BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In 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
	)	
	)	
Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Management Plan	)	Docket No. 40162

FINAL BRIEF OF
GEORGIA POWER COMPANY

June 29, 2016

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In 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
Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Management Plan	)	Docket No. 40162

A RIEF
POWER COMPANY

The matters presently pending before the Georgia Public Service Commission (the "Commission") are Georgia Power Company's ("Georgia Power" or the "Company") 2016 Integrated Resource Plan ("IRP") and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT ("Decertification Application") in Docket No. 40161 and its Application for the Certification, Decertification, and Amended Demand Side Management Plan in Docket No. 40162 ("DSM Application").

I. SUMMARY OF THE ARGUMENT

In light of the significant uncertainty facing the Company, it is more important than ever that the Company take measured, proactive action to ensure that it will be in a position to continue to provide safe, reliable and cost-effective electric service to customers in any future scenario. The Company's IRP provides a clear roadmap into the energy future and, as modified by the Stipulation, should be adopted by the Commission. The Stipulation resolves nearly all of the contested issues between the Company and the Commission

Public Interest Advocacy Staff ("PIA Staff") (with the exception of one policy decision left for the Commission) and is a reasonable compromise that provides benefits to all customers, while taking into account many of the recommendations raised by intervenors in this proceeding.

The Company's IRP outlines a number of proactive steps that continue to build on the Company's track record of industry-leading foresight and leadership. The Renewable Energy Development Initiative ("REDI") is a significant commitment to new renewable generation development in Georgia. The Company's original proposal for 525 MW of renewable procurement was measured and based upon the Company's experience. The increase in the size of REDI to 1,200 MW provided for in the Stipulation is not without risk, but the Stipulation is significantly more measured in this respect than the alternative levels of procurement advocated for in this proceeding by some intervenors. And yet, in procuring 1,200 MW of renewable generation through REDI—which will be the largest active renewable solicitation in the country and the largest in recent history (the majority of which will have projected benefits for customers)—the Company and this Commission will solidify the reputation of the state of Georgia as a regional and national leader in renewable generation development.

Similarly, implementing the methodology detailed in the "Framework for Determining the Costs and Benefits of Solar Generation in Georgia" (such methodology, the "Framework") is a proactive step designed to ensure that all renewable resources are fairly evaluated through a comprehensive and detailed technical analysis so that the Company and its customers receive net benefits that are commensurate with the price being paid. It is especially important to approve the Framework in a timely manner to ensure it is in place when additional non-dispatchable, intermittent resources are added in the future. The

Company's increased target planning reserve margin also represents proactive action to adjust the Company's planning to account for actual operational changes observed on the system in order to provide customers with increased reliability.

Finally, the Company's request for authorization to take actions to preserve the option for timely deployment of nuclear generation similarly represents a proactive yet balanced approach to maintaining the diversity of the Company's generating fleet. By investing a relatively small amount today compared to the total cost of nuclear generation, the Company will be able to position itself to deploy nuclear in a timely manner in the future when it is needed. Proactive action today will provide flexibility for customers in the future.

To borrow from a common aphorism, an ounce of proactive action is worth a pound of reactive action. The Company's IRP, as modified by the Stipulation, positions the Company to respond to a myriad of economic, regulatory and operational uncertainties in the coming years and should be adopted by this Commission.

II. PROCEDURAL HISTORY AND BACKGROUND

On January 29, 2016, Georgia Power filed its application for approval of the IRP as required by O.C.G.A. § 46-3A-2 and, in conjunction with such filing, also filed its Decertification Application and DSM Application. On February 19, 2016, the Commission issued a Procedural and Scheduling Order ("Procedural Order" or "PSO"). Pursuant to this Procedural Order, on April 5, 2016, Georgia Power pre-filed the Panel Direct Testimony of Jeffrey A. Burleson, Alison R. Chiock, Larry T. Legg and Larry S. Monroe in Docket No. 40161 and the Direct Testimony of Larry T. Legg in Docket No. 40162. Georgia Power presented its direct case to the Commission in Docket Nos. 40161 and 40162 on April 18-20, 2016.

On May 3, 2016, Intervenor Clean Line Energy filed the Testimony of David Berry in Docket Nos. 40161 and 40162; Intervenor Commercial Group filed the Testimony of Steve W. Chriss in Docket No. 40161 and Kenneth Baker in Docket No. 40162; Intervenors Georgia Interfaith Power & Light and SouthFace Energy Institute, Inc. filed the Testimony of R. Thomas Beach in Docket No. 40161, the Testimony of the panel of Dana Bartolomei and Raymond Kuniansky and the Testimony of William M. Cox, PhD in Docket Nos. 40161 and 40162. Also on May 3, 2016, Intervenor Georgia Large Scale Solar Association filed the Testimony of the panel of Colin Meehan, Brian O'Hara, Ryan Sanders and Robert Rynar in Docket Nos. 40161 and 40162; Intervenors Georgia Solar Energy Industries Association ("GSEIA") and Vote Solar filed the Testimony of the panel of James B. Marlow and Mark C. Bell in Docket Nos. 40161 and 40162; Intervenor Southern Alliance for Clean Energy filed the Testimony of John D. Wilson in Docket No. 40161 and Taylor Allred in Docket Nos. 40161 and 40162; Intervenor Sierra Club filed the Testimony of Jeremy I. Fisher, PhD, and the Testimony of Tim Woolf in Docket Nos. 40161 and 40162; and Intervenor Southern Wind Energy Association filed the Testimony of Michael S. Goggin in Docket Nos. 40161 and 40162.

On May 6, 2016, PIA Staff pre-filed the Testimony of the panel of Tom J. Newsome and Philip M. Hayet, the Testimony of Brian D. Smith, the Testimony of the panel of Ralph C. Smith and Robert L. Trokey, the Testimony of Roxie McCullar, and the Testimony of the panel of Jamie Barber, Richard F. Spellman, Daniel Peaco and John L. Kaduk in Docket No. 40161 and the Testimony of the panel of Jamie Barber, Nick Cooper, and Richard F. Spellman in Docket No. 40162.

Hearings regarding the direct testimony of PIA Staff and Intervenors in Docket No. 40161 were held on May 17 and May 18, 2016. Hearings regarding the direct testimony of PIA Staff and Intervenors in Docket No. 40162 were held on May 18 and May 19, 2016.

On May 27, 2016 the Company pre-filed the Rebuttal Testimony of the panel of Jeffrey A. Burleson, Alison R. Chiock, Larry T. Legg, Michael A. Bush and Carl H. Haga, Jr. in Docket No. 40161 and the Rebuttal Testimony of Larry T. Legg in Docket No. 40162. A hearing regarding the Company's Rebuttal Testimony in both dockets was held on June 8 and June 9, 2016.

On June 21, 2016, the Commission amended the Procedural Order extending the deadlines for the parties to file their briefs to June 29, 2016. The amended Procedural and Scheduling Order also delayed the due dates for the date upon which PIA Staff will make its recommendations to the Commission as well as the date upon which the Commission will render a decision.

On June 23, 2016, the Company and PIA Staff entered into a stipulation ("Stipulation"), which is provided as Exhibit A to this brief.

III. ARGUMENT

A. <u>The Stipulation should be adopted by the Commission</u>.

The 2016 IRP contains Georgia Power's plans for meeting the forecasted needs of its customers in a safe, reliable and cost-effective manner through the deployment of a diverse set of supply- and demand-side resources, all in a manner consistent with the public interest. O.C.G.A. § 46-3A-1(7). The

Company performed detailed technical analyses of both demand- and supply-side capacity resources and identified the key assumptions regarding capacity resources and exhaustive supporting data and information. *Id.*; O.C.G.A. § 46-3A-2(b)(2); Commission Rule 515-3-4-.02(32).

On June 23, 2016, the Company and PIA Staff executed the Stipulation, which resolved nearly all of the contested issues in this proceeding between the Company and PIA Staff (with the exception of one policy issue left to the Commission). The Stipulation is a balanced compromise in which neither party received everything that it sought or recommended. Importantly, however, the Stipulation appropriately balances not only the positions of the Company and PIA Staff, but also the interests and recommendations of numerous parties to this proceeding, and strikes a reasonable balance on a myriad of complex, technical issues, all for the benefit of Georgia Power's customers. Under the terms of the Stipulation, the Company's IRP, Decertification Application and DSM Application would be accepted by the Commission as modified by the Stipulation. (Stipulation, Supply Side Para. 1).

Resolution of contested Commission proceedings through a stipulated agreement is a well-established practice. In fact, the Procedural Order specifically contemplates that PIA Staff "may negotiate settlements with other parties, in the public interest." (PSO at 2). The proceeding was not abridged in any respect by the Stipulation, as all intervenors had opportunity to cross examine Company and PIA Staff witnesses and offer testimony and file briefs and proposed orders setting forth their respective positions. Furthermore, the Company and PIA Staff have been available to dialogue with all intervenors concerning settlement potential throughout the proceeding and the Company did, in fact, engage with numerous intervenors concerning settlement positions. The

Stipulation considers that input and incorporates elements of recommendations made by the PIA Staff, the Company and intervenors in this case. Therefore, the record in the case supports the Stipulation, executed by PIA Staff and other intervenors. More importantly, the Stipulation is a well-reasoned and balanced resolution of this case that will provide significant benefits for Georgia Power's customers.

