BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In re: **Georgia Power Company's Application for Approval of Its 2013 Integrated Resource Plan And Application for Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6**	))))))))))))))	**Docket No. 36498**

DIRECT TESTIMONY OF

KYLE C. LEACH, GAREY C. ROZIER,

LARRY T. LEGG AND LARRY S. MONROE

MARCH 19, 2013

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LARRY T. LEGG AND LARRY S. MONROE

IN SUPPORT OF GEORGIA POWER COMPANY'S

2013 INTEGRATED RESOURCE PLAN AND APPLICATION FOR DECERTIFICATION OF PLANT BRANCH UNITS 3 AND 4, PLANT MCMANUS UNITS 1 AND 2, PLANT KRAFT UNITS 1-4, PLANT YATES UNITS 1-5, PLANT BOULEVARD UNITS 2 AND 3, AND PLANT BOWEN UNIT 6

GPSC DOCKET NO. 36498

I. INTRODUCTION

Q. PLEASE STATE YOUR NAMES, TITLES AND BUSINESS ADDRESSES.

A. My name is Kyle C. Leach. I am the Director of Resource Policy and Planning for Georgia Power Company ("Georgia Power" or the "Company"). My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Garey C. Rozier. I am the Manager of Resource Planning for Southern Company Services ("SCS"). My business address is 600 N. 18th Street, Birmingham, Alabama 35203.

A. My name is Larry T. Legg. I am the Manager of Market Planning for Georgia Power. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

A. My name is Larry S. Monroe. I am a General Manager of Environmental Affairs for Georgia Power. My business address is 241 Ralph McGill Boulevard, N.E., Atlanta, Georgia 30308.

Q. MR. LEACH, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from Auburn University in 1983 with a Bachelor of Science degree in Civil Engineering. I joined Georgia Power in 1980 as a co-op in the Civil Engineering department and moved from there into a Power Marketing Engineer role in various regions around Atlanta. I then worked as a Key Account Manager responsible for servicing major Georgia Power industrial accounts, and following that role, I served as Sales Manager at Southern Company's former operating subsidiary in Bristol, England. From 2000 to 2006, I held various positions throughout the marketing organization at Georgia Power, including assistant to the Senior Vice President of Marketing, Manager of the Business Development Organization and Manager of the Key Account program. Most recently, I served as the Director of Federal Regulatory Affairs in Southern Company's Washington D.C. office, where I was the liaison between Southern Company and the Federal Energy Regulatory Commission.

In August 2011, I was appointed the Director of Resource Policy and Planning for Georgia Power. In this position, my responsibilities include integrated resource planning, generation development and procurement and contract administration.

I have testified before the Georgia Public Service Commission (the "Commission") regarding the Company's recent Application for Decertification of Plant Branch Units 1 and 2 and Plant Mitchell Unit 4C, the Application for Certification of the Power Purchase Agreements with BE Alabama LLC from the Tenaska Lindsay Hill Generating Station and with Southern Power Company from the Harris, West Georgia and Dahlberg Electric Generating Plants and Updated Integrated Resource Plan in Docket No. 34218 ("2011 IRP Update"). I have also testified in the Company's Application for the Certification of Capacity from Block 1 and Capacity from Blocks 2-4 in Docket No. 26550, the Review of

Proposed Revisions and Verification of Expenditures Through the Quarter Ending June 30, 2011 Pursuant to Georgia Power Company's Certificate of Public Convenience and Necessity for Plant McDonough Units 4, 5 and 6 in Docket No. 24506, and also in the Vogtle Construction Monitoring proceedings in Docket No. 29849 regarding the Fifth, Sixth and Seventh Semi-Annual Reports.

Q. MR. ROZIER, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from Auburn University in 1972 with a Bachelor of Science degree in Industrial Engineering. After graduation, I joined Georgia Power as an engineer in the System Planning Department. From 1972 to 1989, I held various engineering and managerial positions in transmission planning, generation planning, and bulk power. During this period, I attended Georgia State University and earned a Masters degree in Business Administration in 1982.

In 1989, I transferred to SCS in the position of Director of System Planning, where I was responsible for providing bulk transmission planning and integrated resource planning analysis for Southern Company operating subsidiaries. I returned to Georgia Power in March 1992 as General Manager, Bulk Power Markets and was responsible for transmission planning, integrated resource planning, and bulk power contracts.

In 1996, I was transferred back to SCS, where I assumed my current position as Manager of Resource Planning.

Q. MR. LEGG, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from Mercer University in 1988 with a Bachelor's degree. I joined Georgia Power in 1990 in the Customer Service organization. From 1990 to 2006, I held various staff and managerial positions in Customer Service, Sales, Software Development, Revenue Accounting, and Pricing and Rates. During this period, I attended Georgia State University and earned a Masters degree in Business Administration in 1997.

I was named Rate Design Manager for Georgia Power in 2003 where I led the development of Rate Design for the 2004 Retail Rate Case. In 2006, I assumed my current position as Manager of Market Planning for Georgia Power. In this position, my responsibilities include the load, energy and revenue forecast, as well as economic evaluation of demand side management ("DSM") and marketing programs.

I have previously testified before the Commission in the 2007 IRP in Docket No. 24505, the Vogtle Certification in Docket No. 27800, the 2010 IRP in Docket No. 31081, the 2010 DSM certification in Docket No. 31082 and the 2011 IRP Update.

Q. DR. MONROE, PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from Auburn University in 1979 with a Bachelor of Science degree in Chemical Engineering. After graduation, I joined E.I. DuPont as a plant engineer in Wilmington, North Carolina at a chemical manufacturing facility. In 1981, I left DuPont to attend the Massachusetts Institute of Technology where I studied coal combustion and the formation chemistry of coal emissions, graduating with a Ph.D. in Chemical Engineering in 1989. After graduation, I joined Southern Research Institute ("SRI") in Birmingham, Alabama in 1990. At SRI, I held the position of Group Manager responsible for the Combustion Research facility, coal fuel evaluations, and emissions control technology development.

In 1998, I joined the Southern Company Services Research and Environmental Affairs department in Birmingham, where I was responsible for directing research and development ("R&D") on emissions control technology in support of the generating fleet. In that position, I managed and directly investigated improvements in existing emissions control technologies, as well as developing new technologies for reducing emissions.

In that capacity, I have also served as a co-chairperson and industry representative for numerous committees including emissions control and technology committees at the Electric Power Research Institute ("EPRI"), the Utility Air Regulatory Group, and various working groups of the United States Environmental Protection Agency ("EPA") organized to inform mercury regulations and greenhouse gas guidelines and regulations. I have also testified before both the U.S. Senate and the U.S. House on coal-based technologies.

In January 2011, I was appointed a General Manager in Georgia Power's Environmental Affairs department, where I oversee the air regulatory permitting and reporting group, the air testing and monitoring group, and the environmental services laboratory.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to present and seek approval of Georgia Power's 2013 Integrated Resource Plan ("IRP") and the Application for Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3 and Plant Bowen Unit 6 (the "Decertification Application").

We adopt the 2013 IRP and Decertification Application as filed with the Commission on January 31, 2013 as part of our testimony.

Q. WHAT IS THE IRP?

A. The IRP is primarily comprised of the Company's demand and energy forecast for a twenty year period and its plan for meeting the requirements shown in the forecast in an economical and reliable manner. Within the IRP, the Company provides an analysis of all viable capacity resource options, including both demand-side and supply-side options, to determine candidates for future resource additions and sets forth Georgia Power's planning assumptions and conclusions with respect to the effect of each capacity resource option on the future cost and reliability of electric service.

