-based success of the Advanced Solar Initiatives, which will deliver 745 MW of solar resources at or below the Company's long-term projected avoided costs. The Company also seeks Commission approval for additional renewable demonstration projects to allow for continued exploration of cost-effective renewable resources for the benefit of its customers.

Notably, this IRP includes "A Framework for Determining the Costs and Benefits of Solar Generation in Georgia" ("Framework"), one of the most technical and comprehensive analyses performed to date concerning the benefits and costs of renewable resources of various sizes and configurations. Renewable resources in any form (whether utility scale or distributed generation ("DG")) provide numerous benefits to customers but also impose operating, reliability and other costs and impacts on the system. This analysis provides an in-depth, technical review of those costs and benefits and provides a framework for valuation that can be applied to all forms of renewable and non-renewable resources, and should be adopted as a guide for future policy decisions by the Commission. Two additional documents—"The Costs and Benefits of Distributed Solar Generation in Georgia" and "The Costs and Benefits of Fixed and Variable Wind Delivered to Georgia"—quantify the costs and benefits of such technologies on a per kWh basis under certain specified scenarios.

As this Commission is well aware, one of the key issues facing the Company at this time is the United States Environmental Protection Agency's ("EPA") Clean Power Plan ("CPP"), which was published in final form on October 23, 2015. The CPP will have a significant impact on the Company's customers, as well as the customers of other utilities in the state of Georgia, if the

[1] Georgia Power purchases only the null energy output from some renewable generating facilities that have contracted to sell energy from their facilities to Georgia Power. The ownership of the associated renewable energy credits ("RECs") is specified in each respective power purchase agreement and the party that owns the RECs retains the right to use the RECs. Georgia Power does not report emission reductions from the null energy purchased through power purchase agreements that do not bundle the RECs for sale to Georgia Power.

rule is implemented in its current form. The Company, the Commission, and the Georgia Environmental Protection Division ("EPD") all invested substantial resources during the rulemaking process, which contributed to modifications in the final rules that addressed certain inequities, including treatment of Georgia's early action in building new nuclear power. However, the rule remains fundamentally flawed with many legal, technical, and practical concerns. Since publication of the final rule by the EPA, the Company has continued its in-depth review to fully analyze the most complex and detailed regulation ever issued by the EPA and to understand the impact of the final rule on the Company and its customers.

More than half of the states in the country, along with multiple industries, trade groups and utilities (including Georgia Power and Southern Company's other retail operating companies), have filed petitions with the D.C. Circuit challenging the legality of the CPP as exceeding the EPA's authority in fundamental ways. The petitioners also filed motions with the D.C. Circuit requesting a stay of the rule pending resolution of the litigation. Georgia Power submitted a declaration in support of the request for a stay that projected the financial impact to the Company in the next two years, based on the EPA's modeling assumptions (as reflected in its Integrated Planning Model). Using the EPA's assumptions, in 2016-2017 alone, the CPP would, for Georgia Power, result in $830 million in incremental costs related to increased production costs and an insufficient reserve margin, $70 million in additional transmission projects, $485 million to compensate for impacts to the fuels program and the retirement of over 4,000 MW of fossil-fired units with a current value of over $3.7 billion. Due to the significant changes in the CPP when it was finalized, the EPA's own analysis and modeling of the CPP is currently the best available predictor of its impacts and effects.

On January 21, 2016, the D.C. Circuit Court denied petitioners' requests to stay the rule, but granted an expedited schedule for hearing the case. Following this decision, in late January, Georgia Power joined the states and other industry petitioners in asking the Supreme Court to stay the rule pending resolution of the litigation

As a result of the ongoing litigation regarding numerous fundamental flaws and the pending application to the Supreme Court requesting stay of the rule, there remains a great deal of uncertainty around the rule, and the Company must consider the fact that the rule could be overturned or substantially modified by either the D.C. Circuit or the Supreme Court. The Supreme Court's recent decision that the EPA should have considered costs when it decided whether to regulate utilities under the Mercury and Air Toxics Standards ("MATS") rule shows that the courts can and have disagreed with EPA's rules.

Additional uncertainty exists about the rule and its impacts on Georgia Power's customers because the CPP does not apply directly to generation sources, but instead must be implemented through the development of a State Plan. While State Plans are due September 6, 2016, states may seek a two-year extension until September 6, 2018. The EPD has indicated their intention to request a two-year extension. The EPD has taken initial steps to develop the State Plan, but there is an immense amount of additional analysis, coordination and regulatory process that must take place before the State Plan is completed and approved by the EPA. In light of the many State Plan pathways that are available under the Clean Power Plan and the current uncertainty around the specific pathway and implementation requirements of the CPP for the state of Georgia, the Company has not put forward a CPP compliance plan in this IRP. Instead, the most prudent course of action is to await more clarity regarding the status and impact of the rule, including the direction and implementation details of the State Plan, while making cost-effective decisions to ensure that the Company is positioned to respond to various potential outcomes. Also, as discussed above, there is potential for successful legal challenge of the CPP, creating additional uncertainty.

While the Company has not proposed a CPP compliance plan, this IRP reflects a continuation of the Company's proactive efforts to position its system for a carbon constrained future. Through the development of new nuclear resources and deployment of renewable resources, along with continued implementation of the existing demand-side management ("DSM") programs and optimization of existing gas generation, the Company has taken steps to ensure that its system will be prepared to adapt to future environmental regulations.

The Company's acquisition of additional renewable resources will benefit customers and will also help position the Company to respond to rules or legislation constraining carbon emissions. Nuclear power generation will also play an important role in meeting the future energy needs of the Company's customers in a carbon-constrained environment and will allow the Company to maintain fuel diversity for the benefit of customers. Nuclear generation is the lowest variable cost dispatchable generation in the Company's fleet (aside from hydro) and will provide substantial fuel price stability for customers (based on the historic and projected cost of nuclear fuel). With the Commission's leadership, the Company's pioneering efforts in connection with Plant Vogtle Units 3 and 4 will provide benefit to customers and has only become more critical in light of carbon regulation. The Company is committed to completing Plant Vogtle Units 3 and 4 in an efficient and safe manner, and to keeping the Commission informed of the progress, cost, and value of the project through the construction monitoring process. It is also important that nuclear continue to be evaluated as a possible resource option for the future. The extensive planning needed to license nuclear generation requires that initial efforts take place many years in advance. With the reality of carbon regulation, and the likelihood that new coal generation in Georgia is not a feasible option for the indefinite future, the Company must continue to be proactive in its consideration of future nuclear as a viable baseload option.

The Company has performed an in-depth economic analysis of certain of its fossil-fired generating units to determine the extent to which such plants provide economic benefit to customers. The results of that analysis show that the majority of the Company's coal-fired generating units continue to provide substantial economic benefit for customers across a range of potential future outcomes. Therefore, the Company has not recommended any such coal-fired units for retirement (with the exception of Plant Mitchell Unit 3). However, the results of the economic analysis of Plant McIntosh Unit 1 indicate that in a number of future scenarios, the costs exceed the benefits to customers and, therefore, the unit may be a candidate for future retirement. But this is not a decision that must be made today. The benefit of having Plant McIntosh Unit 1 available to allow the Company to maintain fuel diversity combined with its relatively low cost to maintain over the near term support deferring a decision at least until the Company and the Commission can gain more certainty regarding the impact of the CPP. Deferral of any major resource decisions provides benefit to customers and avoids any irreversible decisions that, in light of future developments, turn out to be premature or not in the best interest of customers.

Given the near-term uncertainty associated with the CPP, the Company continues to identify opportunities to reduce and defer capital and operations and maintenance ("O&M") expenditures for Plant McIntosh Unit 1. The Company will continue to monitor future environmental compliance obligations and the impact such obligations may have on Plant McIntosh Unit 1. The Company's cost reduction and deferral will benefit customers by reducing near-term costs until more clarity is available on developing environmental regulations. Such reduced costs have been reflected in the Unit Retirement Study for Plant McIntosh Unit 1.

The Company is also including in this filing its plans for compliance with the EPA's Disposal of Coal Combustion Residuals from Electric Utilities Rule ("CCR Rule"), Steam Electric Power Generating Effluent Limitations Guidelines ("ELG Rule") and the 316(b) Cooling Water Intake Structure Rule ("316(b) Rule") and seeks Commission approval for such expenditures. The CCR Rule stipulates the requirements for management and disposal of coal combustion residuals. The ELG Rule stipulates the wastewater management requirements from numerous waste streams at steam-electric generating facilities. The 316(b) Rule of the Clean Water Act sets requirements for cooling water intake structures. These rules have been under development for many years, and the Company's economic analysis in the 2013 IRP took such rules into account based on information available at that time. Now that final rules have been issued, the Company has a greater understanding of the cost implications of the rules and seeks approval of the compliance plans and related costs, which are reflected in the Unit Retirement Study for each plant.

Based on the detailed analysis reflected in the Reserve Margin Study, the Company is recommending that the Southern Company electric system ("System") long-term (greater than three years) target planning reserve margin be increased from 15% to 17% and the System short-term (less than three years) target planning reserve margin be increased from 13.5% to 15.5%. Because of the benefit of System operation and the ability to share resources, each Operating Company can carry lower reserves. Thus, Georgia Power's target planning reserve margin will be 15.4% over the long-term and 14% over the short-term. This change is driven by a number of factors, including actual data regarding customer demand and System performance during extreme cold weather events. Due to the timing of the completion of the Reserve Margin Study, the Company's analysis in this IRP (*e.g.,* the Resource Mix Study, etc.) is based on the prior 15% System long-term target planning reserve margin. The Company intends to utilize the increased target planning reserve margin for all future planning purposes. No resource decisions have been altered in this IRP based on the Company's recommended target planning reserve margin changes.

The Company is proposing the continuation of its current DSM programs with slight modifications. The Company continues to believe that DSM is an important ingredient in meeting customers' needs in a reliable and cost-effective manner. However, due to lower avoided costs driven primarily by low natural gas prices, many of the current DSM programs now appear less favorable from the Total Resource Cost ("TRC") and Rate Impact Measure ("RIM") perspectives. Nevertheless, the Company believes there is value in continuing such programs for a number of reasons. First, residential and commercial customers are responding favorably to the Company's programs. Second, there are market efficiencies that can be achieved by maintaining a presence in the marketplace. Furthermore, DSM may be a necessary element of compliance with the Clean Power Plan. Therefore, the Company proposes a continuation of the current slate of DSM programs with slight modifications in order to enhance the Company's overall offering of DSM programs and to provide certain new innovative options for customers.

Leveraging the expertise and resources of Southern Company, Georgia Power remains on the forefront of emerging technologies, utilizing a multi-functional approach to research and development. Through this disciplined and structured approach, the Company is able to assess emerging technologies and identify those that will provide benefit to its customers. These efforts, involving a wide range of technologies and activities including the Connected Community Development and Demonstration Center ("CCDDC") and the High Performance Computing Center ("HPCC"), are described in more detail in Section 13.

Finally, the Company also seeks decertification of a number of smaller generating units. The Company is requesting decertification of combustion turbines ("CTs") at Plant Kraft and Plant Mitchell. The units are no longer cost-effective and also have reliability concerns, and therefore, it is in the best interest of customers to retire these units. The Company is formally requesting the decertification of Plant Mitchell Unit 3, as was communicated to the Commission in January 2015. Lastly, the Company is requesting decertification of its Intercession City CT unit, located in Florida and co-owned with Duke Energy Florida ("DEF"). The annual cost of Florida transmission service associated with the unit has increased steadily and rendered the resource uneconomic. The Company exercised its contractual option in May 2015 to terminate the transmission service and sell the Company's 33% ownership interest in the unit to DEF. The Company has executed a sale agreement with DEF, which agreement is contingent on approval by the Commission and the Federal Energy Regulatory Commission ("FERC").

The proposed 2016 IRP will provide customers with short- and long-term electric service reliability in an economically efficient manner through a diverse portfolio of resources. With the Commission's oversight, the Company has developed a cost-effective and balanced environmental compliance strategy while also maintaining compliance flexibility for the benefit of customers. In addition, the Company is well-positioned for an increase in customer load growth given Georgia's positive long-term economic prospects as a destination state with a business friendly environment. By 2021, the state of Georgia is projected to add over one million new residents, and the ability to have in place the necessary energy infrastructure for such growth is a direct result of the collaborative planning process established by the IRP Act and guided by the Commission. This process has allowed the Company and the Commission to chart a balanced course in meeting customer demand in a dynamic regulatory environment, all while maintaining rates below the national average.

In summary, the Company seeks approval of:

1) Its 2016 Integrated Resource Plan and the associated Action Plan;
2) Procurement of an additional 525 MW of renewable resources through the new Renewable Energy Development Initiative, which will utilize a market-based approach with a carve out for distributed solar resources;
3) Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT with the effective dates as specified in the 2016 Decertification Application;
4) A certificate of public convenience and necessity for four new DSM programs, decertification of two DSM programs, amending the certificate for two DSM programs, and approval of updated program economics for all other previously certified DSM programs as further specified in the 2016 DSM Application in Docket No. 40162;

5) An increase in the System long-term target planning reserve margin from 15% to 17%;
6) Reclassification of the remaining net book value of Plant Mitchell Unit 3 as of its respective retirement date to a regulatory asset account and the amortization of such regulatory asset account ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 36989 until the effective date of the Company's next base rate adjustment, at which time the Company would then begin amortizing the remaining balance over a three year period;
7) Reclassification of any unusable material and supplies ("M&S") inventory balance remaining at the unit retirement dates to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 36989 for recovery over a period to be determined by the Commission in the Company's next base rate case;
8) The capital costs the Company will incur for a portfolio of certain renewable demonstration projects (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 2;
9) 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; and
10) Utilization of the Framework for evaluation of the costs and benefits of renewable resources for purposes of future program design, resource evaluations, and payment calculations, including updating the avoided cost methodologies to reflect these current and future costs and benefits.

1.2 INTRODUCTION

Georgia Power, a subsidiary of Southern Company, is an investor-owned electric utility that serves approximately 2.4 million retail customers in all but four of Georgia's 159 counties. Georgia Power electric service is available in 57,000 of the state's 59,000 square miles.

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. Southern Company also recently acquired AGL Resources, though such acquisition remains subject to regulatory approval. The Operating Companies coordinate system operations and jointly dispatch their generating units to capture the economies available from power pooling and in this function are referred to as the System. 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, Georgia Power, Alabama Power, Gulf Power, and Mississippi Power (collectively, the "Retail OpCos"), also participate in coordinated generation and transmission planning as appropriate.

Georgia Power's common stock is held by Southern Company, which had 131,771 shareholders of record at year end 2015.

As of December 31, 2015, Georgia Power has 132 company-owned generating units (21 fossil steam, 71 hydroelectric, 4 nuclear, 5 combined cycles ("CCs"), and 31 CTs, excluding 3 CTs which are not permitted for normal summer operation) that provide approximately 15,850 MW of retail peak season generating capacity. In addition, the 30 MW solar project at Fort Benning came online December 2015. Of the energy from Company-owned units for the first eleven months of 2015, 32% is from coal, 25% from nuclear, 3% from hydroelectric, and 40% from natural gas and oil.

1.3 THE 2013 IRP

In January 2013, Georgia Power filed its eighth IRP. The 2013 IRP was designed to meet the energy needs of the Company's customers using a mix of supply-side and demand-side resources. The Commission approved the IRP developed by Georgia Power with modifications as specified in its order dated July 17, 2013 (the "2013 IRP Order").

In response to the Commission's 2013 IRP Order, the Company took the following major actions:

1) Retired Plant Branch Units 1, 3 and 4, Plant Yates Units 1-5, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Bowen Unit 6 and Plant Boulevard Units 2 and 3, while taking action to maximize the salvage value of the decertified units;

2) Switched Plant Yates Units 6 and 7 and Plant Gaston Units 1-4 to operate on natural gas and switched Plant McIntosh Unit 1 to operate on Powder River Basin coal;
3) Successfully installed the necessary environmental controls on schedule and under budget for Plant Bowen Units 1 and 2, Plant Wansley Units 1 and 2, Plant Scherer Units 1-3, Plant Hammond Units 1-4, and Plant McIntosh Unit 1 to be in compliance with the MATS rule (baghouses for Plant Bowen Units 3 and 4 are scheduled to be ready for operation by the MATS compliance date of April 16, 2016);
4) Commenced the solar tracking demonstration project at the University of Georgia;
5) Updated the Georgia Power Headquarters solar demonstration project with new technology and initiated the addition of battery storage to the project;
6) Developed plans to install three small wind turbines and a meteorological tower by early 2016 on Skidaway Island and continued to work with Georgia Southern University to study aviary impacts of the project;
7) Completed a Request for Proposal ("RFP") and procured over 439 MW of utility scale solar resources for the Advanced Solar Initiative ("ASI") Prime program, with the resulting PPAs certified by the Commission in December 2014;
8) Issued an RFP in the summer of 2015 for the procurement of 100 MW of distributed solar resources (50 MW competitively bid and 50 MW fixed price);
9) Collaborated with Commission Staff to review generation and transmission modeling and produced compliance reports regarding the status of the natural gas delivery outlook and fuel supply plans for Plants Gaston and Yates as well as MATS environmental controls projects;
10) Responded to the Commission's 2013 IRP Order requiring certain actions related to DSM programs and planning activities;
11) Filed the Achievable Energy-Efficiency Potentials Assessment in January 2015 in response to the Commission's order for a new energy efficiency potential study;
12) Filed complete Process and Impact Evaluation result reports in July 2015 for the eight energy efficiency programs certified in the 2013 DSM certification proceeding; and
13) Complied with the DSM Program Planning Approach to develop the Company's 2016 IRP DSM plan.

1.4 SIGNIFICANT RECENT ACCOMPLISHMENTS

Since concluding the 2013 IRP, the Company has completed the following significant accomplishments.

1.4.1 Renewables

On September 26, 2012, the Company filed the Georgia Power Advanced Solar Initiative in Docket No. 36325, and the Commission approved the program on November 29, 2012. Under the ASI, the Company contracted for energy from 210 MW of solar capacity through both distributed and utility scale projects. Georgia Power contracted for 120 MW of utility scale solar generation through competitive RFPs. Energy from 90 MW of distributed solar resources was procured from small and medium-scale solar projects owned by customers and developers.

The Company's ASI program was expanded in the final order of the 2013 IRP. In the expanded program, known as ASI Prime, the Company contracted for an additional 439 MW of utility scale projects and 100 MW of distributed solar projects. For the procurement of the 439 MW, the Company used a competitive RFP. For the 100 MW of distributed solar projects, the Company used a combination of competitive bidding (50 MW) to procure greenfield projects and customer-sited projects and fixed price offers (50 MW) to procure strictly customer-sited solar resources.

Pursuant to the Commission's orders in Docket Nos. 24505 and 39028, Georgia Power commenced design, procurement and construction of five military solar projects, totaling 166 MW, at the following military bases: Fort Benning; Fort Gordon; Fort Stewart; Naval Submarine Base Kings Bay; and Marine Corps Logistics Base Albany.

On November 4, 2013, Georgia Power filed its Application for the Certification of the PPAs for 250 MW of wind capacity from the Blue Canyon II and Blue Canyon VI Wind Farms in Docket No. 37854. On May 29, 2014, the Commission issued its order certifying the PPAs, and on January 1, 2016, Georgia Power began receiving wind energy under the PPAs.

As part of the same docket, Georgia Power filed a Request for Information ("RFI") on December 8, 2014 regarding availability, pricing and potential PPA terms for utility scale wind with no geographical or delivery preference. A report summarizing the findings from this RFI was provided to the Commission on February 27, 2015.

More details regarding the ASI and ASI Prime programs as well as the military solar projects, Blue Canyon procurement, and Wind RFI are contained in Section 10. In addition, in January 2014, the Company notified the Commission of its plan to cancel the biomass conversion of Plant Mitchell Unit 3, and in January 2015, the Company notified the Commission of its intent to request decertification of that unit in the 2016 IRP.

1.4.2 Plant Vogtle Units 3 and 4

As approved in Docket No. 27800, Georgia Power and its partners—Oglethorpe Power, MEAG Power, and Dalton Utilities—are adding two nuclear units at Plant Vogtle to meet customers' growing needs and provide important fuel diversity and fuel savings benefits. Addition of the units represents a significant capital investment in Georgia and is the largest job-producing project in the state, employing approximately 5,000 people during peak construction and creating 800 permanent jobs when the units begin operating. The Company continues to demonstrate its uncompromised commitment to safe, quality, and compliant construction of the facility. Since the 2013 IRP, significant progress has been made on the project, as described in the Vogtle Construction Monitor report filings in Docket No. 29849.

1.4.3 Reduced Fuel Rates

The fuel diversity of the Company's generating units, bolstered by the addition of more natural gas-fired generation in the recent past, has allowed the Company to maximize the benefit to customers of lower natural gas prices through reduced fuel rates. The average non-seasonal fuel rates have decreased 31% from Fuel Cost Recovery ("FCR")-21 to FCR-24.

1.4.4 DSM Program Implementation

The Company implemented the eight DSM programs that were certified in the 2013 IRP, with a ramp-up during the first three years. As part of the program implementation, the Company hired implementation contractors, set up implementation protocols, hired a program evaluation contractor and completed full program evaluations for the eight energy efficiency programs. In

2013, Georgia Power achieved 320.2 gigawatt hours ("GWh") of gross energy savings as compared to an energy savings target of 325 GWh. In 2014, the energy savings target was 322.9 GWh and the Company achieved 351.5 GWh of gross energy savings. More details regarding the Company's DSM programs are contained in Section 5 and the 2016 DSM Application.

1.5 THE DEMAND-SIDE PLAN

The Company's current DSM portfolio consists of demand response programs, energy efficiency programs, pricing tariffs, and other activities. The Company projects that by 2019 these programs will reduce peak demand by approximately 1,900 MW. This load reduction represents 12% of the Company's current load.

In accordance with the 2013 IRP Order, the Company has continued to work closely with the DSM Working Group ("DSMWG") through the use of the DSM Program Planning Approach for DSM program development. The Company prepared an updated energy efficiency technology catalog, completed and filed an energy efficiency potential study, and conducted a comprehensive analysis of potential DSM programs with the assistance and input of the DSMWG.

The recommended DSM action plan includes seeking Commission approval for a certificate for four new DSM programs, amending the certificate of two currently certified DSM programs, decertifying two DSM programs and updating program economics for the remaining four previously-certified DSM programs in the Company's 2016 DSM Application. The Company also intends to continue the Power Credit residential program, which was previously certified in Docket No. 6315.

However, the avoided cost savings are now significantly lower than those projected in the preparation of the 2013 IRP, which has had a significant and negative impact on the economics of the Company's current and proposed DSM programs relative to the economics projected in the 2013 IRP. As discussed in Section 5, Total Resource Cost Test results declined and Ratepayer Impact Measure Test results worsened, raising concerns for the Company in its efforts to balance the economic benefits these programs provide for participating customers with the rate impacts to all customers within a given class caused by the programs. Nevertheless, the

Company supports the continuation of the energy efficiency programs included in the 2016 DSM Certification filing and also seeks to certify a residential behavioral program, a residential HVAC Service program, a Commercial Small Business Direct Install program, and a Commercial HVAC program. The Company plans to continue to monitor program costs and economics from 2017 through 2019 and will be prepared to modify programs if the significant upward pressure on rates continues. Furthermore, compliance with the final Clean Power Plan State Plan may necessitate modifications to the Company's DSM program plans and potentially require more DSM activities, both of which could result in even more significant upward pressure on rates.