B. <u>REDI, as modified by the Stipulation, should be adopted by the Commission and reflects the continued commitment of Georgia Power and this Commission to responsible but aggressive growth of renewable generation.</u>

REDI, as modified by the Stipulation, will build upon the measured, market-based procurements previously implemented by the Company and this Commission and should be adopted. (Tr. 1863). This 1,200 MW procurement would be the largest currently active renewable solicitation in the United States and one of the largest in the recent past. REDI will leverage the success of the Company's existing Advanced Solar Initiatives in order to continue to responsibly grow the renewable generation market in Georgia and provide projected energy savings for all customers in the absence of a capacity need. (Tr. 1819).

1. The size of REDI agreed to in the Stipulation is a reasonable compromise.

The Stipulation specifies that 1,200 MW of renewable resources will be added through the REDI program over the next five years, comprised of 1,050 MW of utility scale and 150 MW of distributed generation ("DG") renewable resources. (Stipulation, Supply Side Para. 3). This level of procurement will ensure that the Company remains an industry leader in renewable generation. (*See* Tr. 1863). In fact, REDI will be the largest current renewable procurement in the United States. The Company estimates that the 1,200 MW represents nearly two billion dollars in investment in renewable energy and a 150% increase in the Company's current contracted renewable generation. The proposed 1,200 MW procurement strikes a fair balance in this proceeding and appropriately reflects the fact that the Company does not have a capacity need. (Tr. at 225-26). Continuing to employ an incremental approach will allow the Company to appropriately evaluate and take advantage of technology improvements, costs reductions, and state and federal incentives, and to manage integration benefits and challenges. (Tr. 1819).

2. Further increases in the size of REDI are not justified.

While the total amount of resources to be procured is larger than initially proposed by the Company, it is also significantly smaller than the amounts recommended by several intervenors. (Tr. 1522; 1570). It is important to note that under the Stipulation, the Company could potentially procure over 1,600 MW over the next 3 to 5 years. The procurement size for REDI, which is set at 1,200 MW in the Stipulation, continues the measured, incremental approach that has served customers well throughout the Company's prior procurements. Each time the Company has offered a renewable request for proposals ("RFP") to the market, the market has responded with lower, more attractive pricing for the benefit of Georgia Power's customers. (Tr. 2073). For instance, the Company obtained resources through the Large Scale Solar program at 13 cents, whereas average prices for the ASI and ASI-Prime programs were 8.5 cents and 6.5 cents, respectively. (*Id.*).

The Commission should reject certain intervenors' requests to dramatically expand the size of REDI beyond what the Company and PIA Staff agreed to in the Stipulation. (Tr. 1863). Such intervenor recommendations fail to consider the risks that customers assume when the Commission deviates from the success it has achieved through measured procurements. Given that the Company has no current forecasted capacity need for the years that REDI resources will come online, recklessly expanding the size of the REDI program generates additional and potentially significant cost risk for customers (as described in more detail below). (Tr. 1819; 2029).

a. Both in the context of REDI and other renewable procurement, long-term, fixed and levelized Power Purchase Agreements ("PPAs") prices create risk for customers absent a capacity need.

It is important to note that the benefits identified in the context of REDI (as well as other renewable procurements) are based on projections. Future differences between projected and actual costs could ultimately cause such benefits to be reduced or eliminated completely. (Tr. 1820-21). And while it is true that all resource decisions are necessarily based on projections, historically, the vast majority of the Company's resource decisions involve the evaluation of resources to meet an identified capacity need. In other words, the resources were needed to ensure reliability for customers and the amount of MW procured were based upon that express need.

In contrast, the Company's renewable resource procurements have been initiated not on the basis of meeting a capacity need but on the basis of projected energy benefits (though such resources have been assigned some capacity credit as well). (Tr. 1820). When a capacity need is identified, new capacity resources are required to ensure reliability; however, resources obtained primarily for energy benefits are not procured for the sole purpose of ensuring reliability for its customers. Therefore, caution should be exercised when the Company enters into long-term, fixed and levelized PPAs on the basis of projected energy benefits. In the absence of a forecasted capacity need, it is reasonable to procure select amounts of resources where the projected benefits are significant, but it is also reasonable to exercise caution to avoid placing unnecessary risk on customers.

b. The risk to customers is more significant when the Company is entering into fixed, long-term and levelized PPAs at the Company's projected avoided costs.

While the Company supports the procurement of 50 MW of customer-sited DG resources at prices based on the Company's projected avoided costs as specified in the Stipulation, it is important to recognize that such procurement does place risk on customers. Procurement of renewable resources at the Company's projected avoided cost results in essentially no projected benefits and, in fact, creates the potential for increasing the costs to customers. When resources are procured at projected avoided costs (as compared with below avoided costs), even a slight downward movement in future actual avoided costs (relative to the projections) would mean that the Company would actually be paying more for energy than would otherwise be the case. (Tr. 1820-21).

Moreover, in the case of a levelized payment stream, the risk is exacerbated in the early years. (Tr. 1828). Levelized pricing essentially over-pays early in the term and therefore creates greater risk of the Company and its customers not being made whole in the event of early termination or a change in operational profile. (*Id.*). As is discussed below, a market-based approach can mitigate this risk to the extent that such an approach results in PPA prices that are well below projected avoided costs. (Tr. 1863). A large spread between the market-based PPA price and the projected avoided costs provides a greater degree of certainty that such resources will provide actual benefits to all customers over the life of the PPA. (Tr. 1820-21; 1973).

c. The potential phase-out of available tax credits should not serve as a basis for further expansion or acceleration of REDI.

Several intervenors suggested that the Company should expand the REDI RFP to take advantage of investment tax credits ("ITC") and production tax credits ("PTC") and should adjust the timing of the RFP to more closely align with the currently expected phase out of the credits. (Tr. 1386-87; 1489-90; 1688-89).

The Company does not believe the potential tax credit phase out should serve as the predominant factor in determining the size of the Company's renewable programs. (Tr. 2097). The history of federal renewable tax incentives provides ample evidence that anticipated phase-outs and eliminations remain subject to change as dictated by a host of complex and often unpredictable political and regulatory drivers. (Tr. 1820). Therefore, it would be inappropriate for the Company's renewable procurement strategy to be driven by the exigency of the current market, including the potential expiration of particular tax credits. (Tr. 1820).

Nevertheless, the REDI program, as reflected in the Stipulation, creates the strong potential that customers will receive significant benefit from the tax credits through lower PPA pricing. In that regard, the increased level of procurement through REDI agreed to in the Stipulation already takes into account benefits that may be received through ITCs and PTCs under current law. However, the further increase in the procurement based solely on the tax incentives is not warranted, nor has it ever been the policy of the Commission to allow the federal government to dictate renewable procurement in Georgia by requiring that such procurement align with the frequently extended deadlines for ITCs and PTCs. Indeed, if such an approach to renewable procurement had been taken by the Commission in the past, customers would not be recognizing the benefits they do today from declining renewable technology cost and would be paying much more for renewable resources then they do now.

Additionally, the Company does not support accelerating the timing of the REDI RFPs in response to the currently scheduled ITC and PTC phase outs. Intervenors argued that if the Company aligned REDI with the timing of the PTC extension, the Company would be able to capture the full value of the ITC. (Tr. 1377-78, 1440). With respect to solar resources, the federal solar ITC was extended at the full 30% value for projects that start construction by December 31, 2019, and is reduced for 2020 and 2021 before permanently reducing the incentive to 10% for commercial projects and 0% for residential projects after that. (Tr. 1439). All projects participating in the first utility-scale REDI RFP or the DG RFP or customer-sited DG program will have to start construction prior to December 31, 2019 and many, if not most, projects participating in the second REDI RFP will be able to start construction before December 31, 2019. Therefore, the solar resources that participate in REDI should be able to take full advantage of the current ITC (though the Company has no control over the extent to which such credits are ultimately reflected in bids).

For new wind resources, projects will need to start construction prior to December 31, 2016 to be eligible for the full value of the wind PTC. (Tr. 1377, 1662). Projects that begin construction in 2017 are eligible for 80% of the full PTC value. (Tr. 1662). The PTC value is scheduled to reduce to 60% full value in 2018, and 40% full value in 2019. (*Id.*). Actions can be taken now by developers to obtain the full benefit of the PTCs and, in any event, any successful wind bid is likely to reflect some benefit from the PTCs. However, there are a number of practical constraints guiding the timing of the REDI RFPs, including the Commission's rules proscribing the timeline of Company action prior to the issuance of draft RFP documents to the market. The Company does not believe it is appropriate to adjust the timing solely on the basis of current tax incentives that remain subject to future potential changes.

3. The proposed size of the DG portion of REDI is reasonable.

Georgia Power believes the additional 150 MW procurement of DG resources is an acceptable compromise. GSEIA's proposal for a carve out for 250 MW for DG projects is unrealistic and based on inaccurate information related to the ongoing ASI-Prime DG RFP. (Tr. 1523). GSEIA testimony inaccurately cites the "full subscription" and thus, success of the ASI-Prime DG Group A projects, in support of its larger proposal for the REDI DG RFP. (Tr. 1518). However, while that program is moving forward toward completion, as of the date of this brief it is not yet fully subscribed. Projects in all three groups of the ASI-Prime DG solicitation remain under evaluation and the Company continues to fill the portfolios. Furthermore, the Company's prior experience has demonstrated that utility-scale projects generally yield lower bid prices, thereby creating the greatest value for customers. The Company's customers are best served when the Company selects the most cost-effective resources based on all pricing and operational characteristics and utility-scale projects have consistently provided the maximum value (as was acknowledged by numerous parties). Therefore, based on this experience and the continuing lessons learned from the current ASI-Prime DG solicitation, Georgia Power supports a carve out of 50 MW of customer-sited projects from the RFP process as agreed to in the Stipulation.