Q. HOW MANY IRPs HAS THE COMPANY FILED?

A. This 2013 IRP is the eighth full IRP filed by Georgia Power since enactment of the Integrated Resource Planning Act, O.C.G.A. § 46-3A-1 *et seq.*, which requires the filing of such a plan every three years.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Georgia Power's 2013 IRP describes how the Company will cost-effectively and reliably meet its customers' demand for electricity while maintaining the flexibility needed to meet the challenges of a rapidly changing power industry. The IRP contemplates that the Company's forecast requirements will be met with existing capacity resources, existing power purchases, existing DSM programs, capacity additions that have already been approved, additional certified and amended DSM programs and a diverse set of longer-term resource additions. Georgia Power also intends to continue to offer pricing options to its customers that are effective in reducing the demand for electricity.

The 2013 IRP builds on the actions taken in the 2011 IRP Update, where the Company and the Commission took proactive steps to ensure cost-effective, reliable electricity in light of what was at that time an unprecedented period of uncertainty in the industry driven by the impact of new and pending environmental regulations, including, most significantly, the EPA's Mercury and Air Toxics Standards ("MATS") rule. Since the conclusion of the 2011 IRP Update, the Company has continued to refine its analyses of the impact of numerous environmental regulations through a unit-by-unit evaluation of its coal- and oil-fired generating fleet.

Based on that analysis, and drawing on the technical expertise of Southern Company, Georgia Power has presented in this 2013 IRP a plan for MATS compliance that will result in a robust and diverse set of resources that benefits customers. While the Company has been successful in identifying MATS compliance options for a number of its coal-fired generating units that are less costly than had been forecasted, including switching the primary fuel of certain units from coal to natural gas, MATS will nevertheless still impose significant compliance costs on the Company and our customers.

And while MATS compliance has been the most significant factor in the Company's analysis, Georgia Power has also taken into consideration the uncertainty that remains with respect to other pending and potential environmental regulations including the Company's best predictions of the requirements, the timing, and the costs to comply with such rules. These rules include the cooling water intake structure (316(b) rule), the coal combustion residuals ("CCR") ash rule, and the steam effluent guidelines waste water treatment rule.

Taking into account the impact of MATS, as well as other pending or potential regulations, the Company's analysis of its generating units has also led to the conclusion that it is in the best interest of customers to retire approximately 2,100 megawatts ("MW") of generating resources. The Company has requested decertification of these resources in its Decertification Application. Such a slate of retirements is unprecedented in the history of Georgia Power, and the Company fully recognizes the impact these decisions have on employees and local communities. Only after extensive analyses 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 customers.

The Company's MATS compliance strategy and its decertification requests, however, are just one piece of the 2013 IRP. The Company also continues its efforts, in collaboration with the Commission, to responsibly grow its portfolio of renewable resources. With over 1,088 MW of hydro generation, over 62 MW of solar generation (in service or under contract today), and 142 MW of biomass generation, the Company has demonstrated a firm commitment to identifying all cost-effective renewable resources for the benefit of customers. The Georgia Power Advanced Solar Initiative ("GPASI") is the most recent and most significant step taken by the Company to obtain an increasing amount of solar resources, as declining technology prices make such resources more economic. The GPASI builds on the solar resources already obtained by the Company through the Large Scale Solar ("LSS") program and the Green Energy Program. After all resources are obtained through the GPASI, the Company expects to have 270 MW of solar capacity under contract in Georgia. In total, the Company expects to have more than 1,500 MW of renewable generation available to serve customers by the end of 2016.

The Company also continues its disciplined pursuit of cost-effective DSM programs through its collaboration with Commission Staff and the Demand Side Management Working Group ("DSMWG"). The specific certification and amendment requests of the Company have been made concurrently with this filing in the Application for the Certification of its Amended Demand Side

Management Plan in Docket No. 36499 ("2013 DSM Application"). Specifically, in its 2013 DSM Application, the Company requests certification of one new commercial program, amendment of three currently certified programs, decertification of one program (though the program activities will be subsumed by an existing program), and approval of updated program budgets for the remaining programs previously certified in Docket No. 31082. The Company's current DSM portfolio consists of demand response programs, energy efficiency programs, pricing tariffs, and other activities. The Company projects that by 2016, these programs will reduce peak demand by approximately 2,000 MW.

This 2013 IRP is the product of a thorough planning process that has resulted in a robust and diverse portfolio of generation and demand side resources that will continue to provide customers cost-effective, reliable service. The Company is well-positioned for the return of customer load growth given Georgia's positive long-term economic prospects as a state with an attractive climate, relatively low living costs, and a business friendly environment. By 2020, the state of Georgia is projected to add more than 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 facilitated by the IRP Act and guided by the Commission. This process has enabled the Company and the Commission to maintain a reasoned and disciplined approach to meeting customer demand while effectively responding to a changing regulatory environment, all while maintaining rates below the national average.

II. SUPPLY-SIDE PLAN

Q. PLEASE DESCRIBE THE STATUS OF GEORGIA POWER'S CURRENT SUPPLY-SIDE PLAN.

A. Georgia Power's current supply-side plan, as set forth in the 2011 IRP Update and as further supplemented herein, is sufficient to provide cost-effective and reliable sources of capacity and energy through 2015 and beyond. As described more fully below, in light of current and pending environmental regulations that impact all of the Company's coal- and oil-fired steam generating resources, the Company has developed a fleet-wide compliance strategy that results in a diverse, robust set of generation resources. The Company is in the midst of a significant transition in its fleet that will result in a more diverse fuel portfolio and ensure that Georgia Power is able to continue to provide its customers with reliable and affordable electricity while helping to mitigate the risk of fuel price volatility. This period of transition will also result in a more efficient fleet with fewer coal resources, which will reduce customers' exposure to the cost of potential carbon regulation or legislation. Additionally, by further controlling the Company's largest and most efficient coal units in which the Company has already invested significant capital for environmental controls, the Company retains the significant energy benefits of these units, while also positioning itself to be able to respond to future increases or volatility in the cost of natural gas.

Q. PLEASE DESCRIBE THE COMPANY'S 2011 IRP UPDATE.

A. In the 2011 IRP Update, the Company presented its near term plan for seeking to ensure reliable service in light of the significant uncertainty caused by an array of pending environmental regulations, the most significant of which was the EPA's MATS rule. Though the MATS rule had not been finalized at the time the Company filed its 2011 IRP update, it was nevertheless incumbent on the Company, in light of the stringent requirements and compressed compliance timelines contained in the proposed rule, to develop compliance strategies to ensure a reliable supply of electricity for its customers.

Specifically, the Company requested authorization to proceed with initiation of construction of baghouses that were anticipated to be needed at Plants Bowen, Wansley and Hammond to comply with the MATS rule and also recommended deferral of decisions concerning 2,600 MW of generating units. However, the Company asserted that it was reasonable to assume that 2,000 MW of that capacity would be unavailable in 2015 as a result of the MATS rule. In light of the assumed unavailability of 2,000 MW of capacity, the Company sought certification of certain power purchase agreements ("PPA") identified through the 2015 Request for Proposals ("RFP"). Finally, the Company also requested Commission approval for the decertification of Plant Branch Units 1 and 2 and Plant Mitchell Unit 4C.

Q. WHAT DID THE COMMISSION APPROVE IN THE 2011 IRP UPDATE?

A. The Commission approved the Company's expenditures associated with the initiation of construction of baghouses for Plant Bowen Units 1–4, Plant Wansley Units 1 and 2, and Plant Hammond Units 1–4, and the Company was ordered to keep the Commission apprised of its evaluation through monthly reports filed at the Commission. The Commission also certified three PPAs, decertified Plant Branch Units 1 and 2 and Plant Mitchell Unit 4C and approved the accounting treatment requested by the Company in connection with the decertified units.