Summary information for two alternative DSM sensitivity cases is also included in this filing. One alternative sensitivity case, deemed the "Advocacy Case," presents a potential set of DSM programs designed around the recommendations from some members of the DSMWG. The other alternative sensitivity case represents the "Aggressive Case" that was outlined in the DSM Program Planning Approach.

1.6 THE SUPPLY SIDE PLAN

Georgia Power's current supply-side plan, as set forth in the 2016 IRP and as further supplemented herein, is sufficient to provide cost-effective and reliable sources of capacity and energy through 2024 and beyond. More details regarding the Company's supply-side plan are contained in Section 6 and the formal decertification requests are included in the 2016 Decertification Application.

1.6.1 Renewable Strategy

As described in Sections 1.1 and 1.4.1, the Company has a diverse portfolio of renewable resources, including hydro, solar, wind, and biomass generation. The Company's supply-side resources include: approximately 1,100 MW of hydro generation across Georgia; over 300 MW of PPAs with various biomass generators; 250 MW of PPAs for wind energy; 50 MW from the Large Scale Solar program; nearly 750 MW from the ASI and ASI Prime programs; over 150 MW of solar generation from the military projects; and an additional 525 MW of renewable generation as proposed in this 2016 IRP through REDI.

1.6.2 Unit Retirements

In this 2016 IRP, the Company sets forth its compliance strategy for the final CCR, ELG, and 316(b) rules. Given the significant amount of uncertainty around the CPP, as well as the volatility of load forecasts and natural gas price forecasts, the Company is not recommending any coal-fired units for retirement, with the exception of Mitchell Unit 3, until more certainty is achieved regarding the CPP. As described in Section 1.1, the Company is requesting decertification of Plant Mitchell Unit 3, a 155 MW coal unit, and four CTs totaling 222 MW in aggregate, for a total decertification amount of 377 MW.

For additional information regarding development of the Company's compliance strategy for the CCR, ELG, 316(b) and other environmental rules, please see the Environmental Compliance Strategy ("ECS") document included in Technical Appendix Volume 2.

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 the Real Time Pricing ("RTP") program, Demand Plus Energy Credit ("DPEC") and Time of Use ("TOU") rates) have been effective in reducing the peak demand for electricity. In addition, the Company has been promoting its Time of Use Residential Demand ("TOU-RD") tariff under the trade name Smart Usage. The Smart Usage rate is the Company's most effective residential rate for providing pricing signals that encourage demand reduction.

The Company leverages Advanced Metering Infrastructure ("AMI") investment by promoting rates that send strong, clear pricing signals such as the Time of Use Residential Demand rate. The Company's promotions will continue to focus on helping customers save money and energy by reducing usage or shifting loads from the on-peak time period.

Georgia Power also offers the Time of Use-Fuel Cost Recovery ("TOU-FCR") tariff. TOU-FCR is available on a voluntary basis to all customers on TOU base tariffs. Additionally, the Time of Use-Fuel Cost Recovery Three Part ("TOU-FCR-TP") tariff rate was made a permanent tariff effective January 2016. The TOU-FCR-TP rate is available to customers on the Time of Use –

Plug-In Electric Vehicle ("TOU-PEV") and Time of Use-Medium Business ("TOU-MB") rates. TOU-FCR rates will further strengthen price signals seen by customers on time of use rates.

1.8 THE ENVIRONMENTAL PLAN

The ECS (included in Technical Appendix Volume 2) reflects the most recent environmental regulatory developments and related strategies for ensuring full compliance with all current local, state and federal environmental laws and regulations. The ECS establishes a general direction for compliance and allows for individual decisions to be made based upon specific information available at the time. This approach is necessary to maintain the flexibility to match a rapidly changing regulatory environment. The ECS in this IRP has been updated to reflect the Company's compliance strategy for the MATS, ELG and CCR rules, as well as other existing and expected environmental requirements. However, as discussed above, the Company has not proposed a CPP compliance plan until more certainty is available regarding the rule.

The Company anticipates that the Environmental Compliance Cost Recovery ("ECCR") tariff will need to be updated in the next base rate case to reflect the incremental costs of environmental compliance. However, as has been the past practice, the IRP is the most appropriate venue for the Commission to review those specific environmental compliance strategies and related costs. The incremental capital and O&M environmental compliance costs that the Company seeks to have approved are more specifically described in the Selected Supporting Information section of Technical Appendix Volume 2.

1.9 RELIABILITY

Over the next several years, Georgia Power has sufficient resources to maintain an adequate planning reserve margin in light of anticipated demand of its customers and the current regulations impacting electric generating units. Given the uncertain nature of forecasts and of future regulations, the Company will continue to evaluate its resource needs and will respond as necessary to ensure the reliability and economics of the Georgia Power system. Georgia Power and the System maintain adequate reserve margins in their respective plans to ensure reliable and cost-effective service to the Company's customers.

1.10 RESERVE MARGINS

After analyzing the load forecast and weather uncertainty, the cost of expected unserved energy, as well as the current and near-term projected generation reliability of the System, the Company recommends the System long-term target planning reserve margin be increased from 15% to 17%. The recommended System target planning reserve margin is slightly higher than the minimum total cost but carries less risk than the absolute minimum cost point. As demonstrated in the Reserve Margin Study included in Technical Appendix Volume 1, the absolute minimum cost point is higher than it was in the previous study because of updates to certain key assumptions. For the short-term horizon, the Company recommends an increase in the System target planning reserve margin guideline from 13.5% to 15.5%, but may periodically review the availability and cost of resources in the market and adjust short-term resource procurement decisions accordingly. As explained in more detail in the Reserve Margin Study, the recommended change was driven primarily by the following factors: (1) decrease in economic carrying cost of a CT; (2) increased customer demand and unit outages during extreme cold weather events; and (3) increased reliance on natural gas and the resulting increased exposure to gas delivery constraints. Recent actual experience demonstrates that such a change is in the best interest of customers. Due to the timing of the completion of the Reserve Margin Study, the Company's analysis in this IRP (*e.g.*, the Resource Mix Study, etc.) is based on the prior 15% System long-term target planning reserve margin.

Because of the benefit of System operation and the ability to share resources, each Operating Company can carry lower reserves. Thus, Georgia Power's target planning reserve margin will be 15.4% over the long term and 14% over the short term.

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 2016 Load and Energy Forecast ("Budget 2016") includes the retail classes of residential, commercial, industrial, Metropolitan Atlanta Rapid Transit Authority ("MARTA"), and governmental lighting.

The peak demand forecast for Budget 2016 has been adjusted to account for the effects of RTP customers' response, expected cogeneration, and residential and commercial DSM programs.

A detailed discussion of the revised territorial energy and demand forecasts is set forth in Budget 2016 Load and Energy Forecast in Technical Appendix Volume 2.

1.12 TRANSMISSION PLAN

This IRP includes the Company's updated ten-year transmission plan, which identifies the transmission improvements needed to maintain a strong and reliable transmission system. The development of this plan is conducted in accordance with the Southern Company and Georgia Integrated Transmission System ("ITS") transmission planning guidelines and with 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 ITS as required by the amended rules adopted by the Commission in Docket No. 25981. Additional transmission information is also provided as required by Docket No. 31081.

1.13 INTEGRATED RESOURCE PLAN

The Company's 2016 IRP reflects the following:

- Unavailability of Plant Mitchell Unit 3, Plant Kraft Unit 1 CT, Plant Mitchell Units 4A & 4B, and Intercession City CT reflecting decertification requests made in this filing;
- The availability of units achieving MATS compliance as approved in the 2013 IRP;
- Addition of two new nuclear units at Plant Vogtle (Units 3 and 4) for a combined increase in capacity of approximately 1,007 MW by 2020;
- Inclusion of planned solar capacity additions associated with ASI, ASI Prime, Large Scale Solar ("LSS") and the military solar projects;
- Inclusion of the Blue Canyon PPAs;
- Inclusion of the additional 525 MWs of renewable resources requested for approval in this filing;

- Continuation of existing DSM programs, modification of certain existing DSM programs, decertification of two existing DSM program, and addition of four new DSM programs as reflected in the 2016 DSM Application filed concurrently in Docket No. 40162;
- Unit Retirement Studies of certain generating facilities that consider a range of scenario cases assuming certain fuel and carbon views through a matrix approach and reflect the Company's environmental compliance strategy;
- 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; and
- Updated load and energy forecasts as well as updated fuel forecasts.

Furthermore, the IRP was tested under a range of sensitivity analyses to ensure that it will continue to meet customer needs if future conditions change. The different assumptions used in the sensitivity analyses are detailed in Section 6.5.3.

1.14 CONCLUSION

In summary and as previously stated in Section 1.1, the Company seeks approval of:

1) Its 2016 Integrated Resource Plan and the associated Action Plan;
2) Procurement of an additional 525 MW of renewable resources through the new Renewable Energy Development Initiative, which will utilize a market-based approach with a carve out for distributed solar resources;
3) Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT with the effective dates as specified in the 2016 Decertification Application;
4) A certificate of public convenience and necessity for four new DSM programs, decertification of two DSM programs, amending the certificate for two DSM programs, and approval of updated program economics for all other previously certified DSM programs as further specified in the 2016 DSM Application in Docket No. 40162;
5) An increase in the System long-term target planning reserve margin from 15% to 17%;
6) Reclassification of the remaining net book value of Plant Mitchell Unit 3 as of its respective retirement date to a regulatory asset account and the amortization of such

regulatory asset account ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 36989 until the effective date of the Company's next base rate adjustment, at which time the Company would then begin amortizing the remaining balance over a three year period;

7) Reclassification of any unusable M&S inventory balance remaining at the unit retirement dates to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 36989 for recovery over a period to be determined by the Commission in the Company's next base rate case;
8) The capital costs the Company will incur for a portfolio of certain renewable demonstration projects (but not yet the recovery of such costs), as set out in the Selected Supporting Information section of Technical Appendix Volume 2;
9) 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; and
10) Utilization of the Framework for evaluation of the costs and benefits of renewable resources for purposes of future program design, resource evaluations, and payment calculations, including updating the avoided cost methodologies to reflect these current and future costs and benefits.

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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 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 through which both supply-side and demand-side option evaluations are compared on an equitable 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 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 2016 IRP, the Company is presenting the results of multiple scenario planning cases that evaluate the impacts of three different fuel price views as well as three different carbon views, each estimating the impact of additional pressure on carbon dioxide-emitting generation. 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 greenhouse gas regulation, as promulgated by the EPA, will have a 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., greenhouse gas regulation is also projected to have large and disproportionate regional impacts, with particularly negative impacts for the Southeastern U.S. due to its greater use of coal-fired electric generation compared to other regions. In order to evaluate these interactive and regional impacts, the Company employed a national economic model 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 scenario-specific prices of carbon and fuel. These impacts were 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 IN THE RESOURCE MIX STUDY

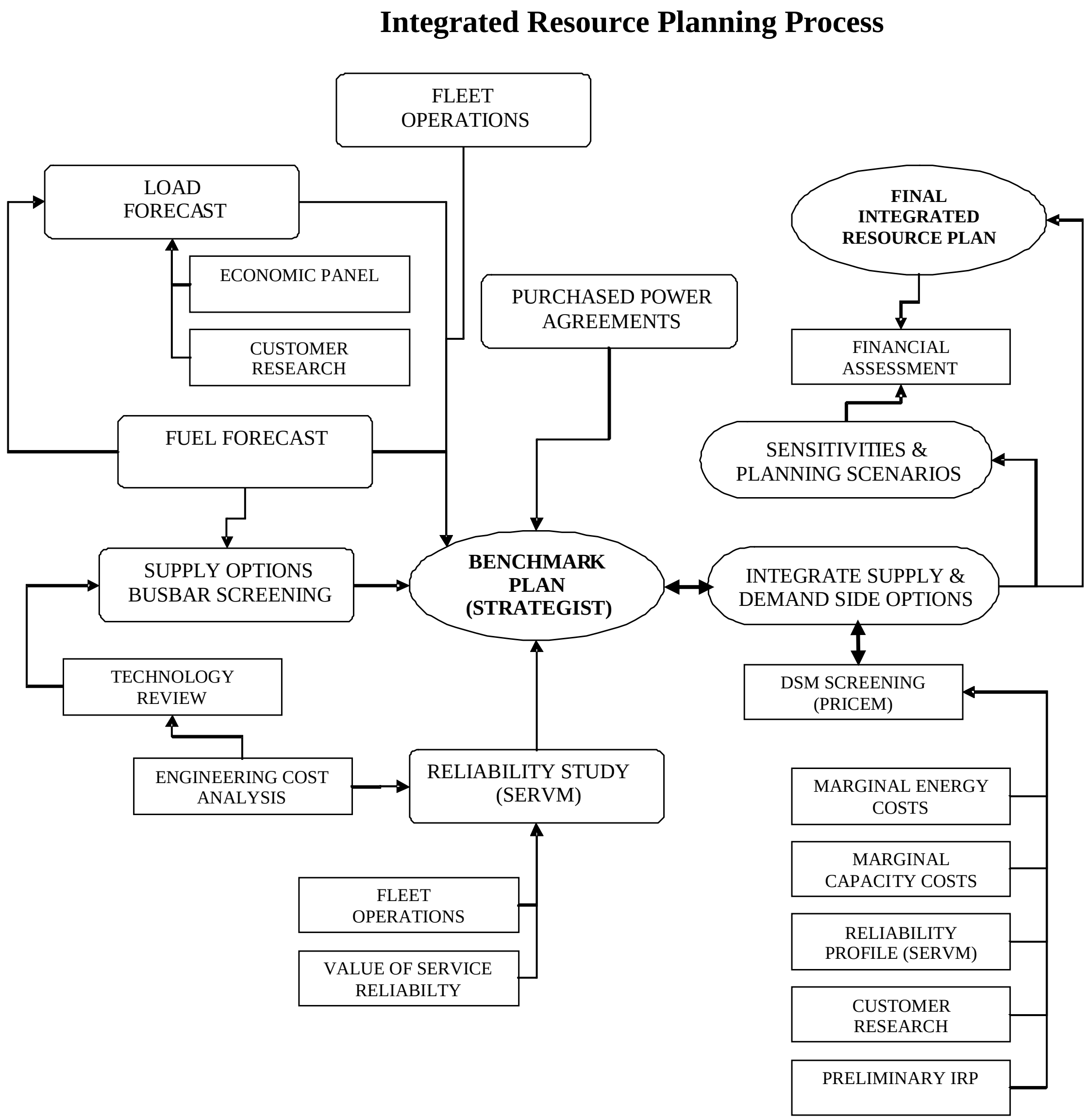
When a need for new capacity exists within the IRP planning process models, the Company evaluates a combination of demand-side and supply-side resources to meet the need in an economical manner. The principal criterion for development of the IRP is to maintain current and future customer value. Customer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

The optimal IRP is one that provides a high level of customer value while anticipating a broad range of potential changes. Therefore, in addition to ensuring compliance with current environmental regulations, the IRP must also appropriately mitigate the risk of future changes in conditions and be flexible enough to be altered if the future is different than expected.

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 integrated process evaluates both supply-side and demand-side programs on an equitable basis.

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) the Load and Energy Forecast; (4) the Reserve Margin Study; (5) demand-side program assessments; (6) existing resource screenings; (7) the generation mix candidate selections; (8) the mix integration; and (9) 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, generation 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 — Both short-term (current year plus two) and long-term (year four and beyond) fuel and allowance forecasts are developed. Short-term forecasts are updated monthly as part of the Retail OpCos' fuel budgeting process and marginal pricing dispatch procedures. The long-term forecasts are initially developed in early spring of each year for use in the Retail OpCos' planning activities. The Company's scenario modeling consultant, Charles River Associates ("CRA"), produces the long term fuel price forecasts used by the Retail OpCos. The development of the long-term forecasts is a highly collaborative effort between CRA, SCS and the Retail OpCos (see Appendix H in the Resource Mix Study found in Technical Appendix Volume 1).

Economic Forecast — Moody's Analytics' macroeconomic forecast is the basis for inflation and cost of capital estimates. Moody's Analytics developed a forecast of economic variables and demographic statistics for the state of Georgia. Key descriptive variables from the economic and demographic forecast of Georgia were used to produce the Budget 2016 Load and Energy Forecast (see Technical Appendix Volume 2).

Technology Evaluation Process and Economic Screening — Feasibility studies for 48 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 on many of the technologies retained for further screening. 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 (see Section 6.4.2.).

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. Such estimates are contained in the Generation Technology Data Book ("GTDB"), which is attached in Technical Appendix Volume 1. Natural gas-fueled simple-cycle CT and CC units along with new nuclear are the generating technologies likely to be added to the system in addition to renewable generation and demand side options. 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.

Load and Energy Forecast — The Budget 2016 Load and Energy Forecast was started in the spring of 2015 and finalized in the fall of 2015. 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.

Reserve Margin Study — This IRP utilizes a 15% System 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 Reserve Margin Study was recently completed for the 2016

IRP which demonstrated that the 15% long-term System planning reserve margin target no longer provides the appropriate balance between reliability and cost and recommends an increase to 17% in the long-term System target planning reserve margin (see the Reserve Margin Study in Technical Appendix Volume 1). Future IRPs will reflect the recommended increase in the reserve margin.

Mix Process

A key part of the benchmark plan in Figure 1 is determining the mix of generating capacity types to economically and reliably serve 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. This least-cost analysis 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.

This effort results in creation of the benchmark plan. The preliminary supply-side plan will be used as the base plan for the demand-side integration process as well as evaluation and integration of renewable resources. The final supply-side plan (or base case) includes the results of the demand-side analysis (see Figure 1, above) as well as planned and committed renewable supply-side resources.

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 widely used throughout the electric industry. 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. The model used to estimate marginal energy cost (PROSYM) is the source of the marginal energy cost used in the model to evaluate DSM programs (PRICEM). These same marginal costs are used extensively in other supply-side evaluations associated with the IRP. 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 existing generating units using marginal cost techniques similar to those used to analyze demand-side programs. See the Unit Retirement Study in Technical Appendix Volume 2 for additional details.

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. In the integration step, those demand-side programs resulting from the DSM evaluation are integrated with the appropriate benchmark supply plan using the Strategist model. After consideration of risk and uncertainty through sensitivity analyses and application of reasonable judgment, the 2016 IRP is finalized.

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3 – BUDGET 2016
LOAD AND ENERGY
FORECAST

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SECTION 3 - BUDGET 2016 LOAD AND ENERGY FORECAST

3.1 GENERAL FORECASTING AND ECONOMICS OVERVIEW

A twenty-year forecast of energy sales and peak demand was developed to meet the planning needs of Georgia Power. Budget 2016 includes the retail classes of residential, commercial, industrial, MARTA, and governmental lighting. The baseline forecast was started in the spring of 2015 and completed in the fall of 2015.

Both the U.S. and Georgia economies have recovered from the Great Recession and are experiencing growth. However, this growth is well below that experienced in previous economic recoveries. Since the recession ended in mid-2009, real U.S. Gross Domestic Product ("GDP") growth has averaged 2.2% per year. Georgia's growth, however, has lagged that of the U.S. over this time period, with its corresponding real Gross State Product ("GSP") growing by an average of just 1.4% per year. The national unemployment rate has fallen from a peak of 10.0% to 5.0% at the end of 2015, while the state's unemployment rate declined from a peak of 10.5% at the end of 2010 to 5.6% as of November 2015.

The modest economic recovery has been reflected in Georgia Power's energy sales statistics for the past few years. Weather normalized total energy sales for 2015 were 1.2% above the prior year's level and remain 1.6% below the previous peak in 2007. The major drop since the recession has been in industrial sales, which remain nearly 6.4% below their pre-recession level on a weather-normalized basis despite growth since 2013. After eight years, residential and commercial energy sales surpassed their pre-recession levels, up 0.8% and 0.2% respectively, in 2015 compared to 2007.

Although underperforming for the past few years, Georgia's economy is expected to regain significant strength over the next several years. Surveys show that the state remains an attractive place to do business and that living costs remain favorable relative to those in many other states. Recent announcements of companies' plans to locate or expand in the state include those by Mercedes Benz, State Farm and Suniva, which are expected to add numerous jobs to the state. Strong demographic trends are expected to propel Georgia into the top tier of states with respect to economic growth. As the economy improves, energy sales will follow suit. Total energy sales are projected to grow at an average annual rate of 1.2% from 2016 to 2025. Industrial sales will be the strongest of the three major customer classes with growth averaging 1.4% per year; commercial and residential sales will average 1.3% and 1.1%, respectively. Peak demand is expected to grow an average of 1.1% per year from 2016 to 2025.

3.2 FORECAST ASSUMPTIONS AND METHODS

Budget 2016 assumptions were developed through a joint effort of Georgia Power and SCS. The forecast was developed through careful consideration and methodical examination of key demographic and economic variables that historically have been significant indicators of energy consumption. Major assumptions include 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 2016 was obtained from Moody's Analytics, 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. The short-term forecasting models incorporate retail electricity prices, for example, 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. "Normal" weather is defined as the twenty-year average of Cooling Degree Days ("CDD") and Heating Degree Days ("HDD") or Cooling Degree Hours ("CDH") and Heating Degree Hours ("HDH").

Short-term energy projections are based on linear regression models developed for the various energy classes. The details of these regression models can be found in Section 4 of the Budget 2016 Load and Energy Forecast in Technical Appendix Volume 2.

The long-term models for the major classes are end-use models. Budget 2016 uses the Load Management Analysis and Planning ("LoadMAP") model to produce the long-term residential, commercial and industrial forecasts. This tool replaces the Residential End-Use Energy Planning System ("REEPS"), the Commercial End-Use Model ("COMMEND") and the Industrial End-Use Forecasting Model ("INFORM") used in previous years. The LoadMAP tool is discussed in greater detail in Section 5 of the Budget 2016 Load and Energy Forecast in Technical Appendix Volume 2.

MARTA and governmental lighting forecasts are based on econometric models and information from Georgia Power field personnel.

The results of the short-term and long-term models are integrated into a unified forecast. In Budget 2016, the short-term forecast results were used for 2016 through 2018 and the long-term results from 2019 to 2035. Additional information on methodology can be found in Section 3 of the Budget 2016 Load and Energy Forecast in Technical Appendix Volume 2.

Budget 2016 uses the Peak Demand Model ("PDM") to predict Georgia Power's peak demands. The PDM replaces the Hourly Electric Load Model ("HELM") used in previous years. The methodology and assumptions used in the PDM tool are discussed in greater detail in Section 6 of the Budget 2016 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 most significant of which are load growth, weather, and generating unit outages. The current System long-term target planning reserve margin requirement is 15% of the total System load. In most years, the 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 13.5% of its own peak demand) and still maintain the target planning reserve margin of 15%. For the short-term horizon (inside three years), there is typically smaller economic uncertainty. Therefore, the Company planned to a lower System target planning reserve margin guideline, which, coincidentally, is also approximately 13.5% (which results in an Operating Company target of 12%).