4. The overall structure of REDI as described in the Stipulation should be approved.

Under the terms of the Stipulation, the Company will issue two utility-scale RFPs, each seeking 525 MW. (Stipulation, Supply Side Para. 3). The first RFP in 2017 will seek projects with in-service dates of 2018 and 2019, while the second RFP in 2019 will seek projects with in-service dates of 2020 and 2021.

Of the 1,050 MW, a total of 300 MW of wind resources may be procured through the REDI RFPs. Bid fees for the utility-scale RFPs will be the greater of five thousand dollars ($5,000) or three hundred dollars per MW ($300/MW). The cost to implement and administer the REDI program will be recovered through the fuel clause and all bid fees collected will be credited to the fuel clause. (Stipulation, Supply Side Para. 3).

Of the 150 MW of DG resources, 100 MW will be procured through a competitive RFP open to projects between 1 kW and 3 MW in size. (Stipulation, Supply Side Para. 4). Such DG resources must have in-service dates of 2018 or 2019 and will enter into a PPA for up to 35 years in length and must interconnect to Georgia Power's distribution system. Bid fees for the DG RFP will be set at $4/kW. (*Id.*). The remaining 50 MW of DG resources will be procured from customer-sited DG projects through an application process, with a subsequent lottery process, if needed. If the customer-sited program is undersubscribed, the remaining MW will be allocated to the REDI DG RFP reserve list. To be eligible for this program, customer-sited DG projects must be 1 kW to 3 MW in size, with a DC rated capacity that is less than or equal to 125% of the actual annual peak demand of the customer's premise for 2015. Customer-sited DG projects will be paid avoided cost pricing based upon a limited application of the Framework, as provided for in the Stipulation. Participant fees for the customer-sited DG projects will be set at $3/kW. (Stipulation, Supply Side Para. 5).

As discussed later, the Company and PIA Staff will collaborate regarding additional evaluation of the Framework. If no consensus is reached, the Company will utilize only the Avoided Energy Cost and Deferred Generation Capacity Cost components in its REDI evaluations. PIA Staff acknowledges that the methodologies proposed for the Avoided Energy Cost and Deferred

Generation Capacity Cost components are consistent with current Commission-approved avoided cost methodologies used in Docket Nos. 4822 and 16573. (Tr.1165-66). Additionally, pursuant to the Stipulation, the Company will evaluate the appropriate transmission and distribution costs and benefits on a case-by-case basis as proposed in the Framework document. (Stipulation, Supply Side Para. 8(a)). Finally, the specific process that will be utilized for the evaluation, whether project and/or portfolio analysis, will be finalized during the review and approval of the REDI RFP documents. (Stipulation, Supply Side Para. 6).

5. In general, a market-based approach to resource procurement is in the best interest of all customers.

The Company continues to believe that a market-based approach (which, under the Stipulation, will be used for all procurements except the 50 MW customer-sited DG procurement) provides the greatest benefit to customers because it ensures that the Company obtains the most cost-effective projects that the market has to offer. (Tr. 1821). A market-based approach is required under the Commission Rules when the Company procures capacity to meet an identified capacity need because this Commission has recognized that approach as the best way to ensure the greatest value for customers. (Commission Rule 515-3-4-.04(b)). There is no compelling reason to depart from that approach when resources are being procured to achieve projected energy savings. As the Company seeks to obtain new renewable resources for the purpose of energy savings, a competitive RFP ensures that the Company's customers obtain the maximum energy benefits. (*Id.*). Furthermore, market-based pricing has historically allowed Georgia Power to procure resources at prices below the Company's projected avoided costs, which is critical to mitigating risk to non-participating customers as discussed above. (*Id.*).

6. Carve outs for particular types of renewable generation are not in the best interest of customers.

It is appropriate for the REDI program to enable all renewable resource types to compete against each other. This ensures that customers will be served by the most cost-effective resources. (Tr. 1822). Bidders will be able to submit blended proposals of different resource types to optimize the production profile of their bids. (*Id.*). Segregating the RFP by resource type would prohibit bidders from being able to make such proposals, as well as create the potential that customers would pay a higher price for energy than would otherwise have been the case. (*Id.*). The REDI program, as structured in the Stipulation, recognizes the potential for diversity in expansion of Georgia Power's renewable portfolio.

The Company specifically notes that the Commission should reject on both procedural and substantive grounds the recommendations of the Biomass for Georgia Coalition ("BFGC") contained in its Post-Hearing Brief filed on June 27, 2016. From a procedural perspective, BFGC's attempt to introduce completely new factual assertions and substantive policy recommendation in the context of a post-hearing brief undermines the entire IRP proceeding. Unlike many of the other intervenors in this proceeding, BFGC did not take the time to pre-file testimony in this proceeding, which would have allowed the Commission and all parties to this proceeding an opportunity to evaluate BFGC's factual assertions and policy recommendations and conduct cross examination with respect to such issues and also allowed the Company to respond, if necessary, through rebuttal testimony. Instead, BFGC completely disregarded the Commission's PSO by introducing unsubstantiated facts and policy recommendations after the record has been closed.[1] The process and procedures guiding a contested proceeding before the Commission are well-established and are guided by both legal and practical considerations and should not be so cavalierly ignored.

From a substantive perspective, the policy recommendations made by BFGC should be rejected. REDI is not reserved only for wind and solar resources as asserted by BFGC. The Company has said consistently throughout the proceedings that all renewables, including solar, wind and biomass should compete in order to provide the most benefit for customers. Therefore, no specific generation type carve outs have been recommended because customers receive the most benefit when all resources are allowed to compete against each other. Finally, QF generators are only entitled to fixed capacity payments when the Company has a capacity need and there is well established Commission precedent regarding this issue. (Final Order Docket No. 4822 at 3 ("Capacity payments . . . will be available when the utility has an identified need pursuant to its integrated resource plan"); Final Order Docket No. 19279 at 5 ("By Commission order in Docket No. 4822-U, long-term capacity payments are available subject to the utilities' need for long-term capacity. The Commission continues to find this approach to be reasonable and sees no reason to vary from it when deciding to make commitments for long-term capacity payments. [Interested Party] has requested that the Commission order Georgia Power to enter into a PPA. This should not occur in absence of the IRP identifying a need for capacity").

7. The Commission should approve the additional sum for REDI utility-scale projects based on a percentage of the

[1] BFGC even goes so far as to characterize its filing as "testimony". Post-Hearing Brief of BFGC at 1. The PSO lays out a clear structure for the filing of testimony during this proceeding and BFGC has failed to adhere to that structure.

associated energy savings achieved as specified in the Stipulation.

The Commission should approve the additional sum amount specified in the Stipulation for certified utility-scale projects. Under O.C.G.A. § 46-3A-8, the Company is entitled to the recovery of an additional sum, as determined by the Commission. The Commission is directed by statute to consider "lost revenues, if any, changed risks, and an equitable sharing of benefits between the utility and its retail customers." O.C.G.A. § 46-3A-8. Because the Company is procuring these resources for energy savings rather than for a capacity need, it is appropriate to tie the additional sum to the projected energy savings, and the stipulated amount of 8.5% ensures that customers will receive the vast majority of such savings. In its initial filing, the Company had proposed to retain only 20% of shared savings as an additional sum. Such proposed level of shared savings is reasonable as an incentive for REDI procurement under the additional sum provided for by law. However, under the Stipulation, the additional sum requested by the Company has been reduced substantially to the stipulated amount of 8.5% of shared savings. Under the Stipulation, customers will continue to receive the overwhelming majority savings, with only a limited amount retained as an additional sum by the Company. (Stipulation, Supply Side, Para. 9).

8. The Company should continue to use an Independent Evaluator ("IE") in developing and conducting its supply-side RFPs as required by Commission Rule 515-3-4-.04(3)(c).

Consistent with the Commission's rules and prior Georgia Power RFPs, the Company will develop the REDI RFPs with the advice and consideration of the Commission Staff and an IE. Under the Commission Rules, an IE serves to maintain transparency and fairness in the RFP process, which helps to prevent claims of affiliate or bidder favoritism in resource selection. (Tr. 1823). The

Commission Rules require that the Company retain an IE, who is selected by and reports to the Commission in carrying out its duties, to assist with the development and evaluation of Georgia Power RFPs. (Commission Rule 515-3-4-.04(3)(c)).

GSEIA suggested that the role of the IE should be limited to the blind analysis of bid and project evaluations after the program guidelines and pro forma documents have been finalized. (Tr. 1520). GSEIA's proposed structure violates the Commission's own established and well-informed rules. (Tr. 1824). The Notice of Proposed Rulemaking ("NOPR") that created the use of an IE considered all aspects of the IE's proposed role and approved the rule that is in place today. (*Id.*). As reiterated by Staff in the 2004 IRP when the IE rules were first considered, it is appropriate for "[t]he IE [to] have significant involvement in (1) the preparation and design of all bid solicitation documents; (2) communications with all bidders; (3) the evaluation of the proposals submitted in response to the RFP; (4) the selection of a winning bidder; and (5) the subsequent negotiation of a [PPAs] between the winning bidder(s) and [Georgia Power]." (Staff Direct Testimony, *In Re: Georgia Power Company's Application for Approval of its 2004 Integrated Resource Plan*, Docket No. 17687, at 76: 9-12 (May 14, 2004)). To restrict the IE's participation to solely a post-bid proposal evaluation role, as proposed by GSEIA, not only violates the Commission Rules but also significantly hampers the purpose of assuring the market of fairness and transparency in the development and issuance of the RFP by allowing those with the most influence to unfairly influence the process rather than allowing an equal voice to all participants through the established processes and forums for participation. (Staff Direct Testimony, *In Re: Georgia Power Company's*

Application for Approval of its 2004 Integrated Resource Plan, Docket No. 17687, at 76: 9-12 (May 14, 2004)).