Q. WHAT STEPS HAS THE COMPANY TAKEN SINCE THE 2011 IRP UPDATE TO EVALUATE THE IMPACT OF MATS ON THE COMPANY'S GENERATING UNITS?

A. Since the 2011 IRP Update, Georgia Power has continued to evaluate the requirements of the final MATS rule and the overall compliance strategy on a unit-by-unit basis, relying on the Company's and Southern Company's extensive research and development expertise. Now that the Company has had the opportunity to further analyze and assess the impact of the final MATS rule, a significant portion of the uncertainty that framed the discussion in the 2011 IRP Update has been eliminated, as the Company has developed a compliance plan that is intended to maintain long-term reliability for customers in a cost-effective manner.

Q. WHAT ARE THE COMPANY'S CONCLUSIONS REGARDING THE NEED FOR BAGHOUSES?

A. As a result of its analysis, the Company determined, and has previously notified the Commission in Docket No. 34218, that only Plant Bowen Units 3 and 4 need baghouses at this time and that MATS compliance can be achieved at Plant Bowen Units 1 and 2, Plant Wansley Units 1 and 2 and Plant Hammond Units 1–4 by installing activated carbon and hydrated lime injection systems and performing precipitator work. Activated carbon and hydrated lime injection systems will also be added to Plant Bowen Units 3 and 4 for mercury control. All units at Plants Bowen, Hammond and Wansley will install scrubber additive systems. For MATS compliance, every coal-fired power plant in the Georgia Power fleet will have a dedicated system added to control mercury emissions and to ensure MATS compliance.

Q. WHY WERE ONLY TWO BAGHOUSES REQUIRED?

A. Capitalizing on differences between the proposed MATS rule and the final rule, the Company utilized its and Southern Company's substantial R&D capabilities and technical expertise to develop a solution that resulted in the removal of five baghouses from its compliance strategy. Chief among the differences in the rule was a change in the particulate matter standard between the proposed and final rules. In the proposed rule, the EPA would have imposed a very stringent and complicated limit on particulate emissions that ultimately would have resulted in a unit-specific limit on particulate matter emissions, thereby removing all compliance margin without accounting for natural variation in the operation of a generating unit. Therefore, the only compliance option under the proposed rule would have been installation of baghouses to attempt to comply under all operating conditions. In the final rule, however, the EPA altered the form of the particulate matter limit such that, while still very stringent, it is a standard limit that applies to all units rather than a unit-specific limit. The limit is also in a form that allows for additional compliance options to be considered and evaluated on a unit-specific basis, as is further explained in the Environmental Compliance Strategy ("ECS") document in Technical Appendix Volume 2 of the 2013 IRP.

Q. WHAT OTHER MATS COMPLIANCE ACTIONS IS THE COMPANY RECOMMENDING?

A. Aside from the coal-fired units for which the Company seeks decertification and the environmental controls being added to Plant Bowen Units 1–4, Plant Wansley Units 1 and 2, and Plant Hammond Units 1–4, additional environmental controls and other changes will be required for some remaining coal-fired units to continue to operate on coal after the MATS compliance date of April 16, 2015. Specifically, Georgia Power plans to switch Plant McIntosh Unit 1 to operate on low-sulfur, lower-priced Powder River Basin ("PRB") coal (pending a successful test burn and further study). If the test burn is deemed successful, Plant McIntosh will also add MATS controls, namely an activated carbon injection system for mercury control and a dry sorbent injection ("DSI") system to ensure compliance with the MATS acid gases limit. In addition, Plant Scherer Units 1-3 will also be retrofitted with additional controls in order to ensure MATS compliance. Although these units will be well controlled due to installation of the required Georgia Multipollutant rule controls, a bromide injection system will be installed in order to most cost-effectively comply with the MATS requirements.

For the other remaining coal-fired units that will continue to operate, the Company has concluded that it is not cost-effective to install the environmental controls necessary to enable these units to remain operational on coal. Instead, the Company has found it to be most cost-effective for customers to switch Plant Yates Units 6 and 7 and Plant Gaston Units 1–4 to natural gas as the primary fuel. See Table 1 below for a summary of the Company's recommended MATS compliance actions.

TABLE 1	
Installation of Environmental Controls for MATS Compliance	
Plant Bowen Units 3 and 4	Baghouses, activated carbon and hydrated lime injection systems and scrubber additive systems
Plant Bowen Units 1 and 2	Activated carbon and hydrated lime injection systems, electrostatic precipitator (" ESP") work, and scrubber additive systems
Plant Wansley Units 1 and 2	Activated carbon and hydrated lime injection systems, ESP work, and scrubber additive systems
Plant Scherer Units 1-3	Bromide Injection system
Plant Hammond Units 1-4	Activated carbon and hydrated lime injection systems, ESP work, and scrubber additive systems
Switching Primary Fuels for MATS Compliance	
Plant Yates Units 6 and 7	Coal to natural gas
Plant McIntosh Unit 1	Bituminous coal to PRB coal; activated carbon and dry sorbent injection systems
Plant Gaston Units 1-4	Coal to natural gas

Q. HOW DO THE COMPANY'S ESTIMATED MATS COMPLIANCE COSTS COMPARE WITH WHAT HAD BEEN PROJECTED DURING THE 2011 IRP UPDATE?

A. While the Company will be required to incur significant capital costs to comply with the final MATS rule, the projected capital costs required for compliance are less than had been anticipated at the time of the 2011 IRP Update. These costs are lower for two primary reasons. First, as discussed above, key changes were made to the final rule that enabled the Company to lower the cost of compliance, thereby benefitting customers. Southern Company, on behalf of Georgia Power and its other operating companies, as well as this Commission, played a major role in communicating to the EPA the need for changes due to the impacts that the overly stringent proposed rule would have had on the reliability and affordability of electricity. Second, because of these changes in the rule, the Company was able to utilize its and Southern Company's substantial R&D capabilities and technical expertise to develop innovative compliance solutions that were less expensive than previously expected.

Q. PLEASE DESCRIBE IN MORE DEPTH HOW THE COMPANY HAS DRAWN ON THE R&D EXPERTISE OF SOUTHERN COMPANY.

A. Southern Company has a long history of R&D in support of the operating companies, including Georgia Power. Southern Company's R&D programs cover a wide range of topics, all aimed at improving technical knowledge in key areas that can provide benefits to customers. In the environmental area, this research is designed to identify cost-effective and reliable solutions for compliance with air, water, and land regulations.

The R&D conducted by Georgia Power and Southern Company concerning emissions control has been directly applicable to the specific technology decisions at Georgia Power plants presented in the 2013 IRP. For example, the research conducted by Southern Company on mercury and particulate control beginning in the 1990s led to innovations in baghouse design. The knowledge gained from this research led to the development of the Compact Hybrid Particulate Collector ("COHPAC") baghouse design that is used at Plant Scherer and will be used at Plant Bowen Units 3 and 4 to achieve MATS compliance. The COHPAC baghouse is now established in the industry as an effective means of improving both particulate control and mercury control and is less costly than traditional baghouse installations.

Southern Company R&D activities were also instrumental in helping Georgia Power identify mercury control technologies (a primary component of MATS compliance) that were significantly less costly than baghouse installations. This process began in the early 2000s, when Southern Company conducted several activated carbon injection studies and discovered that sulfur oxides present in flue gas can interfere with mercury capture by activated carbon. This sulfur chemistry interference is the reason that the use of activated carbon for the control of mercury without a baghouse was widely considered to be infeasible while burning higher sulfur coals. However, building on Southern Company's discovery in the early 2000s, testing at Plants Bowen, Hammond, and Wansley in 2012 led by Southern Company researchers showed that the careful use of hydrated lime greatly reduced the interference, and that the injection of both activated carbon and hydrated lime into an ESP was a viable option for certain units and less costly than a baghouse. This testing was conducted as part of the initial baghouse work approved by the Commission in the 2011 IRP Update.