As discussed in Section 1, based on the results of the Reserve Margin Study included in this 2016 IRP, the Company is recommending an increase in the System target planning reserve margin. Specifically, the Company is recommending a long-term System target planning reserve margin of 17% (which results in an Operating Company target of 15.4%) and a short-term System target planning reserve margin of 15.5% (which results in an Operating Company target of 14%).

As a member of the System, Georgia Power shares reserves with the other Operating Companies for purposes of operations and with the other Retail OpCos for purposes of planning. Georgia Power and the other Retail OpCos are currently projected to have adequate reserves through 2024. Without reserve sharing with the other Retail OpCos, the Company's first year of capacity need is 2024. Even with the recommended increased target planning reserve margin, the Company's first year of capacity need remains at 2024. Of course, uncertainties in forecasts and development of a CPP State Plan and subsequent compliance actions could potentially impact the timing of the next capacity need. Georgia Power will continue to monitor circumstances and, as necessary, will adjust plans for review and consideration by the Commission to ensure the

Company can continue to provide an adequate and cost-effective level of reliability to its customers.

See Tables 4.1.1 and 4.1.1a, Tables 4.1.2 and 4.1.2a, and Figures 4.1 and 4.1a in the IRP Main Document Reference Tables section of Technical Appendix Volume 1 for additional details.

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 2016 IRP filing. Included in this section are:

- A review of significant events since the Company's 2013 IRP filing that are relevant to the screening and assessment of demand-side resources;
- A discussion of newly proposed DSM programs, as well as changes to existing programs, which includes amendments and decertifications;
- 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 Commission's IRP Rules and the DSM Program Planning Approach outlined in the 2013 IRP Order, 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 2013 IRP filing, certain events have affected the screening of demand-side resources. These events are described below.

5.1.1 2013 IRP Filing Approval

In the 2013 IRP Order, the Commission decertified one program, amended the certificates of three programs, and certified one new program as part of the Company's proposed DSM portfolio. The Company also agreed to Commission Staff's recommendation to increase participation levels by 10% for all programs, excluding the CFL Giveaway program. The 2013 IRP Order approved program plans for the following programs:

Residential Programs:

- Lighting

- Appliance
- EarthCents New Home
- Home Energy Improvement
- Refrigerator/Freezer Recycling

Commercial Programs:

- Custom
- Prescriptive
- Small Business

Additionally, a program evaluation plan was developed and filed with the Commission in 2014, and the Company completed and filed the program evaluations results in 2015.

5.1.2 Program Evaluation Results

As specified in the 2013 IRP Order, process and impact evaluations were to be performed on each of the eight certified DSM programs prior to the 2016 IRP. Nexant was selected by the Company to perform the program evaluations. Program evaluations were completed and filed on July 31, 2015. The results were considered in the development of the 2016 IRP, as well as the program plans in the Company's 2016 DSM Application. Additionally, as part of the 2013 Order, the Company agreed to have a process and impact evaluation performed on the Low Income Weatherization program. TetraTech was selected by the Company to perform the program evaluation, and this report was also filed on July 31, 2015.

5.1.3 2016 DSM Program Planning Approach

As part of the 2010 IRP Order and reaffirmed in the 2013 IRP Order, the Commission approved the Nine Step DSM Planning Process (renamed the "DSM Program Planning Approach") that guided the development of the Company's 2016 IRP DSM plan.

In addition, the Company met with the Demand Side Management Working Group ("DSMWG") seven times from 2013 through 2015 in an attempt to reach agreement on DSM program development. The Company met with DSMWG subcommittees twice in 2015 to discuss DSM program concepts and modeling of a DSM sensitivity case proposed by certain members of the DSMWG. Finally, the Company also hosted several telephone conference calls and shared data with the DSMWG as late as December 2015 in preparation for, and leading up to, the 2016 IRP filing.

5.1.4 2014 Report on Demand Response Programs

On January 17, 2014, the Company filed with the Commission a "Report on Demand Response Programs" in accordance with the 2013 IRP Order.

5.1.5 2016 IRP Avoided Cost/Fuel Price Decreases

The estimated avoided fuel cost savings resulting from DSM measures installed by customers in the proposed DSM programs included in the 2016 IRP have continued to decline when compared to the fuel cost savings reflected in the 2010 and 2013 IRP filings. These changes in avoided cost savings have a significant and negative impact on the economics of the Company's current and proposed DSM programs. The Company's recommended Proposed Case highlights that TRC Test results declined and RIM Test results worsened, causing concerns for the Company in its efforts to balance the economic benefits these programs provide for participating customers, with the rate impacts to all customers within a given class they are a part of. The Company plans to monitor program costs and economics from 2017 through 2019 and will be prepared to modify programs if significant upward pressure on rates continues.

5.2 DISCUSSION OF CURRENT AND PROPOSED DSM PROGRAMS

5.2.1 Continuation and Expansion of Current Certified DSM Programs and Addition of Four New Certified DSM Programs

5.2.1.1 Residential DSM Programs

In the 2016 DSM Application, the Company is requesting the following actions or adjustments for the currently-certified residential DSM programs, as well as the proposal of new programs or decertification of current programs.

Residential Programs

- EarthCents New Home Program - Updated program economics
- Home Energy Improvement Program - Updated program economics
- Lighting Program - Updated program economics
- Appliance Program - Decertify the current program
- Refrigerator/Freezer Recycling Program - Updated program economics
- Power Credit Program - No changes requested
- Heating, Ventilation, and Air Conditioning ("HVAC") Service Program – Grant a new certificate
- Behavioral Program – Grant a new certificate

EarthCents New Home Program. This program focuses on a whole-house approach to improve the energy efficiency of new homes, promote the installation of energy efficient measures in new home construction, and improve the performance of participating homes to at least 7.5% above the applicable Georgia State Energy Code at the time the home is built. Additionally, it promotes improvements in individual measures such as high efficiency electric heating and cooling equipment, LED replacements for incandescent bulbs, and heat pump water heaters.

Details of the program are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost-effectiveness results of the EarthCents New Home Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
Earthcents New Home Program	844	5,551,131	($5,370,272)	$2,859	$1,769,926	$5,373,131	$176,312

Home Energy Improvement Program. This program promotes a comprehensive, whole-house approach to improve the energy efficiency and comfort of existing homes. It also offers an alternate path that allows customers to make improvements to individual areas of the thermal envelope and equipment in their homes.

Details of the program are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost effectiveness results of the Home Energy Improvement Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
Home Energy Improvement Program	17,165	18,419,369	($20,407,807)	$3,026,523	$3,419,656	$23,434,330	$3,790,541

Lighting Program. This program promotes the purchase and installation of energy efficient lighting and lighting fixtures through customer education, retailer partnerships and training, promotional giveaways of high efficiency lights, and customer incentives.

Details of the program are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost effectiveness results of the Lighting Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
Lighting Program	2,238	25,394,511	($19,733,828)	$1,609,764	$9,660,347	$21,343,592	$2,274,120

Appliance Program. The Company requests decertification of this program due to low customer participation rates and reduced program cost-effectiveness.

Refrigerator/Freezer Recycling Program. This program aims to eliminate inefficient or extraneous refrigerators and freezers 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 and freezers. The program provides cash incentives, free pickup and recycling services for qualifying equipment.

Details of the program are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost effectiveness results of the Refrigerator/Freezer Recycling Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
Refrigerator/Freezer Recycling Program	776	10,239,089	($7,576,429)	$748,092	$306,893	$8,324,520	$894,524

Power Credit Program. This program is a residential load control program that allows the Company to cycle HVAC systems during periods of high system capacity constraints and high energy costs during the summer season. Energy from HVAC units is shifted to off-peak periods that typically have lower demand and energy costs. The program currently has approximately 48,000 participants and provides approximately 100 MW of demand reduction.

HVAC Service Program. This program is designed to increase the operating efficiency of existing residential HVAC equipment for participating customers. The program will include HVAC system diagnostics and maintenance designed to improve the efficiency of residential HVAC equipment.

Details of the program are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost effectiveness results of the HVAC Service Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
HVAC Service Program	480	961,449	($1,690,818)	($371,415)	($1,147,840)	$1,319,403	($355,239)

While the program does not pass TRC in the year 2017, it does pass the test beginning in the third year of program implementation.

Behavioral Program. This program provides residential customers with electricity consumption information for their home and compares each home's consumption to a group of similar homes. Customers that use less electricity than their comparison group receive positive encouragement to continue their energy-conserving behaviors. Likewise, customers that use more electricity than their comparison group are encouraged to take actions to save energy, such as participating in Company DSM programs or changing their electricity consumption behavior

Details of the program are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost effectiveness results of the Behavioral Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
Behavioral Program	2,362	18,959,000	($2,168,937)	$111,736	$111,736	$2,280,673	$155,065

5.2.1.2 Commercial DSM Programs

In its 2016 DSM Application, the Company is also requesting the following actions or adjustments for the following commercial DSM programs:

Commercial Programs

- Commercial Prescriptive Program – Update program economics
- Commercial Custom Program – Update program economics
- Commercial Small Business Program – Decertify the current program
- Small Commercial Direct Install Program – Grant a new certificate
- Commercial HVAC Program – Grant a new certificate

Commercial Energy Efficiency Program. The prescriptive and custom programs will be marketed and advertised as one program to commercial customers for ease of implementation and to avoid market confusion. They will be marketed as the "Commercial Energy Efficiency Program" to new and existing customers, but will continue to have separate budgets, energy savings targets, and economic analyses.

Prescriptive Program. This program promotes the purchase of eligible high-efficiency equipment installed at qualifying customer facilities. Customer incentives will reduce the incremental cost to upgrade to high-efficiency equipment and measures over standard efficiency options. One significant change will be that HVAC equipment will be removed from this program and a new commercial HVAC program will be established.

Details of the program are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost effectiveness results of the Prescriptive Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
Prescriptive Program	44,208	207,455,814	($71,324,095)	$126,421,113	$143,600,972	$197,745,208	$134,475,957

Custom Program. This program provides a platform for comprehensive energy efficiency projects 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 and customer incentives on the verifiable energy savings resulting from the measures. Measurement and verification procedures vary depending on the energy efficient products installed.

Details of the program continuation are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost effectiveness results of the Custom Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
Custom Program	11,705	54,614,513	($21,974,045)	$15,326,538	$31,207,994	$37,300,583	$17,316,328

Small Business Program. The Company requests decertification of this program to allow for the development of the new Small Commercial Direct Install Program that should better reflect the needs of a hard-to-reach segment of the commercial market.

Small Commercial Direct Install Program. This program will offer qualifying customers the opportunity for energy savings through measures that will typically be installed directly in their facilities. Customers who are eligible for the Small Commercial Direct Install Program will also be eligible to participate in the Custom and Prescriptive programs.

Details of the program are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost effectiveness results of the Small Commercial Direct Install Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
Small Commercial Direct Install Program	3,953	12,728,457	($9,887,002)	$988,059	$2,078,877	$10,875,061	$1,330,962

HVAC Program. This program will offer incentives on select HVAC equipment. The initial intent will focus on establishing a midstream program by partnering with equipment distributors. In this model, the incentives are designed to offset distributers' costs for stocking a larger share of high-efficiency HVAC equipment, and to encourage the promotion of high-efficiency equipment to commercial customers. Increasing the share of high-efficiency HVAC equipment held in stock by local and regional distributors will ensure that businesses have more high-efficiency options available for purchase when their current equipment must be replaced.

Details of the program are outlined in the twelve-year Program Plan found in the 2016 DSM Application, Docket 40162.

The 2017 expected energy reductions and cost effectiveness results of the HVAC Program are:

Program	Demand Reduction (kW)	Energy Reduction (kWh)	Ratepayer Impact Measure Test	Total Resource Cost Test	Program Administrator Cost Test	Participants Test	Societal Test
HVAC Program	1,541	3,434,391	($4,751,817)	$148,271	$2,038,058	$4,900,087	$319,837

Each of the twelve-year DSM Program Plans allows for ongoing review and modification of program design features through regular program monitoring, as well as the formal program evaluation plan in an effort to maximize energy savings while maintaining economic efficiency. 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. Additionally, as new measures and technologies evolve during the twelve-year filed program life, the Company may add such measures to these programs. Any new measures being added will follow the same economic screening process as those approved by the Commission, and the Commission would be made aware of any additions prior to the Company offering the new measures to customers as required.

5.2.2 Continuation of the Low Income Weatherization Program

The Low Income Weatherization program began in January 1996, and was designed to provide monetary assistance to Resource Services Ministries ("RSM") and the Georgia Environmental Finance Authority ("GEFA") to augment their existing weatherization assistance efforts for low income customers.

The program approved in the 2013 IRP provided for annual funding of $1.75 million to GEFA and $250,000 to RSM. The Company plans to continue the funding of the Low Income Weatherization program at its current annual funding level of $2 million through December 31, 2016. The distribution of those funds will vary for 2017 through 2019. RSM will continue to receive funding at an unspecified level to be determined at a later date. Due to the Company being unable to contract with GEFA for program year 2016, the remaining funds will be distributed directly through a number of channels and delivery methods. This will ensure that the customers who are in the most need of energy efficiency improvements will not see a gap in service now that GEFA is no longer administering a portion of the program.

Moving forward, the Company intends to consider any and all options for the effective distribution of these funds annually.

5.2.3 Education Initiative

In 2011, the Company re-initiated its classroom presence through its Learning Power Program. The curriculum promotes an understanding of energy and energy efficiency from a grass roots perspective. Lessons have been developed for grades pre-K-12. The method of delivery is highly interactive and hands-on, with lessons delivered by skilled Georgia Power employees, known as Education Coordinators. There is one Education Coordinator dedicated to each region of the state. Since the launch of the program in August of 2011, the Company has delivered

12,325 programs to 313,837 students through December 2015. Since 2011, approximately 3,000 teachers have been interviewed, and average results over the life of the survey are as follows:

- It was beneficial to their students (98%);
- It increased their students' knowledge about energy efficiency (98%); and
- It improved their students' commitment to energy efficiency (91%).

In addition, Learning Power leaves teachers feeling very well informed about energy and energy efficiency after Education Coordinators present.

- Before the presentation, 44% felt very well informed about energy and energy efficiency; and
- After the presentation, 97% felt very well informed about energy and energy efficiency.

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

The Company also provides a number of other avenues for one-on-one, customized assistance to customers to help them better understand their energy usage and identify energy efficiency opportunities. Additionally, more than 9,000 in-home 2,500 in-facility, and 36,000 on-line energy audits were offered to customers in 2015 to assist in identifying energy and money savings opportunities. These audits also serve as marketing channels to direct customers to participate in other energy efficiency programs. Furthermore, over 27,000 calls a year are received through the Company's residential energy efficiency hotline from residential customers seeking energy efficiency advice. One-on-one energy efficiency assistance is also offered and is typically directed towards helping the Company's larger commercial and industrial customers through the Company's Key Account Managers, however varying levels of energy efficiency assistance can be provided to any customer by virtually any Company employee.

5.2.5 Energy Efficiency Awareness Initiative

The Company's Energy Efficiency Awareness Initiative promotes the benefits of energy efficiency and educates customers about specific ways to save money and energy. The

Commission-approved budget for this initiative was $4.4 million annually for years 2011 through 2013. This budget had historically supported awareness in the residential market. Since there was a need going forward to also raise awareness in the commercial market, the Company requested, and was granted in the 2013 IRP, an increase in this annual budget to $5.4 million. This request kept the residential campaign at $4.4 million annually and added $1 million annually for commercial general awareness.

The Company uses direct marketing channels to efficiently reach its customer base. Television, radio, print, internet, billboards, local office advertising, and direct mail are the primary channels 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 www.georgiapower.com to learn ways to save energy through general energy efficiency information, helpful tips, and specific information about energy efficiency programs offered by the Company. Social media is also used to communicate with online customers, including Facebook, Twitter, and YouTube.

5.2.6 Demand Response Tariffs

For many years, the Company has offered its customers a menu of demand response tariffs, such as:

- Real Time Pricing, which offers customers marginal pricing for incremental load; as prices increase, customers can respond by reducing their demand;
- Demand Plus Energy Credit ("DPEC"), which is an interruptible service tariff that provides commercial and industrial customers with a demand credit for the potential of demand reduction, plus an energy credit when DPEC is called;
- Demand tariffs, which align with the Company's cost of service and encourage demand reduction; and
- Time of Use tariffs, which 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.

5.2.7 Pilot Studies & Budgets

Georgia Power engages in pilot studies when needed to better understand emerging energy efficiency options for the benefit of customers. In the 2016 IRP, the Company is seeking Commission approval of a proposed budget for residential and commercial pilots, outlined in the Company's 2016 DSM Application. A portion of the proposed pilot studies budget would be used to cover certain energy efficiency cost components of the Company's proposed Connected Community Development and Demonstration Center and the High Performance Computing Center.

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 included identifying DSM measures and programs with input from the DSMWG. Additionally, economic evaluations were performed for each measure and program to determine the program cost-effectiveness based on the industry-standard benefit/cost tests and as required by the Commission IRP rules. The tests conducted are the RIM, TRC, Participants Test ("PT"), Program Administrator Cost Test ("PACT"), and Societal Cost Test ("SCT"). The RIM test assesses fairness and equity by measuring what happens to customer rates due to changes in utility revenues and operating costs caused by the program. The TRC test assesses economic efficiency and societal impact by measuring the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The PT assesses the impact on a program participant by measuring the quantifiable benefits and costs to the customer due to participation in a program. The PACT assesses the net costs of a DSM program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The SCT is a variant of the TRC test and includes an adder to avoided fuel costs to simulate environmental externalities.

The Company met with, discussed, and shared presentations related to DSM program design details with the DSMWG at multiple meetings in 2014 and 2015. A smaller sub-group of the DSMWG met and identified the program concepts and measures considered for economic screening in support of the 2016 IRP development. Input from the sub-group participants was used in developing the list of programs and measures within programs to analyze. This list was shared with the larger DSMWG for solicitation of additional feedback or input on this process. An agreement among certain parties of the DSMWG was reached regarding some programs to include in the analysis of a sensitivity case (or the “Advocacy Case”). The preliminary results of the program economic screening were also shared with the DSMWG in December 2015 in advance of the Company’s filing.

5.3.2 DSM Program Economic Screening Policy

The Company continues to follow the Commission’s economic screening policy outlined in the 2004 IRP Order, Docket No. 17687, which requires the Company to offer a DSM plan that minimizes upward pressure on rates and maximizes economic efficiency. Additionally, the Company’s DSM plan treats DSM as a priority resource. In fact, the first step in the Company’s IRP process is to reduce the Company’s energy and demand forecast by the recommended Proposed Case’s energy and demand impacts prior to developing the supply-side alternatives. The recommended Proposed Case’s cost-effectiveness results presented herein reflect the continuation of, or modifications to, certain current DSM programs, the addition of new DSM programs, and the decertification of certain existing DSM programs. However, due to the decline in avoided costs since the 2013 IRP, the rate impacts for the proposed programs will be larger than those in the DSM programs approved in the 2013 IRP. At the same time, while the DSM programs provide TRC benefits, such benefits are not as large as in the 2013 IRP due to the decline in avoided costs. The recommended Proposed Case’s DSM programs will average almost $149 million Net Present Value (“NPV”) over the life of the measures in TRC benefits annually but will, on average, put $184 million of upward pressure on rates (NPV over the life of the measures) annually for years 2017 - 2019.

The Aggressive Case’s sensitivity cost-effectiveness results are also presented herein, as outlined in the DSM Program Planning Approach. The Aggressive Case is not recommended by the

Company and is not a DSM plan that should be approved by this Commission due to the significant upward pressure on rates and poor economic efficiency, relative to the upward pressure on rates that would result. The Aggressive Case sensitivity includes programs from the recommended Proposed Case, but with customer participation at higher penetration levels and associated higher budgets, as well as additional programs, measures, and associated budgets to help reach almost 11.6% cumulative energy savings by 2028 when compared to the Budget 2016 forecast.

At the request of some members of the DSMWG, the Company agreed to analyze another case, identified as the DSMWG Advocacy Case), which achieved almost 5.6% cumulative energy savings by 2028 when compared to the B2016 forecast. The results of this sensitivity case were shared with the entire DSMWG in December 2015.

The higher levels of market penetration in both the Advocacy and Aggressive sensitivity cases ultimately result in rate impacts of approximately $257 million and $754 million (NPV over the life of the measures), respectively, annually on average for years 2017 - 2019 over the alternative supply-side resource plan. These plans, if implemented as analyzed, would increase customer's rates (or RIM) approximately one and a half to four times more than the Company's recommended Proposed Case, while only increasing the economic efficiency (or TRC benefits) by about one and a quarter to two and a half times, respectively, for the same timeframe. The Advocacy Case is a ramp up of the energies included in the Company's Proposed Case, as well as additional programs proposed by certain members of the DSMWG. The Company does not recommend the approval of the Advocacy Case due to the rate impacts of the plan, and the program assumptions upon which it is based.

5.3.3 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, which include industry conferences and trade associations, among others. Additional input was provided by the DSMWG members, some of whom have 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. Additionally, customer feedback was reviewed as a source of information for program additions and improvements. Information gathered was shared with the DSMWG in program development discussions. A compilation of the qualitative screening of DSM measures is included in the DSM Program Documentation section of Technical Appendix Volume 2.

5.3.3.1 Residential Technology

More than 100 residential DSM measures were identified for economic screening and possible inclusion in residential programs. These measures provided potential energy savings through:

- Compliance with state standards and codes;
- Increased energy efficiency for electric equipment;
- Electric space cooling and heating equipment;
- Electric lighting;
- Electric water heating;
- Customer behavior improvements; and
- Heating and cooling savings resulting from improvements to the building's thermal shell.

In addition to specific measures, the building type (single family - new and existing, multifamily - new and existing, or manufactured housing - new and existing) was considered in the economic analysis.

5.3.3.2 Commercial Technology

More than 125 commercial DSM measures were identified for economic screening and possible inclusion in commercial programs. These measures provide energy savings through:

- Compliance with state standards and codes;
- Increased energy efficiency for electric equipment;
- Electric space cooling and heating equipment;
- Electric lighting;

- Electric water heating;
- Customer behavior improvements; and
- Heating and cooling savings resulting from improvements to the building's thermal shell.

In addition to specific measures, the building type (the type of customer operation, such as schools or offices) was considered along with the construction type (new and existing) when conducting the economic analysis.

5.3.3.3 Industrial Technology

A total of six custom industrial DSM measure categories within one custom program were identified for economic screening and are available for the Advocacy Case and Aggressive Case sensitivities. No industrial programs are included in the Company's Proposed DSM case. These measures provide energy savings through:

- Electric space cooling and heating equipment;
- Electric lighting;
- Motors;
- Compressed air;
- Industrial process equipment; and
- Retro-commissioning.