9. In addition to REDI, the Company's Renewable & Nonrenewable ("RNR") and Qualified Facility ("QF") programs provide additional opportunities for renewable DG in Georgia.

For customers with renewable DG resources that choose not to participate in REDI, the Company's RNR and QF programs will continue to provide simple and streamlined methods to sell excess generation to the Company at prices that are not intended to put upward pressure on the rates of customers. (Tr. 1864). Additionally, Georgia Power customers can install DG solar on their premises simply to offset their own usage without participating in any particular program. (Tr. 1826). Contrary to the assertions of GSEIA, Georgia Power has not taken any action to restrict the ability of its customers to self-generate. (Tr. 1826).

a. The RNR program is structured in accordance with the Georgia Cogeneration Act of 1979 (O.C.G.A. § 46-3-50 et. al.) and provides a simple, understandable structure with minimal contractual requirements.

For small customers seeking to participate in a behind-the-meter purchase program, the Company offers the RNR program. (Tr. 1827). Participation in the RNR program is structured in accordance with the Georgia Cogeneration and Distributed Generation Act of 2001. O.C.G.A. § 46-3-50, et. al. Residential customers with facilities under 10 kW and commercial customers with facilities under 100 kW are compensated for energy pushed back to the grid based on the Company's solar avoided cost that is filed annually with the Commission in Docket No. 16573. (Tr. 1827; Schedule RNR-8). The RNR contract is a very simple four page contract that only requires the customer to provide basic and absolutely necessary identifying data, facility (array) information, and assurance that the customer will construct and maintain an interconnected generator to meet safety, power quality, and interconnection requirements pursuant to the applicable laws. (Tr. 1827). The Company's RNR program is simple, structured to ensure the safety and reliability of the System, and designed to prevent cross-subsidies and ensure that other customers are not forced to bear any additional interconnection costs caused by the DG resource. (Tr. 1827).

It is not appropriate to offer long-term, fixed, levelized pricing to RNR customers at the projected avoided costs. (Tr. 1828). Such a payment structure would introduce significant risk to non-participating customers and is not in accordance with Commission policy. (*Id.*). Further, the RNR contract does not include contractual obligations like collateral security arrangements to protect the Company and its customers over the long-term.

This Commission has previously considered whether long-term fixed price contracts are appropriate as part of its approval of the Company's existing avoided cost methodologies in Docket No. 4822 establishing the Company's avoided cost methodologies. In that docket, Staff itself expressed concern about the customer risks that result from fixed payments based on projections. (Final Order Docket No. 4822, at 16)("[t]he Adversary Staff expressed concern about the ratepayer risks that could result from locked-in payments based on projections."). In its Final Order in Docket No. 4822, the Commission stated that it "does not approve fixed energy payments as a general policy." (*Id.* at 25). That Final Order directed those who wished to obtain such fixed payments to participate in an RFP. (Tr. 1828). Through an RFP process, the Commission and the Company have the opportunity to mitigate the risks associated with levelized payment through review of project selection and contractual requirements, including collateral security arrangements. (*Id.*).

b. The Company's QF program has been approved by the Commission and is designed to accommodate a wide range of projects.

Renewable generators can also sell generation back to the Company as a QF under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). (Tr. 1826). For QFs, the process is straightforward. The form and process required for a QF to sell its output to the Company were determined by the Commission when it implemented PURPA in Docket No. 4822, which was further refined in Docket No. 19279. (Tr. 1827). Docket Nos. 4822 and 19279 were both lengthy, fully litigated proceedings in which the Commission determined the eligibility criteria for each type of QF contract and the methodology for calculating the payments associated with each type of QF contract. Specifically, in Docket No. 4822, the Commission fully considered and approved the methodology for calculating the energy and any capacity payments to be paid to QFs. In compliance with PURPA, in the years for which there is no supply-side capacity need, the Company offers QFs the standard energy-only QF contract.[2] Under this contract, QFs are paid the day-ahead projected avoided cost energy estimates. For years in which there is an identified capacity need, QFs 30 MW or smaller are offered the standard energy and capacity QF contract, which calculates energy and capacity payments pursuant to the methodology approved in Docket No. 4822. Pursuant to the Commission's Rules and Orders, QFs larger than 30 MW seeking long-term capacity payments are required to participate in the RFP process. (See Final Order Docket No. 4822, at 1; Commission Rule 515-3-4-.04(f)(1)). Additionally, if a QF can meet the more robust deliverability requirements of the QF proxy program, which were developed and refined in Docket No. 19279, the QF can notice into a Company's traditional supply-side RFP and will be paid energy and capacity payments equal to the (proxy) price paid to the last displaced bidder in the RFP. The existing QF

[2] *See also City of Ketchikan, Alaska*, 94 FERC ¶ 61,293, at 62,062 (2001) ("Thus, while utilities may have an obligation under PURPA to purchase from a QF, that obligation does not require a utility to pay for capacity that it does not need.")

program and avoided cost methodology used to set energy and capacity payments for QFs has served the Commission, the Company, and customers well and accommodates a wide range of QFs.

For QF customers, the process of contracting with the Company is both straightforward and necessary. The form and process required for a QF to sell its output to the Company were approved when the Commission implemented PURPA in Georgia in Docket No. 4822, as modified in Docket No. 19279. (Tr. 1827). The pro-forma contract includes the standard contract terms and provisions that the Commission determined were reasonable in Docket No. 4822. (*Id.*) QF customers are compensated using day-ahead projected avoided energy cost estimates. (*Id.*). The current process is fair, transparent, consistent and subject to the review and approval of this Commission. As described above, offering a long-term, levelized and fixed PPA price is not in the best interest of customers or in accordance with Commission policy.

C. **The Company continues to believe that the Framework is essential for proper evaluation of renewable resources and should be adopted as the methodology for assessing the net benefits of renewable resources and ensuring that all customers benefit from such resources.**

As Georgia Power continues to grow its renewable portfolio, it is crucial to identify, quantify and allocate all of the appropriate benefits and costs of these intermittent, non-dispatchable generation resources to ensure that such resources provide net benefits for all customers. (Tr. 58). 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. (Tr. 58). The Framework appropriately recognizes the numerous benefits of utility-scale and DG renewable resources, but also accounts for the operating, reliability and other impacts of renewable generation on the System. (Tr. 908; 1592).

The Company continues to believe that the Framework should be implemented in a timely manner. Regardless of the amount of resources that are impacted at this time, the prudent regulatory action is to implement the Framework in a timely manner, rather than waiting until more resources are potentially impacted. (Tr. 1814). Failure to implement the Framework places the Company and its customers at risk of inaccurately compensating generators for energy delivered to the System and selecting more costly resources in future solicitations. (Tr. 1814). Because the Framework is a comprehensive and technically sound method for determining the costs and benefits of renewable resources, implementation at this time would provide the proper foundation for future renewable resource decisions and ensure that all of the Company's customers benefit from such resources. (Tr. 1814-15).

The Framework methodologies that have been developed are mature and ready for use as proposed by the Company. The Framework identifies the majority of the major cost/benefit components of renewables, including the unique operational characteristics of renewables such as intermittency and lack of dispatchability. (Tr. 1974; 76). Those components for which methodologies have yet to be determined are relatively small in scope and are included in the Framework structure as placeholders. (Tr. 1815). The incorporation of placeholders for these components should not prevent the Framework from being implemented. (*Id.*). Further, the placeholders will not be utilized until they are developed and presented for approval in a regulatory proceeding before the Commission.

1. The Company and Staff will work together to develop a process and recommendations for the implementation of the Framework.

Pursuant to the Stipulation, PIA Staff and the Company have agreed to work together to develop a process and recommendation for full implementation of the Framework within four months of the final order in this proceeding. (Stipulation, Supply Side Para. 7). This is a reasonable compromise that will ensure that ample time is provided to allow for resolution of any outstanding issues. If an agreement is reached between the Company and PIA Staff on the implementation of the Framework, the Stipulation contemplates that the Company and PIA Staff can recommend to the Commission the utilization of the full Framework for purposes of the 2017 REDI RFP. (*Id.*) In the event that no agreement is reached, the REDI resources will only be evaluated based on Avoided Energy and Deferred Generation Capacity cost components consistent with the Framework methodology and, subsequently, the Company will perform an illustrative analysis utilizing the entire Framework. This illustrative analysis will include all aspects of the Framework including specifically, Generation Remix, Support Capacity, and Bottom Out Adjustments and will allow the PIA Staff and the IE to gain familiarity with the Framework. (Stipulation, Supply Side Para. 8(b)). The Company will evaluate the appropriate transmission and distribution costs and benefits on a case by case basis as proposed in the Framework document. (Stipulation, Supply Side Para. 8(a)).

D. The Commission should authorize the Company to take the actions needed at this time to ensure that the Company is able to deploy new nuclear generation in a timely manner if needed.

Nuclear generation is a low variable cost, emissions-free, dispatchable, baseload resource and will play a pivotal role in allowing the Company to maintain diversity in its supply-side resources. (Tr. 1833). In light of the value of nuclear generation, the Company has requested in this IRP that the Commission approve the expenditure of up to $174.5 million to investigate the option of pursuing new nuclear generation as a potential future base-load option at a site in Stewart County, Georgia. (Tr. 1835). This work involves those actions that are necessary to seek and obtain a Combined Operating License ("COL") from the United States Nuclear Regulatory Commission ("NRC"). (Tr. 1832, 1909).