Southern Company has also conducted various investigations of chemical additives to flue gas scrubbers to help retain captured mercury in the scrubber and has studied the use of calcium bromide as a coal additive for increasing mercury capture by scrubbers on low chlorine coals, such as the PRB coal used at Plant Scherer. These additives are incorporated into the Company's compliance strategy for the plants to achieve mercury MATS compliance at the least cost.

In summary, the Company has been able to utilize Southern Company's R&D expertise to inform environmental compliance strategy decisions that provide lower cost compliance options for our customers.

Q. WHY IS IT VITAL THAT THE COMPANY RETAIN A DIVERSE FLEET OF GENERATING RESOURCES?

A. Maintaining a diverse fleet of generating resources gives the Company the ability to capitalize on the lowest cost fuel options over the long term. A fleet that is over reliant on one particular fuel would cause customers to bear significant risk with respect to the cost of that particular fuel. By maintaining a diverse fleet of resources, the Company mitigates risk with respect to any particular fuel source. For instance, based on the resources assumed in this IRP, the Company has projected that under a low gas price scenario in 2020, the Company could generate up to 50% of its electricity from its natural gas resources (while reducing its coal generation to just 18%). On the other hand, in a high gas price scenario, the Company would be able to shift and generate up to 40% of its electricity from coal resources (while reducing natural gas-fired generation to just 28%). In either fuel cost scenario, the Company's growing nuclear generation fleet will continue to produce stable, low cost energy. This flexibility will deliver significant benefits to customers.

Flexibility is critical in light of the various risk factors that could result in higher than forecast natural gas prices, whether over the short- or long-term. For instance, a temporary but significant interruption in natural gas production could lead to a spike in natural gas prices over the short-term or new regulation of hydraulic fracturing drilling ("fracking") could lead to a longer-term increase in natural gas prices. In either case, the Company's diverse fleet will allow it to shift generation in order to benefit from the lowest cost fuel option. Together, the Company's nuclear and renewable generating resources account for approximately 30% of the Company's electricity production.

A diverse fleet also provides operational flexibility that further protects customers. Coal and natural gas generation rely on two completely separate fuel delivery infrastructures. By maintaining a diverse fleet, the Company is able to more quickly and efficiently adjust to a disruption in the supply chain of one particular fuel. Unlike coal generation, for which stockpiles are maintained on site, natural gas generation relies on "just in time delivery." A significant disruption in natural gas transportation could impact the Company's ability to rely on a particular natural gas generation facility. In such an event, the Company's diverse fleet would allow the Company to shift generation if needed to continue to provide reliable service to customers.

As mentioned above, nuclear generation is a crucial factor in maintaining diversity in the Company's generation fleet, and the addition of Plant Vogtle Units 3 and 4 will only enhance such diversity. Nuclear generation provides a protection to customers because of its consistent, low fuel price and zero carbon emissions.

The Company's cost-effective renewable resources, including hydroelectric resources, are also an important source of fuel diversity for customers. These resources have a positive impact on the fuel costs and emissions of the Company.

Q. WHAT ROLE DO OTHER PENDING AND POTENTIAL ENVIRONMENTAL REGULATIONS PLAY IN THE COMPANY'S ANALYSES?

A. The Company takes into account the potential future impact of additional environmental regulations through the controls assumed in the Unit Retirement Study ("URS") as evaluated across the nine planning scenarios. There are two ways in which future environmental rules are factored into the URS. First, the structure of the scenarios accounts for differing levels of stringency for future regulations that restrict emissions of greenhouse gases, primarily carbon dioxide ("CO_2"). By evaluating a range of future CO_2 emissions restrictions as a cost per ton of emissions, the impact of any such future regulation can be evaluated in the scenario results. Since there have been, and currently are, multiple legislative and regulatory approaches for greenhouse gas emissions being considered at the federal level, the price-based scenario evaluation is a robust method to evaluate a wide range of potential regulatory outcomes.

Second, the impacts of pending and future environmental rules are considered and the anticipated costs of compliance are included in the URS just as with MATS. As previously discussed, these rules include the 316(b) rule, the CCR rule, and the steam effluent guidelines rule. These rules are currently being promulgated by EPA, and the Company has included the anticipated impacts of these rules in its analysis based on known stringency, timing, and the projected costs to comply.

Q. FOR WHICH UNITS DOES THE COMPANY REQUEST DECERTIFICATION?

A. As shown in Table 2, the Company is requesting decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3 and Plant Bowen Unit 6 (collectively, the "Retirement Units") for a total of 2,093 MW of generating capacity.

TABLE 2	
Requested Decertifications and Applicable Dates	
Plant Branch Units 3 and 4	By the MATS compliance date of April 16, 2015
Plant Yates Units 1-5	By the MATS compliance date of April 16, 2015
Plant McManus Units 1 and 2	By the MATS compliance date of April 16, 2015
Plant Kraft Units 1-4	1 year past the MATS compliance date (by April 16, 2016)
Plant Boulevard Units 2 and 3	Date of the final order in this proceeding
Plant Bowen Unit 6	By April 16, 2013

Q. PLEASE DESCRIBE THE EVALUATION PROCESS THAT LED TO THE COMPANY'S DECERTIFICATION REQUESTS.

A. The Company explored all feasible compliance options for its generating units in its attempt to identify optimal compliance solutions across its fleet. From plant to plant, and in some cases from unit to unit, a unique set of compliance options are feasible based on factors such as the unit's design, operating characteristics, and existing environmental controls, and the Company has thoroughly vetted numerous potential scenarios. And though the MATS rule and other existing and pending environmental regulations are the key drivers, the current forecasts of natural gas prices and the recent economic downturn and resulting loss of load have also had a negative impact on the economics of the Retirement Units.

The Retirement Units have a long and distinguished history of service to Georgia Power customers, and the Company is mindful of the impact that plant retirements can have on the communities in which the plants are located. Nevertheless, based primarily on the results of the URS, the Company believes that it is in the best interest of customers that these particular units be retired.

Q. PLEASE EXPLAIN THE METHODOLOGY USED IN THE COMPANY'S 2013 UNIT RETIREMENT STUDY.

A. At the most basic level, the URS compares the projected value of the continued operation of a particular unit to the value of replacement generation over a 30 year period. The value of a coal/oil unit is determined by analyzing the energy and capacity benefits of continued operation in light of the fixed and variable costs associated with investing in the unit to meet compliance requirements. The value of replacement generation is determined by analyzing the energy and capacity benefits related to the fixed and variable costs associated with adding the replacement generation to the system. The values of both options are then compared to determine which results in the greater net benefit for customers.

Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED DECERTIFICATION OF PLANT BRANCH UNITS 3 AND 4.

A. Plant Branch Units 3 and 4 are two coal-fired units with a total capacity of 509 MW and 507 MW, respectively, which were placed in service in 1968 and 1969, respectively. As a result of MATS and the Georgia Multipollutant Rule, continued operation of Plant Branch Units 3 and 4 would require major capital investment to achieve compliance, and economic analysis shows that it would not be beneficial for customers. Therefore, the Company requests decertification of these units. To put the magnitude of these costs into perspective, the total combined cost of MATS compliance for all the units the Company plans to control or fuel switch is roughly equal to the cost of bringing Plant Branch Units 3 and 4 alone into compliance with both MATS and the Georgia Multipollutant Rule. The Company requests that the timing of the retirements of Plant Branch Units 3 and 4 coincide with the applicable MATS compliance deadline for these units of April 16, 2015.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO THE PREVIOUSLY APPROVED DECERTIFICATION DATE FOR PLANT BRANCH UNITS 1?