5.3.4 Economic Screening

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

First, 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. EnerSim 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 DOE and is listed on their website as "Qualified Software."[2] Energy usage for non-weather-sensitive end-uses was calculated using either the EnerSim program, secondary sources, or from other end-use specific calculations.

Second, each potential end-use measure that was passed to 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 useful life of the end-use equipment. Utility avoided costs include estimates of the supply side capacity and energy costs that can be avoided by each measure and savings from generation, transmission, distribution, fuel, environmental, and other system-production costs.

The following industry-standard, DSM 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, the Cost of Saved Energy ("CSE"), also referred to as Levelized Cost per annual kWh saved, is provided for each of the programs. The CSE is the total cost per kWh of realizing the efficiency improvement. CSE is determined by dividing levelized program costs by the annual energy savings, as shown in the following equation. Levelized program costs are calculated using a Capital Recovery Factor ("CRF"), which incorporates the number of years that the energy savings persist, and an annual discount rate.

CSE Equation:

$$\text{CSE} = \frac{\text{Program Costs (\$) x CRF}}{\text{Annual Energy Savings (kWh)}}$$

A compilation of the economic screening of DSM measures that passed the qualitative screening is included in the DSM Program Documentation section of Technical Appendix Volume 2.

[2] http://energy.gov/eere/buildings/qualified-software-calculating-commercial-building-tax-deductions

5.3.5 Long Term Percentage Rate Impacts

The Company has provided an analysis of the long term percentage rate impact as required by the 2013 IRP Order. Prior to this filing, the Company and Commission Staff worked collaboratively on the methodology for calculating the long term percentage rate impacts of certified demand side programs.

Please see the DSM Program Documentation section of Technical Appendix Volume 2 for annual long term percentage rate impacts.

5.4 DEMAND-SIDE PROGRAM DEVELOPMENT

5.4.1 Demand-Side Resource Policy

In the 2004 IRP, the Commission directed that proposed DSM plans should minimize upward pressure on rates (negative RIM results) and maximize economic efficiency (positive TRC results). The Commission further directed that the cost/benefit analysis results of each initiative should use all three tests (PT, RIM and TRC) and should balance economic efficiency (TRC benefits) and fairness and equity (RIM benefits/cost). This Commission policy was affirmed in the 2007, 2010, and 2013 IRPs. The Company utilized this same philosophy in analyzing the programs for the 2016 IRP.

This IRP adheres with the DSM Program Planning Approach for developing the 2016 IRP, approved by the Commission in July 2013 as part of the 2013 IRP Order.

5.4.2 Twelve-Year DSM Program Plans

The Company has developed twelve-year program plans outlining the implementation details behind each individual program included in the recommended Proposed Case. Each of the energy efficiency program plans are provided in the 2016 DSM Application, Docket 40162.

Included in each program plan are the following details:

- Program Summary – outlines the goals of the program;

- Program Structure – outlines the intended participant eligibility, home or facility eligibility, and specific measures and incentives where appropriate;
- Program Implementation – outlines the intended target market, key market players, as well as marketing and outreach plans;
- Program Operation – outlines the intended customer participation process and program administrative procedures; and
- Program Evaluation – outlines the intended performance metrics, expected program budget, cost-effectiveness expectations, as well as plans to develop an independent third-party evaluation plan after programs are approved.

5.5 REGULATORY TREATMENT OF DSM PROGRAM COSTS AND THE ADDITIONAL SUM

The Company is requesting the continued collection of costs for all approved and certified DSM programs and activities through the existing Residential and Commercial DSM tariffs. The Company is also requesting the continued collection of an additional sum amount for certified energy efficiency programs through these tariffs. These tariffs will be filed as part of the Company's 2016 base rate case and would be implemented with any approved change of rates on January 1, 2017.

5.6 SUMMARY OF DSM CASES

5.6.1 <u>Proposed Case – Georgia Power Recommended Case</u>

The energy efficiency programs in the Company's Proposed Case for the 2016 IRP achieve an average of almost \$149 million (NPV over the life of the measures) in TRC benefits while putting upward pressure on rates of almost \$184 million (NPV over the life of the measures) annually over years 2017 - 2019. The Company is concerned that these results are not striking the balance needed when considering energy efficiency programs, but recommends continuing the established energy efficiency programs approved in the 2013 DSM Certification filing, including the changes discussed above, to achieve approximately the same levels of energy savings that are currently being achieved. The Company's recommendation to continue the programs at this time is based on the desire to minimize market disruption, to continue meeting customers' expectations, and to maintain positive relationships with vendors performing qualified program improvements. The Company is also seeking to decertify the Appliance Program due to lack of customer participation and reduced program cost effectiveness and the Commercial Small Business program in order to redesign a more effective program for the small commercial segment of the market. The Company is also seeking to certify the new Residential HVAC Service and Behavioral Programs, as well as the new Commercial HVAC and Small Commercial Direct Install Programs. The Company plans to monitor program costs and economics from 2017 through 2019 and will be prepared to modify programs if significant upward pressure on rates continues.

The Company's DSM portfolio included in the 2016 IRP consists of currently certified programs as well as new programs, modified based on data gathered in the implementation phase, as well as input from the DSMWG and an independent third party evaluation. If the Proposed Case is approved, the Company will continue to enhance these programs as more information becomes available relative to market penetration and customer feedback through an ongoing evaluation process. The Company will keep the Commission fully informed of potential changes to programs through notification to, or approval by, Commission Staff, as required.

The Company's Proposed Case summary economics are provided in the DSM Program Documentation section of Technical Appendix Volume 2. As part of the DSM Program Planning Approach, the Company agreed to calculate the generation avoided costs for its DSM change case using its system tool. The avoided generation costs for the Company's Proposed Case from the system tool were not significantly different than the avoided generation costs obtained from PRICEM. Also, the avoided generation costs for the Advocacy and Aggressive sensitivity cases from the system tool were not significantly different than the avoided costs obtained from PRICEM.

5.6.2 <u>DSMWG Advocacy Case</u>

The DSMWG Advocacy Case was developed as a sensitivity case to the Company's recommended DSM plan and is based on requests made by certain members of the DSMWG. The Company presents the results of this case for informational purposes.

If the DSMWG Advocacy Case is implemented, the portfolio would put additional upward pressure on rates of approximately $257 million (NPV over the life of the measures) on average annually for years 2017 - 2019, approximately one and a half times higher than the Company's recommended Proposed Case, while only increasing the economic efficiency (or TRC benefits) by about one and a quarter times. Over the 2017 – 2028 program years evaluated within this sensitivity case, rates would increase on average by about $354 million annually (NPV over the life of the measures). The Advocacy Case included a ramp up of the Company's Proposed Case, as well as additional programs proposed by certain members of the DSMWG, which included program assumptions that the Company does not agree with. Therefore, the Company does not recommend approval of the DSMWG Advocacy Case.

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

5.6.3 Aggressive Case

The Aggressive Case was developed to represent an aggressive DSM sensitivity and was developed with input from the DSMWG, as outlined in the DSM Program Planning Approach. It serves as a reference point to estimate the maximum achievable potential for increased energy efficiency and the impacts of such aggressive adoption of DSM. This increased energy efficiency comes at a high cost to customers. The higher impacts from the Aggressive Case ultimately result in an average annual rate impact of more than $754 million (NPV over the life of the measures) for years 2017 - 2019, more than four times higher than the Company's recommended Proposed Case, while only increasing the economic efficiency (or TRC benefits) by about two and a half times. Over the 2017 – 2028 program years evaluated within this sensitivity case, rates would increase on average by almost $883 million annually (NPV over the life of the measures). The Company does not recommend the approval of the Aggressive Case.

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

5.7 RECOMMENDED DSM ACTION PLAN

In summary, the Company's recommended DSM action plan includes the following:

- Implementation of the six residential programs outlined in Section 5.2.1.1 and detailed further in the Certification Application;
- Implementation of the four commercial programs outlined in Section 5.2.1.2 and detailed further in the Certification Application;
- Continuation of the Power Credit program;
- Continuation of the additional DSM programs detailed in Section 5.2.2, 5.2.3, 5.2.4 and 5.2.5; and
- Conduct pilot studies detailed in Section 5.2.7.

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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;
- Modeling existing 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 benchmark plan; and
- Evaluating the benchmark plan across a range of changing assumptions.

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

The 2016 IRP contains a supply-side plan that reflects the Company's decisions for transitioning its generation fleet to best meet the requirements of existing and potential environmental rules and regulations, but does not yet reflect impacts from the CPP. Encompassing previous actions and decisions resulting from the IRP planning process overseen by the Commission, as well as the Company's requested actions in this 2016 IRP filing, the supply-side plan reflects an efficient and diverse fleet of resources. Further detail regarding existing and committed units is located in the Resource Ledger in Technical Appendix Volume 1.

6.2.1 Previous Resource Commitments

The supply-side plan reflects previous decisions and actions resulting from the IRP planning process, including the retirements of Plant Branch Units 1-4, Plant Bowen Unit 6, Plant Boulevard Units 2 and 3, Plant McManus Units 1 and 2, Plant Yates Units 1–5, and Plant Kraft Units 1-4. The plan also includes the addition of resources, most notably the two new nuclear units at Plant Vogtle Units 3 and 4, capacity planned and procured for the Company's ASI and

ASI Prime programs, Military Solar, Blue Canyon, and Proxy Qualifying Facilities' ("QFs") capacity resulting from the 2015 RFP.

6.2.2 Implementation of the MATS Strategy as Approved in the 2013 IRP

In addition to the units listed in section 6.2.1 that were decertified as part of the Company's MATS strategy in the 2013 IRP, the Company is nearing the successful completion of over $1 billion of investment approved in the 2013 IRP for the continued operation of its remaining fleet. This includes achieving MATS compliance at Plants Bowen, Wansley, Scherer, Hammond, and McIntosh through varying applications of baghouses and MATS additives. Plant Yates 6 and 7 and Plant Gaston Units 1-4 have switched to natural gas to continue operations.

6.2.3 Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT

The supply-side plan reflects the unavailability of Plant Mitchell Units 3, 4A and 4B, and Plant Kraft Unit 1 CT effective as of the date of the final order in this proceeding. It also reflects the unavailability of the Intercession City CT effective approximately one month after the date of the final order in this proceeding in order to allow time to complete the closing of the sale.

6.2.4 Blackstart Resources and Transmission System Restoration Plan

For system restoration purposes, certain generating units are designated as "Blackstart Resources." Blackstart Resources are defined, per NERC reliability standards, as "a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan." A review and assessment of Blackstart Resources and the Company's Transmission Operator system restoration plan continues in conjunction with unit retirement studies. System restoration plans will continue to be updated annually at a minimum or as required due to changes in the future mix of generating assets.

6.3 SUPPLY-SIDE OPTIONS

Based on current projections, the fact that no State Plan for the CPP exists, and reflecting reserve sharing for the Retail OpCos, the Company is projected to have adequate capacity reserves through 2024 and, thus, there is no plan in this IRP to add capacity within the next three years. As discussed in Section 6.2, the Company has implemented its MATS compliance strategy as approved in the 2013 IRP. In addition, the Company has completed a review of its CT fleet, which has resulted in the decertification of three small CTs. Acting in the best interest of its customers, the Company is also divesting itself of its ownership in the Intercession City CT, primarily owned by Duke Energy Florida, and is also requesting decertification of Plant Mitchell Unit 3 where the biomass conversion project was cancelled in January 2014.

6.4 NEW GENERATING TECHNOLOGIES

The Company continually evaluates conventional and emerging generating technologies as a starting point in developing a base supply-side plan, as described in Section 13. 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 an expansive portfolio of conventional and new supply-side generation technologies;
- Initiates a preliminary technology screening analysis based on technical, economic, environmental, and resource availability information by Southern Company's Technology Strategy Coordination Team ("TSCT");
- 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 2016 technology screening process identified 48 technologies for strategic assessment. They are listed in Section 13.3 and Table 13.3.2 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.*, Ocean Thermal Generation) or their early stage of development (*e.g.*, magnetohydrodynamics). Twenty-seven technologies were carried forward for more detailed analysis (refer to Section 13, Table 13.3.3).

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, such as being scalable and repeatable.

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 compare the screening-level 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. Busbar models are very useful in screening evaluations for generation technology options but should not be used for making final resource decisions since that requires more detailed modeling.

All data assumptions are shown in Table 6.4.2 in the IRP Main Document Reference Tables section of Technical Appendix Volume 1. A capital cost comparison and busbar curves are shown in Figures 6.4.2.1 and 6.4.2.2, respectively, in the IRP Main Document Reference Tables section of Technical Appendix Volume 1.

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 2016 Generation Technology Data Book, included in Technical Appendix Volume 1, provides the capital cost for pre-licensed nuclear generation.

The Company's ability to reliably serve customers in a cost-effective manner is highly dependent upon maintaining a diverse fleet of generation resources. In order to continue to maintain a diverse, reliable and cost-effective power supply over the long term, new nuclear must be considered as a potential future resource addition. Future nuclear generation is critical to maintaining a cost-effective energy supply in Georgia for years to come because nuclear generation: (1) is an emissions free source of power; (2) will continue to help maintain power supply diversity; and (3) is a reliable source of baseload energy.

While energy efficiency and renewable resources are important elements of the plan, they cannot provide a reliable and economic supply of electricity to customers without other resources in place. Adding only natural gas-fired resources or a combination of energy efficiency, renewables, and natural gas-fired resources in the future would result in an over-reliance on a fuel with a history of volatility and which is subject to potential future cost increases driven by regulation, changing market conditions and other factors. Nuclear generation provides stable, predictable, low-cost energy for customers because of its ability to generate twenty-four hours a day, seven days a week at very high capacity factors. Preserving the option to add baseload nuclear power is critical to maintaining long-term reliability for customers. However, the long lead time needed for licensing new nuclear units means that action must be taken well in advance to preserve nuclear as a future resource option for customers when needed. As the Company and the Commission constructively work together to ensure that the best cost options for future generation are available for customers, new nuclear should remain as a viable option.

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;
- CT – with SCR;
- CC – "F";
- CC – "F", with carbon capture and compression (CCC); and
- Nuclear.

Intermittent resources were not included as technologies for the model to select due to model limitations associated with the inclusion of intermittent resources but instead were reflected in the model as planned and committed resources. Such planned resources include the recommended addition of 525 MW of renewable resources through REDI. In addition, it should be noted that the analysis and scenario work reflected in the Framework, the Solar Analysis and the Wind Analysis (which included modeling the inclusion of varying levels of renewable resources) show that additional intermittent renewable resources could provide benefit for customers. It should also be noted that the supply-side additions modeled in this Mix Study are not determinative of the resources that will ultimately be selected to meet an identified capacity need. Any capacity need identified will be met in accordance with the Commission's RFP rules.

6.5 SUPPLY-SIDE PLAN

To develop a supply-side plan, the technologies that passed the detailed screening are further evaluated using the Strategist 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 Strategist model is in Section 15.

6.5.1 Base Case Assumptions

Generating Unit Costs — The types of generating units used in developing the benchmark plan were nuclear, CC (both with and without CCC), and CT (both with and without SCR).

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

Reliability Needs — The supply-side plan is currently developed to meet the currently approved System target planning reserve margin of 15%. This target was developed in the prior Reserve Margin Study using a combination of economic studies, electric industry experience, and operator input available at the time of their development. 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. The Company intends to base future supply-side plans upon the new 17% System target planning reserve margin that is being recommended in the Reserve Margin Study filed in this 2016 IRP.

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 Analytics 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 the Mix Study 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 that is most economical in a particular timeframe with the given assumptions. As prescribed by the Commission's rules and orders, a combination of self-owned generation and resources selected through a competitive bidding process will be used for determining how the capacity needs are to be met when action is taken to deploy resources.

The optimization process is essentially a trade-off between fixed costs and variable operating costs for the various generating unit options. Figure 6.5.2.1 in the IRP Main Document Reference Tables section of Technical Appendix Volume 1 depicts changes in energy mix by fuel source for the 2016–2035 planning period. Figure 6.5.2.2 in the IRP Main Document Reference Tables section of Technical Appendix Volume 1 shows the portion of annual energy needs met by nuclear, coal and hydro units over the planning period 2016 - 2035. Table 6.5.2.1 in the same section of Technical Appendix Volume 1 shows the Retail OpCos' Benchmark Capacity Plan.

6.5.3 Reference Case Sensitivities

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 understand the effect that different assumptions will have on the supply-side plan; and
- To identify and focus attention on additional studies to be performed.

The following sensitivities were performed in developing the Company's IRP. These sensitivities are analyzed in detail in the Retail OpCo Mix Study found in Technical Appendix Volume 1.

- Forecast of load:
    - Sensitivity 1 evaluates zero load growth from 2016 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 20 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, these sensitivities produce separate evaluations of the impacts on the load and energy forecasts, which include effects from demand-side programs, and new supply-side resources.

- Unit availability:
  - Sensitivities 6 and 7 evaluate lower and higher forced outage rates.
- Fuel prices:
  - Sensitivities 12 through 20 evaluate the impacts of fuel prices through the scenario planning cases which have three separate fuel price environments and resulting forecasts combined with varying estimates of carbon 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.
- Inflation in plant construction costs and costs of capital:
  - Sensitivity 10 incorporates a higher cost of capital assumption.
  - Sensitivities 8 and 9 analyze the impacts of doubling and halving 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 12 through 20 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 for the Retail OpCos; and
- System marginal costs.

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 INTEGRATION PROCESS

In the integration step, those demand-side programs resulting from the DSM evaluation are integrated with the planned and committed renewable resources and the appropriate benchmark supply plan using the Strategist model. The outcome of this method is a cost-effective mix of demand-side and supply-side resources for the Retail OpCos in aggregate that is then distributed among the Retail OpCos as described in Section 7.2.

7.2 DISTRIBUTING CAPACITY AMONG THE RETAIL OPERATING COMPANIES

After the integration step, the mix optimization process is performed for all of the Retail OpCos in aggregate in order to make the full benefits of coordinated planning available to the Retail OpCos. For long-range planning purposes, the generating unit resources resulting from the mix process must then be distributed or allocated among the Retail OpCos based on their particular needs and current resources including demand-side resources. This planned distribution is performed through an analysis of each Retail OpCo's existing supply- and demand-side resources and energy needs. As the time for commitment to new capacity approaches, additional detailed studies are performed to identify the resources for meeting specific Retail OpCo requirements. The decision to acquire new generating capacity or demand-side resources will be made by the Retail OpCo based on studies of customer needs and the operational, cost, and financial assumptions specific to the operating company and the options available. Under the framework established in the state of Georgia, when a capacity need is identified through an IRP, the Company will meet such identified need through an RFP in accordance with the Commission's RFP rules.

See the Mix Study in 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 2016 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 2035 in order to reliably serve these new requirements and replace units retired from service. The IRP models 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 2016 – 2025, reflecting reserve sharing for the Retail OpCos, Georgia Power is projected to have sufficient resources to meet customers' needs given the resource decisions approved by the Commission in the 2013 IRP and other previous filings, as described in preceding sections. For the year 2025, the Company has a capacity need based on 10 years of projected load growth and expiration of PPAs currently serving Retail OpCos' loads. Without reserve sharing, the Company's first year of capacity need is 2024.

The long-term plan for each of the scenario cases varies depending on the assumptions for that case. For some of the scenario cases, a mix of gas technologies (CTs and CCs) was 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 was selected in addition to 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 projects the proper mix of capacity in sufficient amounts to meet minimum reliability criteria. The IRP (as shown in Figure 8.2 and Table 8.2 in the IRP Main Document Reference Tables section of Technical Appendix Volume 1) shows the resource needs for the years 2016 – 2035 based on current environmental requirements and other base case assumptions. When Georgia Power acquires resources to meet capacity needs identified in the IRP, the actual generation technology will be selected in accordance with the Commission's RFP rules and will utilize Georgia Power-specific information where necessary.

8.3 PLAN REVIEW BASED ON OTHER PLANNING OBJECTIVES

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

- **Flexibility** — Can the plan 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 base case IRP, while nuclear is selected in certain scenario planning cases with carbon prices. The relatively short lead time (four years or less excluding RFP and certification processes) required for a greenfield simple cycle CT and the utilization of short-term purchases will provide the flexibility to meet any uncertainties that may arise.

- **Reliability** — Does the plan provide reliable service for all customers?

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

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

  Yes. The IRP adequately models needed capacity resources in the future and minimizes the need for rate increases. There is flexibility to alter the plan as needed. For instance, as renewables continue to improve and can be procured below avoided costs projected for the base plan, such resources can be added by the Company to minimize projected energy costs. In addition, 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.

- **Environmental** — Does the plan ensure compliance with environmental regulations?

  Yes. In addition to complying with all existing laws and regulations, the Company reviews and assesses pending rules, regulations and legislation in regard to environmental issues that may impact Georgia Power and Southern Company. Note that although the CPP is a final rule, the requirements for compliance will not be known until State Plans are developed and approved by the EPA. 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 are also included in the Mix Study in Technical Appendix Volume 1 and the Financial Review in Technical Appendix Volume 2.

- **Risk** — Does the plan appropriately mitigate the risk of future changes in conditions?

  Yes. There is a risk that the load growth will be more or less than expected and that the demand-side programs may not 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.

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9 – SUMMARY OF TRANSMISSION PLAN

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SECTION 9 - SUMMARY OF TRANSMISSION PLAN

9.1 TRANSMISSION PLAN

This IRP includes the Company's ten-year transmission plan, which identifies the transmission improvements needed to maintain a strong and reliable transmission system, based upon current planning assumptions. Along with the ten-year plan, Georgia Power has included a comprehensive and detailed bulk transmission plan of the Georgia Integrated Transmission System summarizing studies, project lists, processes, data files and other information as required by the amended rules adopted by the Commission in Docket No. 25981.

9.2 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 Power's transmission planning are as follows:

- Identify and recommend projects that are consistent with the Guidelines for Planning the Georgia Integrated Transmission System 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 land acquisition and 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 and control areas.

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.

9.3 TEN-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 of the next ten years. 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. Additional Transmission Planning information required per Docket No. 31081 is available in Technical Appendix Volume 3.