The only party to this proceeding that has filed testimony opposing the Company's request is PIA Staff and, under the terms of the Stipulation, the Company and Staff have agreed that this is a policy decision for the Commission. (Stipulation, Supply Side Para. 20). While agreeing that new nuclear generation may be an economic generation resource at some point in the future, PIA Staff has asserted that the Company does not need to begin pursuing the option of new nuclear at this time but, instead, that the Company should wait until 2019 when it has more information on the costs of Plant Vogtle Units 3 and 4. (Tr. 747, 1865). As detailed by the Company and explained further below, delaying action until 2019 could place the Company in a position where it is unable to deploy nuclear in a timely manner should it be later identified as the most cost-effective resource for customers. (Tr. 1833). Furthermore, the Company's proposed actions will, at a reasonable cost, provide benefit to customers even if nuclear generation is not selected as a generation resource until sometime beyond 2019. Taking these actions now to preserve the option for timely deployment of nuclear generation proactively positions the Company to be able to select the resource that is in the best interest of all customers.

1. The lead time for new nuclear generation can be significantly reduced at this time through an investment that is very small relative to the total projected costs, with only minimal rate impacts on customers.

The lead time needed to investigate, permit and construct a generation facility is a primary consideration when the Company determines the most cost-effective generation resource for customers. Generally speaking, the Company will select the most cost-effective resource to meet an identified capacity resource need, but that is only possible when the need date is compatible with the lead time for the identified generation resource. Where the lead time for a particular generation resource would not permit completion prior to the need date, such resource will not be available to be selected and the Company could be forced to select a less cost-effective generation resource. (Tr. 1833-34).

Nuclear generation is a unique resource in many ways, including the fact that it has a lead time that is significantly longer than that of other generation resources. The Company currently estimates that nuclear generation has a 17-year lead time, which includes seven years needed to obtain approval of a COL. (Tr. 1833, 1835). The work required during this initial seven year period includes detailed site evaluation, site and regional infrastructure planning, site design and preparation, preliminary resource evaluation, preliminary design and development of commercial scope of work, and finally, NRC licensing. (Tr. 1935).

As described in more detail below, there are a number of circumstances that could cause the need year for new generation to move forward in time to a point within the 17-year window. In such a circumstance, nuclear generation would not be an available resource for customers should it be selected as the most cost-effective generation resource.

However, through the investment of approximately only 1.5% of the total projected cost of two nuclear units now, the Company would be able to reduce the lead time of new nuclear generation by 40%. (Tr. 1834, 1866). More specifically, by investing the $174.5 million now, the Company can cut the lead time for nuclear generation by seven years (down to ten years), thus permitting nuclear generation to be considered on a more level playing field against other generation resource alternatives in terms of deployment time. (Tr. 1833-34).

The impact on customers of the $174.5 million investment is relatively minimal. As a result of the current base rate freeze and as is shown in Staff Exhibit [48] (filed by the Company as HR-2-2), customers' rates would not be impacted by the costs until 2020. Until rates are reset in 2020, the only impact on customers would be the potential for very minimal reductions in any earnings sharing in the event that the Company's earnings are above the top end of the authorized earnings band. Beyond 2020, the impact on customer rates would be very small (monthly impacts to the typical residential customer range from $0.25 per month to $0.33 per month). As explained below, costs spent to preserve the nuclear option would be capitalized and would not be recovered from customers until such time as a project is certified, at which point that cost would be added to the capital cost of that certified project, or if a project is not certified, such cost would be recovered through rates over a period determined by the Commission in a future rate proceeding.

2. There are a number of circumstances that could put the Company in a situation where it is unable to deploy nuclear generation in a timely manner.

While Staff has acknowledged that new nuclear generation may be needed as soon as 20 years from now, there are a number of circumstances that could pull forward the need for new nuclear generation to a point inside the projected 17-year lead time. For instance, in the event that new regulations are imposed on natural gas fracking, leading to a significant increase in natural gas prices, the need year for nuclear generation could be pulled forward significantly as projected natural gas generation life-cycle costs increase. (Tr. 1833). Similarly, future environmental regulations could pull forward the need for nuclear generation, particularly in the event of any environmental regulations that require incremental retirements of a significant amount of the Company's generation assets. (Tr. 1833). In such instances, delaying these activities until 2019 may place the Company in a position where it is forced to select alternative, less cost-effective generation because it lacks the sufficient time to pursue nuclear generation. (Tr. 1833-34).

3. Taking action at this time would allow the Company to capitalize on certain accumulated expertise and would achieve efficiencies by enabling the Company to rely on the same design as is being utilized for Plant Vogtle Units 3 and 4.

Outside of the need to ensure the availability of nuclear generation for timely deployment, there are other benefits to customers if the Company is authorized to take action at this time. First, by commencing work now the Company can capitalize on the existing pool of technical experts at both the Company and the NRC that were involved in the licensing of Plant Vogtle Units 3 & 4. (Tr. 1865). Delaying action would create the potential for loss of such accumulated expertise.

Second, granting the Company's request at this time would also make it likely that the Company would be able to reference the current AP 1000 Design Control Document ("DCD") Revision 19 if the AP 1000 design is ultimately selected for the COL. (Tr. 1834). The current DCD expires on February 2021 and failure to submit the Combined Operating License Application ("COLA") before such date would risk forcing the Company to base its COLA on a revised DCD. (Tr. 1834). The benefit of using the current DCD used to construct the Vogtle units is that the Company will already have experience with the design and construction requirements from its construction of Plant Vogtle Units 3 and 4 and can avoid many of the first-of-a-kind challenges encountered when constructing with a new design basis. (Tr. 1920). Consistency in the licensing and design basis is beneficial so that the Company can fully leverage the lessons learned from the construction of Plant Vogtle Units 3 and 4. (Tr. 1920). While an Early Site Permit ("ESP") is an option that permits an applicant to obtain approval for a potential nuclear reactor site, an ESP is not tied to a specific certified design and thus, would not mitigate the risk associated with the expiration of the current Westinghouse AP 1000 DCD and would also prolong the process, ultimately making it more costly for customers. (Tr. 1943).

Third, taking the steps now to preserve the option of new nuclear mitigates a number of future risks, including reduction in the Company's overall nuclear generation mix due to the aging of the existing nuclear fleet and the uncertainty of a subsequent license renewal request to extend the operating license for Plant Hatch Unit 1, currently expiring in 2034, for an additional 20 years. (Tr. 1834).

4. PIA Staff's objections based on the capital cost of Plant Vogtle Units 3 and 4 and the lack of co-owner involvement are not sufficient basis for delaying action.

PIA Staff recommended delaying a decision until 2019 when the final capital costs for Plant Vogtle Units 3 and 4 are known. (Tr. 748). However, while the Company agrees that the capital cost of new nuclear is an important component of the overall economics, many other factors can have an even greater influence on the overall economics of nuclear generation, including natural gas forecasts, load forecasts, environmental regulations (specifically as they relate to carbon emissions or natural gas fracking), potential impacts to other forms of baseload generation and changes in the projected cost of other resource options. (Tr. 790-92, 1835-36). For example, an increase in the price of natural gas forecasts over the 60-year life of the facility could have a much more significant impact on the timing of when nuclear is selected than modest changes in the capital cost. (Tr. 1836). It is also important to remember that the Company is only asking for costs related to the development and application for a COL and that those projections are based on the Company's licensing experience for Plant Vogtle Units 3 and 4, for which the cost is known.

Staff also asserts that the lack of co-owner involvement in the Company's investigation of new nuclear at the Stewart County site suggests a lack of support for new nuclear generation. (Tr. 750). In making its assertion, Staff fails to recognize the structure of the agreement between the Vogtle co-owners required co-owner consent to allow the preliminary site investigation and licensing work for Plant Vogtle Units 3 and 4. (Tr. 1836). At the time the Vogtle co-owners provided their consent, they also secured, and later exercised, options giving them the right to participate in the project. (*Id.*) No such consent requirement exists in the case of the land purchased in Stewart County. (Tr. 1837). Moreover, it is worth noting that the Company both acquired the property and applied for the licenses for both Plant Hatch Units 1 and 2 and the Plant Vogtle Units 1 and 2 without co-owners. (*Id.*). The absence of co-owner involvement in the preliminary investigation of the Stewart County land should not be interpreted as evidence of lack of support for new nuclear generation.

5. A more limited scope of work than that proposed by the Company would not provide the same benefits to customers.

Staff implied during its cross examination of Company witnesses that a smaller subset of the Company's proposed actions could be considered as a possible solution at a significantly reduced cost. (Tr. 1936). While it is certainly true that less cost would be incurred in such a scenario, the benefit of such actions would be greatly reduced as compared with the Company's proposed course of action. Specifically, such a limited scope of action would not allow the Company to submit the COLA in a timely manner to allow the Company to reference the current DCD. (Tr. 1936). Furthermore, such limited actions would not allow the Company to fully leverage the resource knowledge of the NRC resources and Company personnel with prior experience who would be useful in developing the COLA. (*Id.*).

6. The Company's position on the recovery of financing costs on disallowed costs under the NCCR statute does not add additional risk to new nuclear and should not impact the Commission's decision in this IRP.