A. The Company requests that the Commission amend its final order in Docket No. 34218 to extend the decertification date of Unit 1 from December 31, 2013 to April 16, 2015.

Q. WHY IS THE COMPANY REQUESTING THIS AMENDMENT?

A. Once it was determined that decertification of Plant Branch Units 3 and 4 was in the best interest of customers, the Company also determined that maintaining Plant Branch Unit 1 in its current state was the most economic choice for providing needed startup steam to Units 3 and 4. Therefore, this adjustment in the decertification date of Plant Branch Unit 1 is necessary to ensure an economic and reliable method for the startup of Plant Branch Units 3 and 4 until their retirement in 2015. As a result, the compliance deadline in the Georgia Multipollutant Rule for Branch 1 must be amended, and the Georgia Environmental Protection Division ("EPD") has recently proposed to align the Multipollutant Rule deadlines for Branch 1, 3, and 4 with the MATS compliance deadline of April 16, 2015.

Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED DECERTIFICATION OF PLANT MCMANUS UNITS 1 AND 2.

A. Plant McManus Units 1 and 2 are oil-fired steam units that went in service in 1952 and 1959, respectively, and have 43 MW and 79 MW of generating capacity, respectively. Economic analysis shows that investing in these units for continued operation would not be beneficial for customers. As oil-fired units, little to no energy benefit is realized, and given the recent economic downturn, the value of capacity has decreased. In addition, the MATS rule contains requirements which limit an oil-fired plant's capacity factor, thus further limiting the value of Plant McManus. The Company requests that the Commission approve retirement of the units by the MATS compliance deadline of April 16, 2015.

Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED DECERTIFICATION OF PLANT KRAFT UNITS 1-4.

A. Plant Kraft Units 1-4 are a combination of coal and oil-fired units with natural gas backup that were placed in service at various times between 1958 and 1971 and have a total generating capacity of 316 MW. As initially described in Docket No. 34218, fuel switching to natural gas was shown as the most economic option for continued operation of Plant Kraft Units 1-4, but the Company subsequently determined that it was not feasible to obtain the supply of natural gas that would be needed to allow the units to operate on natural gas. Because neither controlling nor converting the units was a viable option, operation on oil remained as the only option for continued operation. However, similar to Plant McManus, as oil-fired units, Plant Kraft Units 1-4 provide little or no energy benefit, and given the recent economic downturn, the value of capacity has decreased. In addition, the MATS rule contains requirements which limit an oil-fired plant's capacity factor, thus further limiting the value of Plant Kraft operating on oil. Therefore, the Company requests that the Commission approve retirement of the units one year past the MATS compliance deadline of April 16, 2016. The additional year is necessary to ensure needed transmission improvements are completed prior to the retirement of the units.

Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED DECERTIFICATION OF PLANT YATES UNITS 1-5.

A. Plant Yates Units 1-5 are coal-fired generating units that were placed into service at various times between 1950 and 1958 and have 579 MW of total generating capacity. Given the cost to bring these units into compliance with MATS, economic analysis shows that investing in these units for continued operation would not be beneficial for customers. The Company requests that the Commission approve retirement of the units by the MATS compliance deadline of April 16, 2015.

Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED DECERTIFICATION OF PLANT BOULEVARD UNITS 2 AND 3.

A. Plant Boulevard Units 2 and 3 are two oil-fired combustion turbines rated at a capacity of 14 MW each and were installed in 1970 along with Unit 1. Units 2 and 3 have recently experienced significant equipment failures. Based on the cost of repair, the age of the units, and the potential for additional failure, the Company's economic analysis demonstrates that the repairs are not in customers' best interest. The Company requests decertification of the units effective as of the date of the final order in this proceeding.

Q. PLEASE EXPLAIN WHY THE COMPANY HAS REQUESTED DECERTIFICATION OF PLANT BOWEN UNIT 6.

A. Plant Bowen Unit 6 is a 32 MW oil-fired CT that can only operate during the non-summer months due to ozone nonattainment requirements in the area. An evaluation determined that it is uneconomic to continue operating this unit. To help facilitate baghouse construction occurring at Plant Bowen Units 3 and 4, the Company determined that it is most optimal for this unit to be removed no later than June 1, 2013. The Company requests expedited decertification of the unit by April 16, 2013.

Q. PLEASE EXPLAIN WHY THE COMPANY IS REQUESTING EXPEDITED APPROVAL OF THE DECERTIFICATION OF PLANT BOWEN UNIT 6.

A. While evaluating the cost-effectiveness of the unit, the Company proactively sought sale opportunities for the generator and was able to reach an agreement to sell the unit (which sale is contingent on Commission approval of decertification) that is in the best interest of customers. The Company requests that the Commission grant this decertification by April 16, 2013 to take advantage of the sale agreement. Expedited Commission approval of the decertification of the unit will allow the buyer sufficient time to remove the unit before June 1, 2013, and help facilitate construction of the baghouses for Plant Bowen Units 3 and 4 given certain logistical constraints of the site.

Q. WHAT IMPACT WILL THE DECERTIFICATION OF CERTAIN OF THE RETIREMENT UNITS HAVE UPON THE AMOUNT OF WHOLESALE BLOCK CAPACITY CERTIFIED BY THE COMMISSION?

A. The decertification and retirement of Plant Branch Units 3 and 4 and Plant Yates 1-5, which make up a portion of the wholesale block capacity certified by the Commission, will reduce Block 1 and Blocks 2-4 accordingly, while the requested amendment to the decertification date for Plant Branch Unit 1 will delay the impact of the retirement of Plant Branch Unit 1 on Blocks 2-4.

Block 1 and Blocks 2-4 were certified by the Commission on March 26, 2012 in Docket No. 26550. Block 1 is comprised of 250 MW of coal-fired capacity that will become available to retail on April 1, 2016 and Blocks 2-4 is comprised of 312 MW of coal-fired capacity that will become available to retail on January 1, 2015. The Commission previously approved the decertification and retirement of Plant Branch Units 1 and 2, which reduced the capacity of Block 1 and Blocks 2-4 by 21 MW and 46 MW, respectively. If the Commission approves decertification of Plant Branch Units 3 and 4, the capacity of Block 1 will be further reduced by approximately 187 MW and if the Commission approves the decertification of Plant Yates 1-5, Blocks 2-4 will be further reduced by 57 MW.

Q. WHAT EFFECT DID THE COMMISSION'S PREVIOUS DECERTIFICATION OF PLANT MITCHELL UNIT 4C HAVE UPON THE BLOCKS 5 AND 6 CAPACITY PREVIOUSLY CERTIFIED BY THE COMMISSION?

A. On March 5, 2010, the Commission certified Blocks 5 and 6, consisting of 178 MW of oil-fired peaking capacity. Portions of the Blocks 5 and 6 capacity will become available to retail at different times as the existing wholesale contracts expire, with the total capacity in retail rate base on January 1, 2016. With the retirement of Plant Mitchell Unit 4C in March 2012, the capacity was reduced to 170 MW. However, the Commission specified in its order accepting Blocks 5 and 6 that the Company should market this capacity in the wholesale market for years 2011 through 2015, and the Company has been diligently seeking opportunities to remarket this capacity as requested by the Commission.