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10 – RENEWABLE RESOURCES

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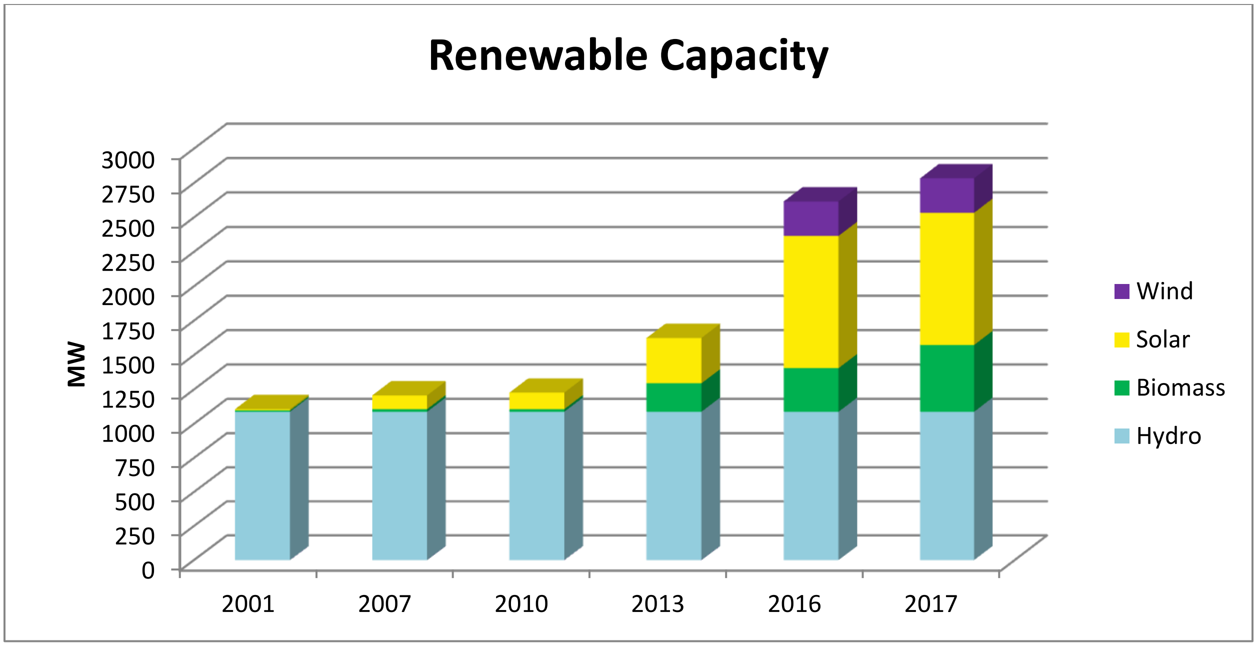
SECTION 10 - RENEWABLE RESOURCES

10.1 RENEWABLE RESOURCES OVERVIEW

Georgia Power has continued its pursuit of the integration of renewable generation resources, guided by the overarching goal of providing customers with clean, safe, cost-effective and reliable energy. Maintaining a diverse portfolio of fuel resources, including diversity within the Company's portfolio of renewable resources, helps the Company achieve this goal. Through diligent research and development efforts, along with careful monitoring of market conditions, the Company has invested in renewable resource technologies as they have become both technically and economically viable, while also taking steps to ensure system reliability. As a result of these efforts, the Company's partnership with the Commission and collaboration with the renewable energy community, Georgia Power has been able to add more than 1.3 gigawatts ("GW") of renewable resources to its system in the past six years. Since the last IRP, the Company was awarded "Fastest Growing Solar Portfolio" and "2014 Investor Owned Utility of the Year" by solar industry associations. The Company is currently projected to add over 1 GW of solar capacity by the end of 2016 including over 150 MW of planned company-owned solar.[3] Additionally, the Company continues to further diversify its portfolio of assets with 250 MW of contracted wind capacity, nearly 500 MW of contracted biomass generation including landfill methane gas, and over 1 GW of hydro generation to serve customers. The Company has successfully expanded its portfolio of renewable generation at prices below the Company's projected avoided costs, thereby providing projected cost savings for customers. The following graph illustrates the expected cumulative contracted renewable capacity for Georgia Power through 2017, by resource type.[4]

[3] All current and forward-looking online and contracted solar capacity numbers are shown in Alternating Current (AC) values only.

[4] Georgia Power purchases only the null energy output from some renewable generating facilities that have contracted to sell energy from their facilities to Georgia Power. The ownership of the associated renewable energy credits is specified in each respective power purchase agreement and the party that owns the RECs retains the right to use the RECs. Georgia Power does not report emission reductions from the null energy purchased through power purchase agreements that do not bundle the RECs for sale to Georgia Power.



In this IRP, Georgia Power proposes continued growth of renewable capacity through a new program that will procure 525 MW of renewable energy. As discussed later in this section, the new renewable procurement program will build upon the success of the Company's current renewable programs, which have been guided and approved by the Commission. By procuring resources projected to put downward pressure on rates for Georgia Power customers, this new program will continue to add diversity to the Company's generating portfolio, with the intent to deliver energy savings for customers.

10.2 BENEFITS AND COSTS OF RENEWABLES

When considering any generation technology, including renewable resources, it is crucial that all of the appropriate benefits and costs of such technology be determined and allocated in a way that ensures equitable treatment and continued reliability of the system. Such analysis is particularly important in light of the dramatic increase of renewable resources being deployed to serve customers. To that end, SCS, on behalf of the Retail OpCos, has established a methodology for determining the costs and benefits of renewable generation on the Southern Company electric system. Georgia Power has applied this methodology using Georgia specific information and assumptions in order to capture the specific benefits and costs associated with implementing renewable generation in Georgia. This comprehensive methodology is contained in the document entitled "A Framework for Determining the Costs and Benefits of Solar

Generation in Georgia," which is included in Technical Appendix Volume 1. While it focuses on solar resources, this methodology is applicable to all forms of generation. Fairly assessing and allocating the benefits and costs of renewable generation will help assure continued cost-effective additions of renewable resources for the benefit of all customers while addressing potential cost shifting and upward rate pressure that might otherwise occur. The resulting benefit and cost data should serve as the basis for new avoided cost calculations, renewable program development, project evaluation, and rate design.

The amount of benefits and costs attributable to intermittent renewable generation will vary based on the penetration level and characteristics of the renewable generation on the Georgia Power electrical system. Tables 1 and 2 list the applicability of each component identified in the Framework based on the renewable technology.

Table 1: Components by Resource Type – Solar

Component	Utility Scale Solar	Distributed Solar	
	(Transmission & Distribution)	(Greenfield)	(Separately Metered & Behind the Meter)
1. Avoided Fuel and Purchased Power Costs	Benefit	Benefit	Benefit
2. Avoided Generation VO&M Costs	Benefit	Benefit	Benefit
3. Avoided Environmental Compliance Costs	Benefit	Benefit	Benefit
4. Deferred Generation Capacity Costs	Benefit	Benefit	Benefit
5. Deferred Generation FO&M Costs	Benefit	Benefit	Benefit
6. Deferred Transmission Investment	Location Dependent	Benefit	Benefit
7. Reduced Transmission Losses	Location Dependent	Benefit	Benefit
8. Reduced Distribution Losses	N/A	Location Dependent	Benefit
9. Distribution Operations Costs	N/A	Cost	Cost
10. Generation Remix Costs	Cost	Cost	Cost
11. Ancillary Services: Scheduling, System Control, and Dispatch	Included in Support Capacity		
12. Ancillary Services: Reactive Supply and Voltage Control	N/A	Cost	Cost
13. Ancillary Services: Regulation	Cost	Cost	Cost
14. Ancillary Services: Operating Reserve – Spinning & Supplemental	Included in Support Capacity		
15. Support Capacity (Flexible Reserves)	Cost	Cost	Cost
16. Bottom Out Costs	Cost	Cost	Cost
17. Long Term Service Agreement Maintenance Costs	Cost	Cost	Cost
18. Target Reserve Margin Costs	TBD	TBD	TBD
19. Program and Administration Costs	Cost		

Table 2: Components by Resource Type - Wind & Biomass

Component	Wind (Fixed Delivery)	Wind (As Delivered)	Biomass
1. Avoided Fuel and Purchased Power Costs	Benefit	Benefit	Benefit
2. Avoided Generation VO&M Costs	Benefit	Benefit	Benefit
3. Avoided Environmental Compliance Costs	Benefit	Benefit	Benefit
4. Deferred Generation Capacity Costs	Benefit	Benefit	Benefit
5. Deferred Generation FO&M Costs	Benefit	Benefit	Benefit
6. Deferred Transmission Investment	Location Dependent	Location Dependent	Location Dependent
7. Reduced Transmission Losses	Location Dependent	Location Dependent	Location Dependent
8. Reduced Distribution Losses	N/A	N/A	Location Dependent
9. Distribution Operations Costs	N/A	N/A	Location Dependent
10. Generation Remix Costs	N/A	Benefit or Cost	N/A
11. Ancillary Services: Scheduling, System Control, and Dispatch	Included in Support Capacity		
12. Ancillary Services: Reactive Supply and Voltage Control	N/A	N/A	N/A
13. Ancillary Services: Regulation	N/A	Cost	Benefit
14. Ancillary Services: Operating Reserve – Spinning & Supplemental	Included in Support Capacity		
15. Support Capacity (Flexible Reserves)	N/A	Cost	Benefit
16. Bottom Out Costs	Cost	Cost	Benefit
17. Long Term Service Agreement Maintenance Costs	Cost	Cost	Cost
18. Target Reserve Margin Costs	TBD	TBD	TBD
19. Program and Administration Costs	Cost		

The Framework describes the components reviewed along with the methodologies employed to determine the benefits and costs of intermittent renewable generation. A second document—"The Costs and Benefits of Distributed Solar Generation in Georgia" ("Solar Analysis")—quantifies the benefits and costs specific to solar generation based on eight 1,000 MW (1,000 – 8,000 MW) penetration tranches of distributed solar on the Georgia Power electrical system (see Technical Appendix Volume 1). The following conclusions were reached as a result of the Solar Analysis:

1. The total benefit provided by solar generation exceeds the total cost caused by solar generation; however, with increasing penetration levels the overall benefit to the system declines.
2. The net avoided costs remain stable up through 2,000MW of distributed solar, after which the net avoided costs decline steadily.
3. Distributed solar generation provides deferred generation capacity and deferred transmission benefit up to a penetration level of 7,000MW – the breakpoint at which the peak shifts from mid-afternoon to dusk.
4. Compared to the avoided energy benefits provided by distributed solar, the deferred transmission investment benefits are extremely small on a relative basis.

5. Costs associated with Support Capacity and Generation Remix are immediately incurred with low penetrations of solar.
6. There is a significant breakpoint between 4,000 and 5,000 MW of distributed solar generation for Bottom Out conditions.

The Company will continue to monitor the economics of existing energy storage technologies and the commercially viability of new and emerging energy storage technologies. Based on this monitoring, the Company will update its analysis as necessary to determine any impacts such as storage and advancing inverter technologies may have on the Framework and the Solar Analysis.

In addition to the Solar Analysis, the Company conducted similar analysis of imported wind generation based on the methodologies outlined in the Framework. "The Costs and Benefits of Fixed and Variable Wind Delivered to Georgia" ("Wind Analysis") quantifies the costs and benefits of wind imports based on two 1,000 MW (1,000 MW and 2,000 MW) tranches (see Technical Appendix Volume 1). The following conclusions were reached as a result of the Wind Analysis:

1. Compared to the solar analysis, the Generation Remix impacts at the assumed levels of penetration are a benefit rather than a cost.
2. Since the wind analysis studied imports of wind to Georgia at the bulk transmission level, there are no Deferred Transmission Investment costs or Reduced Distribution Losses.
3. The difference in value between fixed wind and variable wind is relatively small due to the use of the same assumed wind production profile; therefore, while the procurement costs and/or transmission delivery costs of these two wind products may be significantly different, their avoided cost values to Georgia Power are similar.
4. Due to the higher capacity factors of wind generation as compared to solar generation, the per-MWH costs for Support Capacity and Bottom Out are relatively small.
5. Bottom Out costs are immediately incurred with low penetrations of wind generation and are relatively small.

10.3 NEW RENEWABLE ENERGY PROCUREMENT

10.3.1 Renewable Energy Development Initiative

As part of its continued effort to responsibly grow the renewable generation market in Georgia and provide energy benefits to all customers, the Company is proposing the procurement of an additional 525 MW of renewable capacity through 2019 if such procurement can be obtained below the Company's projected avoided costs. In order to provide the maximum amount of benefit to customers, the Company is proposing to procure this energy through three distinct programs: (1) RFPs from renewable developers with utility scale projects to fulfill an annual portfolio capacity target; (2) RFPs from developers with smaller, distributed scale projects to fulfill an annual portfolio capacity; and, (3) smaller, distributed scale solar purchase offerings from Georgia Power customer-sited projects.

10.3.1.1 Utility Scale RFP

Under the utility scale portion of the REDI RFPs, Georgia Power proposes to purchase energy from up to 425 MW of renewable generation scheduled to achieve commercial operation no later than December 31, 2019. The Company will file a detailed RFP schedule in September 2016 that will outline the timeline for the 425 MW RFP. The Company will accept proposals for solar, wind, and biomass projects with 2018 or 2019 commercial operation dates ("COD") based on transmission impacts and overall value. The Company will take ownership of all Renewable Energy Credits ("RECs") produced by these facilities. Third-party proposals that allow for Georgia Power ownership will be considered.

For utility scale resource bids, the Company will accept proposals for projects that are greater than 3 MW in size, but no larger than 210 MW in size that can attain commercial operation in 2018. The Company will also accept proposals for projects greater than 3 MW in size but no larger than 215 MW in size that can attain commercial operation in 2019. Consistent with the ASI-Prime utility scale RFP, the PPAs will be for a term of up to 30 years.

For all renewable resources bids, the Company will accept both "as delivered" proposals and "firm block" proposals. The cost of upgrades on Southern Company's electric system to deliver to Southern Balancing Authority Area load, if required, will be imputed into the total bid costs.

However, for renewable resources located outside of the Southern Balancing Authority Area, proposals must bear all transmission delivery cost and risk to the point of delivery at the Southern Balancing Authority Area interface. The Company will accept proposals for delivery to the Southern Balancing Authority Area interface across high voltage direct current ("HVDC") lines.

The RFP will require bidders to bid projects with a price that results in savings for customers when compared to the Company's projected avoided costs utilizing the new proposed methodology, including all appropriate benefits and costs. The Company requests to share the projected savings through the RFP at a rate of 20%. The bid fees will be established at a level to account for all administrative and technical evaluation costs.

10.3.1.2 <u>Distributed Generation RFP</u>

The Company proposes to issue an RFP no later than May of 2017 for 50 MW of Solar DG capacity from projects in Georgia that are greater than 1 kW but no more than 3 MW, with a COD in 2018 or 2019. Consistent with the most recent ASI DG RFP, the PPAs will be for a term of up to 35 years and the solar DG must interconnect to Georgia Power owned distribution facilities. The new DG RFP process will be consistent with the 2013 ASI utility scale RFP in terms of the evaluation process and assignment of costs but will utilize the new proposed methodology. The application fees will be established at a level to account for all administrative and technical evaluation costs.

10.3.1.3 <u>Customer-Sited Solar Distributed Generation</u>

Once the DG RFP has concluded, the Company will then seek to procure 50 MW of customer-sited solar projects at a price equal to the last winning evaluated bid price in the DG RFP. These projects will be selected through an application process and if oversubscribed, a lottery will be conducted. If the customer-sited program is undersubscribed, the remaining capacity will be awarded from the reserve list of the DG RFP. All projects are required to reach COD by December 31, 2019.

10.4 CUSTOMER SUPPORT AND EDUCATION INITIATIVES

Georgia Power continuously seeks to add value in its relationships with customers by serving as an overall resource for energy information and expertise. Georgia Power leverages its experience and research to provide customers with the information they need in order to make the best decisions for utilizing renewable energy for their homes or businesses and meeting each customer's particular needs and goals.

10.4.1 <u>Customer Solar Support</u>

The Company's Rooftop Solar Service program commenced July 1, 2015 and provides enhanced support and education to residential customers interested in rooftop solar and offers installation options from Georgia Power's unregulated business, Energy Services. The Company guides interested customers to a tool on the Company's website to learn general information about solar energy, determine approximate system size, and estimate annual bill savings and project payback in years. Interested customers are directed to schedule an appointment with one of Georgia Power's solar energy experts, who provides custom solar analysis based on customer-specific inputs. After a consultation with the solar energy expert, interested customers are referred to qualified solar installers—either certified independent installers linked from Georgia Power's website or the Company's unregulated Energy Services team—who can provide installation guidance, services, and installation quotes. Through the end of 2015, the Company received more than 950 consultation requests.

Although the current Rooftop Solar Service program was implemented for residential support, the Company also provides a variety of support for non-residential customers interested in solar, including providing such customers with bill savings and payback analysis. The Company has 18 customer support representatives at its Business Call Center to answer customer calls regarding specific programs including the Rooftop Solar Service program. Additionally, 25 employees have received specialized training in order to serve as Solar Energy Consultants. These Solar Energy Consultants are located throughout each of the Company's 11 regions across the state and serve as a local source of information for customers who are interested in, or currently have, solar. Information available on Georgia Power's website also aids customers in the evaluation of available solar generation and renewable program offerings and provides basic solar education. The Company has received positive feedback regarding both the Solar Energy Consultants and the additional solar-related information available at GeorgiaPower.com. These efforts support Georgia Power's goal to provide expertise to its customers as they make energy decisions.

10.5 OTHER SOLAR PROGRAMS FOR CUSTOMERS

10.5.1 Renewable Energy Purchase Programs

Georgia Power currently purchases energy from DG resources up to 100 kW in size through the Renewable and Non-Renewable ("RNR") tariff. Georgia Power proposes to modify the RNR tariff to create a more practical program for customers. Participants would be compensated using updated avoided costs based on appropriate components outlined in the Framework. The modified tariff will be available for bi-directional metering only and will comply with the Georgia Cogeneration Distributed Generation Act of 2001, which requires Georgia Power to purchase excess energy. Under this option, customers offset their usage and sell any excess energy back to the Company. The Company currently has 366 customers participating in the RNR bi-directional metering tariff with a total capacity of 3.6 MW.

The Company's single-directional metering option in the current RNR and Solar Purchase ("SP") tariffs, which allows customers to sell RECs and 100% of energy produced to supply the Green Energy Program, will be discontinued and treated in accordance with the proposed changes to that program. Therefore, the remaining option for customers wishing to participate in single-directional metering program will be through REDI as described in Section 10.3.1. Bi-directional metering options will also be available to these customers.

Georgia Power also purchases energy from QFs up to 80,000 kW in accordance with the Public Utility Regulatory Policies Act ("PURPA"). The Company also proposes a similar change to the QF program payments to reflect pricing based on the avoided costs utilizing the new proposed methodology.

Customers with DG installed on their premise who choose not to participate in Georgia Power's programs are referred to as "non-participants." These customers install solar with the goal to supply some of the power they consume from their distributed generation. The Company is currently aware of more than 200 non-participants, totaling more than 3 MW of capacity. For safety and reliability, the Company proposes to require an interconnection agreement for all non-participants in order for Georgia Power to accurately account for all generation connected to its infrastructure. These interconnection agreements are essential in identifying where distributed generation resources are located on the grid in order to maintain safe, efficient, and reliable operation of the grid.

10.5.2 Simple Solar Program

For customers who cannot or choose not to install solar, but would like to support solar energy or be able to claim their energy usage as solar energy, the Company offers the Simple Solar Program, which will replace the current Green Energy Program. The Simple Solar Program will offer an option for customers to offset either 50% or 100% of their monthly usage with solar energy supplied by RECs produced from solar generation in Georgia.

The Commission approved Georgia Power's original Green Energy Program in 2003 in Docket No. 16573. After contracting for renewable energy resources, the Company began enrollments and started billing customers in 2006. The Green Energy Program currently serves approximately 3,800 participants that voluntarily pay a premium to support energy generation from renewable resources. The Green Energy Program has stimulated the growth of renewable generation in Georgia and is directly responsible for 6.4 MW of landfill gas and 5.4 MW of solar generation currently online. However, the cost of the Green Energy Program has exceeded revenues by more than $6.6 million to date, due to lower-than-projected avoided energy costs, higher long-term contracted prices for the renewable energy to supply the program, as well as lower than expected customer participation. Furthermore, as a result of recent solar tax credits, rebates, declining technology costs and other distributed generation purchase programs, a growing number of customers choose to install their own renewable generation rather than purchase through the Green Energy Program. The Green Energy Program successfully incentivized the growth of renewable resources at a time when they were not cost-effective for customers. Now that renewable energy has become more economical, it is appropriate to replace the Green Energy Program with the Simple Solar Program to reflect current conditions.

Due to this evolving renewable landscape, Georgia Power proposes the Simple Solar Program to replace the current structure of the Green Energy Program. The new Simple Solar Program can benefit customers who want to support solar energy or have renewable energy goals, who rent their homes or businesses, cannot afford a rooftop solar installation, prefer not to install solar, or otherwise live in an area where solar power is not an option.

The new Simple Solar Program will offer customers the option to purchase solar energy at a competitive price. The initial cost to customers for solar energy through the Simple Solar Program will be an additional $0.01 per kWh. Any revenues to the Company will be used to purchase wholesale or Company-owned solar RECs, if available, as well as offset any marketing expenses to help cover the costs of the program. Customers on all tariffs, and in all classes, will be eligible to participate in the Simple Solar Program. The new program will also include a Large Volume Purchase option for a contracted volume discount and a Special Event Purchase option for one-time purchases.

The Company proposes to end the current Green Energy Program and withdraw the related tariff, upon approval of this new offering. All customers currently participating in the program will be notified and given the option to opt into the new Simple Solar Program. All customers participating in the current Large Volume option of the Green Energy Program may opt to continue their existing contract terms before being offered a new Large Volume contract under the new program. All contracts with generators who currently supply the Green Energy Program will not support the new Simple Solar Program, but will continue to sell renewable energy to Georgia Power through the terms of their contracts and such costs will be recovered through the Company's fuel rates. The Company does not plan to renew the existing Green Energy Program supply contracts once those contracts reach their expiration dates, assuming Commission approval of the Simple Solar Program. After expiration of the current agreements, Green Energy Program suppliers will still be able to sell their output to the Company under other contractual terms such as through the modified RNR tariff, REDI or PURPA process.

10.6 BIOMASS

The Company has one of the largest portfolios of biomass capacity under development in the country.[5] These resources provide both system reliability and fuel diversity benefits. Through implementation of the QF and Proxy QF programs, the Company has entered into contracts for nearly 500 MW from PURPA-eligible biomass fuel resources.

10.6.1 Proxy QFs

As a result of Georgia Power's 2015 supply-side RFP, the Company has executed several power purchase agreements with QFs throughout the Company's service territory. The table below contains a summary of the QFs that are counter parties to Georgia Power's standard offer contract utilizing the proxy methodology. Two of the woody biomass projects totaling 54 MW came online in June of 2015 and one of the landfill gas projects totaling 6.3 MW came online in December of 2015. One woody biomass project and four landfill gas projects are scheduled to become commercially operational in 2016. The remaining projects have a required commercial operation date of June 1, 2017.

Fuel Type	No. of Contracts	Total Capacity (MW)
Woody biomass	6	235.5
Landfill Gas	5	39.9
Biogas	2	6.4

10.7 WIND ENERGY

Georgia Power continues to evaluate wind resources where they may prove economical for its customers. As outlined in Section 10.3, the Company will consider wind energy proposals submitted through REDI. Wind activities to date include the Blue Canyon Wind Purchase and the companion Wind RFI, as well as the small-scale demonstration project. The Company is also evaluating off-system wind and corresponding HVDC delivery options to the Southern Balancing Authority Area interface.