In Docket No. 29849, the Company submitted a legal opinion by former Georgia Supreme Court Justice Norman Fletcher regarding the prudence standard under the IRP Act. The Fletcher Expert Report notes that Senate Bill 31 does not provide for the treatment of financing costs collected on construction costs that are "disallowed" by the Commission. Staff interprets this report as stating that it is the Company's position that the Commission lacks authority to disallow increased financing costs related to a delay of construction on a nuclear plant even if those costs were found by the Commission to be imprudently incurred. (Tr. 855). Therefore, Staff argues that the Company's interpretation creates uncertainty and adds additional risk to the nuclear generation profile and must be considered in assessing the nuclear option to model the cost of new nuclear properly. (Tr. 856).

However, as the Company's counsel stated at the rebuttal hearing, the Company's position is that "this Commission has the ability to disallow costs that it finds to be imprudent, period." (Tr. 1969). Furthermore, Staff's position appears to suggest that some amount of imprudent costs should be assumed for purposes of modeling. However, that approach has never been taken by the Company or required by the Commission and is not appropriate for modeling. (Tr. 1836).

7. The Company did not force the selection of nuclear generation in the Resource Mix Study.

Staff witness Brian Smith testified that it appeared as if the Company forced its models to select new nuclear generation. (Tr. 733). Contrary to this assertion, the Company's model selected nuclear generation without any constraints or artificial limitations. (Tr. 1838). During subsequent iterative model runs, certain modeling constraints were imposed because the Company's models selected more nuclear generation resources than would have been feasible to finance and construct over a particular time period. (*Id.*). However, it is simply not the case that the Company took any artificial action to make nuclear generation resources appear more valuable in the Company's models.

8. The Commission should approve the Company's accounting requests in connection with the costs incurred to preserve the option for new nuclear.

The costs incurred by the Company in connection with its efforts to preserve the option for timely deployment of nuclear resources will be accrued in FERC Account 183 (Preliminary Survey & Investigation Costs) and reflected in rate base if approved by the Commission in this proceeding. (Tr. 1807). The costs would not begin to be recovered immediately. Instead, if the Company requests, and the Commission approves the certification of new nuclear, the costs accrued in account 183 would be moved to Construction Work in Process and recovery of such costs would commence as determined in a base rate case following commercial operation of the units. (Tr. 1909-10). However, in the event that the Company does not ultimately construct new nuclear generation, the Company seeks Commission authorization to record these costs in a regulatory asset account for recovery over a time period to be approved by the Commission in a future rate case. (Tr. 1807). This authorization is necessary because, under Accounting Standards Codification No. 980 Regulated Operations ("ASC 980"), approval by this Commission can provide reasonable assurance of the existence of such an asset. Due to the magnitude of the costs in question, the Company requires specific approval at this time.

9. Requiring shareholders to cover preliminary investigation costs is contrary to the regulatory compact and would also effectively prevent future recovery of such costs from customers.

Generally speaking, under the regulatory compact, the Company is obligated to provide safe, reliable and cost-effective energy to its customers and is, in exchange, given the opportunity to earn a fair rate of return on and recovery of its investment. (Tr. 1916, 1922-23). The Company believes that taking action now to preserve the potential for new nuclear generation is in the best interest of customers and therefore, such costs are appropriately borne by customers. If the Commission determines that it is not in the best interest of customers to preserve nuclear generation as an option at this time, the Company will cease such activities. In fact, the Company is not willing to take these actions if the Commission were to deny the Company's requested accounting treatment. Furthermore, under ASC 980, given the magnitude of the costs to explore the new nuclear option, the Company cannot defer costs in a regulatory asset for future recovery from its customers without some reasonable assurance of cost recovery, and without such assurance of cost recovery, the Company would be required to expense those costs. (Tr. 804, 1837). There is no accounting mechanism that would allow the Company to expense costs to shareholders and then later capitalize them for recovery from its customers if the Company moves forward with certifying new nuclear. (Tr. 1923). The Company seeks to make these investments solely for the benefit of its retail customers and therefore, it is appropriate for customers to bear these costs. (Tr. 1866, 1918).

E. <u>The Commission should adopt the target planning reserve margin contained in the Stipulation as a reasonable compromise between the Company and Staff</u>.

1. The Company's Reserve Margin Study provides an ample evidentiary basis to support the stipulated target planning reserve margin.

Pursuant to the Stipulation, the Company's long-term target planning reserve margin will be increased to 16.25%. (Stipulation, Supply Side Para. 14). This target planning reserve margin reflects a reasonable compromise between the Company and PIA Staff and is well supported by the analysis contained in the Company's Reserve Margin Study.

As in prior IRP proceedings, the Company performed an in-depth technical analysis to determine the economically optimum long-term target planning reserve margin. (Tr. 75-77; Tr. 1861) and then made further adjustments based on the Value at Risk ("VaR") analysis. The Company has used this same comprehensive approach, without fundamental alteration, in previous reserve margin studies and this Commission has adopted reserve margin recommendations based on the results and analysis provided in such studies. (Tr. 77; 1861). Neither Staff nor any other intervenor offered an alternative analysis for establishing the optimal target planning reserve margin. (Tr. 768; 1861).

As detailed in the Reserve Margin Study, a number of newly-identified operational factors influenced a slight increase in the Company's target planning reserve margin. (Tr. 1861). The Company described five operational drivers for the change in long-term target planning reserve margin: (1) the difference in winter and summer peaks narrowing; (2) the modeling of winter peaks; (3) higher unplanned outages during low temperatures; (4) increased renewable capacity penetration; and (5) lower availability of non-firm gas transportation during the winter than in the summer. (Tr. 76-77; 1809; 1861; 1876). No party filed testimony discrediting or challenging the Company's reliance on these operational drivers. (Tr. 1810). Accordingly, the operational drivers identified through the Reserve Margin Study support the stipulated target planning reserve margin.

Furthermore, this Commission has previously accepted target planning reserve margin adjustments based on the VaR analysis. (Tr. 1811). For example, the 2013 Reserve Margin Study identified a long-term target planning reserve margin of 14.25% but adjusted the target to 15% based on the VaR analysis. (*Id.*). In this instance, the VaR analysis determined that system reliability could be nearly doubled by increasing the target planning reserve margin to 17%. (Tr. 1810).

It is appropriate to increase the long-term target planning reserve margin at this time so that future planning evaluations and decisions, including the 2019 IRP, reflect the most appropriate economic and reliable planning reserve margin target. (Tr. 1811; 1862). As Company Witness Haga stated, "you don't want to wait until you smell smoke to start developing a fire evacuation plan." (Tr. 1903). Updating the target planning reserve margin at this time will ensure that the Company implements all resource decisions guided by the optimal reserve margin.

2. The same target planning reserve margin is and will continue to be used across the System so the Company's customers will not be subsidizing other operating companies.

Pursuant to the Stipulation, Supply Side Paragraph 14, the Company will notify Staff once all of the Southern operating companies approve and implement the revised target planning reserve margin. During the hearings, several Commissioners raised concerns over the potential that target planning reserve margins could vary between the Southern operating companies, raising concerns about cross-subsidization. (Tr. 1906-09). However, Company witnesses were clear that the Company would never let its customers subsidize the reliability of other operating companies. (Tr. 1906). Therefore, upon Commission approval, the overall System planning reserve margin of 16.25% will be recommended to the System and the Company will report to the Staff on the status of the other operating company approvals. As was made clear by Company witnesses, in light of the integrated operation of the System and in order to prevent cross-subsidization, there are no circumstances in which the System will operate under different long-term planning reserve margins.

3. The Cost of Expected Unserved Energy ("EUE") study provides a reasonable estimate of the cost of unserved energy to support the stipulated target planning reserve margin.

The current EUE study provides a reasonable estimation of the expected costs to customers of unserved energy. (Tr. 1813). While it is true that the EUE study relied on in this proceeding only gathered information from customers of Georgia Power and Mississippi Power, there is no evidence to suggest that the cost of EUE will vary materially between operating companies within the Southern Company system. (*Id.*). Furthermore, though the current study was initiated in (Stipulation Supply Side Para. 16). 2011, no evidence has been introduced to suggest that there have been any material changes in the cost of EUE in that time period, and in fact, the Company believes that if a change has occurred, it would likely have increased the costs of EUE, which all things being equal would lead to a higher target planning reserve margin. (Tr. 1814). Pursuant to the Stipulation, the Company has agreed to discuss the timing of future EUE studies with Staff. (Stipulation, Supply Side Para. 14).

F. <u>The Company's decertification requests should be approved as specified in the Stipulation.</u>

The Stipulation approves the Company's request to decertify Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT and Intercession City CT. (Stipulation, Supply Side Para. 2.). The Company's economic analysis showed that these units provided little or no economic value for customers and therefore, that it was in the best interest of customers for these units to be retired. (Tr. 64-65). No party to this proceeding has challenged these requested decertifications and this Commission should adopt this recommendation.

G. <u>The Company will defer spending at Plant McIntosh Unit 1 and Plant Hammond Units 1-4.</u>

The Company and Staff both concur that it is in the best interest of customers to retain Plant McIntosh Unit 1 and Plant Hammond Units 1-4. However, pursuant to the Stipulation, the Company and Staff have agreed that it is appropriate to limit annual capital expenditures at Plant McIntosh Unit 1 and Plant Hammond Units 1-4 to $1 million and $5 million, respectively, through July 31, 2019. (Stipulation, Supply Side Para. 15). The Company agrees to make a filing with the Commission prior to incurring expenditures that exceed the annual limit. (*Id.*). Although one intervenor filed testimony recommending the retirement of Plant McIntosh Unit 1 and Plant Hammond Units 1-4, such units should be retained as specified in the Stipulation in light of the =Company's agreement to limit capital spending over the next three years until the units are reevaluated in the Company's next IRP.