Q. HAS THE COMPANY BEEN EXPLORING ADDITIONAL OPPORTUNITIES TO MARKET CAPACITY CURRENTLY SERVING THE RETAIL JURISDICTION IN ADDITION TO WHAT THE COMMISSION APPROVED IN ITS ORDER ACCEPTING BLOCKS 5 AND 6?

A. In addition to block sales, the Company is also considering additional remarketing opportunities, including long-term requirements service agreements. Requirements service 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 the Company's load resources for planning as well as generation commitment and dispatch, thereby resulting in greater economies of scale. Our retail customers would benefit from these agreements through joint planning of generation and transmission capacity, as well as economies of scale resulting in capacity and energy savings. The Company will continue to look for such arrangements and will keep the Commission informed of any such opportunities.

Q. PLEASE DESCRIBE HOW RENEWABLE RESOURCES FIT INTO THE COMPANY'S 2013 IRP.

A. Georgia Power continues to pursue opportunities to cultivate renewable generation in Georgia in a responsible manner. As a result of the collaborative efforts of Georgia Power, the Commission, and the renewable energy community, there currently are 11.6 MW of solar generation (with another 50 MW under contract to commence service in the future), 142 MW of biomass generation including landfill methane gas, and 1,088 MW of hydro generation serving customers. Combined, these resources provide enough electric capacity to power the peak needs of more than 257,000 homes. With the introduction of the GPASI, the total amount of solar energy under contract by Georgia Power is expected to be more than 270 MW by the end of 2014. In addition to procuring cost-effective renewable resources, Georgia Power also supports research and demonstration of renewable and emerging technologies. In all of these efforts, the Company seeks to responsibly expand the fuel diversity of our supply mix through our commitment to renewable generation. Notably, Georgia Power is one of the national leaders among utilities operating in states in which there is no mandate for solar procurement.

Q. PLEASE DESCRIBE IN MORE DETAIL THE COLLABORATIVE STEPS RECENTLY TAKEN BY THE COMPANY, THE COMMISSION AND THE SOLAR ENERGY COMMUNITY TO ENCOURAGE THE DEVELOPMENT OF NEW SOLAR RESOURCES IN GEORGIA?

A. On June 7, 2011, the Commission requested that Georgia Power and Commission Staff develop options for expanding large-scale solar projects. In response to the Commission's request, the Company developed the 2015 LSS proposal. The Commission approved the Company's LSS proposal on July 22, 2011 in Docket No. 34229 and ordered the Company to file the LSS program's procedural details within 30 days. Under the LSS proposal, the Company purchased a total of 50 MW of solar capacity. This purchase was in addition to the Company's current solar procurement activities and will add to the generation procured through the 2015 RFP. 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.

On September 26, 2012, Georgia Power filed the GPASI in Docket No. 36325. This initiative complements other ongoing efforts to pursue cost-effective renewable resources and was designed to maximize opportunities for solar development by encouraging wider participation. The resources procured under the GPASI will be in addition to the solar resources the Company currently procures through the Commission-approved Green Energy contract, Solar Procurement and Renewable and Non-Renewable Resources tariff, the LSS program, and other Qualifying Facility ("QF") purchases.

Q. WHAT IS THE STATUS OF SOLAR PHOTOVOLTAIC DEMONSTRATION PROJECTS CURRENTLY UNDERWAY AT SOUTHERN COMPANY FACILITIES?

A. There are three solar demonstrations underway at Southern Company facilities. The first is located on the roof of the Georgia Power headquarters building in Atlanta, Georgia. The objective of this pilot-scale demonstration is to compare the performance and reliability of seven different commercially available photovoltaic ("PV") technologies. A second solar demonstration project, conducted by Southern Company Research & Environmental Affairs, is located on the rooftop of the Alabama Power headquarters building in Birmingham, Alabama. The objective of this pilot-scale demonstration is to gain system-wide experience with micro-inverters being used on different commercially available solar technologies and to compare different module technologies, similar to the Georgia Power demonstration project. The third solar demonstration project, also conducted by Southern Company Research & Environmental Affairs, is located at an Alabama Power facility in Mobile, Alabama. This project continues the work of the previous two projects but will focus on the specific effect of coastal weather on solar output.

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 has evaluated several potential solar projects, including high profile sites at customer locations as well as installations at or on Company-owned facilities. The Company will continue to seek optimal locations to install this portfolio of projects totaling 1 MW and gain valuable experience in installing, owning and operating solar PV projects.

Q. IS THE COMPANY PROPOSING ANY REVISIONS TO THE COMPANY'S SELF-BUILD SOLAR PV DEMONSTRATION PROJECT?

A. Yes. The Company seeks to revise the solar demonstration project at the Georgia Power headquarters building into a second phase once the final results of the initial solar demonstration are complete. The Company wishes to expand the demonstration project as a test bed for commercially viable solar technologies. Upon completion of the initial phase, as outlined above, the Company intends to update the existing solar systems on the roof of the Georgia Power headquarters building to reflect the most recent and emerging solar technologies. The research goals of the demonstration project would remain the same through evaluation of environmental impacts such as sunlight hours, temperature and humidity. In addition, the Company seeks to implement a battery storage demonstration project as a complement to the existing Georgia Power headquarters building solar demonstration. A battery storage system could be installed on one or more of the 4 kilowatt (" kW") solar modules to help evaluate the benefits and costs of battery storage. The Company expects the cost of modifying the Georgia Power headquarters building solar demonstration to add both the battery storage evaluation and the newest commercially viable technologies would not exceed $200,000.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED WIND DEMONSTRATION PILOT PROJECT.

A. Georgia Power and Southern Company are evaluating a potential project to compare and evaluate several different small to medium (20-100kW) wind turbine technologies. Between four and six small wind turbines, of both horizontal and vertical axis designs, would be installed in the Georgia Power service territory. The intent of the demonstration would be to understand the feasibility of small scale wind generation as well as evaluating wind resources in various geographic areas of the state. These efforts are in addition to the Company's continuing evaluation of utility scale off-shore wind installations. The Company expects the cost of the Small Wind Demonstration Pilot Project not to exceed $9,000 per kW installed.

Q. PLEASE DESCRIBE THE STATUS OF THE COMPANY'S PROCUREMENT FROM QFs.

A. The Company continues to purchase capacity and energy under the QF proxy contract methodology in conjunction with the Company's RFPs. Three proxy contracts with QFs that noticed into the 2015 RFP have been executed and approved to date in 2013, for a total of 81 MW. The Company continues to negotiate with other QFs that noticed into the 2015 RFP and will file any executed contracts for Commission approval this year. The Company has 24 standard QF contracts currently in place at the avoided cost rate and continues to contract with QFs as applicable pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA").

Q. WHAT IS THE STATUS OF THE CONVERSION OF PLANT MITCHELL UNIT 3?

A. The Company continues to evaluate the economic benefit to customers of the Plant Mitchell Unit 3 biomass conversion. A decision concerning the conversion of Plant Mitchell Unit 3 is being deferred at this time. The Company is currently conducting a thorough evaluation of the impacts of the final EPA Industrial Boiler Maximum Achievable Control Technology ("IB MACT") standard and the revised National Ambient Air Quality Standard for fine particular matter (PM 2.5), both of which were released in December. Additionally, the Company recently completed a study on the feasibility of using Direct Injection ("DI") technology for the Mitchell project. The study estimates the required equipment modification, performance, emissions, and cost associated with using DI for the project. The Company shared the results of the study with the Commission Staff in January 2013. In this 2013 IRP, Plant Mitchell Unit 3 is currently assumed to be unavailable in 2015 and 2016 and then available as a biomass generating unit in 2017.