[5] Georgia Power purchases only the null energy output from some renewable generating facilities that have contracted to sell energy from their facilities to Georgia Power. The ownership of the associated renewable energy credits is specified in each respective power purchase agreement and the party that owns the RECs retains the right to use the RECs. Georgia Power does not report emission reductions from the null energy purchased through power purchase agreements that do not bundle the RECs for sale to Georgia Power.

As outlined further in Section 10.8.1, recent advances in wind turbine technology may enable wind to be a viable option within the state of Georgia. The Company is proposing a High Wind Study, as outlined in Section 10.8.1, in order to evaluate the wind potential in the state. The Company is committed to continued evaluation of wind as a potential energy source both within and outside the service territory.

10.7.1 <u>Wind Procurement</u>

<u>Blue Canyon Wind Purchase</u>

On January 1, 2016, Georgia Power began receiving wind energy purchased through 20 year PPAs from Energías de Portugal Renewables pursuant to the certificate issued by the Commission in Docket No. 37854. As outlined in Docket No. 37854, 250 MW of wind capacity and the corresponding RECs are being sold from the Blue Canyon II and Blue Canyon VI projects located in Comanche and Caddo Counties, OK. The Commission concluded that the Blue Canyon PPAs provide unique benefits to Georgia Power customers.

<u>Wind RFI</u>

In response to the Commission's Order on May 29, 2014 in Docket No. 37854, Georgia Power filed an RFI on December 8, 2014 regarding availability, pricing and potential PPA terms for utility scale wind with no geographical or delivery preference ("2015 Wind RFI"). Georgia Power provided the findings from the 2015 Wind RFI to the Commission on February 27, 2015. The full results and report can be found in Technical Appendix Volume 1.

10.7.2 <u>Off-System Wind Projects</u>

Georgia Power continues to evaluate the procurement of wind energy generated from wind farms across the Midwest and Texas and the delivery of that power through existing transmission to the Southern Company Balancing Authority. Market conditions and transmission availability may allow for the procurement of wind resources that could be below the new avoided cost projections that would also provide greater diversity for the Company's energy portfolio. These wind projects will have the opportunity to participate in the Company's proposed REDI.

10.7.3 High Voltage Direct Current Transmission Lines

Georgia Power continues to assess the potential to utilize HVDC lines. The use of HVDC lines could facilitate delivery from either the Oklahoma panhandle into the Tennessee Valley Authority ("TVA") balancing area which adjoins the Retail OpCos' transmission system or from the Electric Reliability Council of Texas ("ERCOT"). The use of HVDC lines can potentially eliminate delivery risk across the Southwest Power Pool ("SPP") and Midcontinent Independent System Operator ("MISO") transmission systems. The HVDC projects are currently in the development stage with an estimated in-service service date after 2020. The proposed projects that rely on the HVDC solution are not without concern. Any delay in the construction schedule of an HVDC line will likely affect the ability of these projects to come online in a timely fashion.

10.8 DEMONSTRATION PROJECTS

10.8.1 Research and Demonstration Projects

The Company continues to research and evaluate potential technologies and renewable generation solutions that will add value, efficiencies or complement existing generation sites. Costs and details of the following suggested demonstration projects can be found in the selected supporting documentation of Technical Appendix Volume 2.

Closed Ash Pond Solar

Installing solar on the Company's closed ash ponds and surrounding areas potentially provides an opportunity to further decrease the cost of solar generation to the benefit of customers through reduced real estate and transmission costs. Limited usage land could include: (i) closed ash ponds or landfills; (ii) reclaimed land where a former ash pond or landfill has been removed; and (iii) undeveloped lands, all located on existing Georgia Power owned coal-fired facilities. These properties have easy access to transmission and restricted use. Additionally, using various emerging solar technologies allows the Company to achieve the dual purpose of ash pond/landfill closure and solar development. As the opportunities for landfill-to-solar-field conversions continue to increase in the coming years, the Company will benefit from installation and operation experience of such solar energy cover. Specifically, if there are steps or cost advantages that can be taken prior to closing an ash pond, Georgia Power would like to take advantage of those savings and pass them along to customers. The timing is critical to learn lessons prior to future ash pond closures.

Georgia Power proposes to develop a solar project of up to 10 MW at Company-owned coal-fired generating facilities. The project may include evaluation of different technologies, including traditional and non-traditional racking systems and solar energy covers. The output of the system will be tied into the site's existing infrastructure to serve Georgia Power customers. The project will provide a baseline understanding of what might be required to permit and build solar facilities on top of closed solid waste facilities, as well as reclaimed or underdeveloped plant properties.

High Wind Study

As a result of the 2015 Wind RFI for wind energy, one of the key risks identified for wind generation is the transmission cost to deliver the generation from its source into the Southern Company network. Additionally, current wind potential for standard 80 meter hub height wind turbines in Georgia is small and uneconomical. However, there have been recent reports highlighting future "high wind" potential.

In April of 2015, the U.S. Department of Energy released a new report, "The Wind Vision"[6], exploring potential wind energy resources at higher elevations across the United States based on a map developed by National Renewable Energy Laboratory ("NREL"). This potential resource would utilize taller wind turbines with larger rotors than ever deployed in the United States. The advancement in turbine technology allows designs to range from 110-140 meter hub heights (up to 450 feet); 30 meters (nearly 100 feet) higher than the average wind turbine tower installed in 39 states today.

The potential resource NREL map identifies the Southeast as a "new region" with a greater than 30% capacity factor based on new technological advances. The preliminary resource map from

[6] [DOE] United States Department of Energy, April 2015. Wind Vision: A new Era for Wind Power in the United States. DOE/GO-102015-4557. Washington D.C. Accessed November 2015. http://energy.gov/eere/wind/maps/wind-vision

"The Wind Vision" study requires site-specific data collection and validation. The Company believes it is important to validate site-specific locations in Georgia identified with "High Wind Potential." Therefore, the Company proposes a project that would allow it to further study high wind potential. This proposed project includes purchasing wind measurement instrumentation, siting, installation and monitoring of wind data for high elevations at multiple locations for a minimum of two years. This project could lead to potential wind turbine development in future IRPs.

10.8.2 Updates on Existing Demonstration Projects

Distributed Solar Demonstration Projects

In 2015, the Company updated its existing rooftop solar demonstration project, located at its corporate headquarters, to reflect recent and emerging solar panel technologies. The updates include a comparison of inverter types, array orientations and advanced technology racking and inverter integration. During 2016, a battery energy storage system will be added to the rooftop demonstration project.

The research goals of the demonstration project remain the same: through evaluation of environmental impacts such as sunlight hours, temperature and humidity, the Company continues to compare the performance and reliability of different commercially available PV technologies. This project also seeks to maximize output from the solar projects through a variety of system orientation and optimization factors. Addition of the storage system will allow the Company to evaluate the cost impacts and benefits of storage systems when paired with solar technology.

1 MW Solar Self-Build Demonstration

In the 2010 IRP, the Commission approved the Company's request to develop a portfolio of solar demonstration projects totaling up to 1 MW to evaluate solar project siting, procurement, construction, and maintenance. The Company evaluated several potential solar projects and selected the Atlanta Falcons' new Mercedes Benz Stadium as the host site for the project. The broad scope of this project demonstrates how solar technology can be included into a full campus by employing innovative construction techniques and incorporating solar technology into construction plans upfront. This 1 MW installation will include the use of a truss-supported parking deck solar installation, cantilevered surface parking lot solar canopies, non-penetrating ballasted surface parking lot solar canopies and solar canopies affixed to the security gate entrances into the new stadium. During the design phase, particular attention has been paid to the aesthetic characteristics of the PV installations at each of the sites on the campus, while also paying attention to efficiency and production of the solar system. This has required the use of panel technologies such as clear-backed, frameless solar panels and racking solutions such as an elevated steel truss system and cantilevered steel structures to minimize the physical interference of the solar installations, so as not to limit the usability and functionality of each of the structures or locations that serve as host sites. Furthermore, the geographic location of this solar facility will provide the Company with valuable data on the impact of solar located in major load centers and any potential benefit or adverse impacts it may have on a heavily loaded distribution system. While the project is still under construction, it has already provided the Company with valuable experience about the sensitive design and procurement processes of parking deck solar canopies and the challenges and benefits of incorporating grid-tied distributed generation solutions during the design phase of new facilities in major load centers.

Solar PV Tracking and Orientation Study

In the 2013 IRP, the Commission approved a research project to demonstrate and test:

- Fixed-tilt, south facing PV panels (most standard technology, would serve as a control);
- Fixed-tilt, southwest facing PV (improved capacity value, decreased annual energy);
- Single-axis tracking (advanced technology, but becoming more common); and
- Dual-axis tracking (most advanced technology).

Georgia Power has partnered with the University of Georgia to lease 10 acres in Athens, Georgia to develop this test facility. The 1 MW PV solar tracking demonstration project is expected to be commissioned in the first quarter of 2016. Production results from the different orientations and racking will be monitored by the Electric Power Research Institute ("EPRI"), SunPower, Southern Company and UGA. Additionally, long-term maintenance and costs on each system will be monitored in Southern Company's maintenance system.

Small Wind Demonstration Pilot Project

As part of the 2013 IRP, the Commission approved the Company's proposed "Small Wind Demonstration Pilot Project" to demonstrate the feasibility of small-scale wind generation and evaluate different resources in various geographic areas across the state of Georgia. In April 2014, the project team initiated the process of identifying two locations, one coastal and one mountain site. A coastal site was identified and a partnership was formed with Skidaway Institute of Oceanography ("SkIO"). In April of 2015, Georgia Power signed a two-year lease agreement with an optional six-month extension with the University System of Georgia Board of Regents for the property referred to as "Helicopter Field" on the campus of SkIO. The intent of the research lease is to erect one meteorological tower (approx. 198' height) and install three small wind turbines (hub height at 120' and blade lengths 12'-21'). The wind turbine output and data will be collected for approximately one year. The University of Georgia has an option to issue a change request to keep the turbines. The met tower and turbines for the coastal site have been ordered. Additionally, a research partnership was formed and an agreement was signed in December of 2014 with Georgia Southern University. The research will focus on potential impacts of wind turbines on noise, vibration and avian species. Currently, AWS TruePower is performing a study on a potential mountain site location in Jasper, Georgia. The intention is to move forward with a Light Detection and Ranging (LiDAR) box at the wind location and further evaluate the viability of installing up to two wind turbines at that location.

10.9 UPDATES ON EXISTING RENEWABLE ENERGY PROGRAMS

10.9.1 Large Scale Solar Update

The Commission approved the Company's LSS proposal on July 22, 2011 in Docket No. 34229, under which the Company entered into PPAs for terms of 20 years for individual solar projects in Georgia that were greater than 1 MW, but less than or equal to 30 MW in size. These purchases are at a fixed-cost energy price, which was determined using the projected long-term avoided energy costs, plus a credit for the capacity that solar provides, and participants retain the RECs. All projects were online as part of the LSS program as of June 2015.

10.9.2 Georgia Power Advanced Solar Initiative Update

The Commission approved the Company's ASI proposal on November 29, 2012 in Docket No. 36325. Through the ASI and ASI Prime programs, the Company purchased energy from solar generation in two distinct ways: (1) through RFPs from solar developers for utility scale projects to fulfill an annual portfolio capacity target; and (2) from smaller, distributed scale solar purchase offerings.

Under the first ASI, Georgia Power expected to purchase up to 60 MW of utility scale solar generation per year, for two years, for a total procurement of 120 MW. The first RFP was released to bidders on May 10, 2013 in order to procure 60 MW of additional solar, with an expected COD of January 1, 2015. On December 17, 2013, the Commission approved 4 PPAs that provided 50 MW worth of projects. Since the Company did not procure the full 60 MW, 10 MW rolled over to the second RFP, with a resulting total of 70 MW to be released in 2014.

The second component of the ASI involved smaller solar facilities, up to 100 kW in size, and mid-sized facilities, greater than 100 kW up to 1 MW in size. These two distributed scale solar purchase offerings were referred to as the Small-Scale and Medium-Scale options. The Small/Medium Scale programs were to procure a total of 90 MW of energy from the new solar capacity, split into 45 MW offerings annually for two years. Applications resulted in 504.8 MW worth of projects, which were selected through a lottery process with a waiting list. Ultimately, 31.2 MW of the total 45 MW allotted were brought online by participants in 2013, and the remaining MWs carried over into the 2014 program.

For the 2014 ASI program, the application period was from March 26, 2014 through April 4, 2014 for all Small and Medium scale projects. The Company was seeking approximately 59 MW worth of capacity. Applications resulted in 842.9 MW worth of projects, from which the winning projects were selected through a lottery process, with all remaining projects placed on the waitlist. At the time of this filing, 56 MW of the 59 MW are online.

Before the Company released the second ASI RFP for utility scale resources, the program was expanded in the final order of the 2013 IRP. In the expanded program, known as ASI Prime, the Company procured 425 MW of utility-scale solar energy through an RFP process, consisting of

210 MW to be in service by the end of 2015 and 215 MW to be in service by the end of 2016. In addition, the ASI Prime program included 100 MW of distributed solar projects, procured using a combination of competitive bidding (50 MW) and fixed price offers (50 MW).

In April of 2014, the Commission approved the Company's 2015/2016 ASI and ASI Prime RFP to procure a total of 495 MW of utility scale solar resources, which consisted of 425 MW from the 2013 IRP and 70 MW remaining from the first ASI utility scale program.

The procurement of the 70 MW for the ASI program followed the guidelines from the Commission's November 29, 2012 Order. For the procurement of the 425 MW in connection with ASI Prime, the RFP followed the guidelines approved by the Commission in the 2013 IRP Order. On December 18, 2014, the Commission approved the 515.25 MW of ASI and ASI Prime PPAs.

2015 DG Program

The 2013 IRP Order provided for 50 MW of new DG solar resources to be procured in both 2015 and 2016. Pursuant to the Commission's Order Approving Guidelines for the 2015 Distributed Generation Program issued in Docket No. 36325, the 2015 and 2016 ASI DG programs were combined for a solicitation totaling 100 MW. Of the 100 MW, 50 MW were allocated to be competitively bid with the remaining 50 MW receiving fixed pricing and customer sited preference. Additionally, the size limit for DG projects was increased to 3 MW. All projects through this program should be online by the end of 2016.

10.9.3 Renewable Self-Build Projects

Pursuant to the Commission's orders in Docket Nos. 24505 and 39028, Georgia Power has commenced design, procurement and construction of the military solar projects specified in the table below. These projects will provide an economic supply of electric power for the Company's customers, while also contributing to the military's mandates regarding renewable energy, energy security and providing a significant investment in Georgia military bases. All projects are expected to be online by year-end 2016.

Project	Project Size	Projected Commercial Operation Date
Fort Benning	30 MW AC	12/31/2015
Fort Gordon	30 MW AC	9/1/2016
Fort Stewart	45 MW AC	9/1/2016
Naval Submarine Base Kings Bay	30 MW AC	12/1/2016
Marine Corps Logistics Base (MCLB) Albany	31 MW AC	12/1/2016

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11 – HYDRO ELECTRIC OPERATION AND RE-LICENSING

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SECTION 11 - HYDRO ELECTRIC OPERATION AND RE-LICENSING

11.1 FOREWORD

Georgia Power operates 18 hydro electric facilities and has an ownership interest in a 19th (Rocky Mountain) with a total of 71 generating units in Georgia. All but one of these facilities (Estatoah) is licensed under the Federal Power Act (through the Federal Energy Regulatory Commission). These facilities provide 1,087 MW of capacity and have provided approximately 2,134,251 MWh of energy over the 20-year period from 1996 to 2015 to the customers of Georgia Power. The following information details the relicensing dates, schedules, requirements and estimated risk of environmental challenges to continued operation associated with these facilities.

11.2 GEORGIA POWER HYDRO PLANT RE-LICENSING SCHEDULE

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

Bartletts Ferry

License Expires 12/21/2044

FERC issued a new operating license on December 22, 2014, which is effective for 30 years. This license included environmental enhancements for dissolved oxygen, reservoir fluctuation limits, and improvements to recreation facilities, among other things. Georgia Power is currently implementing the capital enhancements in 2015 and 2016. For 2015, actual post-license expenditures were approximately $1,640,000. In 2016, Georgia Power is budgeted to spend an additional $1,000,000 on capital post-license enhancements.

Wallace Dam

License Expires 6/01/2020

The relicense process began internally in 2013; a Notice of Intent to Relicense the project was filed with the FERC on February 18, 2015. Consultation with stakeholders will continue until May 2018, when Georgia Power will file its license application with FERC. FERC will issue a new license by June 2020 that will likely include environmental enhancements. For 2015, relicensing expenditures were $1,262,000. In addition, Georgia Power has budgeted the following for relicensing Wallace Dam:

2016:	$1,000,000
2017:	$1,500,000
2018:	$1,200,000
2019:	$1,200,000
2020:	$1,200,000
	========
Total:	$6,100,000

Beginning in 2020, post license environmental and recreational enhancements that may be required by the new FERC license will begin to be constructed/implemented.

<u>Langdale, Riverview, and Lloyd Shoals Projects</u>

License Expires 1/01/2024

The relicense process is scheduled to start in 2017; a Notice of Intent to Relicense the projects must be filed with FERC prior to January 1, 2019. Georgia Power has budgeted the following for relicensing these projects:

2017:	$ 300,000
2018:	$ 550,000
2019:	$ 550,000
	========
Total:	$1,400,000

<u>Rocky Mountain Pumped Storage Project</u> (Co-owned and Jointly Licensed with Oglethorpe Power)

License Expires 1/01/2027

The relicense process is scheduled to start in 2020; a Notice of Intent to Relicense the project must be filed with FERC prior to January 1, 2022.

<u>Sinclair Project</u>

License Expires 5/01/2036

The relicense process is scheduled to start in 2030; a Notice of Intent to Relicense the project must be filed with FERC prior to May 1, 2031.

North Georgia Project (includes Burton, Nacoochee, Terrora, Tallulah, Tugalo, Yonah)

License Expires 9/01/2036

The relicense process is scheduled to start in 2030; a Notice of Intent to Relicense the project must be filed with FERC prior to September 1, 2031.

11.3 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). Wallace Dam is the only hydro facility that Georgia Power is actively relicensing at this time. The Company is not currently considering any changes to its operations for the Wallace Dam proceeding.

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.

12 – WHOLESALE GENERATION

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SECTION 12 - WHOLESALE GENERATION

12.1 OVERVIEW

In recent years, the Company has offered, and the Commission has accepted, certain wholesale capacity blocks to the retail jurisdiction pursuant to the Company's agreement with Commission Staff in Docket No. 26550. As additional wholesale contracts expire, the Company will evaluate when to offer the wholesale capacity blocks to the retail jurisdiction. The Company also continues to pursue additional potential long-term requirements service agreements with certain wholesale customers as described below.

12.2 WHOLESALE REQUIREMENTS CONTRACTS

The Company is considering additional potential long-term requirements service agreements with other wholesale customers and may provide such 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 wholesale 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. 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 an IRP which includes the subject requirements load.

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13 – EMERGING TECHNOLOGIES

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SECTION 13 – EMERGING TECHNOLOGIES

13.1 TECHNOLOGY EVALUATION PROCESS

Technologies that pass the technology screen (see Section 13.3) transition to the Technology Evaluation Process. The Technology Evaluation Process is overseen by the Technology Strategy Coordination Team. The TSCT consists of stakeholders across the various Southern Company subsidiaries from research, engineering, finance and planning in order to ensure complementary skill sets are utilized in evaluating technologies.

<u>Mission of the TSCT</u>

To coordinate the multi-functional Retail OpCo efforts associated with energy resource technology assessments to ensure appropriate metrics and standards are used in Integrated Resource Planning and other strategic activities.

<u>TSCT Stakeholders</u>

- SCS Retail Generation Development
- SCS Resource Planning
- SCS Strategic Generation Planning
- SCS Engineering & Construction Services ("E&CS") New Generation Projects
- SCS E&CS Technical Services
- SCS Financial Planning & Analysis
- SCS Research & Technology Management
- SCS Environmental Assessment
- SCS Environmental Strategy
- SCS Planning & Regulatory Support
- SNC Nuclear Development

<u>Technology Categories</u>

The TSCT categorizes energy technologies as follows:

Developmental: These technologies are not ready for deployment, but show promise.

Available: These technologies can be purchased but are not yet deployed anywhere in the world with reasonable infrastructure and supply chain to indicate continued deployment is viable. As such, the confidence level of the cost and performance data is considered to be lower than for technologies in the Deployed or Generation Technology Data Book categories.

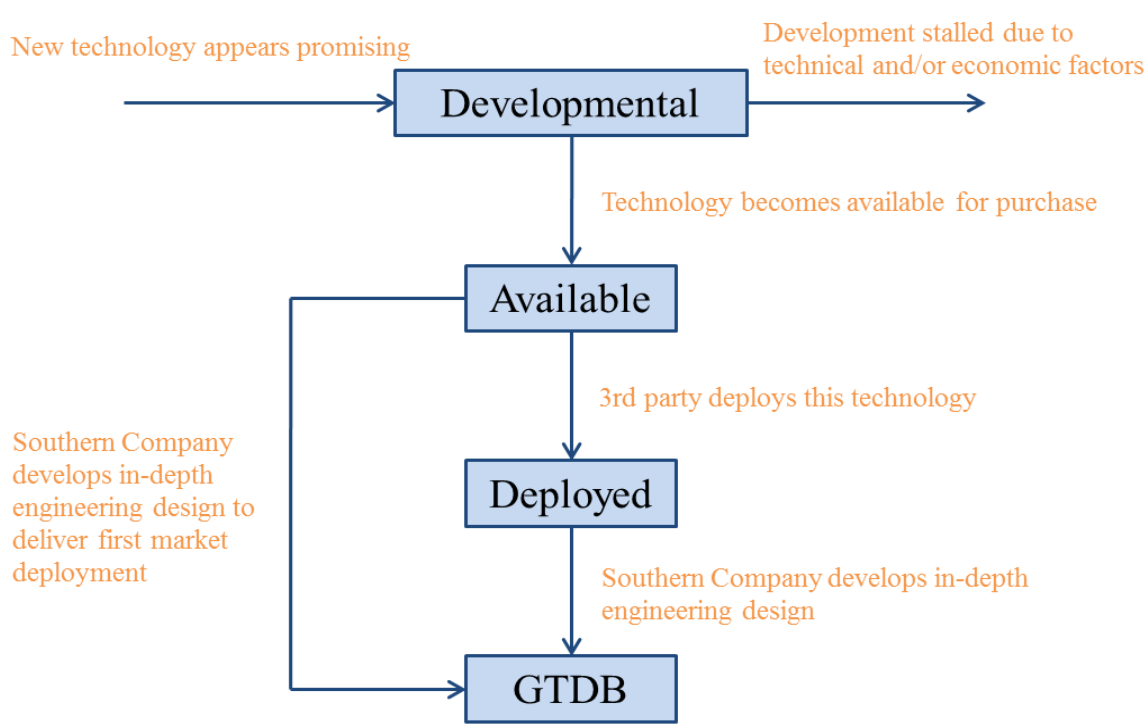
Deployed: These technologies are available for purchase with reasonable infrastructure and supply chain to indicate continued deployment is viable. The confidence level of the cost and performance data is considered greater than that for Available technologies, but not yet at the required level needed to be considered for inclusion in the GTDB.