H. <u>The Company's environmental compliance strategy, including those measures specifically identified in Technical Appendix Volume 2, should be approved.</u>

The Company's environmental compliance strategy should be approved by the Commission, including, as specified in the Stipulation, those measures taken to comply with existing government imposed environmental mandates as presented in Technical Appendix Volume 2, Summary of Capital Expenditures, Closures, and O&M Expenses filed as part of the 2016 IRP, subject to the limits discussed above regarding Plant McIntosh Unit 1 and Plant Hammond Units 1-4. (Stipulation Supply Side Para. 16). No party to this proceeding has offered testimony challenging the Company's environmental compliance strategy or the cost estimates contained in the Company's filing, which served as the basis for the Company's decisions regarding its generating fleet. Therefore, the Commission should approve the Company's overall environmental compliance strategy.

I. The Commission should approve the Self-Build Solar Projects, including the Commercial and Industrial Program and the Demonstration Projects.

1. The 200 MW of renewable self-build projects should be approved as a reasonable compromise to allow the Company to continue its investment in Georgia military bases as well as other projects in the public interest.

The Stipulation authorizes the Company to construct 200 MW of self-build capacity, at least 125 MW of which must be constructed in connection with military sites (including potential projects at Robins Air Force Base and Fort Benning). (Stipulation, Supply Side Para. 11). This authorization will allow the Company to proactively engage military and non-military projects to identify opportunities to leverage these projects for the public interest. (*Id.*). The Commission should approve such authorization. The Company's efforts will provide benefits to Georgia's military bases similar in nature to the military projects previously authorized by this Commission, strengthening Georgia investment in these bases by contributing towards the military's renewable and energy security mandates while providing an economical supply of energy. Any non-military projects will meet a particular public interest and involve projects not reasonably achievable through the competitive bid process. The RECs generated from all non-military projects shall accrue to the benefit of all customers. In all cases, any proposed project will be benchmarked against the Company's projected avoided costs.

2. The proposed Commercial and Industrial Program should be approved by the Commission.

Similarly, the Commission should authorize the Company to consider the development of a renewable Commercial and Industrial Program. (Stipulation, Supply-Side Para. 12). The maximum size of this program will be 200 MW and any proposed project must be approved by the Commission. In terms of pricing, any proposed project will be benchmarked against the last successful proposal from the Company's utility scale REDI RFP.

3. As provided in the Stipulation, the Commission should approve the Closed Ash Pond Solar Demonstration Project and High Wind Study proposed by the Company.

The Stipulation recommends implementation of both the Closed Ash Pond Solar Demonstration Project and the High Wind demonstration project. (Stipulation, Supply Side Para. 10). The Closed Ash Pond Solar Demonstration Project will allow the Company to study the economic and physical feasibility of including solar-integrated solutions as part of the Company's ash pond closure program and is an important part of the Company's strategy for the future use of ash ponds. (Tr. 1829). This demonstration project will enable the Company to gather more information concerning how the Company might be able to close the ash ponds in a manner that is more conducive to future use. (*Id.*). More specifically, the project will provide the Company with information regarding the challenges and opportunities with respect to physical orientation and installation methods of solar on a more-sensitive or limited-use parcel of land than traditional greenfield or rooftop installations. (*Id.*). Under the terms of the Stipulation, the Company will be required to file quarterly construction monitoring reports and will be required to demonstrate the reasonableness and prudency of any recovery in excess of the budget for this project as filed in the 2016 IRP. (Stipulation, Supply Side Para. 10). It is important to pursue the Closed Ash Pond Solar Demonstration Project now because the Company has already commenced development of its comprehensive ash pond closure plan. (Tr. 1829). Undertaking this demonstration project at this time will allow the Company to develop best practices to improve the cost-effectiveness of future coal ash pond solar installations and will also address the Commission's request that the Company explore greater utilization of plant sites like Plant Branch. (Tr. 1829-30).

One of the key risks identified in the Company's 2015 Wind Request for Information for wind energy was the transmission cost to deliver the generation from its source to the Southern Company network. (IRP Main Document at 10-115). However, a recent DOE study highlighted the potential of higher elevation wind resources that would utilize taller wind turbines with larger rotors than ever deployed in the United States. (*Id.*). The Company believes it is important to validate site-specific locations in Georgia identified with "High Wind potential" and proposes a project that would allow it to further study high wind potential. (*Id.* at 10-116). 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 and could lead to potential wind turbine development in future IRPs. (*Id.*). Per the Stipulation, the Company agrees to file quarterly status reports and will collaborate with the Staff on what, if any, information from the wind study will be made available to interested parties. (*Id.*).

J. <u>The Stipulation appropriately resolves the cost recovery And accounting issues in this proceeding.</u>

The Stipulation provides that the remaining net book value of Plant Mitchell Unit 3 shall be reclassified as a regulatory asset and the Company shall continue to provide for amortization expense at the same rate as determined in the Company's 2013 base rate case and that any unusable Materials & Supplies

("M&S") inventory balance remaining at the date of the unit retirement shall be reclassified as a regulatory asset account and deferred for consideration in the Company's 2019 Rate Case. (Stipulation, Supply Side Para. 17). In addition, the Company and PIA Staff agree that any over- or under- recovered cost of removal balances for each Retirement Unit shall be deferred for consideration until the Company's 2019 Rate Case. (Stipulation, Supply Side Para. 18). This proposed resolution regarding the Company's retirement-related accounting requests is reasonable and should be approved by the Commission. Such treatment will give full opportunity to all parties to put forward their respective positions in the 2019 Rate Case.

K. Miscellaneous IRP Issues

The Company and PIA Staff also agree that the Simple Solar Program should be approved with the modifications to the sourcing of the program as recommended by Staff. (Stipulation, Supply Side Para. 10). Specifically, the Company will obtain RECs for the Simple Solar Program from sources outside of the Company-owned projects or PPAs. (*Id.*). Within six months of the final order, the Company and PIA Staff will work together to address modeling issues, including the retirement study, and will aim to conclude such discussions 12 months prior to the filing of the 2019 IRP. (Stipulation, Supply Side Para. 13). The Company will report to the Commission regarding dismantling and remediation of the Plant Kraft generating site and provide information regarding the appraised value of the site. (Stipulation, Supply Side Para. 19). The Company's Load and Energy Forecast and Transmission Plan should also be approved by the Commission. There are no remaining contested issues in this proceeding regarding either the forecast or the transmission plan and thus, those items should be approved. Within ten days of filing the 2019 IRP or any IRP updates, the Company agrees to provide PIA Staff working copies of all models used to develop that IRP configured to replicate inputs used to derive results incorporated in its base case scenario. (Stipulation, Supply Side Para. 21). The Company also agrees to provide an amount not to exceed $300,000 annually for specialized assistance for the ongoing review and analysis required by the Stipulation and the Company shall be fully entitled to recover the full amount of such costs. (Stipulation, Supply Side Para. 22). With respect to the Electric Transportation Initiatives and associated costs, the Company and PIA Staff reserve the right to address these costs and the merits of the program through the Annual Surveillance Report process and future rate cases. (Stipulation, Supply Side Para. 23).

L. <u>The Commission should approve the Company's DSM Application as modified by the Stipulation.</u>

As with the supply-side issues, the Stipulation for the demand side plan contains a balanced compromise between the Company and PIA Staff regarding a wide variety of contested DSM positions and should be adopted by the Commission. (Stipulation, DSM Para. 1). Overall, the Company's proposed DSM portfolio consists of energy efficiency programs, demand response programs, pricing tariffs, and other activities. The Company projects that by 2019, these programs including the updates reflected in this filing will reduce peak demand by approximately 1,900 MW. (Tr. 72). This load reduction represents 12% of the Company's current load. (*Id.*). In the Company's DSM Application, the Company seeks approval for a certificate of public convenience and necessity for four new DSM programs, an amendment to the certificate of two currently-certified DSM programs, decertification of two DSM programs, and updated program economics for the remaining four previously-certified DSM programs, all as detailed further in the Company's 2016 DSM Application.

1. The targeted amount of energy and demand savings and budgets are reasonable and strike an appropriate balance between economic efficiency and rate impacts in accordance with Commission policy.

The energy savings to be targeted by the Company were not changed in the Stipulation. The Company's slate of certified DSM programs (not including Power Credit) are projected to result in over 1,000,000 MWH of energy savings and 258 MW of demand savings in 2017-2019. (DSM Application, DSM Program Planner Summary, D-2 Cumulative Impacts Tab). The Stipulation recommends a number of adjustments to the Company's proposed budgets. (Stipulation, DSM Paras. 11-13). The Company believes that it is still possible to achieve the targeted energy savings under the more constrained budgets.

As indicated in the Company's initial filing, lower avoided costs have continued to have 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 (*i.e.*, Total Resource Cost ("TRC") test results declined and Rate Impact Measure ("RIM") test results worsened). Nevertheless, the Company continues to support its proposed slate of DSM programs in the interest of continuing to maintain a presence in the marketplace. Therefore, the Commission should approve the Company's programs described in the DSM Application with the budget adjustments as provided in exhibit 8 attached to the Stipulation. (Stipulation, DSM Para. 5).

2. The Commission should find that the Company's DSM planning and modeling approach treats DSM as a priority resource in accordance with the Commission's precedent and the Company's past practice.

The Commission and the Company have consistently followed a policy that balances the overall economic efficiency of proposed DSM programs (as measured by the TRC test) against the upward pressure on rates caused by such programs (as measured by the RIM test). The Commission first established this policy in the 2004 IRP in Docket No. 17687 (2004 IRP Final Order) and it has been followed and relied upon in every subsequent IRP proceeding.