III. DEMAND-SIDE PLAN

Q. WHAT IS GEORGIA POWER'S PROPOSED DEMAND-SIDE PLAN?

A. The recommended DSM action plan includes seeking Commission approval for a certificate for one new DSM program, certification amendment for three currently certified DSM programs, decertification of one DSM program (though the program activities will be subsumed by an existing program) and updated program economics for the remaining certified DSM programs in the Company's 2013 DSM Application. The Company also intends to continue the Power Credit residential program, which was previously certified in Docket No. 6315 and reauthorized by the Commission in Docket No. 13305.

In accordance with the final order in the 2010 IRP, the Company has continued to work closely with the DSMWG through the use of the Nine Step process 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.

However, the Company notes that the current lower avoided cost savings have had a significant and negative impact on the economics of the Company's current and proposed DSM programs. Total Resource Cost ("TRC") Test results declined and Ratepayer Impact Measure ("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 on all customers within a given class caused by the programs. For a variety of reasons, including a desire to minimize market disruption, to continue meeting customers' expectations, and to maintain positive relationships with vendors performing qualified program improvements, the Company supports continuation of the energy efficiency programs approved in the 2010 DSM Certification filing and also seeks to certify a Small Business program targeted toward a hard to reach customer sector. The Company plans to continue to monitor program costs and economics during 2014 - 2016 and will be prepared to modify or discontinue programs in the future if the significant upward pressure on rates continues.

Summary information for two alternative DSM sensitivity cases is also included in the filing. One alternative sensitivity case, deemed the "Advocacy Sensitivity Case," presents a potential set of DSM programs designed around the recommendations from some members of the DSMWG to achieve 10 year cumulative energy savings of 9.5 percent. The other alternative sensitivity case represents the "Aggressive Sensitivity Case" that was outlined in the Nine Step process. The Company does not recommend approval of either of these sensitivity cases.

Q. HOW WERE NEW DSM MEASURES EVALUATED IN THE 2013 IRP?

A. The Company continues to follow the Commission's economic screening policy outlined in the 2004 IRP Final Order, Docket No. 17687, which directs that the proposed DSM plans minimize upward pressure on rates and maximize 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 proposed DSM plan energy and demand impacts prior to developing any supply-side alternatives. Also, dispatchable DSM resources are included with supply-side resources prior to evaluating the need for future supply-side resources. The Company conducted the cost/benefit analysis results of each initiative using the Participant Test ("PT"), RIM Test, and TRC Test.

Q. WHAT IMPACT WILL DSM PROGRAMS HAVE UPON THE COMPANY'S DEMAND FORECAST?

A. The Company projects that by 2016, these programs will reduce peak demand by approximately 2,000 MW. This load reduction represents more than 12 percent of the Company's current peak demand.

Q. PLEASE DESCRIBE THE COMPANY'S PLAN FOR OFFERING NEW PRICING OPTIONS FOR CUSTOMERS.

A. 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 our Real Time Pricing program, Demand Plus Energy Credit and Time of Use ("TOU") rates) have been effective in reducing the peak demand for electricity.

Georgia Power completed installation of the Advanced Metering Infrastructure ("AMI") "smart" meters in 2012. The Company leverages the AMI investment by promoting rates that send strong, clear pricing signals such as the Time of Use-Residential Energy Only and Time of Use Plug-in Electric Vehicle ("TOU-PEV") rates. 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") rider. TOU-FCR was made permanent and expanded in 2012, and is now 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") pilot rate was introduced in 2012. The TOU-FCR-TP pilot rate is available to customers on the TOU-PEV and Time of Use-Medium Business rates. TOU-FCR rates will further strengthen price signals seen by customers on time of use rates.

IV. <u>FORECASTING</u>

Q. PLEASE SUMMARIZE GEORGIA POWER'S DEMAND AND ENERGY FORECASTS THAT WERE FILED IN THE 2013 IRP.

A. The nation's recovery from the Great Recession has been full of promise that, for the most part, has not yet materialized. Georgia's economic recovery has been similar, but with a lag and, by some measures, weaker than the nation's. Although 2013 is expected to be another year of moderate growth, 2014 and 2015 are expected to be significantly stronger before the economy settles down to its long-term growth rate.

Much like the nation overall, Georgia's economy is expected to regain strength over the next several years. Surveys show that the state remains an attractive place to do business. Living costs also remain attractive relative to many states. The demographic forces that once propelled the state to near the top of the economic growth league will continue to strengthen as ongoing home price adjustments break the housing logjam that nearly halted net migration during the recession. As the economy improves, energy sales will follow suit. A detailed discussion of the revised territorial energy and demand forecasts is set forth in Technical Appendix Volume 2 of the 2013 IRP.

V. RESERVE MARGIN

Q. DOES GEORGIA POWER'S 2013 IRP PROVIDE SUFFICIENT RELIABILITY FOR GEORGIA POWER'S CUSTOMERS?

A. Yes. After an analysis of load forecast and weather uncertainty, the cost of Expected Unserved Energy ("EUE"), as well as the current and near-term projected generation reliability of the Southern Electric System, the Company will continue to maintain its long-term planning target reserve margin at 15 percent. These planning reserves are needed to protect against any shortfall in capacity due to unforeseen future events, such as greater than expected load growth, generation unit forced outages, or unusual weather. These reserve margins are based on balancing the cost of adding new generation to maintain an acceptable level of reliability versus the weighted average of the outage cost to the various customer classes.

Q. DID THE COMPANY CONDUCT AN EXPECTED UNSERVED ENERGY STUDY FOR THE 2013 IRP?

A. An outage cost survey of Georgia Power and Mississippi Power customers was completed in 2011 by Freeman Sullivan & Company in accordance with the Commission's final order in the 2010 IRP. The cost to non-residential customer classes of EUE from this survey is substantially higher than in previous studies. Since EUE is so infrequent, even at lower reserve margins, this change only slightly increased the reserve margin for the minimum cost point. For results of the study, see the EUE Study in Technical Appendix Volume 1.

Q. WHAT RESERVE MARGIN DOES THE 2013 IRP MAINTAIN FOR GEORGIA POWER'S CUSTOMERS?

A. For the short-term horizon, the Company will maintain a 13.5% system planning reserve margin guideline, but may periodically review the availability and cost of resources in the market and adjust short-term resource procurement decisions accordingly. For the long-term, the Company will maintain a reserve margin target of 15%.

VI. TRANSMISSION

Q. PLEASE DESCRIBE GEORGIA POWER'S TRANSMISSION PLAN FILED IN THE 2013 IRP.

A. This IRP includes the Company's ten-year transmission plan, which identifies the transmission improvements needed (based upon current planning assumptions) to maintain a strong and reliable transmission system. The development of this plan is conducted in accordance with the Southern Company System transmission planning guidelines and with the North American Electric Reliability Council planning standards. Along with the ten-year plan, Georgia Power has included a comprehensive and detailed bulk transmission plan of the Georgia Integrated Transmission System, as required by the amended rules adopted by the Commission in Docket No. 25981. Additional transmission information has also been provided as required by the Commission order in Docket No. 31081.

VII. COST RECOVERY

Q. WHAT ARE THE COSTS THE COMPANY SEEKS TO RECOVER IN CONNECTION WITH THE RETIREMENT UNITS?

A. The costs associated with the Retirement Units include: (1) the net book value ("NBV") of the Retirement Units that will remain at the proposed retirement dates (including Plant Bowen Unit 6 if the Commission does not grant expedited decertification); (2) Construction Work in Progress ("CWIP") balances directly attributable to environmental controls that will now no longer be completed; (3) any remaining Materials & Supplies ("M&S") inventory that cannot be sold or used at another generating plant; and (4) any costs that represent recoverable fuel costs under the Company's FCR tariffs incurred in connection with the termination of any fuel transportation contracts associated with the Retirement Units.