GTDB: These technologies are viable for inclusion in plans for meeting future system generation needs.

Technology Evaluation Process

The TSCT annually reviews each technology category and provides feedback on whether any changes are needed. This review includes updates to the cost and performance data of each technology to ensure the latest information about the technology is being used in its assessment. A technology may be included for the first time in the process, move from one category to another, or drop out of the process altogether. Figure 1 illustrates how a technology might move between categories.

Figure 1: How technologies move between categories within the Technology Evaluation Process.



If a technology in the Available or Deployed categories shows promise, an in-depth engineering evaluation is performed that may lead to a reference plant design being developed. This technology is then included as appropriate in the GTDB. Technologies in the GTDB form the list of technologies used in pre-screening for the IRP. Refer to the Resource Mix Study in Technical Appendix Volume 1 for more information.

13.2 RESEARCH ACTIVITIES

Georgia Power, as a subsidiary of Southern Company, is involved in a wide range of research activities and programs to capture and/or facilitate the development of emerging technologies that offer significant benefit to Georgia Power's customer base. Southern Company Research and Environmental Affairs ("R&EA"), on behalf of the Operating Companies, works closely with stakeholders from engineering, finance, and planning to ensure emerging technologies are captured and appropriately considered. These activities can be categorized into five major strategic areas: Bulk Generation; Environmental Controls; Energy End Use; Transmission and Distribution; and Renewables, Storage and Distributed Generation. Each of these areas is composed of a number of groups of programs or projects. Each of the following program areas are led by Southern Company's R&EA while individual projects within each of programs may be specific to a particular Operating Company as noted below.

13.2.1 Bulk Generation Technology

The Generation Technology group identifies technology options and quantifies their value in anticipation of changing business needs with the goal of providing a more focused technology response. The group evaluates and develops new concepts in energy systems; supports new technological advancement in the areas of energy production, use, and supply; and promotes a more robust relationship with key stakeholders to identify unconventional and future opportunities for more valuable integrated energy systems.

Examples of Southern Company's efforts in this area are:

Advanced Energy Systems - One example of these systems is Generation IV nuclear reactors that have the potential to produce high quality, sustainable energy at low cost with inherent safety, a low waste profile, and enhanced security. Southern Company is engaged in efforts to advance Generation IV nuclear through collaboration with other industry and government agencies in order to promote demonstration of advanced nuclear reactor concepts.

Simple, Combined, and Advanced Cycle Power Research Program – This program works to maximize gas turbine fleet availability and performance; analyze, develop, and demonstrate emerging advanced natural gas generation concepts for retrofit or greenfield applications, and provide generation technology assessment for system planning support. One example of this type of project is the Advanced Ultrasupercritical ("AUSC") Generation demonstration hosted by Southern Company to expose candidate alloys to 1400°F steam temperature and actual flue gas environments for the purpose of studying fireside corrosion and steam-side oxidation. Results from this successful effort allowed the domestic AUSC program to advance to its next phase (planning and design of a component testing facility) and provided important material data for development of next generation, higher efficiency power-producing technologies.

Plant and Fuels Enhancements Program – This program researches, develops and demonstrates advanced technologies that reduce existing plant operating costs or improve reliability. One goal is to provide solutions to highly specialized plant problems that have been screened with regard to risk, probability of success and rate of return. The program also analyzes, develops and demonstrates emerging advanced generation concepts for greenfield or retrofit applications.

13.2.2 Environmental Controls Program

The Environmental Controls Program works to develop technologies and provide strategic research and development to facilitate both short and long term environmental compliance decisions.

Some specific examples of efforts within the Environmental Controls Program are:

Carbon Capture, Utilization, and Storage **–** This program supports the development of economic CO_2 capture technology; demonstrates secure CO_2 storage within the Southern Company territory, engages in stakeholder outreach to ensure support for technology deployment, and promotes the development of new systems and tools, modeling capabilities, and business models to support commercial deployment. These goals are achieved through the

Southern Company's National Carbon Capture Center ("NCCC"), a focal point of the DOE's efforts to develop advanced technologies to reduce greenhouse gas emissions from coal-based power generation. The NCCC is funded by DOE and managed and operated by Southern Company. It is located at Southern Company's Power Systems Development Facility in Wilsonville, Alabama.

***Water Research Center* –** Southern Company's Water Research Center provides a site for testing technologies to address water withdrawal, consumption, recycling and/or improvement of water quality associated with the power generation process. This center supports technology developers in accelerating development of technically and economically viable water treatment and use minimization technologies for enabling coal-based power generation to remain a key contributor in the effort to provide affordable, reliable, and clean power generation. The center is a tailored collaboration with EPRI and is housed at Georgia Power's Plant Bowen near Cartersville, Georgia.

13.2.3 Energy End Use Research

The Energy End Use Program works to provide customer-focused technologies and technical information to support the operating companies' efforts to sustain and grow profitable electric energy sales, to promote energy efficiency and economic development and to enhance customer satisfaction.

Examples of Energy End Use programs are provided below:

***Industrial Energy Efficiency Program* –** This program brings new industrial electrotechnologies, or new applications of existing technologies to the market. One example would be additive manufacturing (3-D printing) to enhance manufacturing within the service territory.

***Building Energy Efficiency Program* –** The purpose of this program is to identify, assess, and demonstrate new energy efficient technologies and software products for application in building design, energy-related HVAC, water heating, lighting, appliances, and building structures.

Georgia Power Electric Transportation Initiatives – This program will facilitate the adoption and use of electric vehicles ("EV") in Georgia. Georgia Power's pilot program involves promoting public education, supporting community charging stations, including more charging options at its facilities, and offering promotional rebates to residential and business customers for the installation of EV chargers. This pilot program will evaluate such things as charging behaviors and patterns, as well as utilization of charging options (i.e. residential, business, and community). Such data will help inform the development of the necessary infrastructure to support EVs, as well as provide valuable information to the Company and Commission on how best to support and shape the growing EV market to benefit customers. By encouraging the deployment of this technology, Georgia Power will contribute to developing the EV marketplace, which will result in numerous customer benefits including the efficient off-peak usage of electric energy.

Power Quality ("PQ") Program – The PQ Program identifies, assesses, and demonstrates new PQ technologies that will increase customer productivity by providing for point-of-use enhanced PQ and assist personnel with troubleshooting and analysis. This program evaluates other end-use technologies and their PQ impacts to the power delivery system.

13.2.4 Transmission and Distribution

The Transmission and Distribution Program works to develop and deploy the next generation of transmission and distribution technology in order to improve reliability, reduce cost, and modernize the grid.

Following are some examples of these efforts:

Transmission Lines Program – The purpose of this program is to deploy and develop tools, technology, and work practices in order to further improve the effectiveness of the Southern Company transmission system.

Substations Program – This program develops tools and technology to ensure substations are reliable, secure, and intelligent.

Distribution Program **–** This program evaluates new technologies, techniques, and concepts to identify proper investments that increase safety, reliability, and efficiency. One example of this is the Unmanned Aerial Vehicle program under development to provide improved and safer assessment capabilities.

Transmission Operations and Planning Program **–** This program improves reliability and stability by providing technology options to optimize the planning, design, construction, and operation of the transmission system.

13.2.5 Renewables, Storage, and Distributed Generation

Renewables, Storage, and Distributed Generation Program ("RSDG") – The mission of this program is to evaluate biomass, wind, solar, and other utility scale or distributed technologies for energy production and storage. This group executes technical and economic research to evaluate, develop, and demonstrate promising future RSDG technologies.

Energy storage technologies are receiving a high level of public attention. Storage technologies, particularly lithium-ion batteries, are declining in cost. Equipment costs for a lithium-ion battery system can vary significantly depending on the application.[7] Battery technology improvements are being evaluated and declining costs are being monitored by Georgia Power and Southern Company. As with other technologies, battery technologies are evaluated and compared against other storage and generating technologies to determine the associated benefits for the Company and its customers.

Examples of efforts in this area are provided below:

Southeastern Solar Research Center ("SSRC") - Southern Company's SSRC is focused on the demonstration and testing of solar technologies within the unique environment of the Southeast. The SSRC is the host site for a DOE funded research project to perform accelerated aging studies on solar panels. It will also demonstrate and test short-term solar power forecasting technologies. The forecasting project began in Q4 2014 and is projected to run at least through

[7] 'Lazard's Levelized Cost of Storage Analysis – Version 1.0', Lazard, November 2015, pp.15-16.

2016; participants include EPRI, two other electric utility companies, and University of California-San Diego.

Solar Plant 1 MW Array Orientation Demonstration – As described in Section 10.8.2, Georgia Power is nearing completion of a 1 MW PV demonstration which will include various tracking technologies and array orientations. This project will provide opportunities to monitor O&M for the tracker systems at utility-scale sizes and to understand the impacts of array configurations on soiling and O&M. Project collaborators include the University of Georgia.

Advanced Solar Plant Design – Projects and other efforts are ongoing to evaluate and explore new solar plant designs and configurations. Goals include cost reduction, increased energy output, and easier integration to the grid. Southern Company is developing and testing a plant design that allows solar PV energy to go directly to batteries instead of through an inverter in order to capture energy that would have been clipped. This inverter testing is also planned at the SSRC.

DOE SUNRISE Project – The SUNRISE project started at the beginning of 2013. It is an EPRI led project with participation by other utilities including TVA, National Grid, and SMUD. The goal of this project is to address impacts of solar generation across multiple utility functions. Through modeling and simulation, Southern Company's strategic plans will be developed to maintain system reliability. The project is focused on operation simulation tools and analysis; for example, it includes substantial distribution feeder hosting capacity simulations and transmission system modeling.

Smart Inverter Demonstration Project – This project involves installation of a 1MW PV facility with smart inverter capability. The inverters will be tested in a variety of smart inverter modes to determine their effectiveness at managing grid impacts from a solar plant. Georgia Power plans to begin demonstration of the inverters in the spring of 2016, contingent on witness testing and approval by GPC Distribution Reliability Management. This project is part of the Georgia Power Solar Plant 1 MW Array Orientation Demonstration discussed in this section and in Section 10.8.2.

***Onshore Wind Evaluation* –** A number of existing and ongoing projects throughout Southern Company's footprint have measured the wind resource available to potential utility-scale wind. Results to date indicate limited resource for current turbine technology; however, this data is being used to look at implications for advanced turbine technologies.

Small-Scale Battery Storage Demonstration with Solar PV – Two 5 kW/20 kWh energy storage systems have been installed to demonstrate solar PV integration. One system is located in Gulfport, MS and one system is located in Mobile, AL. An additional installation is planned for Atlanta, GA. These projects will provide experience using small-scale battery storage for PV smoothing and shifting on residential scale systems.

Commercial-Scale Battery Storage Demonstrations – Two 40kW/50kWh energy storage systems have been installed to further understand operational challenges, integration, and the value of storage. The systems are connected at the edge of the grid, between the secondary of the transformer and the customer. Southern Company installed these lithium ion battery storage systems at a fire station in Alpharetta, Georgia and a similar site in Gulfport, MS in order to test storage applications such as peak shaving, backup power, and power quality support.

***Large-scale battery storage coupled with solar PV* –** The Cedartown Energy Storage demonstration is a joint project between Southern Company and EPRI to construct and operate a 1MW/2MWh lithium ion based distributed energy storage system. The project will assess the technology's ability to enhance the integration of a 1 MW solar PV system in Cedartown, GA. The demonstration will also evaluate the grid impacts of the storage system in support of applications such as load smoothing, peak shaving, and voltage support.

***Tesla Battery Demonstration Project* –** Southern Company signed a project agreement with Tesla in 2015 to demonstrate Tesla's utility scale battery systems. The Tesla Powerpack comes in units of 250 kW to 500kW with two to four hours of energy. The site selection and integration design for the demonstration effort is underway. The Tesla Powerpack can help balance variable sources of generation and provide peak demand shaving, energy arbitrage, back-up power, and power quality support.

Comparison and Optimization of Design Options for Compressed Air Energy Storage (“CAES”) – The purpose of this project is to evaluate different CAES design options for use by Southern Company. CAES is one of the cheapest and most mature technologies for energy storage and is one of few technologies that can store energy at a large scale.

Connected Community Development and Demonstration Center and High Performance Computing Center – To remain on the forefront of emerging technologies, Georgia Power continually seeks to better understand how distributed energy resources (“DER”), state-of-the-art end-use energy efficiency and demand response technologies, and grid-facing communication technologies can be optimally combined in both residential and commercial applications to benefit customers. In addition, with the increasing deployment of DER technologies, the Company also seeks to gain experience with Distributed Energy Resource Management System (“DERMS”) to allow for the overall integration, control and functionality of those resources. DERMS will be capable of integrating multiple types of DER and other grid edge devices and will allow for direct operator control of any device connected to the system, monitoring the connected and dependent microgrid, and responding autonomously to issues such as reconfiguration, excessive loadings or communications failures. The proposed Connected Community Development and Demonstration Center will focus on the application and interaction of these technologies in a single residential community while the proposed High Performance Computing Center will focus on the application and interaction of these technologies in a single commercial application at the Georgia Tech High Performance Computing Center.

These multi-functional projects will provide greater insight into the ways in which the Company can continue to serve as the comprehensive source for meeting its customers’ energy needs. Georgia Power is committed to being the trusted energy partner for its customers, and these projects will position the Company to better support customers by allowing the Company to (i) gain first-hand experience assessing state-of-the-art homes and businesses that leverage technology to alter effective consumption patterns; (ii) evaluate customer acceptance of variable rates and automated response and assess customer engagement and satisfaction; and (iii) determine the magnitude of future communication infrastructure requirements and bandwith needed to support these emerging technologies.

13.3 TECHNOLOGY SCREENING

Before a technology is considered in the Technology Evaluation Process (see Section 13.1), an initial screen is done by R&EA to determine if further evaluation is merited. The following table summarizes the technologies screened for entry into the Technology Evaluation Process.

Table 13.3.1 Technology Screening Table

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. Ultrasupercritical Pulverized Coal ("USC")	This technology involves the evolution of coal-fueled generation to slightly higher steam pressures and temperatures than supercritical conditions to attain 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.

Technology	Description	Status
4. Advanced Ultrasupercritical Pulverized Coal ("AUSC")	This technology represents the targeted design of current US and international AUSC research and embodies coal-fueled generation to steam conditions higher than that achieved by existing ultrasupercritical pulverized coal technology for even higher thermal efficiency (steam conditions approaching 5000psia and 1400F). The environmental performance would be similar to, though slightly better than, subcritical supercritical pulverized coal due to efficiency gains. This technology is nearing demonstration phases but requires more materials development to be completed.	**NOT RETAINED** for further screening at this time due to current level of development**.**
5. Atmospheric Fluidized Bed Combustion ("AFBC")	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.	**NOT RETAINED** for further screening at this time 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 temperatures 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.	**NOT RETAINED** for further screening at this time due to lack of commercial development.
7. Topping PFBC ("TPFBC")	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.	**NOT RETAINED** for further screening at this time due to lack of commercial development.

Technology	Description	Status
8. Oxygen-Blown Integrated Gasification Combined Cycle ("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 IGCC	This technology is based on an advanced concept using an air blown transport gasifier and associated combustor. Air blown IGCC offers lower capital costs and higher efficiency compared to oxygen blown IGCC. Commercial deployment is underway at Plant Ratcliffe in Mississippi and in China. Further improvements to the technology that have the potential for lower capital cost and higher efficiency are being evaluated at the NCCC facility operated at Southern Company in conjunction with the DOE.	**RETAINED** for further screening.
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.	**NOT RETAINED** for further screening at this time 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 CTs 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.	**NOT RETAINED** for further screening at this time due to its low level of development and high degree of uncertainty with cost projections.

Technology	Description	Status
12. Magnetohydrodynamics ("MHD")	MHD's 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 through 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 a very high cost.	**NOT RETAINED** for further screening at this time 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 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.	**RETAINED** for further screening.
14. Combined Cycle ("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. Each of the major Original Equipment Manufacturers ("OEMs") now offer packaged CC plants, based on advanced gas turbine technology, which offer greater thermal efficiencies and increased operational flexibility compared to conventional units. State-of-the-art NOx control systems will be incorporated for environmental compliance. A number of advanced CT-based cycles such as the Cascaded Humidified Advanced Turbine ("CHAT"), Humidified Air Injection ("HAI"), and Kalina cycles have the potential for higher thermal efficiencies; however they have not been commercially demonstrated.	**RETAINED** for further screening.

Technology	**Description**	**Status**
15. Phosphoric Acid Fuel Cells (“PAFC”)	Phosphoric acid electrolyte systems using natural gas are the most mature fuel cell technology and, as such, have the most extensive track record for operational experience. Recent industry activity from Doosan suggests renewed commitment to PAFC technology. This system has shown improvements as well as a reduction in cost. Attractive features include modular construction, low environmental impact, siting flexibility, and high efficiencies at small sizes.	**RETAINED** for further screening.
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 polymer electrolyte membrane 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 catalysts. Also, by-producing heat at these high temperatures, there are more applications than phosphoric acid systems, such as cogeneration and incorporation of a bottoming cycle. These fuel cells also have potential for use with coal gasification in integrated gasification fuel cell power plants. About 40 units are in the field with capacities ranging from 250kW to 1 MW. Cost, material selection under high temperature operation, and cell durability remain important issues. Fuel Cell Energy is the only commercializer in the US for MCFC technology. SOFCs are 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. Environmental characteristics are expected to be excellent for all fuel cell technologies.	**RETAINED** for further screening.

Technology	Description	Status
17. Fuel Cell CC ("FCCC")	See Advanced High Temperature 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/Micro-tubular ("MT") hybrid in Ca. and achieved 52% efficiency even though the system was not optimized. FuelCell Energy is also testing an atmospheric MCFC/MT hybrid system. DOE Vision 21 power plant highlights such system at efficiency of 60-70% (80-90% with thermal) with 0 air pollutants and CO2 (with sequestration) by 2015. The costs from such a system should be at par with market rate.	**NOT RETAINED** for further screening at this time due to the level of development and cost uncertainties.
18. Reciprocating Engines	Diesel or gas fired generators could potentially have economics competitive with CTs at very low capacity factors and for dispersed applications. Natural gas fired reciprocating engines are emerging in niche markets around the world, mostly in co-generation applications. The current trend is towards larger systems with heat recovery and/or chillers. There are environmental concerns due to relatively high emission rates for certain pollutants when burning diesel fuel.	**RETAINED** for further screening.
19. Microturbines	Microturbines could potentially have economics competitive with CTs at very low capacity factors and for dispersed applications. Microturbines are emerging in niche markets around the world, mostly in co-generation applications. The current trend is towards larger systems with heat recovery and/or chillers. There are environmental concerns due to relatively high emission rates for certain pollutants when burning diesel fuel.	**RETAINED** for further screening.

Technology	Description	Status
20. Pumped Storage Hydroelectric	Pumped hydroelectric energy storage is a large, mature, and commercial utility-scale technology used at many locations in the United States and around the world. Southern Company currently applies this technology on its system. This application has the highest capacity of the energy storage technologies assessed, since its size is limited only by the size of the available upper reservoir. Facilities of this type must deal with environmental issues related to land use and the availability of the water source.	**RETAINED** for further screening.
21. 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 1000 MW underground pumped storage generation facility is being developed in Wiscasset, Maine. Gravity Power, LLC is also developing an underground pumped hydro based on a large piston/cylinder assembly.	**NOT RETAINED** for further screening at this time due to high cost and stage of technology development.
22. Compressed Air Energy Storage - Gen I (Brayton Cycle Based)	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 ("AEC") and began commercial operation in June 1991 and is an integral part of AEC's dispatch. CAES cycles can utilize 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.	**RETAINED** for further screening.

Technology	Description	Status
23. CAES - Gen II (CT Based)	CAES plant hardware is commercially available. Generation II CAES is a newer design iteration of traditional CAES designs which utilizes a CT and an exhaust heat exchanger to heat the air in the expansion cycle, rather than an integral combustion system. This design appears to be more economically favorable than Generation I. Although subsystems have been proven, this cycle has yet to be demonstrated as an integrated system. CAES cycles can utilize 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.	**RETAINED** for further screening.
24. Advanced Lead/Acid Batteries	Lead/acid technology is mature, but life at elevated operating temperatures with heavy duty cycles is of concern. Advanced batteries are being developed to achieve 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.	**RETAINED** for further screening. (advanced battery)

Technology	Description	Status
25. Flow Batteries	Flow batteries have attracted a lot of interest from investors and developers from stationary energy storage. Flow batteries offer the ability to store energy for long periods of time without losing their charge, relative ease in scaling up, and relative high cycle life. Flow batteries can be categorized into different classes, with true redox and hybrid redox further along the commercialization path. Other classes of flow batteries, such as membraneless, organic, metal hydride, and nano-network are in the early R&D stage.	**NOT RETAINED** for further screening at this time due to stage of technology development.
26. Lithium Ion based Batteries	Lithium ion technology is mature based upon the use of the technology in electronics and EVs. Applications of Li-ion batteries for utility scale, stationary applications are quickly emerging with deployments in California leading the way. Advanced Li-ion chemistries and batteries are being developed to achieve higher energy and/or power density, higher reliability, lower maintenance and longer life, at a cost that can be competitive with other storage approaches. Potential applications include load management/peak shaving applications to defer T&D upgrades, defer 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.	**RETAINED** for further screening. (advanced battery)

Technology	Description	Status
27. 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 has 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.	**NOT RETAINED** for further screening at this time due to high costs, early status of development and better suitability for dispersed generation applications.
28. Nuclear Advanced Light Water Reactor (“LWR”) – 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 have been considered for several sites in the US. The APWR has been discussed for several US sites, but no 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.	**RETAINED** for further screening.

Technology	Description	Status
29. Nuclear Advanced Light Water Reactor – Passive	Southern Company has made a commitment to this technology as evidenced by the ongoing construction of two AP1000 (1000 MW) nuclear units at the Vogtle site for commercial operation in 2019 and 2020. In addition to the Westinghouse AP1000 design, this category includes the Economic Simplified Boiling Water Reactor ("ESBWR"), a passive Boiler Water Reactor ("BWR") design under development by GE. The ESBWR design is not yet certified by the Nuclear Regulatory Committee ("NRC"). 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.
30. Nuclear Advanced Light Water Reactor – Modular	The economics of the smaller advanced modular reactor designs, such as the B&W mPower (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.	**NOT RETAINED** for further screening at this time due to development status.

Technology	Description	Status
31. Generation IV Nuclear	There have been several generations of nuclear technology developed over the last 70 years. The AP1000 would be considered a Generation III+ design where a typical PWR or BWR would be considered Generation II. There are multiple Gen IV designs which can be categorized by the type of coolant they feature. This ranges from water to molten salt to liquid metal and even gases. The best Gen IV designs are “walk away safe” meaning they require no operator intervention to shut down. They are much cheaper to build and they have a lower fuel cost than traditional machines. They have a smaller footprint but produce the same amount of power as a traditional reactor. They have shorter construction times. They produce substantially less radioactive waste and they are proliferation resistant meaning the fuel cannot be used for weapons. They are also capable of online refueling and load following.	**NOT RETAINED** for further screening at this time due to development status.