The 2010 IRP Final Order in Docket No. 31802 ("2010 Order") established a formal policy "consistent with EISA Standard 16 that recognizes cost-effective energy as a priority resource." (2010 Order at 21; 2010 IRP Final Stipulation, Section II, Para. 7). However, nothing in the 2010 Order altered the Commission's directive to balance economic efficiency against rate impact[3] and the 2010 Order did not include language requiring that the Company "revamp" or overhaul its existing DSM approach. The Company's current planning and modeling approach reflects the purpose and spirit of this Commission's DSM policy. The Company follows industry standard best practices and the National Action Plan for Energy Efficiency Guide to Resource Planning. (Tr. 1845-46). The Company determines an appropriate portfolio of DSM measures and programs to benefit its customers through a process that includes: (1) utilizing standard utility cost-effectiveness screening tools; (2) incorporating input from a variety of stakeholders; and (3) leveraging lessons learned through program delivery and program evaluation to create the proposed DSM portfolio. (Tr. 1846).

The Company's DSM modeling approach considers and treats DSM as a priority resource. (Tr. 45). Allowing system planning tools to select DSM as a resource, as recommended by a number of intervenors, would actually

[3] EISA Standard 16 provides that "each electric utility shall adopt policies establishing cost-effective energy as a priority resource." EISA Standard 16 does not, however, prescribe or require that state commissions impose a particular policy. Rather, Section 111 of PURPA requires that state utility commissions *consider* certain standards. The federal government has no authority to determine or dictate the DSM policy in the state of Georgia. (Tr. 1313-14). Accordingly, the Commission remains free to craft Georgia DSM policy and determine whether the Company's proposed plans reflect treatment of DSM as a priority resource.

disadvantage DSM, because generation modeling does not consider factors like transmission and distribution avoided costs. (Tr. 1846). In addition, system planning tools do not adequately evaluate the impacts of energy efficiency programs on the Company's revenues. (*Id.*). These limitations are why the Company's modeling and planning methods more appropriately select a mix of energy efficiency measures to comport with the policy goals and objectives of this Commission.

As acknowledged by PIA Staff, the 2010 Order did not eliminate use of the RIM test. (Tr. 1319-21). The 2010 Order recognized that a passing RIM test ratio above 1.0 should not be mandatory. The Company has abided by this directive, as demonstrated by the fact that all of the energy efficiency programs set forth in DSM Application have a RIM test ratio of less than 1.0 (meaning that they all create upward pressure on rates). In addition, the 2010 Order did not repeal the Commission's long-standing directive that the Company's DSM programs should balance economic efficiency against upward pressure on rates, as was affirmed by the 2013 Order, in which the Commission relied exclusively on the TRC and RIM tests in reaching its determination. (2013 Order at 23).

The Company supports this Commission's longstanding policy requiring that the Company consider the impact of DSM activities on all customers—both participants and non-participants—because of the differing impact of subsidized DSM measures on such customers. All things being equal, the rates and bills of non-participants will increase as a result of the Company's DSM program. (Tr. 1843). GPC Exhibit-3, the 2011-2015 GPC Energy Efficiency Program Participation Chart, demonstrated that approximately 3% of commercial customers and 12% of residential customers participated in the Company's DSM programs. (Tr. 1326). Therefore, it is especially appropriate and reasonable that this Commission consider the impact DSM programs will have on close to 90% of the Company's customers (*i.e.,* non-participants). (Tr. 1327). Of the commonly accepted screening tests, the RIM test is the only test that directly measures impacts on non-participants. (Tr. 843).

Several intervenors also compare the Company's historic and projected energy savings to other states. (Tr. 362-63; Tr. 401; Tr. 448). This is an invalid method for establishing the appropriate level of DSM programs because such comparisons incorrectly assume a "one size fits all" approach to DSM policies. (Tr. 1847). In reality, each state must make its own unique determinations regarding policies that will guide ratepayer-subsidized DSM implementation. A number of state-specific considerations will shape such policy development including: the energy-intensity of customers in each state, cost of electricity, capacity needs, regulatory structure, and other state level initiatives such as energy efficiency goals or mandates, renewable portfolio standards, and state or regional greenhouse gas control initiatives. (Tr. 1847).

3. The agreed up on Additional Sum amount leaves in place the prior methodology and is a reasonable compromise.

Georgia law requires that the Company be granted an Additional Sum in connection with certified demand-side capacity resources. O.C.G.A. § 46-3A-9. Georgia law establishes that the following criteria be considered in determining an additional sum: "lost revenues, if any, changed risks, and equitable sharing of benefits." (*Id.*). The Stipulation adopts an Additional Sum identical to that agreed to in connection with the 2013 IRP. Specifically, the Additional Sum will be equal to 8.5% of actual net benefits based on net energy savings from the Program Administrators Cost Test ("PACT"). (Stipulation, DSM Para. 6). In the event that the Additional Sum amount exceeds the annual program costs, any further Additional Sum will be equal to 4% of the actual net benefits based on net energy savings from the PACT. (*Id.*). This Additional Sum methodology represents a reasonable compromise between the Company and Staff and should be adopted. The methodology is firmly rooted in the statutorily-established concept of “equitable sharing of benefits” and provides an appropriate incentive for the Company in its DSM efforts.

4. Continuation of the DSM true-up is reasonable and should be approved.

The Stipulation specifies that that the current DSM true-up process will continue until the next IRP, and the true-up balance in existence (whether positive or negative) will be incorporated into any change in the DSM tariffs in the Company’s 2019 base rate case. (Stipulation, DSM Para. 15). This approach maintains consistency in the Commission’s handling of actual DSM costs and should be approved by the Commission.

5. PIA Staff and the Company will collaborate to review the value of Residential Mid-Stream Retail Products Program.

PIA Staff recommended that the Company implement a residential mid-stream products program. (Tr. 257) Based on preliminary analysis performed in connection with a similar program, the Company has a number of fundamental concerns regarding the program design. (DSM Tr. 512)). However, for purposes of the Stipulation, the Company has agreed to explore the program further in the context of the DSM Working Group (“DSMWG”) over the next three years. (Stipulation, DSM Para. 3). Discussion through the DSMWG will give all working group participants an opportunity to better understand and analyze the program.

6. The DSM Program Planning Approach should remain unchanged except for those modifications specified in the Stipulation.

The Company and PIA Staff have agreed that the DSM Program Planning Approach should largely remain unchanged. (Stipulation, DSM Para. 4). This approach has been effective at facilitating an efficient planning process and interaction with the DSMWG. The only modification agreed to by the Company and the PIA Staff is that the Company will utilize a Technical Reference Manual in lieu of the Technology Catalog. The Company will work collaboratively with the DSMWG to propose new measures to be added at any point during the measure evaluation process.

7. The program design, implementation and evaluation recommendations in the Stipulation should be adopted.

Under the terms of the Stipulation, the Company will explore ways in which it can incorporate more customers in the Residential Behavioral Program while still achieving the targeted energy savings and remaining within the established budgets. (Stipulation, DSM Para. 7). The Stipulation also specifies that the Company will seek to obtain at least 25% of portfolio savings each year from the residential sector. (Stipulation, DSM Para. 8). In terms of program design and evaluation, the Company has agreed in the Stipulation to provide program plans to Staff for review prior to implementation (Stipulation, DSM Para. 9) and to provide detailed evaluation plans for each of the approved DSM programs within 120 days of the selection of an implementation contractor for each of the certified programs. (Stipulation, DSM Para. 10).

8. Miscellaneous DSM Issues.

Under the terms of Stipulation, the Company and PIA Staff will work together to jointly develop a methodology for calculation of the long term percentage rate impacts of the Company's DSM program. (Stipulation, DSM Para. 2). This analysis will provide an additional data point for the Commission to consider in addition to the traditional RIM analysis. The Commission should adopt the pilot budget recommended under the terms of the Stipulation. (Stipulation, DSM Para. 12). A pilot budget will facilitate the Company's efforts to explore new and innovative DSM measures and program concepts that could potentially be developed into full-scale programs. Historically, pilot programs have served as invaluable testing grounds for the Company and led to the development of one full-scale DSM program—the Residential Behavioral Program. Continuation of such pilot programs is expected to continue to provide similar benefits to customers. The Company and PIA Staff have also agreed that the Company will implement a Commercial and Residential Building Usage Data awareness option requested by PIA Staff and several intervenors, with a cost of $300,000 for 2017 and $100,000 annually for 2018 and 2019. (Stipulation, DSM Para. 11). This is a reasonable resolution and will allow the Company to evaluate the effectiveness of such an option. As specified in the Stipulation, this customer awareness option will be made available to customers within one year of the final order in this proceeding and there will be no assumed energy saving or goal attributed to it. The Commission should also adopt the agreed upon Learning Power program annual budget of $3 million (Stipulation, DSM Para. 13). The Learning Power program has proven to be very popular and will continue to provide benefits to customers. (DSM Tr. 57). Finally, the Commission should adopt the Stipulation's recommendation not to shift residential and commercial customer awareness to cross-cutting costs. (Stipulation, DSM Para. 14).

IV. CONCLUSION

For the reasons set forth above, and based on the record in this proceeding, the Commission should approve Georgia Power Company's 2016 IRP, Decertification Application and DSM Application, as modified by the Stipulation.

Respectfully submitted, this 29th day of June, 2016.

Brandon F. Marzo
Steven J. Hewitson
Jack E. Jirak
Attorneys for Georgia Power Company

TROUTMAN SANDERS LLP
Bank of America Plaza
Suite 5200
600 Peachtree Street, N.E.
Atlanta, Georgia 30308-2216
(404) 885-3000