Q. PLEASE DESCRIBE THE ACCOUNTING TREATMENT BEING REQUESTED BY THE COMPANY TO RECOVER THE NBV OF PLANT BRANCH UNITS 3 AND 4 AND PLANT BOULEVARD UNITS 2 AND 3 THAT WILL REMAIN ON THE PROPOSED RETIREMENT DATES.

A. The Company proposes to reclassify the NBV remaining on the proposed retirement dates of the units to a regulatory asset account. The regulatory asset would be amortized ratably over a period equal to the respective unit's remaining useful life as approved by the Commission in Docket No. 31958. This is consistent with the accounting treatment approved by the Commission in Docket No. 34218 in connection with the retirement of Plant Branch Units 1 and 2 and Plant Mitchell Unit 4C.

Q. PLEASE DESCRIBE THE ACCOUNTING TREATMENT BEING REQUESTED BY THE COMPANY TO RECOVER THE NBV OF PLANT BOWEN UNIT 6 THAT WILL REMAIN ON THE PROPOSED RETIREMENT DATE IF THE COMMISSION DOES NOT APPROVE EXPEDITED DECERTIFICATION OF THE UNIT.

A. If the Commission does not approve expedited decertification of Plant Bowen Unit 6, the Company proposes to reclassify the NBV remaining on the proposed retirement date of the unit to a regulatory asset account, just as with Plant Branch Units 3 and 4 and Plant Boulevard Units 2 and 3. The regulatory asset would be amortized ratably over a period equal to the respective unit's remaining useful life as approved by the Commission in Docket No. 31958.

Q. PLEASE DESCRIBE THE ACCOUNTING TREATMENT BEING REQUESTED BY THE COMPANY TO RECOVER THE CWIP BALANCES ASSOCIATED WITH ENVIRONMENTAL CONTROLS FOR PLANT BRANCH UNITS 3 AND 4 AND PLANT YATES UNITS 6 AND 7.

A. The Company has $38 million and $14 million of CWIP attributable to environmental controls at Plant Branch Units 3 and 4 and Plant Yates Units 6 and 7, respectively, that have been reclassified to regulatory asset accounts in accordance with the Commission's Order in Docket No. 31958. The Company proposes to amortize the $38 million and $14 million balances ratably over three years beginning January 2014.

Q. PLEASE DESCRIBE THE ACCOUNTING TREATMENT BEING REQUESTED BY THE COMPANY TO RECOVER THE REMAINING M&S INVENTORY BALANCES ASSOCIATED WITH THE RETIREMENT UNITS.

A. The Company proposes to reclassify the balances associated with any remaining, unusable M&S inventory to a regulatory asset account by the respective retirement dates for each Retirement Unit, in accordance with the Commission's Order in Docket No. 31958. The Company proposes to amortize the regulatory asset balance for recovery over a period to be determined by the Commission in the Company's next base rate case following the unit retirements.

The Company will make every effort to manage M&S inventory balances, while maintaining an adequate level to ensure the units continue to operate up to their proposed retirement dates. While the Company will take appropriate steps to find uses for existing inventory, including the sale of such inventory, it is reasonable to expect there will be some inventory that cannot be used at other Georgia Power generating plants.

Q. PLEASE DESCRIBE THE ACCOUNTING TREATMENT BEING REQUESTED BY THE COMPANY TO RECOVER ANY FUEL RELATED COSTS ASSOCIATED WITH THE RETIREMENT UNITS.

A. The Company proposes to record any costs that represent recoverable fuel costs under the Company's FCR tariffs incurred in connection with the termination of any fuel transportation contracts associated with the Retirement Units as incurred. All such costs, along with the associated carrying costs, would be deferred until the Company's next fuel rate case following the conclusion of this IRP for recovery through the FCR tariffs over a period to be determined by the Commission. Furthermore, such fuel expenses would be excluded from the calculation of under- or over-recovered fuel expense for the purpose of the interim fuel rider adjustment mechanism. The Company shall use good faith efforts to look for opportunities to reduce such costs that would otherwise remain upon the unit retirement dates. This proposed treatment is consistent with the accounting treatment approved by the Commission in Docket No. 24506 in connection with the extension of the commercial operation dates of the Plant McDonough-Atkinson combined cycle generating units.

Q. HOW WILL THE ACCOUNTING TREATMENT BEING PROPOSED BY THE COMPANY IN CONNECTION WITH THE DECERTIFICATION AND RETIREMENT OF THE RETIREMENT UNITS IMPACT CUSTOMERS?

A. The Company has proposed to recover the remaining costs of the units being retired in a manner that significantly limits any impact on customer rates. The most significant costs resulting from the decision to retire these units—the remaining net book values—will be amortized at the same rate the Commission approved in Docket No. 31958, and thus, will have no incremental impact on current rates. The three year amortization period proposed for the relatively small balances related to CWIP and the amortization period established by the Commission for the M&S inventory is expected to result in limited customer rate impact. Likewise, any fuel or fuel transportation costs recovered through the FCR tariff would be amortized over a period approved by the Commission and would not be expected to have a significant incremental impact since the current costs of such contracts are already included in rates.

VIII. CONCLUSION

Q. WHAT IS GEORGIA POWER REQUESTING OF THE COMMISSION IN THE 2013 IRP?

A. The Company seeks approval of:

1) Its 2013 Integrated Resource Plan and the associated Action Plan;

2) Decertification of Plant Branch Units 3 and 4, Plant Yates Units 1-5, and Plant McManus Units 1 and 2 effective by the MATS compliance date of April 16, 2015, decertification of Plant Kraft Units 1-4 one year past the MATS compliance date (by April 16, 2016), decertification of Plant Boulevard Units 2 and 3 effective as of the date of the final order in this

proceeding, and approval of expedited decertification of Plant Bowen Unit 6 by April 16, 2013 as specified in the 2013 Decertification Application;

3) A switch to natural gas as the primary fuel for Plant Yates Units 6 and 7 and Plant Gaston Units 1-4;

4) An amendment of the decertification date specified in the Commission's final order in Docket No. 34218 for Plant Branch Unit 1 from December 31, 2013 to coincide with the decertification of Plant Branch Units 3 and 4;

5) A certificate of public convenience and necessity for one new DSM program, a certificate amendment for three previously certified programs, decertification of one DSM program, and approval of updated program economics and budgets for all other previously certified energy efficiency DSM programs and other DSM activities as further specified in the 2013 DSM Application in Docket No. 36499;

6) Reclassification of the remaining net book values of Plant Branch Units 3 and 4 and Plant Boulevard Units 2 and 3 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective unit's remaining useful life approved in Docket No. 31958;

7) In the event the Commission does not approve the expedited decertification of Plant Bowen Unit 6, reclassification of the remaining net book value of Plant Bowen Unit 6 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 unit's remaining useful life approved in Docket No. 31958;

8) Amortization of approximately $38 million of Plant Branch Units 3 and 4 and approximately $14 million of Plant Yates Units 6 and 7 environmental CWIP (which has been reclassified as a regulatory asset in

accordance with the Commission's Order in Docket No. 31958) ratably over a three year period beginning January 2014;

9) 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. 31958 for recovery over a period to be determined by the Commission in the Company's next base rate case following the unit retirements;

10) Recovery of any costs that represent recoverable fuel costs under the Company's FCR tariffs incurred in connection with the termination of any fuel transportation contracts associated with the Retirement Units over a period to be determined by the Commission in the Company's first fuel case following the conclusion of this IRP;

11) 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; and

12) 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.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.