Technology	Description	Status
32. Nuclear Small Modular Reactor (SMR)	Small Modular Reactors ("SMR") are nuclear reactors that typically have an output of 300 MWs or less and correspond to the International Atomic Energy Agency ("IAEA") definition of a small-sized reactor. The modular component of SMRs refers to two attributes of the designs: (1) the ability of the reactor to be manufactured mostly in a factory setting and (2) each reactor is considered a separate module, thus allowing for phased installations at each site. SMR designs are currently in varying stages of design and development, globally. However, small nuclear reactors are not a new concept. For example, small nuclear reactors are a main energy source for the U.S. Naval Fleet. Additionally, there are several operating nuclear reactors in the world that can be considered small. Conversely, SMRs are new designs that incorporate advancements in safety and technology. SMR manufacturers are proposing new Generation III+ and IV designs that incorporate concepts such as advanced safety design, smaller footprints and components, modular construction, smaller fuel sources, and new fuel designs. Several potential uses of SMRs have been identified, including remote and developing country electrification, retiring coal plant repowering, government and military base power, as well as incremental base load generation.	**RETAINED** for further screening.

Technology	Description	Status
33. Solar Thermal Parabolic Trough	Solar technologies based on focusing the sun's energy to heat a working fluid operate 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 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 or to augment thermal loads in processes such as post-combustion carbon capture, giving a lower-cost method of utilizing solar energy to power.	**RETAINED** for further screening.
34. Solar PV	Cost has dropped significantly in recent years, Research continues to increase efficiency and reduce cost. Issues include the site specific solar insolation resource and large land area requirements. Breakthroughs in PV technology could make this a very attractive alternative. The technology has excellent environmental aspects.	**RETAINED** for further screening.
35. Wind Power	Available wind resources in the Southeastern U.S. and the expected resulting capacity factors are not adequate to support significant utility scale use of this technology, based on current economics. Advancing wind turbine technologies could increase potential viability.	**RETAINED** for further screening.
36. Tall Tower/Large Rotor Wind Power	Turbines with towers over 110m and rotor diameters greater than 110m. There are currently no known installations in the US in this category, but improvements in turbine technology could allow for significantly higher capacity factors with a proportionately smaller increase in cost.	**RETAINED** for further screening.
37. Offshore Wind Power	There is a significant resource in the Southeastern U.S for offshore wind, but that resource needs to be directly measured to reduce uncertainty. As of the end of 2015, there is only one project in the US moving forward with development and construction; the Block Island project (~30MW)	**RETAINED** for further screening.

Technology	Description	Status
38. 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.	**NOT RETAINED** for further screening at this time due to limited interest and high level of environmental concern.
39. 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-consuming power plant.	**RETAINED** for further screening.
40. Co-fired Biomass or Wood Waste	Co-firing 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. Co-firing at up to 10% is probably the upper limit with traditional woody biomass. Co-firing at higher levels with advanced fuels such as pellets and torrefied wood is possible, but is potentially detrimental to SCR emission reduction system catalysts.	**RETAINED** for further screening.
41. 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.

Technology	Description	Status
42. Geothermal	Geothermal resources in the Southeastern U.S. are not adequate to support utility scale of this technology. Technologies are being monitored on a research level for potential niche applications.	**NOT RETAINED** for further screening at this time due to limited applicability in Georgia Power's and Southern Company's territory.
43. 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 the Southeastern U.S.	**NOT RETAINED** for further screening at this time due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
44. 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 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.	**NOT RETAINED** for further screening at this time due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
45. 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.	**NOT RETAINED** for further screening at this time due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.

Technology	Description	Status
46. 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.	**NOT RETAINED** for further screening at this time due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
47. 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.	**NOT RETAINED** for further screening at this time due to cost uncertainties, level of development, lack of good sites in Georgia Power's and Southern Company's territory, and potential environmental considerations.
48. Direct-fired Supercritical CO2 cycle	Carbon dioxide used in a closed-loop direct-fired Brayton power cycle has particular advantages due to the nature of the fluid properties in a supercritical state. Also named the "Allam Cycle", this technology uses recuperation to increase efficiency, but can also use higher temperature operation as would any thermodynamic cycle. The technology is fired with gaseous fuel, and due to the nature of the cycle, creates pipeline-ready CO2 for a zero- or near-zero emissions plant. Material and mechanical design present current challenges. There is ongoing industry development work.	**NOT RETAINED** for further screening at this time due to current level of development.

Table 13.3.2 Candidate Technologies

COAL-FUELED	**NUCLEAR**
Subcritical Pulverized Coal	Advanced LWR Evolutionary
Supercritical Pulverized Coal	Advanced LWR Passive
Ultrasupercritical Pulverized Coal	Advanced LWR Modular
Advanced Ultrasupercritical Pulverized Coal	Generation IV
Atmospheric Fluidized Bed Combustion	Small Modular Reactor
Pressurized Fluidized Bed Combustion	
Topping Pressurized Fluidized Bed Combustion	**RENEWABLES**
Oxygen-Blown IGCC	Solar Thermal Parabolic Trough
Air-Blown IGCC	Solar PV
Non-Integrated Coal Gasification Combined Cycle	Wind Power
Integrated Gasification Fuel Cell Combined Cycle	Tall Tower Large Rotor Wind Power
Magnetohydrodynamics	Offshore Wind Power
	Municipal Solid Waste
LIQUID/GAS FUELED	Dedicated Biomass
CT (Conventional/ Advanced)	Co-fired Biomass or Wood Waste
CC Conventional/ Advanced	Landfill gas
Phosphoric Acid Fuel Cells	Geothermal
MCFC & SOFC	Solar Stirling Dish
Fuel Cell CC	Solar Central Receiver Technology
Reciprocating Engine	Compact Linear Fresnel Reflector
Microturbines	Ocean Energy and Hydrokinetic Generation
	Ocean Thermal Generation
ENERGY STORAGE	Direct-fired Supercritical CO2 cycle
Pumped Storage Hydroelectric	
Underground Pumped Storage Hydroelectric	
Compressed Air Energy Storage- Gen I	
Compressed Air Energy Storage- Gen II	
Advanced Lead/Acid Battery	
Flow Batteries	
Lithium Ion based Batteries	
Flywheel Energy Storage	

Table 13.3.3 Technologies Selected for Further Screening

COAL-FUELED:	**NUCLEAR:**
Subcritical Pulverized Coal	Advanced LWR - Evolutionary
Supercritical Pulverized Coal	Advanced LWR - Passive
Ultrasupercritical Pulverized Coal	Small Modular Reactor
Oxygen-Blown IGCC	
Air-Blown IGCC	**RENEWABLES:**
	Solar Thermal Parabolic Trough
GAS-FUELED:	Solar PV
CT Conventional/Advanced	Wind Power
CC Conventional/ Advanced	Tall Tower Large Rotor Wind Power
Phosphoric Acid Fuel Cell	Offshore Wind Power
MCFC & SOFC	Dedicated Biomass
Reciprocating Engines	Co-fired Biomass or Wood Waste
Microturbines	Landfill Gas
ENERGY STORAGE:	
Pumped Storage Hydroelectric	
Compressed Air Energy Storage Gen I	
Compressed Air Energy Storage Gen II	
Advanced Lead Acid Batteries	
Lithium-Ion Batteries	

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14 – ACTION PLAN

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SECTION 14 - ACTION PLAN

Pending Commission approval where necessary, the Company's action plan includes the following primary components:

- Build, operate, and maintain the necessary generation, transmission, and distribution infrastructure to serve the growing needs of Georgia;
- Move to the new long-term System planning reserve margin target of 17%;
- Continue to implement and develop all transmission and distribution projects necessary to ensure adequate reliability to the Company's customers in the state of Georgia;
- Meet all environmental requirements;
- Retire Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and the Intercession City CT as specified in the 2016 Decertification Application;
- Reclassify the remaining net book value of Plant Mitchell Unit 3 as of its respective retirement date to a regulatory asset account and amortize such regulatory asset account ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 36989 until the effective date of the Company's next base rate adjustment, at which time the Company would then begin amortizing the remaining balance over a three year period;
- Reclassify any unusable material and supplies ("M&S") inventory balance remaining at the unit retirement dates to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 36989 for recovery over a period to be determined by the Commission in the Company's next base rate case;
- Implement the portfolio of renewable demonstration projects as described in Section 10;
- Implement the certified DSM programs approved in Docket No. 40162;
- Continue the Power Credit program;
- Continue the additional DSM programs detailed in Sections 5.2.2, 5.2.3, 5.2.4 and 5.2.5;
- Conduct pilot studies detailed in Section 5.2.7;
- Utilize QF contracts and continue to encourage additional resources in compliance with PURPA and the Commission's Avoided Cost Order and utilize the methodologies outlined in the Framework;

- Continue to assess opportunities to integrate cost-effective resources into the Company's supply mix; and
- Implement ASI and REDI.

15 – ATTACHMENTS

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SECTION 15 - ATTACHMENTS

ATTACHMENT 15.1 – MAJOR MODELS USED IN IRP

Economic Model

Georgia Power'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 Analytics, whose large-scale macro-econometric models produce economic and demographic forecasts for the U.S. and for the state of Georgia. The forecast models of Moody's Analytics are proprietary.

Load Management and Planning: Residential

The Residential LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the residential sector. This model was developed by EnerNOC (formerly Global Energy Partners, LLC), and was initially developed in 2007 and first used for the EPRI National Potential Study.

Load Management and Planning: Commercial

The Commercial LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the commercial sector. This model was developed by EnerNOC (formerly Global Energy Partners, LLC), and was initially developed in 2007 and first used for the EPRI National Potential Study.

Load Management and Planning: Industrial

The Industrial LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the industrial sector. This model was developed by EnerNOC (formerly Global Energy Partners, LLC), and was initially developed in 2007 and first used for the EPRI National Potential Study.

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 Peak Demand Model

PDM 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. The Peak Demand Model was developed by Corios.

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 draws from unit historical failure and repair times are used to simulate unplanned outages. 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 53 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 costs for use in various models and analyses. 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 30 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 used 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.

SAMLite

SAMLite 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 SAMLite 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.

SAMLite provides a key calculation for numerous studies. It is used or has been used in: (1) calculating revenue requirements streams for PRICEM; and, (2) calculating the economic carrying cost rates and net present value of revenue requirements for many studies including 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.

Strategist/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 by the Retail OpCos 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 SAMLite; (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, and electric resistance heat loads, as well as solar generation, 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.

GenVal

GenVal is a model that is used to project the economic dispatch of a generating unit within the Southern Company fleet of resources. It utilizes hourly marginal costs from PROSYM, as well as the operating characteristics of the generating unit to be analyzed. The useful information that can be gathered from GenVal includes the system production cost impacts due to the inclusion of the generating unit within the Southern Company generation fleet.

ATTACHMENT 15.2– SUMMARY OF THE SYSTEM POOLING ARRANGEMENT

Introduction

Georgia Power is a member of the Southern Company System, which consists of the 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 FERC. SCS acts as agent for the Operating Companies in the administration of the IIC.

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) is functionally separate from the planning process for Southern Power.

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 Southern Company System is interconnected are shown in Table 15.3.1 below.

Table 15.2.1 – Non-Associated Utilities

Florida Power & Light Company	Duke Energy Florida
JEA	City of Tallahassee
Duke Energy Corporation (Carolinas)	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

Basic Principles of the IIC

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 next made available to the other Operating Companies to serve their customers if the cost of the Pool energy is less than the cost of energy from their own resources.

    c. 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 Georgia Power'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 reiterated 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, such 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 15.3– ACRONYMS, ABBREVIATIONS & TERMINOLOGY

2016 Decertification Application	Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, & Intercession City CT
2016 IRP	2016 Integrated Resource Plan
316(b) Rule	316(b) Cooling Water Intake Structure Rule
ABWR	Advanced Boiling Water Reactor
AEC	Alabama Electric Cooperative
AFBC	Atmospheric Fluidized Bed Combustion
AMI	Advanced Metering Infrastructure
APWR	Advanced Pressurized Water Reactor
AUSC	Advanced Ultrasupercritical
BCII	Blue Canyon II
BCIV	Blue Canyon IV
BOEM	Bureau of Ocean Energy Management
Budget 2016	Budget 2016 Load and Energy Forecast
BWR	Boiling Water Reactor
CAES	Compressed Air Energy Storage
CC	Combined Cycle
CCDDC	Connected Community Development and Demonstration Center
CCR	Coal Combustion Residuals from Electric Utilities Rule
CDD	Cooling Degree Days
CDH	Cooling Degree Hours
CHAT	Cascaded Humidified Advanced Turbine
COD	Commercial Operation Date
Company	Georgia Power Company
COMMEND	Commercial End-Use Model
Commission	Georgia Public Service Commission
CPP	Clean Power Plan
CRA	Charles River Associates
CRF	Capital Recovery Factor
CSE	Cost of Saved Energy
CT	Combustion Turbine
DEF	Duke Energy Florida
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DOE	Department of Energy
DPEC	Demand Plus Energy Credit
DSM	Demand Side Management
DSMWG	Demand Side Management Working Group
E&CS	Engineering & Construction Services
ECCR	Environmental Compliance Cost Recovery
ECS	Environmental Compliance Strategy
EDPR	Energías de Portugal Renewables

EFOR	Equivalent Forced Outage Rate
ELG Rule	Steam Electric Power Generating Effluent Limitations Guidelines
EnerSim	Engineering Simulation Model
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPD	Environmental Protection Division
EPR	European Pressurized Water Reactor
EPRI	Electric Power Research Institute
ESBWR	Economic Simplified Boiling Water Reactor
EUE	Expected Unserved Energy
FCCC	Fuel Cell Combined Cycle
FCR	Fuel Cost Recovery
Framework	A Framework for Determining the Costs and Benefits of Solar Generation in Georgia
GDP	U.S. Gross Domestic Product
GEFA	Georgia Environmental Finance Authority
Georgia Power	Georgia Power Company
GTDB	Generation Technology Data Book
GSP	Gross State Product
GWh	Gigawatt hours
HAI	Humidified Air Injection
HDD	Heating Degree Days
HDH	Heating Degree Hours
HELM	Hourly Electric Load Model
HPCC	High Performance Computing Center
HVAC	Heating, Ventilation and Air Conditioning
HVDC	High Voltage Direct Current
IAEA	International Atomic Energy Agency
IGCC	Integrated Gasification Combined Cycle
IIC	Intercompany Interchange Contract
INFORM	Industrial End-Use Forecasting Model
ITS	Integrated Transmission System
LiDAR	Light Detection and Ranging
LoadMAP	Load Management Analysis and Planning
LSS	Large Scale Solar
LWR	Light Water Reactor
M&S	Material and Supplies
MARTA	Metropolitan Atlanta Rapid Transit Authority
MATS	Mercury and Air Toxics Standards
MCFC	Molten Carbonate Fuel Cell
MHD	Magnetohydrodynamics
MISO	Midcontinent Independent System Operator
MSW	Municipal Solid Waste
MT	Micro Tubular
MW	Megawatt

NCCC	National Carbon Capture Center
NERC	North American Electric Reliability Council
NOx	Nitrogen Oxide
NPV	Net Present Value
NRC	Nuclear Regulatory Committee
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
Operating Companies	Georgia Power Company, Alabama Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company
Order Approving 2015 DG Guidelines	Commission's Order Approving Guidelines for the 2015 Distributed Generation Program
PACT	Program Administrator Cost Test
PAFC	Phosphoric Acid Fuel Cells
PDM	Peak Demand Model
PFBC	Pressurized Fluidized Bed Combustion
PPA	Power Purchase Agreement
PQ	Power Quality
PRB	Powder River Basin
PRICEM	Profitability Reliability Incremental Cost Evaluation Model
Proposed Case	Georgia Power's recommended case for DSM
PURPA	Public Utility Regulatory Policies Act
PT	Participants Test
QF	Qualifying Facility
R&EA	Research and Environmental Affairs
REC	Renewable Energy Credit
REDI	Renewable Energy Development Initiative
REEPS	Residential End-Use Energy Planning System
Retail OpCos	Georgia Power Company, Alabama Power Company, Gulf Power Company, and Mississippi Power Company
RFI	Request for Information
RFP	Request for Proposal
RIM	Rate Impact Measure
RNR	Renewable and Non-Renewable
RSDG	Renewables, Storage, and Distributed Generation Program
RSM	Resource Services Ministries
RTP	Real Time Pricing
SCS	Southern Company Services
SCT	Societal Cost Test
SERC	Southeastern Electric Reliability Council
SERVM	Strategic Energy Risk Evaluation Model
SkIO	Skidaway Institute of Oceanography
SMR	Small Modular Reactors
SO_2	Sulfur Dioxide

SOFC	Solid Oxide Fuel Cell
Solar Analysis	The Costs and Benefits of Distributed Solar Generation in Georgia
SPP	Southeast Power Pool
SSRC	Southeastern Solar Research Center
System	Southern Company electric system
T&D	Transmission and Distribution
TSCT	Technology Strategy Coordination Team
TOU	Time of Use
TOU-RD	Time of Use Residential Demand
TOU-FCR	Time of Use-Fuel Cost Recovery
TOU-MB	Time of Use-Medium Business
TOU-FCR-PEV	Time of Use – Plug-In Electric Vehicle
TOU-FCR-TP	Time of Use-Fuel Cost Recovery Three Part
TP-East	Transmission Planning-East
TPFBC	Topping Pressurized Fluidized Bed Combustion
TRC	Total Resource Cost
TSCT	Technology Strategy Coordination Team
UPH	Underground Pumped Storage Hydroelectric
USC	Ultrasupercritical Pulverized Coal
Wind Analysis	The Costs and Benefits of Fixed and Variable Wind Delivered to Georgia

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Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT

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APPLICATION FOR DECERTIFICATION OF PLANT MITCHELL UNITS 3, 4A AND 4B, PLANT KRAFT UNIT 1 CT, AND INTERCESSION CITY CT

DOCKET NO. 40161

1. INTRODUCTION

In accordance with and as supported by Georgia Power Company's ("Georgia Power" or the "Company") 2016 Integrated Resource Plan ("IRP"), the Company hereby files this Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT ("2016 Decertification Application") pursuant to O.C.G.A. § 46-3A-3 and Commission Rules 515-3-4-.08. The units presented for decertification represent 377 megawatts ("MW") of generating capacity. Only after extensive analysis and evaluation and after exploring a wide range of feasible compliance options did the Company determine that retirement and decertification of these units is in the best interest of all customers. The Company hereby incorporates by reference all other portions of the Company's 2016 IRP filing into this 2016 Decertification Application.

2. DECERTIFICATION REQUESTS

2.1 Need for Decertification

As described in Sections 1.1, 1.6.2, and Section 6 of the Main Document, retirement and decertification is the most cost-effective approach for Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT. While these units have provided significant benefit to customers, the analysis demonstrates that retirement of these units is in the best interest of all customers.

Plant Mitchell Unit 3 is a coal-fired unit with a total capacity of 155 MW and was placed in service in 1964. Plant Mitchell Units 4A and 4B CTs have a total capacity of 31 MW each and were placed in service in 1971. Plant Kraft Unit 1 CT is a 17 MW CT placed in service in

1969, and the Intercession City CT is a 143 MW unit placed in service in 1997. The economic analyses for Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT are contained in Sections 1.6.5, 1.6.11, 1.6.10, and 1.6.9 of the Unit Retirement Study in Technical Appendix Volume 2. The analysis for each unit shows that continued operations is not in the best interest of customers. In the case of the Intercession City CT unit, located in Florida and co-owned with Duke Energy Florida ("DEF"), the Company exercised its contractual option in May 2015 to terminate the transmission service and sell the Company's 33% ownership interest in the unit to DEF, which is not an affiliate of the Company. The Company has executed a sale agreement with DEF, which agreement is contingent on approval by the Commission and the Federal Energy Regulatory Commission ("FERC"). DEF will seek FERC approval under Section 203 of the Federal Power Act. A copy of the sale agreement is included in the Selected Supporting Information section in Technical Appendix Volume 2.

2.2 Analysis of Transmission Impacts

In accordance with the Commission's order in Docket No. 31081, the Company performed an analysis of the results of the requested decertifications on transmission facilities. The transmission facilities added, modified or avoided as a result of this decertification request are as follows:

Plant	**Impact**	**Project Name**	**Date**
Plant Mitchell Unit 3	None	N/A	N/A
Plant Mitchell Units 4A and 4B	Project needed if Plant Mitchell units 4A and 4B retired	Plant Mitchell Substation 230/115kV Autotransformer	2015
Plant Kraft CT	None	N/A	N/A
Intercession City CT	None	N/A	N/A

2.3 Cost Recovery

In connection with the proposed decertifications, the Company requests that the Commission approve the following:

1) Reclassification of the remaining net book value of Plant Mitchell Unit 3 as of its respective retirement date to a regulatory asset account and the amortization of such regulatory asset account ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 36989 until the effective date of the Company's next base rate adjustment, at which time the Company would then begin amortizing the remaining balance over a three year period; and

2) Reclassification of any unusable material and supplies ("M&S") inventory balance remaining at the unit retirement dates to a regulatory asset as identified in accordance with the Commission's Order in Docket No. 36989 for recovery over a period to be determined by the Commission in the Company's next base rate case.

The Plant Mitchell Unit 3 construction work in progress ("CWIP") regulatory asset is currently being amortized over a two-year period. Amortization of the regulatory asset began in 2015 and was included as part of the approved Environmental Compliance Cost Recovery ("ECCR") tariff in the 2015 Compliance Filing. Plant Mitchell Units 4A and 4B are fully depreciated, and Plant Kraft Unit 1 CT is projected to be fully depreciated by April 2016. The remaining net book value of Intercession City CT is expected to be offset by the proceeds from the sale of the unit.

3. CONCLUSION

As set forth in the Company's 2016 IRP, Georgia Power's current supply-side plan, which incorporates the requested decertifications contained herein, is sufficient to provide cost-effective and reliable sources of capacity and energy for customers. The known and reasonably expected effects of these retirements on the Company's 2016 IRP are described more fully in the Main Document and the Technical Appendices. The requests contained in this 2016 Decertification Application are in the public interest and substantially comply with the relevant Commission rules. Therefore, the Company requests that the Commission approve the following:

1) Decertification of Plant Mitchell Units 3, 4A and 4B and Plant Kraft Unit 1 CT effective as of the date of the final order in this proceeding;

2) Decertification of Intercession City as of the date of the closing of the sale with DEF; and

3) The related cost recovery as detailed in Section 2.3 of this 2016 Decertification Application.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the within and foregoing GEORGIA POWER COMPANY'S INTEGRATED RESOURCE PLAN AND APPLICATION FOR DECERTIFICATION OF PLANT MITCHELL UNITS 3, 4A AND 4B, PLANT KRAFT UNIT 1 CT AND INTERCESSION CITY CT in Docket No. 40161 upon all parties listed below via electronic service or by hand delivery and addressed as follows:

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This 29th day of January, 2016.

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